Global Hydrogen Review 2021



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Executive summary

Executive Summary

After several false starts, a new beginning around the corner

The time is ripe to tap into hydrogen's potential contribution to a sustainable energy system. In 2019, at the time of the release of the IEA's landmark report *The Future of Hydrogen* for the G20, only France, Japan and Korea had strategies for the use of hydrogen. Today, 17 governments have released hydrogen strategies, more than 20 governments have publicly announced they are working to develop strategies, and numerous companies are seeking to tap into hydrogen business opportunities. Such efforts are timely: hydrogen will be needed for an energy system with net zero emissions. In the IEA's Net Zero by 2050: A Roadmap for the Global Energy Sector, hydrogen use extends to several parts of the energy sector and grows sixfold from today's levels to meet 10% of total final energy consumption by 2050. This is all supplied from low-carbon sources.

Hydrogen supplies are becoming cleaner … too slowly

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

Europe is leading electrolyser capacity deployment, with 40% of global installed capacity, and is set to remain the largest market in the near term on the back of the ambitious hydrogen strategies of the European Union and the United Kingdom. Australia's plans suggest it could catch up with Europe in a few years; Latin America and the Middle East are expected to deploy large amounts of capacity as well, in particular for export. The People's Republic of China ("China") made a slow start, but its number of project announcements is growing fast, and the United States is stepping up ambitions with its recently announced Hydrogen Earthshot.

Sixteen projects for producing hydrogen from fossil fuels with carbon capture, utilisation and storage (CCUS) are operational today, producing 0.7 Mt of hydrogen annually. Another 50 projects are under development and, if realised, could increase the annual hydrogen production to more than 9 Mt by 2030. Canada and the United States lead in the production of hydrogen from fossil fuels with CCUS, with more than 80% of global capacity production, although the United

Kingdom and the Netherlands are pushing to become leaders in the field and account for a major part of the projects under development.

Expanding the reach of hydrogen use

Hydrogen can be used in many more applications than those common today. Although this still accounts for a small share of total hydrogen demand, recent progress to expand its reach has been strong, particularly in transport. The cost of automotive fuel cells has fallen by 70% since 2008 thanks to technological progress and growing sales of fuel cell electric vehicles (FCEVs). Thanks to the efforts by Korea, the Unites States, China and Japan, the number of FCEVs on the road grew more than sixfold from 7 000 in 2017 to over 43 000 by mid-2021. In 2017, practically all FCEVs were passenger cars. Today, one-fifth are buses and trucks, indicating a shift to the long-distance segment where hydrogen can better compete with electric vehicles. However, the total number of FCEVs is still well below the estimated 11 million electric vehicles on the road today. Several demonstration projects for the use of hydrogen-based fuels in rail, shipping and aviation are already under development and are expected to open new opportunities for creating hydrogen demand.

Hydrogen is a key pillar of decarbonisation for industry, although most of the technologies that can contribute significantly are still nascent. Major steps are being taken. The world's first pilot project for producing carbon-free steel using low-carbon hydrogen began operation this year in Sweden. In Spain, a pilot project for the use of variable renewables-based hydrogen for ammonia production will start at the end of 2021. Several projects at a scale of tens of kilotonnes of hydrogen are expected to become operational over the next two to three years. Demonstration projects for using hydrogen in industrial applications such as cement, ceramics or glass manufacturing are also under development.

Governments need to scale up ambitions and support demand creation

Countries that have adopted hydrogen strategies have committed at least USD 37 billion; the private sector has announced an additional investment of USD 300 billion. But putting the hydrogen sector on track for net zero emissions by 2050 requires USD 1 200 billion of investment in low-carbon hydrogen supply and use through to 2030.

The focus of most government policies is on producing low-carbon hydrogen. Measures to increase demand are receiving less attention. Japan, Korea, France and the Netherlands have adopted targets for FCEV deployment. But boosting the role of low-carbon hydrogen in clean energy transitions requires a step change in demand creation. Governments are starting to announce a wide variety of policy instruments, including carbon prices, auctions, quotas, mandates and requirements in public procurement. Most of these measures have not yet entered into force. Their quick and widespread enactment could unlock more projects to scale up hydrogen demand.

Low-carbon hydrogen can become competitive within the next decade

A key barrier for low-carbon hydrogen is the cost gap with hydrogen from unabated fossil fuels. At present, producing hydrogen from fossil fuels is the cheapest option in most parts of the world. Depending on regional gas prices, the levelised cost of hydrogen production from natural gas ranges from USD 0.5 to USD 1.7 per kilogramme (kg). Using CCUS technologies to reduce the CO_2 emissions from hydrogen production increases the levelised cost of production to around USD 1 to USD 2 per kg. Using renewable electricity to produce hydrogen costs USD 3 to USD 8 per kg.

There is significant scope for cutting production costs through technology innovation and increased deployment. The potential is reflected in the IEA's *Net Zero Emissions by 2050 Scenario* (NZE Scenario) in which hydrogen from renewables falls to as low as USD 1.3 per kg by 2030 in regions with excellent renewable resources (range USD 1.3-3.5 per kg), comparable with the cost of hydrogen from natural gas with CCUS. In the longer term, hydrogen costs from renewable electricity fall as low as USD 1 per kg (range USD 1.0-3.0 per kg) in the NZE Scenario, making hydrogen from solar PV cost-competitive with hydrogen from natural gas even without CCUS in several regions.

Meeting climate pledges requires faster and more decisive action

While the adoption of hydrogen as a clean fuel is accelerating, it still falls short of what is required to help reach net zero emissions by 2050. If all the announced industrial plans are realised, by 2030:

- Total hydrogen demand could grow as high as 105 Mt – compared with more than 200 Mt in the NZE Scenario
- Low-carbon hydrogen production could reach more than 17 Mt – one-eighth of the production level required in the NZE Scenario
- Electrolysis capacity could rise to 90 GW – well below the nearly 850 GW in the NZE Scenario
- Up to 6 million FCEVs could be deployed – 40% of the level of deployment in the NZE Scenario (15 million FCEVs)

Much faster adoption of low-carbon hydrogen is needed to put the world on track for a sustainable energy system by 2050. Developing a global hydrogen market can help countries with limited domestic supply potential while providing export opportunities for countries with large renewable or CO_2 storage potential. There is also a need to accelerate technology innovation efforts. Several critical hydrogen technologies today are in early stages of development. We estimate that USD 90 billion of public money needs to be channeled into clean energy innovation worldwide as quickly as possible – with around half of it dedicated to hydrogen-related technologies.

Stronger international co-operation: a key lever for success

International co-operation is critical to accelerate the adoption of hydrogen. Japan has spearheaded developments through the Hydrogen Energy Ministerial Meeting since 2018. Several bilateral and multilateral co-operation agreements and initiatives have since been announced, including the Clean Energy Ministerial Hydrogen Initiative, the Hydrogen Mission of Mission Innovation and the Global Partnership for Hydrogen of the United Nations Industrial Development Organization. These join the existing International Partnership for Hydrogen and Fuel Cells in the Economy and the IEA Hydrogen and Advanced Fuel Cells Technology Collaboration Programme. Stronger coordination among such initiatives is important to avoid duplication of efforts and ensure efficient progress.

IEA policy recommendations

Governments must take a lead in the energy transformation. In The Future of Hydrogen, the IEA identified a series of recommendations for near-term action. This report offers more detail about how policies can accelerate the adoption of hydrogen as a clean fuel:

- **Develop strategies and roadmaps on the role of hydrogen in energy systems**: National hydrogen strategies and roadmaps with concrete targets for deploying low-carbon production and, particularly, stimulating significant demand are critical to build stakeholder confidence about the potential market for low-carbon hydrogen. This is a vital first step to create momentum and trigger more investments to scale up and accelerate deployment.
- **Create incentives for using low-carbon hydrogen to displace unabated fossil fuels**: Demand creation is lagging behind what is needed to help put the world on track to reach net-zero emissions by 2030. It is critical to increase concrete measures on this front to tap into hydrogen's full potential as a clean energy vector. Currently, low-carbon hydrogen is more costly to use than unabated fossil-based hydrogen in areas where hydrogen is already being employed – and it is more costly to use than fossil fuels in areas where hydrogen could eventually replace them. Some countries are already using carbon pricing to close this cost gap but this is not enough. Wider adoption combined with other policy instruments like auctions, mandates, quotas and hydrogen requirements in public procurement can help de-risk investments and improve the economic feasibility of low-carbon hydrogen.
- **Mobilise investment in production, infrastructure and factories**: A policy framework that stimulates demand can, in turn, prompt investment in low-carbon production plants, infrastructure and manufacturing capacity. However, without stronger policy action, this process will not happen at the necessary pace to meet climate goals. Providing tailor-made support to selected shovel-ready flagship projects can kick-start the scaling up of low-carbon hydrogen and the development of infrastructure to connect supply sources to demand centres and manufacturing capacities from which later projects can benefit. Adequate infrastructure planning is critical to avoid delays or the creation of assets that can become stranded in the near or medium term.
- **Provide strong innovation support to ensure critical technologies reach commercialisation soon**: Continuous innovation is essential to drive down costs and increase the competitiveness of hydrogen technologies. Unlocking the full potential demand for hydrogen will require strong demonstration efforts over the next decade. An increase of R&D budgets and support for demonstration projects is urgently needed to make sure key hydrogen technologies reach commercialisation as soon as possible.
- **Establish appropriate certification, standardisation and regulation regimes**: The adoption of hydrogen will spawn new value chains. This will require modifying current regulatory frameworks and defining new standards and certification schemes to remove barriers preventing widespread adoption. International agreement on methodology to calculate the carbon footprint of hydrogen production is particularly important to ensure that hydrogen production is truly low-carbon. It will also play a fundamental role in developing a global hydrogen market.

Introduction

Overview

In the run-up to the 26th Conference of the Parties to the UN Framework Convention on Climate Change (COP 26), a growing number of countries are announcing targets to achieve net zero GHG emissions over the next decades. In turn, more than 100 companies that consume large volumes of energy or produce energy-consuming goods have followed suit. As demonstrated in the IEA Net zero by 2050 roadmap, achieving these targets will require immediate action to turn the 2020s into a decade of massive clean energy expansion.

Hydrogen will need to play an important role in the transition to net zero emissions. Since the first Hydrogen Energy Ministerial (HEM) meeting in Japan in 2018, momentum has grown and an increasing number of governments and companies are establishing visions and plans for hydrogen.

At the Osaka Summit in 2019, G20 leaders emphasised hydrogen's role in enabling the clean energy transition. The IEA prepared the landmark report The Future of Hydrogen for the summit, with detailed analysis of the state of hydrogen technologies and their potential to contribute to energy system transformation, as well as challenges that need to be overcome. In addition, during the 10th Clean Energy Ministerial (CEM) meeting in Vancouver, the Hydrogen Initiative (H2I) was launched to accelerate hydrogen deployment, and during the 6th Mission Innovation Ministerial, the Clean Hydrogen Mission to reduce the cost of clean hydrogen was announced.

This Global Hydrogen Review is an output of H2I that is intended to inform energy sector stakeholders on the current status and future prospects of hydrogen and serve as an input to the discussions at the HEM of Japan. It comprehensively examines what is needed to address climate change and compares actual progress with stated government and industry ambitions and with key actions announced in the Global Action Agenda launched in the HEM 2019. Focusing on hydrogen's usefulness in meeting climate goals, this Review aims to help decision makers fine-tune strategies to attract investment and facilitate deployment of hydrogen technologies while also creating demand for hydrogen and hydrogen-based fuels.

This Review's analysis comprises seven chapters. First, the chapter on **policy trends** describes progress made by governments in adopting hydrogen-related policies. Next, two comprehensive chapters on **global hydrogen demand** and **supply** provide in-depth analyses of recent advances in different sectors and technologies and explore how trends could evolve in the medium and long term.

A chapter on **infrastructure and hydrogen trade** emphasises the need to develop both these areas while ramping up demand and supply. It also details the status and opportunities for deploying hydrogen infrastructure, as well as recent trends and the outlook for hydrogen trade.

Investments and innovation are combined into one chapter to reflect how they mutually underpin trends in the development and uptake of hydrogen technologies. Meanwhile, the chapter on **insights on selected regions** recaps progress in regions and countries where governments and industry are particularly active in advancing hydrogen deployment.

The final chapter provides **policy recommendations** to accelerate the adoption of hydrogen technologies in the next decade, with a view to ensuring it becomes economically and technically viable and socially acceptable.

The Hydrogen Initiative

Developed under the CEM framework, H2I is a voluntary multi-government 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, the European Commission, Finland, Germany, India, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, the Republic of Korea (hereafter Korea), the Russian Federation (hereafter Russia), Saudi Arabia, South Africa, the United Kingdom and the United States. Canada, the European Commission, Japan, the Netherlands and the 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 Initiative 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's Advanced Fuel Cells and Hydrogen Technology Collaboration Programmes (TCPs), all of which are part of the H2I Advisory Group. 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 and Thyssenkrupp.

The Global Hydrogen Review

Following IEA recommendations in The Future of Hydrogen, this Global Hydrogen Review aims to track progress in hydrogen production and demand, as well as in other areas of critical importance such as policy, regulation and infrastructure development. To do this effectively and comprehensively, the IEA has established co-operative relationships with other relevant institutions to provide sound analysis based on the best possible data, and to create synergies among other international efforts, building on their respective strengths and experiences.

The Hydrogen Council in particular shared critical information on technology costs and performance from its industry network, which enriched IEA databases, modelling assumptions and techno-economic parameters.

Meanwhile, the IPHE contributed inputs on the developmental status of standards, codes and regulations. Leveraging its government network and established process to collect data and work collaboratively on regulatory issues, it also provided valuable information on the technology deployment and policy targets of its member governments.

The IEA TCPs and their networks of researchers and stakeholders also provided valuable inputs. The Hydrogen TCP helped the IEA update its latest assessment of the technology readiness levels of specific hydrogen technologies and offered insights on emerging technologies and barriers that need to be overcome to facilitate their deployment. The Advanced Fuel Cells TCP contributed with its annual tracking of fuel cell electric vehicles and infrastructure deployment.

Types of hydrogen in the Global Hydrogen Review

Hydrogen is a very versatile fuel that can be produced using all types of energy sources (coal, oil, natural gas, biomass, renewables and nuclear) through a very wide variety of technologies (reforming, gasification, electrolysis, pyrolysis, water splitting and many others). In recent years, colours have been used to refer to different hydrogen production routes (e.g. green for hydrogen from renewables and blue for production from natural gas with carbon capture, utilisation and storage [CCUS]), and specialised terms currently under discussion include “safe”, “sustainable”, “low-carbon” and “clean”. There is no international agreement on the use of these terms as yet, nor have their meanings in this context been clearly defined.

Because of the various energy sources that can be used, the environmental impacts of each production route can vary considerably; plus, the geographic region and the process configuration applied also influence impacts. For these reasons, the

IEA does not specifically espouse any of the above terms. Recognising that the potential of hydrogen to reduce CO_2 emissions depends strongly on how it is produced, this report highlights the role low-carbon hydrogen production routes can have in the clean energy transition. Low-carbon hydrogen in this report includes hydrogen produced from renewable and nuclear electricity, biomass, and fossil fuels with CCUS.[1]

Production from fossil fuels with CCUS is included only if upstream emissions are sufficiently low, if capture – at high rates – is applied to all CO_2 streams associated with the production route, and if all CO_2 is permanently stored to prevent its release into the atmosphere. The same principle applies to low-carbon feedstocks and hydrogen-based fuels made using low-carbon hydrogen and a sustainable carbon source (of biogenic origin or directly captured from the atmosphere).

This report also highlights the importance of establishing standards and certification to properly recognise the carbon footprints of the different hydrogen production routes. Since no standards have been internationally agreed and adopted, the IEA continues to differentiate the types of hydrogen by the technology used in their production, and uses this as the basis of its current definition of low-carbon hydrogen. This may evolve as dialogue within the international hydrogen community advances and more evidence and agreement emerge.

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[1] In this report, CCUS includes CO_2 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 [EOR] 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.

Scenarios used in this Global Hydrogen Review

Outlook for hydrogen production and use

This Global Hydrogen Review relies on three indicators to track progress on hydrogen production and use:

- on-the-ground progress in hydrogen technology deployment
- government ambitions to integrate hydrogen into long-term energy strategies
- gaps between on-the-ground progress, government ambitions and projected energy transition requirements.

In this report, the Projects Case reflects on-the-ground progress. It takes all projects in the pipeline[2] into account as well as announced industry stakeholder plans to deploy hydrogen technologies across the entire value chain (from production to use in different end-use sectors).

Government targets and ambitions related to deploying hydrogen technologies are presented as hydrogen pledges. To gather relevant information from governments around the world, a joint IEA–European Commission work stream was established within the framework of the CEM Hydrogen Initiative, to consult governments around the world about their hydrogen targets and ambitions.

Pledges presented in this report include official targets (i.e. clear goals of national hydrogen strategies and roadmaps) as well as ambitions (i.e. plans communicated in consultations through the H2I work stream, but for which governments have not yet made official announcements or adopted a strategy or roadmap).

For the first time, the IEA's May 2021 report Net zero by 2050 lays out in detail what is needed from the energy sector to reach net zero CO_2 emissions by 2050, in line with the Paris Agreement's ambitious target to limit global temperature rise to 1.5°C. Based on these findings, this Review compares actual implemented actions with clean energy transition needs using two IEA scenarios: the Net zero Emissions by 2050 Scenario and the Announced Pledges Scenario.

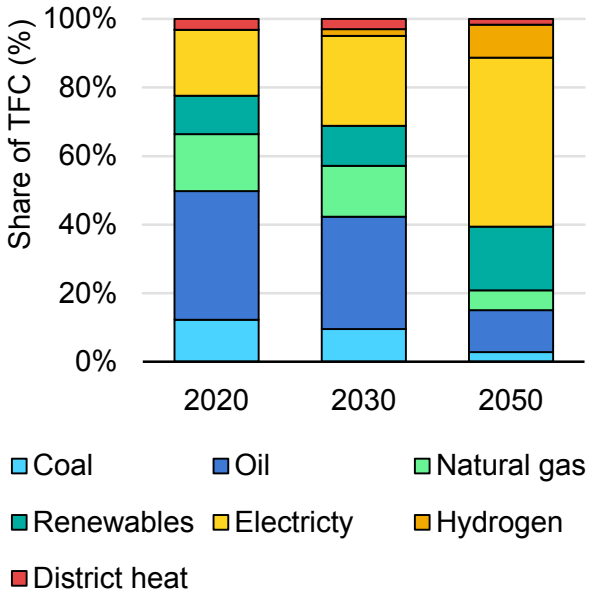
The Announced Pledges Scenario considers all national net zero emissions pledges that governments have announced to date and assumes they are realised in full and on time. This scenario thereby shows how far full implementation of national net zero emissions pledges would take the world towards reaching climate goals, and it highlights the potential contributions of different technologies, including hydrogen.

[2] In addition to projects already operational, this includes those currently under construction, that have reached final investment decision (FID) and that are undergoing feasibility studies.

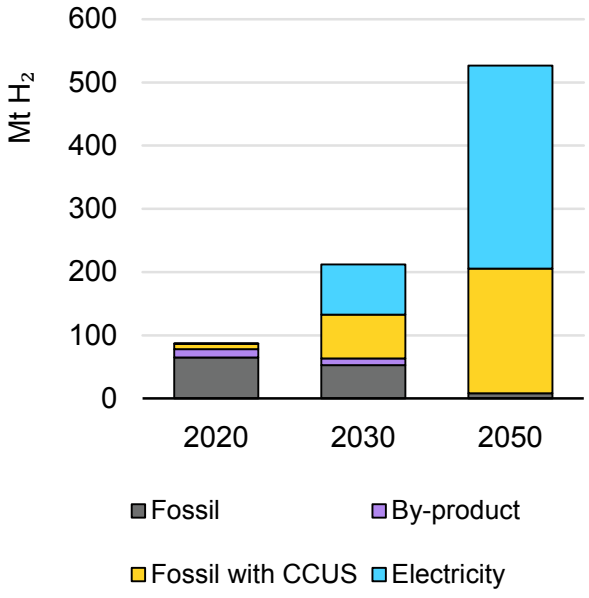
The role of hydrogen in the Net zero Emissions by 2050 Scenario

Hydrogen is an important part of the Net zero Emissions Scenario, but is only one piece of the puzzle

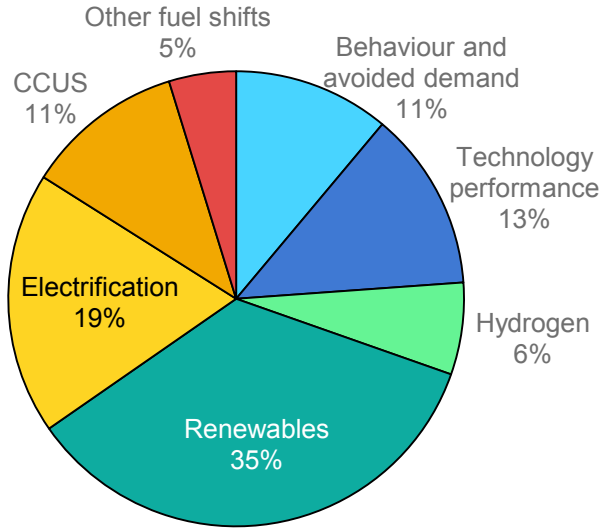
Share of total final energy consumption by fuel in the NZE, 2020-2050



Sources of hydrogen production in the NZE, 2020-2050



Cumulative emissions reduction by mitigation measure in the NZE, 2021-2050



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Notes: NZE = Net zero Emissions Scenario. TFC = total final energy consumption. CCUS = carbon capture, utilisation and storage. “Behaviour” refers to energy service demand changes linked to user decisions (e.g. heating temperature changes). “Avoided demand” refers to energy service demand changes from technology developments (e.g. digitalisation). “Other fuel shifts” refers to switching from coal and oil to natural gas, nuclear, hydropower, geothermal, concentrating solar power or marine energy. “Hydrogen” includes hydrogen and hydrogen-based fuels.

Source: IEA (2021), Net zero by 2050.

Achieving net zero emissions by 2050 will require a broad range of technologies to transform the energy system. The key pillars of decarbonising the global energy system are energy efficiency, behavioural change, electrification, renewables, hydrogen and hydrogen-based fuels, and CCUS. The importance of hydrogen in the Net zero Emissions Scenario is reflected in its increasing share in total final energy consumption (TFC): in 2020, hydrogen and hydrogen-based fuels accounted for less than 0.1%,[3] but by 2030 they meet 2% of TFC and in 2050, 10%.

Nevertheless, this demand increase alone is not enough to make hydrogen a key pillar of decarbonisation. Hydrogen production must also become much cleaner than it is today. For instance, of the ~90 Mt H_2 used in 2020, around 80% was produced from fossil fuels, mostly unabated. Practically all the remainder came from residual gases produced in refineries and the petrochemical industry. This resulted in almost 900 Mt CO_2 emitted in the production of hydrogen, equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined.

In the Net zero Emissions Scenario, hydrogen production undergoes an unparalleled transformation. By 2030, when total production reaches more than 200 Mt H_2, 70% is produced using low-carbon technologies (electrolysis or fossil fuels with CCUS). Hydrogen production then grows to over 500 Mt H_2 by 2050, practically all based on low-carbon technologies. Reaching these goals will require that installed electrolysis capacity increase from 0.3 GW today to close to 850 GW by 2030 and almost 3 600 GW by 2050, while CO_2 captured in hydrogen production must rise from 135 Mt today to 680 Mt in 2030 and 1 800 Mt in 2050.

Strong hydrogen demand growth and the adoption of cleaner technologies for its production thus enable hydrogen and hydrogen-based fuels to avoid up to 60 Gt CO_2 emissions in 2021-2050 in the Net zero Emissions Scenario, representing 6.5% of total cumulative emissions reductions. Hydrogen fuel use is particularly critical for reducing emissions in the hard-to-decarbonise sectors in which direct electrification is difficult to implement, i.e. heavy industry (particularly steel manufacturing and chemical production), heavy-duty road transport, shipping and aviation. In the power sector, hydrogen can also provide flexibility by helping to balance rising shares of variable renewable energy generation and facilitating seasonal energy storage.

[3] This excludes industry sector on-site hydrogen production and use, which consumes around 6% of final energy consumption in industry today. Including on-site hydrogen production in industry, hydrogen and hydrogen-based fuels meet 1% of total final energy consumption today, 4% by 2030 and 13% by 2050 in the Net Zero Emissions Scenario.

Policy trends across key areas for hydrogen deployment

Progress in five key areas for hydrogen policymaking

Introduction

Integrating hydrogen as a new vector into energy systems is a complex endeavour: without government intervention, it will not be realised at the pace required to meet climate ambitions. Many governments are therefore already working with diverse stakeholders to address key challenges and identify smart policies that can facilitate this transformation. As needs differ for each country and industry, policies and actions must be based on relevant priorities and constraints, including resource availability and existing infrastructure.

In The Future of Hydrogen, the IEA identified five key areas for governments to define comprehensive policy frameworks to facilitate hydrogen adoption across the entire energy system:

1. Establish targets and/or long-term policy signals.
2. Support demand creation.
3. Mitigate investment risks.
4. Promote R&D, innovation, strategic demonstration projects and knowledge-sharing.
5. Harmonise standards and removing barriers.

The Global Hydrogen Review tracks and reports progress in these areas with the aim of apprising governments and stakeholders of the pace of change in hydrogen policymaking. The Review highlights new policies being adopted around the world, assesses their impacts and identifies potential gaps. Its dual objectives are to help governments adopt or adapt other countries' successful experiences and avoid repeating failures.

1. Establish targets and/or long-term policy signals

In their long-term energy strategies, governments should determine the most efficient way hydrogen can be used to support decarbonisation efforts. They should then set policies that send long-term signals about this role to boost stakeholder confidence in development of a marketplace for hydrogen and related technologies. Integrated actions can guide future expectations, unlock investments and facilitate co-operation among companies and countries.

When The Future of Hydrogen was released in June 2019, only Japan and Korea had published national hydrogen strategies to define the role of hydrogen in their energy systems, and France had announced a hydrogen deployment plan. Since then, 13 countries (Australia, Canada, Chile, the Czech Republic, France, Germany, Hungary, the Netherlands, Norway, Portugal, Russia, Spain and the United Kingdom) have published hydrogen strategies, along with the European Commission. Colombia announced the release of its strategy for the end of September 2021.

Two countries (Italy and Poland) have released their strategies for public consultation and more than 20 others are actively developing them. Several regional governments have also defined hydrogen strategies and roadmaps, including in Australia (Queensland, South Australia, Tasmania, Victoria and West Australia), Canada (British Columbia), China, France, Germany (Baden-Württemberg, Bavaria, North Germany, North Rhine-Westphalia) and Spain (Basque Country).

Some governments have even taken the additional step of defining hydrogen's role in other, overarching policy frameworks. Japan's Green Growth Strategy, for example, describes the country's vision for producing and using hydrogen and for developing international supply chains.

A coherent picture of future-use cases for hydrogen

The strategies published to date show that, with slight differences, almost all countries hold broadly similar views of the role hydrogen should play in their energy systems. Practically all the strategies (15 of 16) highlight its vital importance in decarbonising the transport and industry sectors.

In the case of transport, most governments emphasise medium- and heavy-duty transport, and Japan and Korea envisage an important role for cars. Several governments highlight the potential use of hydrogen and ammonia in shipping, while a smaller number are considering producing synthetic fuels (synfuels) to decarbonise aviation (Germany recently released a power-to-liquids [PtL] roadmap) or using hydrogen in rail transport. Japan has taken the

additional step of publishing an Interim Report of the Public-Private Council on Fuel Ammonia Introduction on using ammonia in electricity generation and shipping.

In the industry sector, each country's plans focus on the main industries: some target certain subsectors (chemicals in Chile and Spain; steel in Japan), while others take a more cross-sectoral approach (Canada and Germany). Canada and Chile have highlighted the role of hydrogen in decarbonising mining operations, and all countries with significant refining capacities prioritise this sector as well.

Other potential hydrogen uses that are mentioned in strategies but have received less attention are electricity generation – including energy storage and system balancing (11 of 16) – and heat in buildings (7 of 16). Finally, if international hydrogen trade develops, some countries have a clear plan to become exporters (Australia, Canada, Chile and Portugal) while others have started exploring the possibility of importing hydrogen if national production capacity cannot meet future demand (the European Union, Germany, Japan and the Netherlands).

Different views on how to produce hydrogen

Countries that have adopted hydrogen strategies present quite diverse visions on how it should be produced. Hydrogen production from electricity is common to all strategies, in some cases being the preferred route in the long term. Some prioritise renewable power (Chile, Germany, Portugal and Spain), while others are less specific about the origin of the electricity (France's strategy mentions renewable and low-carbon electricity).

While several governments (9 of 16) have set a significant role for the production of hydrogen from fossil fuels with CCUS, others (including the European Union) consider this option for only the short and medium term to reduce emissions from existing assets while supporting the parallel uptake of renewable hydrogen. Canada has taken a different approach; instead of prioritising any specific production pathway, it is focusing on the carbon intensity of hydrogen production, with targets to drive it to zero over time. Some countries (e.g. Canada and Korea) have flagged the potential use of by-product hydrogen (from the chlor-alkali or petrochemical industries) to meet small shares of demand.

Finally, most strategies refer to the potential for emerging technologies, such as methane pyrolysis or biomass-based routes. As these technologies are still at early stages of development, prospects are considered uncertain.

Intermediate milestones to anchor long-term targets

Almost all governments have adopted a phased approach to integrate hydrogen into their energy systems. How they define phases varies, but strategies tend to recognise three stages: scaling up and laying the market foundations (early 2020s); widespread

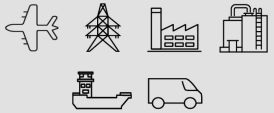
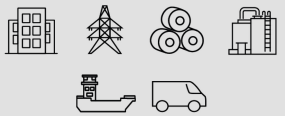
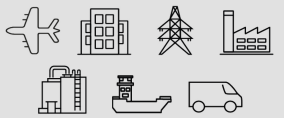
adoption and market maturity (late 2020s to early 2030s); and full implementation of hydrogen as a clean energy vector (post-2030).

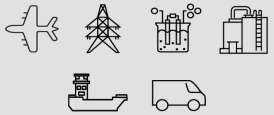
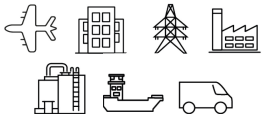
Deployment targets, while not present in all strategies, are a common feature to anchor expected progress within these phases. In some cases, targets have been proposed as a vision or an aspiration (Canada, Japan); in others, they convey a firm commitment with the intent to send strong signals to industry about the future marketplace for hydrogen. To date, practically none of these targets is legally binding.

Governments with adopted national hydrogen strategies; announced targets; priorities for hydrogen and use; and committed funding

Buildings Electricity Exports Industry Industry (chemicals) Industry (steel) Mining Refining Shipping Transport. Aviation

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Australia	National Hydrogen Strategy, 2019	None specified	Coal with CCUS Electrolysis (renewable) Natural gas with CCUS		AUD 1.3 bln (~USD 0.9 bln)
Canada	Hydrogen Strategy for Canada, 2020	Total use: 4 Mt H_2/y 6.2% TFEC	Biomass By-product H_2 Electrolysis Natural gas with CCUS Oil with CCUS		CAD 25 mln by 2026(1) (~USD 19 mln)
Chile	National Green Hydrogen Strategy, 2020	25 GW electrolysis(2)	Electrolysis (renewable)		USD 50 mln for 2021
Czech Republic	Hydrogen Strategy, 2021	Low-carbon demand: 97 kt H_2/yr	Electrolysis		n.a.
European Union	EU Hydrogen Strategy, 2020	40 GW electrolysis	Electrolysis (renewable) Transitional role of natural gas with CCUS		EUR 3.77 bln by 2030 (~USD 4.3 bln)
France	Hydrogen Deployment Plan, 2018 National Strategy for Decarbonised Hydrogen Development, 2020	6.5 GW electrolysis 20-40% industrial H_2 decarbonised (3) 20 000-50 000 FC LDVs (3) 800-2 000 FC HDVs (3) 400-1 000 HRSs (3)	Electrolysis		EUR 7.2 bln by 2030 (~USD 8.2 bln)

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Germany	National Hydrogen Strategy, 2020	5 GW electrolysis	Electrolysis (renewable)		EUR 9 bln by 2030 (~USD 10.3 bln)
Hungary	National Hydrogen Strategy, 2021	Production: 20 kt/yr of low-carbon H_2 16 kt/yr of carbon-free H_2 240 MW electrolysis Use: 34 kt/yr of low-carbon H_2 4 800 FCEVs 20 HRSs	Electrolysis Fossil fuels with CCUS		n.a.
Japan	Strategic Roadmap for Hydrogen and Fuel Cells, 2019 Green Growth Strategy, 2020, 2021 (revised)	Total use: 3 Mt H_2/yr Supply: 420 kt low-carbon H_2 800 000 FCEVs 1 200 FC buses 10 000 FC forklifts 900 HRSs 3 Mt NH_3 fuel demand[4]	Electrolysis Fossil fuels with CCUS		JPY 699.6 bln by 2030 (~USD 6.5 bln)
Korea	Hydrogen Economy Roadmap, 2019	Total use: 1.94 Mt H_2/yr 2.9 million FC cars (plus 3.3 million exported)[5] 1 200 HRSs[5] 80 000 FC taxis[5] 40 000 FC buses[5] 30 000 FC trucks[5] 8 GW stationary FCs (plus 7 GW exported)[5] 2.1 GW of micro-cogeneration FCs[5]	By-product H_2 Electrolysis Natural gas with CCUS		KRW 2.6 tln in 2020 (~USD 2.2 bln)
Netherlands	National Climate Agreement, 2019 Government Strategy on Hydrogen, 2020	3-4 GW electrolysis 300 000 FC cars 3 000 FC HDVs [6]	Electrolysis (renewables) Natural gas with CCUS		EUR 70 mln/yr (~USD 80 mln/yr)
Norway	Government Hydrogen Strategy, 2020 Hydrogen Roadmap, 2021	n.a.[7]	Electrolysis (renewables) Natural gas with CCUS		NOK 200 mln for 2021 (~USD 21 mln)

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Portugal	National Hydrogen Strategy, 2020	2-2.5 GW electrolysis 1.5-2% TFEC 1-5% TFEC in road transport 2-5% TFEC in industry 10-15 vol% H_2 in gas grid 3-5% TFEC in maritime transport 50-100 HRS	Electrolysis (renewables)		EUR 900 mln by 2030 (~USD 1.0 bln)
Russia	Hydrogen roadmap 2020	Exports: 2 Mt H_2	Electrolysis Natural gas with CCUS		n.a.
Spain	National Hydrogen Roadmap, 2020	4 GW electrolysis 25% industrial H_2 decarbonised 5 000-7 500 FC LDVs-HDVs 150-200 FC buses 100-150 HRSs	Electrolysis (renewables)		EUR 1.6 bln (~USD 1.8 bln)
United Kingdom	UK Hydrogen Strategy, 2021	5 GW low-carbon production capacity	Natural gas with CCUS Electrolysis		GBP 1 bln (~USD 1.3 bln)

Note: TFEC = total final energy consumption. (1) In addition to CAD 25 mln, Canada has committed over CAD 10 bln to support clean energy technologies, including H_2. (2) This target refers to projects that at least have funding committed, not to capacity installed by 2030. (3) Target for 2028. (4) From the interim Ammonia Roadmap. (5) Target for 2040. (6) Target for 2025 from the National Climate Agreement, 2019 (currently under revision). (7) Norway's strategy defines targets for the competitiveness of hydrogen technologies and project deployment.

2. Support demand creation

Creating demand for low-carbon hydrogen is critical for its widespread adoption. Policy support to "pull" investment across the value chain will be needed to make projects bankable and overcome deployment hurdles. For technologies that use hydrogen and are ready for commercialisation, policy support to close the price gap with incumbents can stimulate faster deployment and accelerate cost reductions that result from scaling up and learning by doing. Progress is under way, but not enough policies have been implemented to support longer-term targets and create demand for low-carbon hydrogen.

A dynamic situation in the transport sector

National hydrogen strategies place great value on using hydrogen in transport. As fuel cell electric vehicles (FCEVs) are commercially available for passenger cars, light-duty vehicles (LDVs) and buses, several countries have policies to support their deployment.

More than 20 countries offer specific purchase subsidies for FCEVs, ranging from EUR 1 500 (~USD 1 700) per vehicle in Finland to more than USD 30 000 in Korea. In fact, purchasers of fuel cell buses in Korea receive KRW 300 million (~USD 250 000). Tax benefits are in place in at least 20 countries, and at least 17 apply specific company tax benefits to support FCEV adoption in professional fleets.

China launched a new FCEV pilot cities programme in 2020 to enlarge FCEV industry supply chains. In contrast with vehicle purchase subsidies, the scheme rewards clusters of cities based on a series of parameters. To be eligible for financial rewards, city clusters must deploy more than 1 000 FCEVs that meet certain technical standards; achieve a delivered hydrogen price at a maximum of CNY 35.00/kg (~USD 5.00/kg); and provide at least 15 operational hydrogen refuelling stations (HRSs). Based on the plan and how well objectives are met, a maximum of CNY 1.5 billion (~USD 220 million) will be transferred to each selected city cluster between 2020 and 2023.

Hydrogen vehicles may also benefit from programmes to support zero emission vehicles (ZEVs) and implementation of CO_2 emissions standards. Recent examples include California's ZEV mandate; the Dutch government's announcement that ZEVs will make up all public transport bus sales by 2025; and the EU CO_2 emissions standards for heavy-duty vehicles (HDVs). In 2018, Switzerland adopted the LSVA road tax, which levies trucks weighing more than 3.5 tonnes but waives the fee for ZEVs. This created an attractive business case for hydrogen trucks, which are expected to reach about 200 by the end of 2021. While not specific to hydrogen vehicles, which have to compete with alternatives such as battery electric vehicles (BEVs), these policies can stimulate FCEV deployment.

Other policies that can support hydrogen uptake in transport are the California Low Carbon Fuel Standard, Canada's Clean Fuel Standard and the UK Renewable Transport Fuel Obligation, which can also spur adoption of low-carbon hydrogen in biofuel production and refining. Meanwhile, in 2020 the Norwegian government announced that the country's largest ferry connection (Bodø-Værøy-Røst-Moskenes) will be fuelled by hydrogen and in March 2021 the Port of Tokyo stated that it will waive the entry fee for ships powered by LNG or hydrogen. These are the first measures implemented to support hydrogen or hydrogen-derived fuels in shipping, but as the technology has not yet reached the commercial level, it will take time to realise the impact of these policies.

Policies to support hydrogen-derived synthetic fuel use in aviation have attracted attention recently. As part of its Fit for 55 package, in July 2021 the European Commission proposed the ReFuel Aviation Initiative to mandate minimum synthetic fuel shares in aviation, rising from 0.7% in 2030 to 28% in 2050. This measure awaits European Council and European Parliament approval. Germany's strategy mentions a minimum quota of 2% synthetic fuels in aviation by 2030, which has now passed the parliamentary process and is legally binding. In addition, Germany's recently released power-to-liquids (PtL) roadmap targets 200 000 tonnes of hydrogen-based sustainable aviation fuel in 2030. The Dutch government has already expressed interest in these types of measures.

Policies for other sectors still under discussion

Little progress has been achieved on policies for low-carbon hydrogen adoption in other sectors. Despite its anticipated importance, few policies have been designed specifically to create demand for low-carbon hydrogen in industry.

Also in its Fit for 55 package, in July 2021 the European Commission proposed a modification of the Renewable Energy Directive to include a 50% renewable hydrogen consumption in industry by 2030. Germany's strategy includes the potential implementation of obligatory quotas for selected clean products (e.g. hydrogen-based steel) and aims to explore how to implement such solutions at the national and European levels.

India has also announced mandatory quotas for using renewable hydrogen in refining (10% of demand from 2023-24, increasing to 25% in the following five years) and fertiliser production (5% of demand from 2023-24, increasing to 20% in the following five years), with potential extension to the steel industry in the near future. This will spur India to replace part of its current capacity for hydrogen produced from natural gas (typically imported) with hydrogen from renewables while also creating new demand for locally produced hydrogen.

Injecting hydrogen into the natural gas grid has also attracted attention as another means of creating new hydrogen demand. While

no measures have yet been adopted, some countries are taking steps in this direction. For instance, Portugal's national strategy targets 10-15 vol% H_2 blending by 2030 and Chile is preparing a bill to mandate blending quotas.

Lack of targets and policies for demand creation can stall low-carbon supply expansion

Because most government targets and policies to date have been focused exclusively on enlarging hydrogen supplies, low-carbon hydrogen production has outpaced demand growth. Strategic action is therefore needed to avoid the value chain imbalances that can result in inefficient policy support.

If hydrogen demand is not sufficiently stimulated, producers may not be able to secure off-takers and the development of low-carbon hydrogen supply capacity may held back. This could result in low-carbon hydrogen capacity replacing only certain parts of current production in industrial applications, which would impede scale-up and discourage cost reductions, and ultimately delay adoption of hydrogen as a clean energy vector.

3. Mitigate investment risks

Many projects currently under way face risks related to uncertain demand, lack of experience and value chain complexity. Measures to address risks linked to capital and operational costs can help tip the balance in favour of private investment in these first projects.

European countries are leading the way

European policymakers have been particularly active in implementing measures to mitigate the risks of hydrogen-related project developers. In its Climate Agreement (launched June 2020), the Netherlands proposed including hydrogen in the SDE++ scheme, which offers incentives to develop CO_2 reduction technologies and renewable energy. This scheme recently triggered its intended actions and in May 2021 the Dutch government committed EUR 2 billion for the Porthos project to bridge the gap between current rates for CO_2 emissions allowances and the costs involved in capturing, transporting and storing CO_2 underground. This will facilitate development of projects to produce hydrogen from fossil fuels with CCUS.

In September 2020, the European Commission announced a call for tenders for projects to build electrolysis plants at the 100-MW scale. All proposals have been evaluated and some awarded projects have been announced. Perhaps more importantly, the Commission included hydrogen in the Important Projects of Common European Interest (IPCEI) scheme, which allows projects validated by both member states and the Commission to receive public support beyond the usual boundaries of state aid rules. This is expected to unlock significant project investment across the entire hydrogen value chain, stimulating scale-up in the next decade.

Countries beyond Europe are also taking action. In June 2021, Canada announced a new Clean Fuels Fund to help private investors overcome the barrier of high upfront capital costs to construct new clean fuel production capacity, and will provide support to a minimum of ten hydrogen projects.

Public financial institutions are getting involved

Financial institutions can be critical in mitigating the investment risks of first movers. While the European Investment Bank (EIB) provided significant investments for R&D in hydrogen projects in the last decade, it has now shifted its focus to offer financial support and technical assistance for the development of large-scale projects. The EIB signed related collaboration agreements with France Hydrogène (2020) and the Portuguese government (2021).

In May 2020, the Australian government, through the Clean Energy Finance Corporation, made AUD 300 million available through the Advancing Hydrogen Fund, thereby taking the first steps to facilitate

investments in hydrogen projects to scale up production and end uses. In 2021, the government of Chile launched (through CORFO) a USD 50-million call for funding to develop electrolysis projects.

New policy instruments are coming into play

Governments are developing new and innovative policy instruments to support investment in hydrogen projects. In June 2021, the German government announced the H2 Global programme, with the aim of ramping up the international market for hydrogen produced from renewable electricity. The scheme will tender ten-year purchase agreements on hydrogen-based products, providing certainty to investors on project bankability. With a total budget of EUR 900 million, the scheme expects to leverage more than EUR 1.5 billion in private investments.

In its national hydrogen strategy, Germany's federal government also announced that it will launch a new Carbon Contracts for Difference (CCfD) pilot programme to support the use of hydrogen from renewable energy sources in the steel and chemical industries. This programme will pay the difference between the CO_2 abatement costs of the project and the CO_2 price in the EU Emissions Trading Scheme (EU ETS). If the EU ETS price rises above the project's CO_2 abatement costs, companies will have to repay the difference to the government. If the pilot is completed successfully, the scheme may be expanded to other industry subsectors.

The European Commission announced that it is also considering the carbon contracts for difference (CCfD) concept. Recent price increases in the EU ETS – which nearly doubled in 2021 to more than EUR 60/t CO_2 – are expected to limit the public spending needed to bridge the cost gap in these schemes.

Auctions are also a powerful policy instrument, and they have been critical in ramping up other clean energy technologies, such as solar PV and wind energy. They are now about to be applied to hydrogen, with India's New and Renewable Energy Minister announcing (in June 2021) auctions for the production of hydrogen from renewables. The Netherlands' national strategy also mentions the potential use of combined auctions for offshore wind and hydrogen production.

In Chile, the government is holding regular public and open tenders to develop large-scale projects for producing hydrogen from renewable energy sources on public land. As these projects require large land areas, facilitating access to public land with good renewable resources can reduce investment risks and accelerate deployment.

Along with its Hydrogen Strategy, the United Kingdom launched a public consultation on a business model for low-carbon hydrogen with the aim of defining specific policy instruments to help project developers overcome costs barriers.

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

The future success of hydrogen will hinge on innovation. Today, low-carbon hydrogen is more costly than unabated fossil fuel-based hydrogen, which undermines its uptake. Multiple end-use technologies at early stages of development cannot compete in open markets, in part because they have not yet realised the economies of scale that come with maturity. Governments play a key role in setting the research agenda and adopting policy tools that can incentivise the private sector to innovate and bring technologies to the market.

Selected active hydrogen R&D programmes

Country	Programme	Funding and duration
Australia	ARENA's R&D Programme CSIRO Hydrogen Mission	AUD 22 mln (~USD 15 mln) – 5 yr AUD 68 mln (~USD 47 mln) – 5 yr
European Union	Clean Hydrogen for Europe	EUR 1 bln (~USD 1. bln) – 10 yr
France	PEPR Hydrogène	EUR 80 mln (~USD 91 mln) – 8 yr
Germany	National Innovation Programme for Hydrogen and Fuel Cell Technology	EUR >250 mln (~USD 285 mln) – 10 yr
	Wasserstoff-Leitprojekte	EUR 700 mln (~USD 800 mln) – n.a.
Japan	NEDO innovation programmes	JPY 699 bln (~USD 6.5 bln) – 10 yr
Spain	Misiones CDTI	EUR 105 mln (~USD 120 mln) – 3 yr
United Kingdom	Low Carbon Hydrogen Supply	GBP 93 mln (~USD 119 mln) – n.a.
United States	H2@Scale M^{2}FCT – H2New Consortia DOE Hydrogen Program	USD 104 mln – 2 yr USD 100 mln – 5 yr USD 285 m/yr

Hydrogen innovation requires a boost

Programmes to foster hydrogen innovation are not yet flourishing, although some positive signals are emerging and several governments have launched hydrogen-specific programmes to fund R&D in technologies across the entire hydrogen value chain. However, current public R&D spending on hydrogen is below levels dedicated in the early 2000s during the last wave of support for hydrogen technologies (see Chapter Investments and Innovation). Further, integrated efforts will be required to avoid bottlenecks along the value chain.

Government and industry co-operation is critical to ensure the implementation of robust innovation programmes. With more than EUR 1 billion in funding provided since 2008, the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) is a prime example of a public-private partnership to support R&D and technology demonstration. Building on its success, the European Commission will launch the Clean Hydrogen for Europe Joint Undertaking at the end of 2021, with matching budgets of EUR 1 billion from public funding and private investment until 2027.

The European Commission also initiated the European Clean Hydrogen Alliance in July 2021 to bring together industry, national and local public authorities, civil society and other stakeholders to

establish an investment agenda for hydrogen. Similarly, the Chilean Energy Sustainability Agency introduced a Green Hydrogen Incubator in 2021 to co-ordinate stakeholders and provide consulting services to facilitate the development of technology demonstration projects. In Morocco, stakeholders from the private sector, academia and the government established the Green Hydrogen Cluster to support the emerging renewable hydrogen sector. In the United States, the Department of Energy (DOE) launched the First Energy Earthshot dedicated to hydrogen, bringing together stakeholders with the target of slashing the cost of clean hydrogen by 80% (to USD 1.00/kg H_2) by 2030.

International co-operation is growing rapidly

Multilateral initiatives and projects can promote knowledge-sharing and the development of best practices to connect a wider group of stakeholders. For instance, Mission Innovation (MI), which works to catalyse R&D action and investment, has engaged with the FCH JU through the Hydrogen Valley Platform to facilitate collaboration and knowledge-sharing within more than 30 hydrogen valleys across the globe. With the launch of the Clean Hydrogen Mission in June 2021, MI took another step to boost R&D in hydrogen technologies, with the goal of reducing end-to-end clean hydrogen costs to USD 2.00/kg by 2030. MI also aims to establish at least 100 hydrogen valleys, to be featured on the Hydrogen Valley Platform.

In addition to the several bilateral agreements signed between governments in recent years, international co-operation agreements have been established between governments and the private sector (the MOUs between the Port of Rotterdam and the governments of Chile and South Australia is one example). All have the short- to medium-term objective of co-operating to share knowledge, best practices and technology development to reduce costs. They also share the long-term aim of laying the foundations for future international hydrogen supply chains to ensure the development of trade in hydrogen and hydrogen-derived fuels.

In June 2020, the energy ministers of the Pentalateral Forum (Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland) signed a joint political declaration affirming their commitment to strengthen co-operation on hydrogen.

Selected bilateral agreements between governments to co-operate on hydrogen development, 2019-2021

Countries	Objective
Germany - Australia	Formulate new initiatives to accelerate development of a hydrogen industry, including a hydrogen supply chain between the two countries. Focus on technology research and identification of barriers.
Germany - Canada	Form a partnership to integrate renewable energy sources, technological innovation and co-operation, with a focus on hydrogen.
Germany - Chile	Strengthen co-operation in renewable hydrogen and identify viable projects.
Germany - Morocco	Develop clean hydrogen production, research projects and investments across the entire supply chain (two projects have already been announced by the Moroccan agencies MASEN and IRESEN).
Germany - Saudi Arabia	Co-operate on the production, processing and transport of hydrogen from renewable energy sources.
Morocco - Portugal	Examine opportunities and actions needed to develop hydrogen from renewable energy sources.
Netherlands - Chile	Establish a structured dialogue on the development of import-export corridors for green hydrogen, aligning investment agendas and facilitating collaboration among private parties.
Netherlands - Portugal	Co-operate to advance the strategic value chain for producing and transporting renewables-based hydrogen, connecting the hydrogen plans of the two countries.
Japan – United Arab Emirates	Co-operate on technology development, regulatory frameworks and standards to create an international hydrogen supply chain.
Japan - Argentina	Strengthen collaboration on the use of clean fuels and promote investments to deploy large-scale hydrogen production from renewable energy sources.
Japan - Australia	Issue a joint statement highlighting the commitment already in place between the two countries and recognising the importance of co-operation on an international hydrogen supply chain.
Singapore - New Zealand	Boost collaboration on establishing supply chains for low-carbon hydrogen and its derivatives, and strengthen joint R&D, networks and partnerships.
Singapore - Chile	Foster co-operation on projects and initiatives to advance hydrogen deployment through information exchange and the establishment of supply chains and partnerships.
Australia - Korea	Develop joint hydrogen co-operation projects with specific action plans.

5. Harmonise standards and removing barriers

Two broad issues have emerged regarding regulations, codes and standards for hydrogen deployment. The first is the need to review national regulations that define the roles of utilities and grid operators. At present, certain aspects of market structure warrant regulatory frameworks that keep these entities separate. If hydrogen deployment is successful, however, it can concurrently become an integral part of the gas network and support electricity grid resilience and reliability of the electricity grid. Hydrogen will thereby facilitate sector coupling between electricity and gas utilities, creating a new role requiring specific regulation.

The second issue is the need to ensure that a standardisation framework based on national or international norms is in place and is appropriately applicable to the use of hydrogen and its carriers. This ongoing process involves numerous international organisations.

Regulations need to be adapted to remove barriers in the near term

The IPHE's Regulations, Codes, Standards and Safety Working Group conducted a Regulatory Gaps Compendium survey among its participating countries to determine regulatory needs in critical areas for hydrogen and fuel cell deployment. Participants provided input on focal areas within two topics: hydrogen infrastructure and hydrogen for mobility/transportation.

Survey results indicated broad regulatory needs, particularly as industry activity increases and expands beyond road transportation. Critical within the infrastructure area is the establishment of a legal framework for injecting hydrogen into natural gas systems (at both the distribution and transmission levels) and requirements for the scale-up and public use of liquid hydrogen in refuelling infrastructure.

Concerning transportation/mobility, the most critical priority is to enable the use of hydrogen in non-road transport modes – i.e. rail, shipping and aviation. The survey also determined that safety (including maintenance requirements, approvals and inspections) is a priority and improvements should be incorporated into efforts to address the other needs identified.

To remove barriers to hydrogen adoption, some countries have taken the first steps to adapt their regulations. For instance, in 2020 the Chinese National Energy Administration released a draft of the new Energy Law in which hydrogen is classified, for the first time, as an energy carrier. This means hydrogen will now be a freely tradable energy asset and its transportation will be subject to less stringent requirements than for hazardous substances (its previous classification).

Other countries, including Chile, Colombia, Korea and France, have modified their energy legislation to facilitate the adoption of hydrogen

as an energy carrier. As tax regulations can also create significant barriers to hydrogen technology endorsement, several countries are exploring options to reduce this impact. The European Commission recently proposed revision of the Energy Taxation Directive to avoid double taxation of energy products, including hydrogen, and Germany announced that hydrogen produced from renewable electricity will not be subject to the levy used to fund support for clean power.

A low-carbon hydrogen market requires carbon accounting standards

International hydrogen trade could become a cornerstone of the clean energy transition, enabling the export of low-carbon hydrogen from regions with abundant access to renewable energy or low-cost production of hydrogen from fossil fuels with CCUS. To facilitate trade, however, relevant standardisation bodies will need to develop international standards – based on a common definition of low-carbon hydrogen – to remove and/or reduce regulatory barriers.

During the 32nd IPHE Steering Committee, countries recognised that developing internationally agreed accounting standards for different sources of hydrogen along the supply chain will be vital to create a market for low-carbon hydrogen. To this end, a Hydrogen Production Analysis Task Force was established to review and reach consensus on a methodology and analytical framework for determining GHG emissions related to one unit of produced hydrogen.

Such a mutually recognised, international framework will avoid mislabelling or double-counting environmental impacts and should provide consensus on an approach to “certificates of origin”. The methodology is based on principles of inclusiveness (methodologies should not exclude any potential primary energy), flexibility (approaches must allow for unique circumstances and hence flexibility), transparency (methodologies must be transparent in approach and assumptions to build confidence), comparability (the approach should be comparable with those used for other energy vectors), and practicality (methodologies must be practical, facilitating uptake by industry and use in the market).

The methodology also describes the requirements and evaluation methods applied from “well to gate” for the most-used hydrogen production pathways: electrolysis, steam methane reforming with CCUS, by-product and coal gasification with CCUS. Over time, the Task Force intends to develop other methods and to potentially apply the approach to different physical states of hydrogen, diverse energy carriers and emissions arising during transport to the end user. In addition to IPHE activities, some countries (e.g. Australia, France and the United Kingdom) have started to develop certification schemes for hydrogen’s carbon footprint.

Research to develop evidence-based safety standards

During its recent bi-annual Workshop on Research Priorities for Hydrogen Safety, the International Association for Hydrogen Safety (HySafe) mapped state-of-the-art and recent progress in pre-normative research to support standards development, including identifying and ranking pending research needs. Ultimately, research needs were identified for five key safety areas: liquid hydrogen use; the compatibility of certain materials (metals and plastics) with hydrogen; hydrogen leak detection; hydrogen phenomena modelling; and electrolysis safety for unsteady-state operations. Despite recent progress, a significant lack of understanding regarding the accidental behaviour of liquid hydrogen was identified as an outstanding challenge. At the engineering level, major research gaps exist for the non-road transport subsectors.

Hydrogen demand

Overview and outlook

Hydrogen demand has grown strongly since 2000, particularly in refining and industry

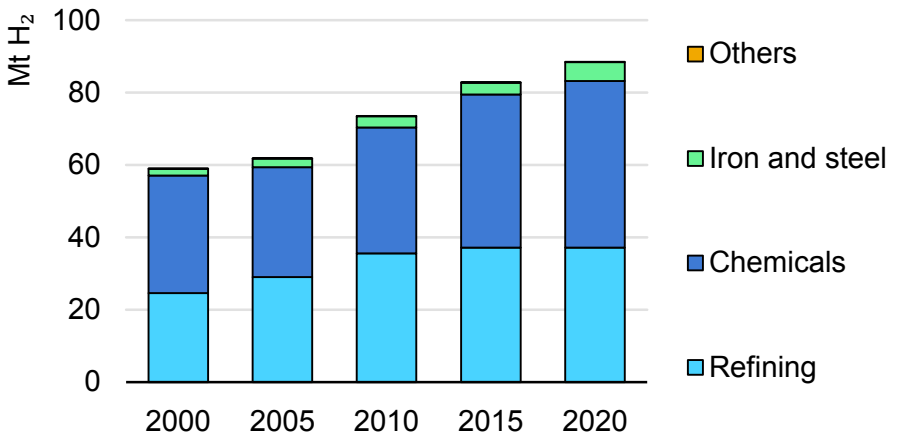
Global hydrogen demand was around 90 Mt H_2[4] in 2020, having grown 50% since the turn of the millennium. Almost all this demand comes from refining and industrial uses. Annually, refineries consume close to 40 Mt H_2 as feedstock and reagents or as a source of energy.

Demand is somewhat higher (more than 50 Mt H_2) in the industry sector, mainly for feedstock. Chemical production accounts for around 45 Mt H_2 of demand, with roughly three-quarters directed to ammonia production and one-quarter to methanol. The remaining 5 Mt H_2 is consumed in the direct reduced iron (DRI) process for steelmaking. This distribution has remained almost unchanged since 2000, apart from a slight increase in demand for DRI production.

The adoption of hydrogen for new applications has been slow, with uptake limited to the last decade, when fuel cell electric vehicle (FCEV) deployment started and pilot projects began to inject hydrogen into gas grids and use it for electricity generation. Positive results from these experiences prompted the development of some hydrogen technologies to the point of commercialisation.

In parallel, concerns about climate change have increased and governments and industry are making strong commitments to reduce emissions. Although this has accelerated the adoption of hydrogen for new applications, demand in this area remains minuscule. In transport, for example, annual hydrogen demand is less than 20 kt H_2 – just 0.02% of total hydrogen demand. As shown in the IEA's Net zero by 2050 roadmap, achieving government decarbonisation goals will require a step change in the pace of rolling out hydrogen technologies across many parts of the energy sector.

Hydrogen demand by sector, 2000-2020



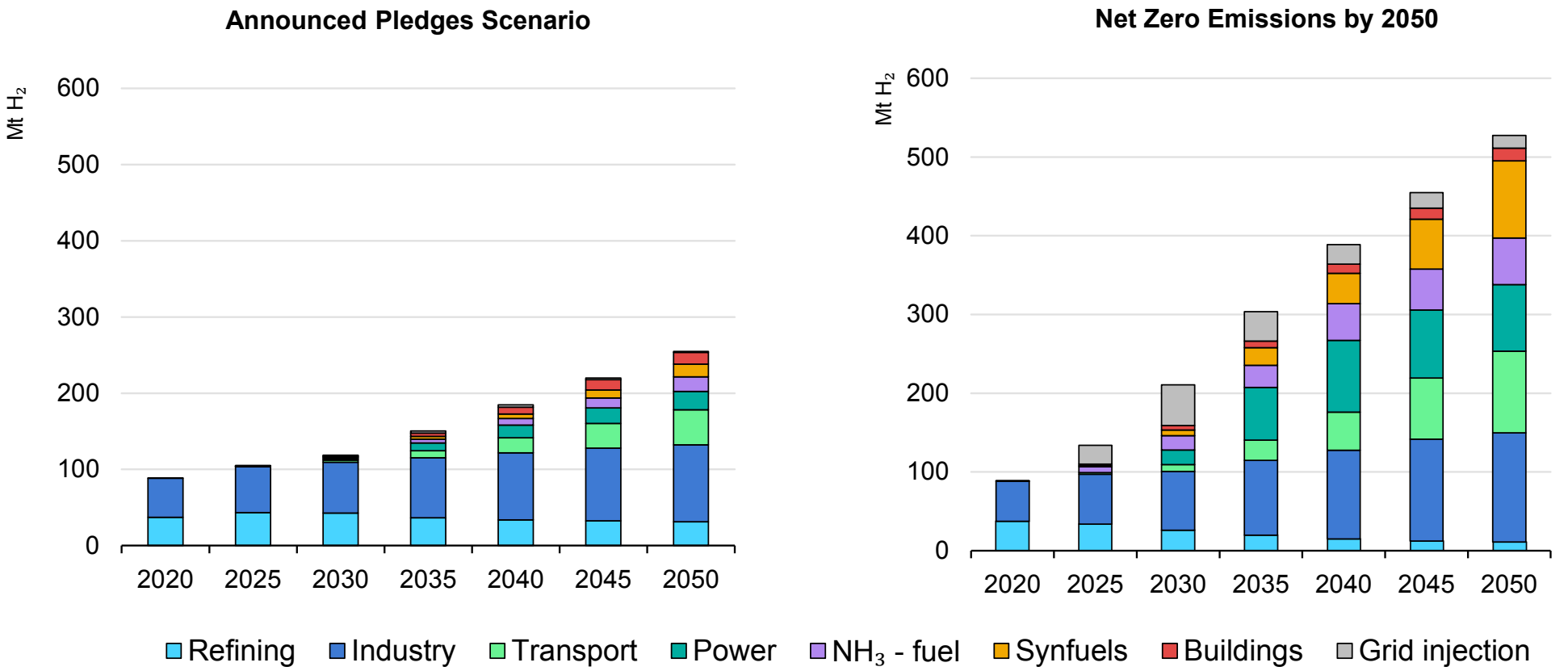
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Note: "Others" refers to small volumes of demand in industrial applications, transport, grid injection and electricity generation.

[4] This includes more than 70 Mt H_2 used as pure hydrogen and less 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 a hydrogen demand.

Government pledges suggest greater hydrogen use, but not nearly enough to the level needed to achieve net zero energy system emissions by 2050

Hydrogen demand by sector in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



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Notes: "NH_3 - fuel" refers to the use of hydrogen to produce ammonia for its use as a fuel. The use of hydrogen to produce ammonia as a feedstock in the chemical subsector is included within industry demand.

Hydrogen-based fuel use must expand to meet ambitious climate and energy goals

The pathway to net zero emissions by 2050 requires substantially wider hydrogen use in existing applications (e.g. the chemical industry) and a significant uptake of hydrogen and hydrogen-based fuels for new uses in heavy industry, heavy-duty road transport, shipping and aviation.

In the Net zero Emissions Scenario, hydrogen demand multiplies almost sixfold to reach 530 Mt H_2 by 2050, with half of this demand in industry and transport. In fact, industry demand nearly triples from around 50 Mt H_2 in 2020 to around 140 Mt H_2 in 2050. Transport demand soars from less than 20 kt H_2 to more than 100 Mt H_2 in 2050, owing to the volumes that small shares of hydrogen can achieve in certain segments.

Power sector penetration also increases significantly as hydrogen's use in gas-fired power plants and stationary fuel cells helps to balance increasing generation from variable renewables; integrate larger shares of solar PV and wind; and provide seasonal energy storage. Hydrogen use in buildings also increases, although its penetration is very limited to certain situations in which other clean and more efficient technologies cannot be adopted and/or it is needed to increase electricity grid flexibility.

By 2050, around one-third of hydrogen demand in the Net zero Emissions Scenario is used to produce hydrogen-based fuels such as ammonia, synthetic kerosene and synthetic methane. Ammonia use expands beyond existing applications (primarily nitrogen fertilisers) to be adopted for use as a fuel.

As ammonia has advantages over the direct use of hydrogen for long-distance shipping, in the Net zero Emissions Scenario it meets around 45% of global shipping fuel demand. To reduce CO_2 emissions in power generation, ammonia is also increasingly co-fired in existing coal plants, with some former coal-fired units being fully retrofitted to use 100% ammonia to provide low-carbon dispatchable power.

Synthetic fuels (synfuels) manufactured from hydrogen and CO_2 captured from biomass applications (bioenergy-fired power or biofuel production) or from the atmosphere (direct air capture [DAC]) are also used in energy applications in the Net zero Emissions Scenario. Synthetic kerosene in particular meets around one-third of global aviation fuel demand while synthetic methane meets around 10% of demand for grid gas use in buildings, industry and transport.

Overall, hydrogen and hydrogen-based fuels meet 10% of global final energy demand in 2050[5].

Refining is the only application for which hydrogen demand decreases in the Net zero Emissions Scenario – from close to 40 Mt H_2 in 2020 to 10 Mt H_2 in 2050: the reason is simply that the need to refine oil drops sharply as clean fuels and technologies replace oil-derived products.

Although recent government net zero commitments create momentum for adopting hydrogen-based fuels across the energy system, volumes are insufficient to achieve net zero emissions by 2050. While in the Announced Pledges Scenario hydrogen demand nearly triples to over 250 Mt H_2 by 2050, this is less than half the amount modelled in the Net zero Emissions Scenario.

Demand in the Announced Pledges Scenario is lower in almost all sectors, with refining being the exception as the rate of replacing oil-based fuels is lower. This strongly impacts hydrogen and hydrogen-based fuel uptake in transport applications, with hydrogen use in transport 55% lower in the Announced Pledges than in the Net zero Emissions Scenario. The difference in demand for hydrogen to produce hydrogen-based fuels is the largest, at 80% less for synfuels in the Announced Pledges than in the Net zero Emissions Scenario, and close to 70% less for ammonia production.

Furthermore, a slower rate of renewables deployment means electricity systems require less balancing of generation and seasonal storage in the Announced Pledges than in the Net zero Emissions Scenario; as a result, hydrogen demand for electricity generation in the Announced Pledges Scenario is about one-quarter that of the Net zero Emissions.

In the case of industry, as the largest single use of hydrogen is for feedstock, demand growth is robust in both scenarios, although it is 30% less in the Announced Pledges than in the Net zero Emissions.

[5] This excludes onsite hydrogen production and use in the industry sector. Including on-site hydrogen production in industry, hydrogen and hydrogen-based fuels meet 13% of global final energy demand by 2050 in the NZE.

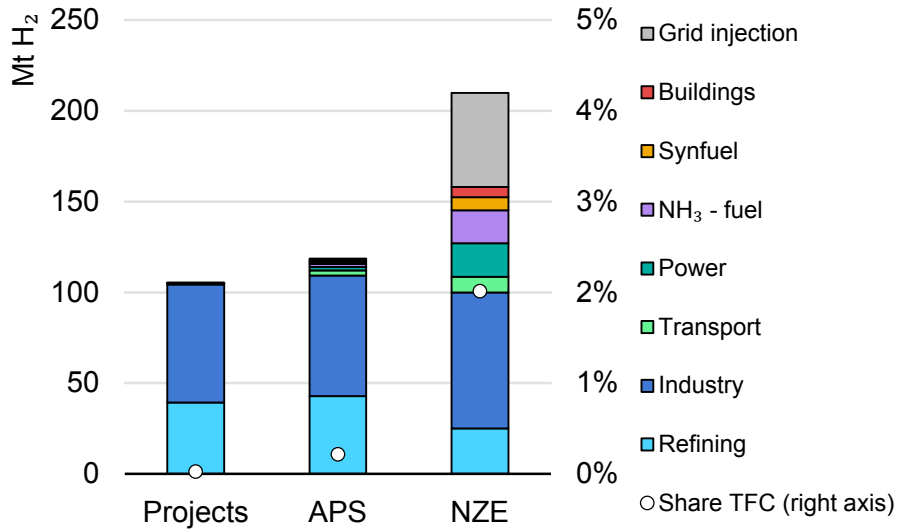
The next decade will be decisive in for laying the foundation for hydrogen's role in the clean energy transition

Increasing the use of hydrogen as a new energy vector is a long-term endeavour, as it can take decades for a new fuel to significantly penetrate the energy mix. Immediate action is therefore required to facilitate the scaling-up process and create the conditions needed by 2030 to ensure that hydrogen technologies can be widely diffused to secure their long-term usefulness in the clean energy transition.

Despite recent strong momentum, projects currently under development indicate that anticipated hydrogen technology deployment in demand sectors does not yet align with the Net zero Emissions Scenario's ambitions. Present government focus on decarbonising hydrogen production is stronger than on stimulating demand for new applications. Apart from notable exceptions for deploying different vehicle types of FCEVs in China, Korea, Japan and some EU countries, few government targets seek to accelerate the adoption of hydrogen-based fuels in end-use sectors.

Moreover, current country ambitions to stimulate hydrogen use for new applications is not sufficient to meet their net zero pledges. Using target-setting on its own as a long-term signal is not effective enough to create the market dynamics needed to unlock private sector investments and stimulate deployment of hydrogen technologies. Targets need to be accompanied by concrete policies to support implementation, including strong demand-side measures that create clearly identifiable markets.

Hydrogen demand in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2030



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. TFC = total final energy consumption. "Share TFC" excludes on-site hydrogen production and use in the industry sector. Including it, hydrogen and hydrogen-based fuels meet less than 2% of total final energy consumption today, 2% in the APS and 4% in the NZE by 2030. "NH_3 fuel" refers to the use of hydrogen to produce ammonia for its use as a fuel.

Governments need to act quickly and decisively from now until 2030 to trigger this transformation. Implementing quotas or mandates to inject hydrogen into the gas grid can create dependable hydrogen demand in this early deployment phase, which can help building up new low-carbon hydrogen production capacity while governments decide, plan and develop hydrogen-specific infrastructure. Once new infrastructure is ready, low-carbon hydrogen production capacity developed in the early deployment phase can migrate from the natural gas grid to supply hydrogen directly to end users in new applications, several of which should be demonstrated and scaled up in upcoming years.

Adopting hydrogen in transport will require support to deploy FCEVs and fuelling infrastructure. In particular, early demonstration and scaled-up hydrogen use in heavy-duty trucks, for operations in which hydrogen may have advantages over battery electric powertrains (e.g. for certain long-haul operations[6]), and the installation of high-throughput, high-pressure refuelling stations along key road freight corridors are important foundations for hydrogen use in road transport.

While BEVs are expected to dominate the transition to net zero emissions in light-duty road transport owing to their higher efficiency and lower total cost of ownership (TCO), support for near-term adoption of hydrogen fuel cells for light-duty vehicles (LDVs) and buses could boost hydrogen and fuel cell demand as well as infrastructure expansion, ultimately reducing the cost of fuel cell trucks and encouraging their adoption.

Similarly, demonstrating hydrogen and ammonia as fuels for shipping, setting quotas for synfuels in aviation, and deploying the corresponding refuelling infrastructure at ports and airports would support hydrogen and hydrogen-based fuel uptake in these sectors in which emissions are hard to abate.

Demonstration of specific end-use technologies, such as hydrogen-based DRI in steelmaking or high-temperature heating applications, will be critical to unleash significant demand growth in industry. In buildings, all sales of natural gas equipment (when it is preferred over electric heat pumps) should be compatible with hydrogen to allow eventual switching. Demonstration and pilot projects for fuel cells and other hydrogen equipment for domestic applications are needed to raise consumer confidence in hydrogen technologies' operational safety and reduce financial risk.

In the power sector, gas turbine manufacturers are confident they can provide gas turbines that run on pure hydrogen by 2030. To incentivise the use of low-carbon hydrogen to reduce emissions from existing gas-fired plants and provide electricity system

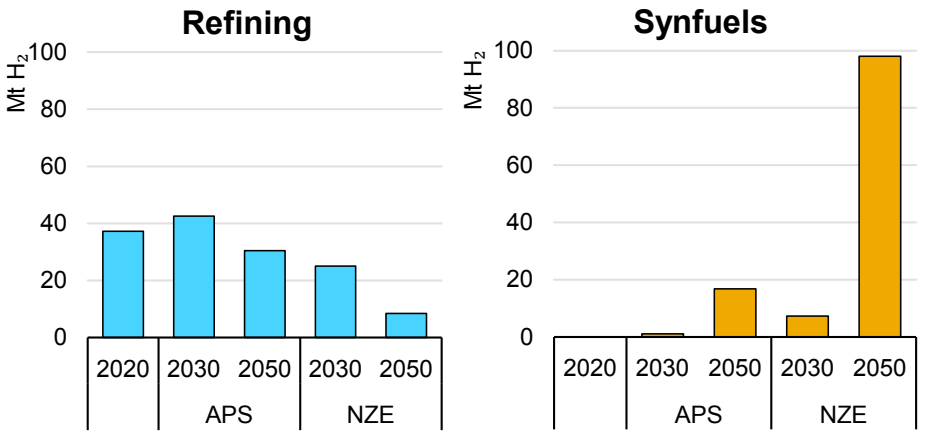
[6] For a comparison of distance-based total cost of ownership (TCO) see Figure 5.7 of Energy Technology Perspectives 2020.

flexibility, strong government support and measures will be needed to close the cost gap between natural gas and low-carbon hydrogen. Co-firing of ammonia in coal-fired power plants has been successfully demonstrated at low co-firing shares, but more RD&D is needed in using pure ammonia directly as fuel in steam or gas turbines.

Refining

Hydrogen demand in refining declines as climate ambitions increase, but synfuels offer new opportunities

Hydrogen demand in refining and synthetic fuels production in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Oil refining was the single largest consumer of hydrogen in 2020 (close to 40 Mt H_2). Refineries use hydrogen to remove impurities (especially sulphur) and to upgrade heavy oil fractions into lighter products. China is the largest consumer of hydrogen for refining (close to 9 Mt H_2/yr), followed by the United States (more than 7 Mt H_2/yr) and the Middle East (close to 4 Mt H_2/yr). Together, these three regions account for more than half of global demand.

Around-half of refining demand is met with by-product hydrogen from other processes in the refinery (e.g. catalytic naphtha reforming) or from other petrochemical processes integrated into certain refineries (e.g. steam crackers). The remainder is met by dedicated on-site production or merchant hydrogen sourced externally. The majority of on-site production is based on natural gas reforming, with some exceptions such as the use of coal gasification, which makes up almost 20% of dedicated hydrogen production at refineries in China.

In 2020, hydrogen production to meet refining demand was responsible for close to 200 Mt CO_2 emissions. However, some ongoing efforts to reduce these emissions are already operative: six plants with facilities retrofitted with CO_2 capture and two others using electrolysers to produce hydrogen. At least another 30 projects are under development to retrofit current fossil-based hydrogen production with CCUS; develop new capacities based on advanced reforming technologies coupled with CCUS; or deploy electrolysis capacities. In the short term, refineries can offer anchor demand for the development of low-carbon hydrogen supplies.

Oil refining is the only sector that shows declining hydrogen demand in the Announced Pledges and Net zero Emissions scenarios. As climate ambitions increase, oil refining activity declines more sharply

as oil demand declines, especially after 2030. In the Announced Pledges Scenario, hydrogen demand increases to more than 40 Mt H_2 to then drop to around 30 Mt H_2 in 2050. The Net zero Emissions shows 25 Mt H_2 in 2030 and 10 Mt H_2 in 2050. Dropping oil demand will create a dilemma for refinery operators, as investing in decarbonising current hydrogen production can be difficult to justify if falling demand entails the risk of stranded assets.

However, the emergence of new sources of hydrogen demand could bolster the business case for such investments by offering the opportunity to supply developing hydrogen markets and meet demand in new sectors (e.g. transport, other industry applications and electricity generation), such as those covered in the Announced Pledges and the Net zero Emissions scenarios. Using low-carbon hydrogen could be an option to decarbonise high-temperature-heat operations in refineries, helping meet the net zero targets of oil and gas companies. Producing low-carbon synthetic hydrocarbon fuels (synfuels) is another significant opportunity. Synfuels are "drop-in" fuels, meaning they can directly replace fuels that are currently oil-derived and make use of existing distribution infrastructure and end-use technologies without modifications.

Demand for such fuels grows in both the Announced Pledges and Net zero Emissions scenarios as they replace incumbent fossil fuels in applications for which direct electrification is challenging. Refineries can also use established supply chains to deliver synfuels to end users, serving today's users of oil-derived fuels. Converting hydrogen into synfuels is very costly, however, which could be a primary impediment to their widespread use (see Chapter Hydrogen supply). The expertise and skills of refinery operators will be critical to develop innovative, efficient and cost-effective solutions.

By 2030 in the Announced Pledges Scenario, hydrogen demand for synfuels reaches 1 Mt H_2. By 2050, it climbs to over 15 Mt H_2, more than making up for the more than 5 Mt H_2 drop in refining demand. In the Net zero Emissions Scenario, hydrogen demand for synfuels climbs to more than 7 Mt H_2 by 2030, compensating for nearly two-thirds of the more than 10-Mt H_2 drop in refining demand. By 2050, it reaches close to 100 Mt H_2, not only replacing the 26 Mt H_2 drop in refining demand but more than doubling current demand – and representing a significant investment opportunity.

If all projects currently in the pipeline materialise (including those already operational; under construction; having reached final investment decision; and undergoing feasibility studies), around 0.25 Mt H_2[7] could be used in synfuel production by 2030, meeting one-fifth of Announced Pledges Scenario requirements but just 3% of the Net zero Emissions Scenario's.

[7] This could increase to 0.5 Mt H_2 if projects at very early stages of development are included (a co-operation agreement among stakeholders has just been announced).

Selected projects operative and under development to decarbonise hydrogen production in refining

Project	Location	Status	Start-up date	Technology	Size
Horizon Oil Sands	Canada	Operational	2009	Oil + CCUS	438 kt CO_2/yr
Port Arthur *	US		2013	Natural gas + CCUS	900 kt CO_2/yr – 118 kt H_2/yr
Port Jerome *	France		2015	Natural gas + CCUS	100 kt CO_2/yr – 39 kt H_2/yr
Quest	Canada		2015	Natural gas + CCUS	1 000 kt CO_2/yr – 300 kt H_2/yr
H&R Ölwerke Hamburg-Neuhof	Germany		2018	Electrolysis (PEM)	5 MW
North West Sturgeon refinery	Canada		2020	Bitumen gasification + CCUS	1 200 kt CO_2/yr
Pernis refinery (gasification)	Netherlands	CCU project – Operational CCUS project – Feasibility studies	2005 2024	Heavy residue gasification with CCU (CCUS from 2024)	400 kt CO_2/yr – 1 000 kt H_2/yr 1 000 kt CO_2/yr – 1 000 kt H_2/yr
Refhyne (2 phases)	Germany	Phase 1 – Operational Phase 2 – Feasibility studies	2021 2025	Electrolysis (PEM)	10 MW 100 MW
HySynergy (3 phases)	Denmark	Phase 1 – Under construction Phases 2/3 – Feasibility studies	2022 2025-30	Electrolysis (PEM)	20 MW 300 MW / 1 000 MW
Multiphly	Netherlands	Under construction	2022	Electrolysis (SOEC)	2.6 MW
Prince George refinery	Canada	FID	2023	Electrolysis (Unknown)	n.a.
OMV Schwechat Refinery	Austria		2023	Electrolysis (PEM)	10 MW
Westkuste 100 (2 phases)	Germany	Phase 1 – FID Phase 2 – Feasibility studies	2023-28	Electrolysis (Alkaline)	30 MW / 300 MW
H24All	Spain	Feasibility studies	2025	Electrolysis (Alkaline)	100 MW
Gela biorefinery	Italy		2023	Electrolysis (PEM)	20 MW
Taranto Sustainable refinery	Italy		2023	Electrolysis (PEM)	10 MW
Castellon refinery	Spain		2023	Electrolysis (Unknown)	20 MW
Pernis refinery (electrolysis)	Netherlands		2023	Electrolysis (Unknown)	200 MW
Saras Sardinia refinery	Italy		2024	Electrolysis (Unknown)	20 MW
Stanlow refinery	United Kingdom		2025	Natural gas + CCUS	90 kt H_2/yr
H2.50	Netherlands		2025	Electrolysis (Unknown)	250 MW
Preem CCS	Sweden		2025	Natural gas + CCUS	500 kt CO_2/yr
Grupa Lotos refinery	Poland		2025	Electrolysis (Unknown)	100 MW
Zeeland refinery	Netherlands		2026	Electrolysis (Unknown)	150 MW
Lingen refinery (2 phases)	Germany	Phase 1 – Feasibility studies Phase 2 – Early stages	2024 n.a.	Electrolysis (Unknown)	50 MW 500 MW
Deltaurus 1 (2 phases)	Netherlands		2024 n.a.	Electrolysis (Unknown)	150 MW 1 000 MW

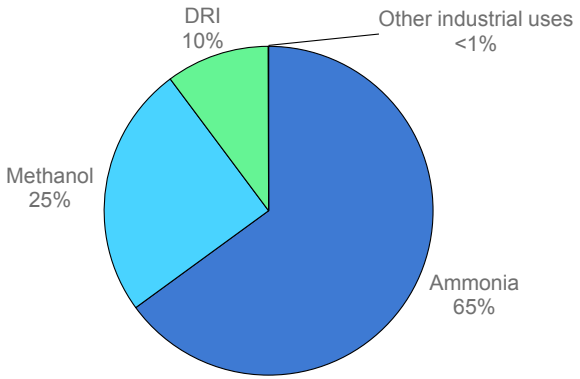
* These plants produce merchant hydrogen to supply refineries.
Notes: Size expressed in captured CO_2 for projects using CCUS and in electrolysis installed capacity for projects using electrolysis.

Industry

Hydrogen technologies are key to industry decarbonisation

Accounting for 38% of total final energy demand, industry is the largest end-use sector and accounts for 26% of global energy system CO_2 emissions. Across industry, 6% of total energy demand is used to produce hydrogen, which serves primarily as a feedstock for chemical production and a reducing agent in iron and steel manufacturing. Industry demand for hydrogen is 51 Mt annually.

Hydrogen demand in industry, 2020



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Note: DRI = direct reduced iron.

Economic development and population growth will require greater output from the key industry sectors that currently use hydrogen, however it is produced. The pursuit of net zero goals for energy systems will drive changes in supply for current uses and initiate new uses, impacting existing assets. Industrial hydrogen demand in the Announced Pledges Scenario therefore rises to 65 Mt by 2030, a 30% increase over current figures, with new uses accounting for 5%. By 2050, demand doubles from today, with the share of new uses rising to 26%.

In the context of clean energy transitions, a major shift to low-carbon hydrogen – produced via electrolysis or through the continued use of fossil fuel technologies equipped with CCUS – displaces current reliance on fossil fuels in hydrogen production. In 2020, industry produced 0.3 Mt of low-carbon hydrogen, mostly through a handful of large-scale CCUS projects, small electrolysis projects in the chemical subsector, and one CCUS project in the iron and steel subsector. By 2030 in the Announced Pledges Scenario, low-carbon hydrogen consumption in industry reaches 7 Mt H_2, growing by a factor of almost 25 to make up 10% of total industry hydrogen demand.

However, analysis of the current pipeline of low-carbon hydrogen projects suggests that around 55% of global demand projected in the Announced Pledges Scenario in 2030 will be met.[8] CCUS-equipped

[8] This could increase to almost 70% if projects at very early stages of development are included (a co-operation agreement among stakeholders has just been announced).

projects producing low-carbon hydrogen are close to projected deployment: with the current CCUS pipeline expected to produce 1.0 Mt of low-carbon hydrogen, they fall just 7% short of the Announced Pledges Scenario's demand of 1.1 Mt H_2. In sharp contrast, electrolytic hydrogen – a key source of low-carbon hydrogen needed to reach climate goals in industry – lags far behind. Announced electrolytic projects expected to be operational by 2030 account for only one-third of required demand in the Announced Pledges Scenario (close to 6 Mt H_2).

Reaching net zero emissions by 2050 requires even higher hydrogen deployment. Relative to the Announced Pledges Scenario, Net zero Emissions shows total hydrogen demand from industry 11% higher in 2030 and 32% higher in 2050 – almost three times greater than current demand. Low-carbon hydrogen plays an even larger role, amounting to 21 Mt H_2 by 2030 (more than three times higher than in the Announced Pledges Scenario). As early as 2030, electrolytic hydrogen consumption is almost triple that of the Announced Pledges Scenario while CCUS-equipped production is more than five times higher.

Chemicals

With demand of 46 Mt H_2 in 2020, ammonia and methanol production – together with other smaller-scale chemical processes – account for the vast majority of industrial use of hydrogen.

Ammonia, predominantly used to produce nitrogen fertilisers, accounts for 2% of global final energy demand and around 1% of energy-related and process CO_2 emissions from the energy sector. Aside from fertiliser[9] applications (70% of total demand), ammonia is used for industrial applications in explosives, synthetic fibres and other specialty materials. As producing 1 tonne of ammonia requires 180 kg of hydrogen, total production of 185 Mt in 2020 required 33 Mt H_2 as feedstock, i.e. 65% of total industry hydrogen demand.

Methanol production is the second-largest consumer of hydrogen in industry, requiring 130 kg H_2/t produced commercially from fossil fuels. Its largest-volume derivative is formaldehyde, but several fuel applications, either directly or after conversion, are also important (e.g. methyl-tert-butyl ether). The 100 Mt of methanol produced globally accounts for 28% of hydrogen demand in the chemical subsector and one-quarter of total industry hydrogen demand. In China, methanol serves as an intermediate in the production of olefins (key chemical precursors for making plastics) from coal, an

[9] Specific decarbonisation opportunities for this subsector are explored in the IEA's forthcoming Nitrogen Fertiliser Technology Roadmap.

alternative to conventional oil-based routes. Producing methanol generates, on average, 2.2 t CO_2 per tonne of end product.

Demand for hydrogen in the chemical subsector is expected to grow, particularly because of rising demand for ammonia and methanol. In the Announced Pledges Scenario, it increases nearly 25% by 2030 and close to 50% by 2050. As current methods to produce both chemicals require hydrogen (irrespective of how it is generated), by 2050 total hydrogen demand from chemicals is roughly the same in the Net zero Emissions Scenario.

New demand comes mostly from new applications in which hydrogen displaces fossil fuels for generating the high-temperature heat required for producing chemicals. Thus, converting to low-carbon hydrogen, rather than expanding the use of hydrogen, is the main challenge for the chemical subsector. Opportunities to obtain low-cost, low-carbon hydrogen may spark chemical production in new regions that have access to low-cost renewable electricity but not fossil fuels.

CO_2 capture is already a mature process technology in specific chemical industry applications. During ammonia production, core process equipment separates CO_2 from hydrogen, and the CO_2 is then used for industrial-scale urea production (note: this leaves a significant portion of generated emissions unabated).

In the United States, the practice of using CO_2 captured from ammonia production for enhanced oil recovery (EOR) is well established; similar projects are also operational in Canada and China. Based on the size of the capture installation and assumptions on capture rate and the energy intensity of the process, in aggregate these projects produce around 0.2 Mt of low-carbon hydrogen annually for ammonia production.

Using electrolytic hydrogen for ammonia production, particularly with variable renewable electricity, is at an early stage of development. Nevertheless, several demonstration projects (1-4 kt H_2/yr) are advancing quickly, including a project by Fertiberia and Iberdrola (Spain) to blend hydrogen produced by solar PV-powered electrolysis, expected to become operational at the end of 2021; a CF Industries electrolyser project (United States); the Western Jutland Green ammonia project (Denmark); and green fertiliser projects with Yara (in the Netherlands, Norway and Australia). In addition, some recently announced projects – extensions of the Fertiberia and Iberdrola partnership, Australian projects in Dyno Nobel's Moranbah plant, and the Origin Energy development in Tasmania's Bell Bay – are aiming to scale up this concept to 30-140 kt H_2/yr.

For methanol production, most projects currently sourcing low-carbon hydrogen are related to electrolytic hydrogen. Volumes are very small to date, with pilot plants operating at 1 MW in Germany and 0.25 MW in Denmark, for example. Together with pre-commercial plants in Iceland and China, electrolytic hydrogen amounts to about 2 kt/yr of low-carbon hydrogen. Several projects aiming to demonstrate the

use of electrolytic hydrogen for methanol production at scales in the range of 1-10 kt H_2/yr include e-Thor and Djewels (the Netherlands), North-C-Methanol (Belgium), and LiquidWind (Sweden).

Although only small projects capturing CO_2 emissions from methanol production are operating, projects currently under development are about to grow in size. Two demonstration projects capturing CO_2 for EOR are under way in China, another is to start in the United States in 2025, and one is under consideration for Canada by 2025. Together, they can add more than 0.3 Mt/yr of low-carbon hydrogen.

New applications in chemicals include the use of hydrogen for producing high-value chemicals (via either methanol or synfuel used in steam crackers) or for providing high-temperature process heat in downstream chemical production. By 2030, such uses trigger additional low-carbon hydrogen demand of 1.0 Mt in the Announced Pledges Scenario and 2.1 Mt in the Net zero Emissions.

While hydrogen demand per tonne of ammonia and methanol is expected to remain stable, rising demand for chemical products, along with the possibility of sourcing hydrogen from renewable electricity and of using additional hydrogen for heat to produce other chemicals in addition to ammonia and methanol, could revolutionise the sector.

Producing chemical products without carbon fuels could also create opportunities to find new sources of carbon, including CCUS and DAC. Overall, the chemical subsector's project pipeline represents only 2.3 Mt of low-carbon hydrogen through 2030,[10] short of targets of 4 Mt in the Announced Pledges Scenario and 7 Mt in Net zero Emissions. Clearly, a redoubling of efforts is required over the next ten years.

Iron and steel

The iron and steel subsector accounts for 10% of industry hydrogen demand, stemming specifically from use in the DRI-EAF steelmaking process route, which accounts for 7% of total crude steel production globally. In the DRI process, hydrogen is produced as a component of a synthesis gas, which together with carbon monoxide reduces iron ore to sponge iron. The synthetic gas is a mixture of carbon monoxide and hydrogen, depending on the energy source used in DRI production. On average, around 40 kg H_2 is needed per tonne of sponge iron. The traditional DRI mixture can contain 0-70% hydrogen.

The most common steel production route today (the integrated route, a sequence of blast and basic oxygen furnaces) does not require hydrogen as an input, as it uses carbon monoxide-rich gases for

[10] 3.1 Mt H_2 if projects at very early stages of development are included

iron ore reduction. However, a small amount of hydrogen is still generated within the blast furnace as an intermediate and as a by-product in the process off-gases.

As a result of announced policies and projects as well as increased steel production through the DRI-EAF process, hydrogen demand from iron and steel almost doubles by 2030 in the Announced Pledges Scenario and increases more than fivefold by 2050. In sharp contrast to small differences in scenario projections in the chemical subsector, Net zero Emissions shows hydrogen demand from iron and steel 85% higher than in the Announced Pledges Scenario by 2030 and 70% higher by 2050. New uses for hydrogen form a key decarbonisation strategy for the iron and steel subsector; in turn, high decarbonisation ambition will spur required levels of deployment.

Multiple new applications present novel opportunities for the future of hydrogen in iron and steel production, with potential volumes of demand in a hydrogen-based DRI-EAF route being the most important. While commercial-scale production for 100% hydrogen-based DRI is not expected until the early 2030s, this route opens an avenue for extensive hydrogen use in the sector. Blending pure hydrogen in DRI and blast furnaces to substitute for a portion of coal and gas, as is currently being trialled, is an incremental step towards the near zero emissions production of crude steel.

Hydrogen can also be used to generate heat for ancillary units, including rolling and other finishing processes, despite being less attractive than induction technology. By 2030, these new uses amount to 2 Mt H_2 or 17% of hydrogen use in iron and steel in the Announced Pledges Scenario and 9 Mt H_2 in Net zero Emissions. Most of these uses of hydrogen are still at pilot or demonstration scale; to meet deployment levels outlined in the Announced Pledges and Net zero Emissions scenarios, rapid action is needed in the next five years for their full commercialisation.

Projects in the pipeline amount to 0.5 Mt[11] of low-carbon hydrogen use. These include the longest-standing low-carbon hydrogen project – a DRI plant equipped with CCUS in United Arab Emirates, which captures CO_2 for use in nearby EOR. In Germany, the Carbon2Chem project uses CO_2 captured from blast furnace gas for methanol production; using some of the carbon entering the blast furnace twice lowers emissions overall relative to a counterfactual in which methanol is produced from fossil fuels (by far, the most widespread practice today). Opportunities to convert gases arising from iron and steelmaking into other chemicals are also under development.

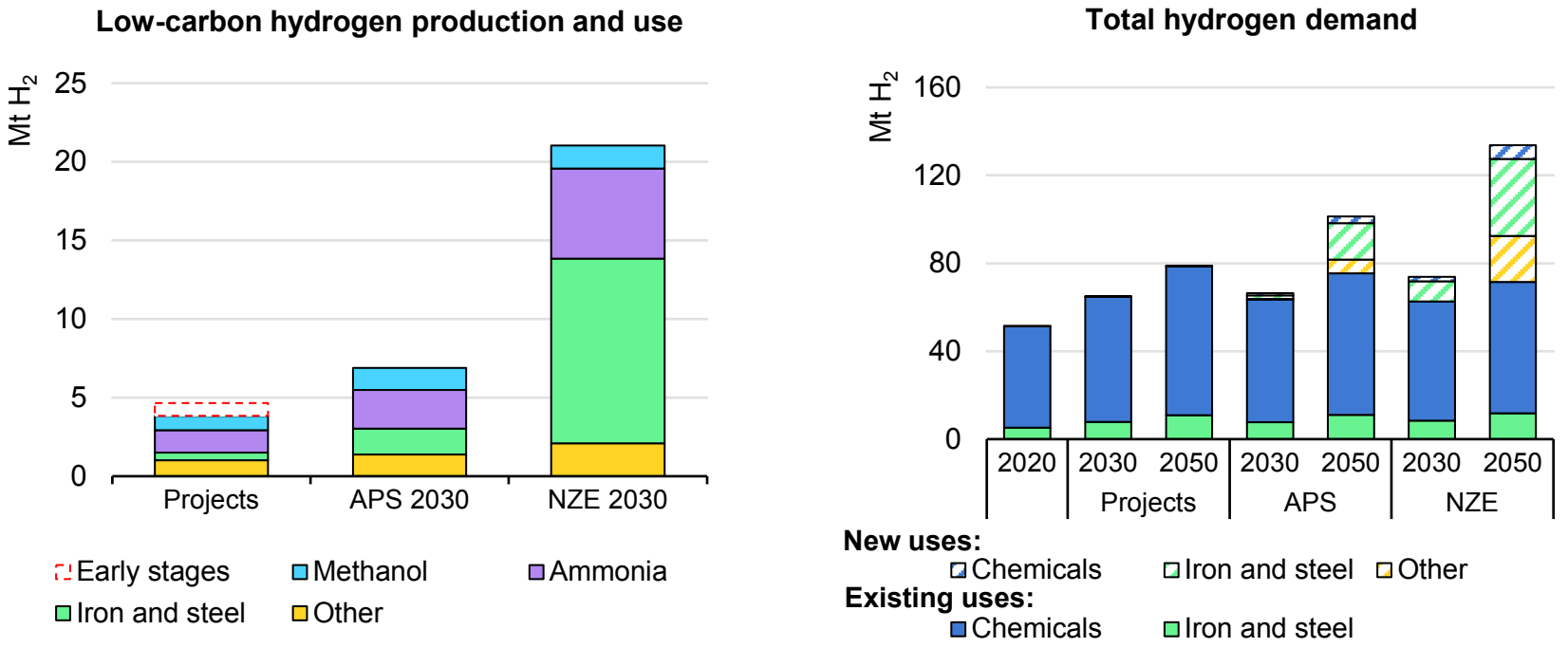
Multiple EU projects are also trialling hydrogen injection into DRI and blast furnaces. The SALCOS (Germany) and H2FUTURE (Austria) projects are operating trials that substitute electrolytic hydrogen to reduce natural gas consumption, amounting together to over

[11] 0.8 Mt H_2 if projects at very early stages of development are included.

1 kt H_2/yr. Thyssenkrupp has successfully trialled the substitution of coal by hydrogen in one tuyere of one of its blast furnaces in Germany and is currently testing higher blending rates. ArcelorMittal (Spain) has also committed to build a DRI unit using hydrogen produced directly from renewable sources.

Aside from blending hydrogen in existing DRI and blast furnaces, high blending shares (up to 100%) in hydrogen-based DRI facilities offer an opportunity to produce steel with very limited use of fossil fuels. As early as the 1990s, a 0.5 Mt full hydrogen-based plant was already operational in Trinidad and Tobago (it is no longer active). The HYBRIT project, developed by SSAB, LKAB and Vattenfall – which will produce sponge iron using 100% hydrogen in combination with biomass – is working towards transitioning from a pilot to large-scale (~1 Mt of DRI) operation by 2025 in Sweden. In June 2021, Volvo Cars signed a collaboration agreement with SSAB to be an off-taker of the fossil-free steel produced in this project.

Low-carbon hydrogen use, 2030, and total hydrogen demand in industry in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2020-2050



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. Other applications include hydrogen use for ceramics production, nickel refining and industrial heating.

Source: IEA (2021), Hydrogen Projects Database.

Selected projects that can increase the use of low-carbon hydrogen in industry

Project	Location	Status	Start-up date	Technology	Size
Ammonia					
Coffeyville fertiliser	United States	Operational	2013	CO_2 capture from oil-based ammonia production; used for EOR	1 Mt CO_2/yr
PCS Nitrogen	United States		2013	CO_2 capture from gas-based ammonia production; used for EOR	0.7 Mt CO_2/yr
Nutrien fertiliser	Canada		2020	CO_2 capture from gas-based ammonia production; used for EOR	0.3 Mt CO_2/yr
Olive Creek	United States	Under construction	2021	Ammonia production via methane pyrolysis	n.a.
Fertiberia/Iberdrola	Spain	Phase 1 – Under construction Phases 2-4 – Feasibility studies	Phase 1 – 2021 Phases 2-4 – 2027	Hydrogen production from solar PV for ammonia production	Phase 1 – 20 MW Phases 2-4 – 810 MW
Western Jutland Green ammonia	Denmark	FID	2023	Electrolytic ammonia production from renewables	10 MW
CF industries	United States		2023	Electrolytic ammonia production using electricity from the grid	20 MW
Green fertiliser project Porsgrunn	Norway		2023	Electrolytic ammonia production using electricity from the grid	Up to 25 MW
Engie - Yara Pilbara	Australia		2023	Electrolytic ammonia production from renewables	10 MW
HyEx	Chile	Feasibility studies	2024	Electrolytic ammonia production form solar PV	50 MW
Yara Sluiskil	Netherlands		2025	Electrolytic ammonia production from renewables	100 MW
Barents blue ammonia	Norway		2025	CO_2 capture and stored from gas-based ammonia production	1 Mt NH3/yr
Esbjerg green ammonia	Denmark		2027	Electrolytic ammonia production from offshore wind	1 GW
CF Fertilisers Ince	United Kingdom		n.a.	CO_2 capture and stored from gas-based ammonia production	0.3 Mt CO_2/yr
Methanol					
Commercial Plant Svartsengi	Iceland	Operational	2011	Electrolytic methanol production from dedicated renewables	6 MW
Karamay Dunhua Oil Technology CCUS EOR	China		2015	CO_2 capture and stored from methanol production; used for EOR	0.1 Mt CO_2/yr
MEFCO2	Germany		2019	Electrolytic methanol production	1 MW
Power2Met	Denmark		2020	Electrolytic methanol production	0.25 MW
Fine Chemical Industry Park of Lanzhou	China		2020	Electrolytic methanol production from dedicated renewables	4.5 MW
Green lab skive	Denmark	Under construction	2022	Electrolytic methanol production from dedicated renewables	12 MW
DJEWELS Chemiepark	Netherlands	Feasibility studies	2022	Electrolytic methanol production from dedicated renewables	20 MW
Lake Charles Methanol	United States		2025	Production of hydrogen and methanol from petcoke gasification with CCUS	4.2 Mt CO_2/yr

Project	Location	Status	Start-up date	Technology	Size
North-C-Methanol	Belgium	Phase 1 – Feasibility studies Phase 2 – Early stages	2024 2028	Electrolytic methanol production from dedicated renewables	Phase 1 – 63 MW Phase 2 – 300 MW
Power-to-Methanol	Belgium		2023 n.a.	Electrolytic methanol production from dedicated renewables	10 MW 100MW
Iron and steel					
Al Reyadah CCUS	United Arab Emirates	Operational	2016	CCUS plant applied on DRI; captured CO_2 used for EOR	0.8 Mt CO_2/yr
Carbon2Chem	Germany		2018	Use of blast furnace gases for methanol production	2 MW
H2FUTURE	Austria		2019	Feeding hydrogen via the coke gas pipeline into resource-optimised blast furnaces	6 MW
GrInHy2.0	Germany		2020	Use of waste heat from integrated steelworks for H_2 production	0.72 MW
SALCOS	Germany		2021	Blending of hydrogen into natural gas-based DRI	2.5 MW
HYBRIT	Sweden	Phase 1 – Operational Phase 2 – Under construction	Phase 1 – 2021 Phase 2 – 2025	100% hydrogen-based steelmaking currently operating at pilot scale; plan to move to demonstration plant by 2025	Phase 1 – 4.5 MW Phase 2 – n.a.
Thyssenkrupp steel plant	Germany	Early stages	2022 2025	Hydrogen injection into blast furnaces	100 MW 400 MW
ArcelorMittal	Spain		2025	Use of hydrogen produced from solar PV electrolysis in DRI	n.a.
H2 Green Steel	Sweden		2030	100% hydrogen-based steelmaking using dedicated renewables	1.5 GW
HBIS	China		n.a.	Using high levels of hydrogen together with coke oven gas in DRI	n.a.
Other applications					
Sun Metals Zinc Refinery	Australia	FID	2022	Replacement of natural gas in zinc refinery process	1 MW
BHP Nickel West Green Hydrogen	Australia	Early stages	2023	Use of electrolytic hydrogen for nickel refining	10 MW
ORANGE.BAT Castellon	Spain		2024	Use of green hydrogen for ceramic production	100 MW
Grange Resources Renewable Hydrogen	Australia		n.a.	Use of hydrogen to replace natural gas for industrial heating in pelletising facilities	100 MW
GREENH2KER	Spain		n.a.	Use of green hydrogen for ceramic production	n.a.

Source: IEA (2021), Hydrogen Projects Database.

Regional insights for hydrogen in industry

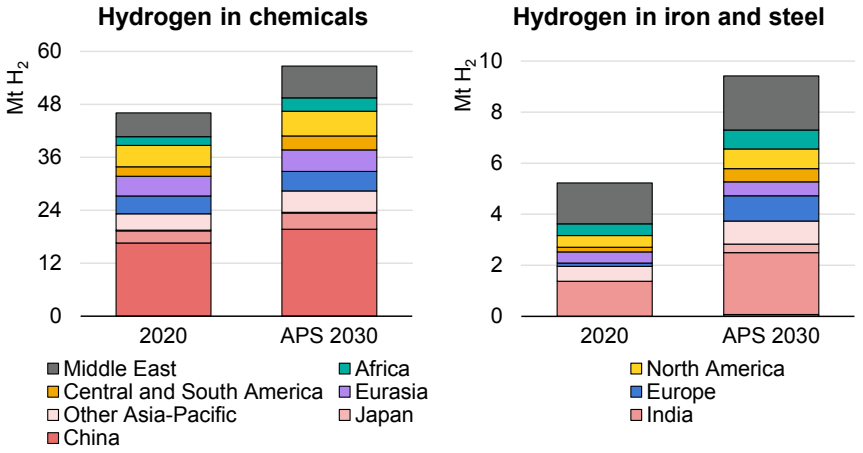
The Asia-Pacific region currently accounts for half of global industrial hydrogen demand, with China alone taking a major portion (17 Mt H_2) for ammonia and methanol production. India is the region's second-highest consumer (4 Mt H_2) for coal-based DRI and ammonia and methanol production. This region remains the front runner in 2030 in the Announced Pledges Scenario, with total demand reaching 32 Mt H_2, used to produce 65 Mt of steel (through fossil and hydrogen-based DRI), 95 Mt of ammonia and 80 Mt of methanol. With growth across all sectors, China accounts for almost two-thirds of Announced Pledges Scenario hydrogen demand. Demand in India rises by 50%, driven mainly by the iron and steel subsector. In the absence of a stated net zero target, growth in India (in the Announced Pledges Scenario) comes largely from coal-based DRI production.

The Middle East is the second-highest hydrogen-consuming region (7 Mt H_2 in 2020), mainly for ammonia and methanol production. By 2030, demand in the Announced Pledges Scenario rises to 9 Mt, prompted by increased chemical production.

Hydrogen consumption remains largely stable in North America, Europe and Eurasia, each rising from 4-5 Mt H_2 currently to around 6 Mt H_2 by 2030 in the Announced Pledges Scenario, mainly due to increased demand from the iron and steel subsector. This is based on the assumption of developed countries maintaining current production levels, even though their share in global output declines as that of maturing developing regions – which require materials to build their infrastructure – increases.

Central and South America show the largest relative growth to 2030: from a low starting point of 2.3 Mt H_2, expanding ammonia and methanol production and rising steel output via DRI-EAF routes boost hydrogen demand by 60%.

Hydrogen demand in industry by sector and region in the Announced Pledges Scenario, 2020-2030



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Note: APS = Announced Pledges Scenario.

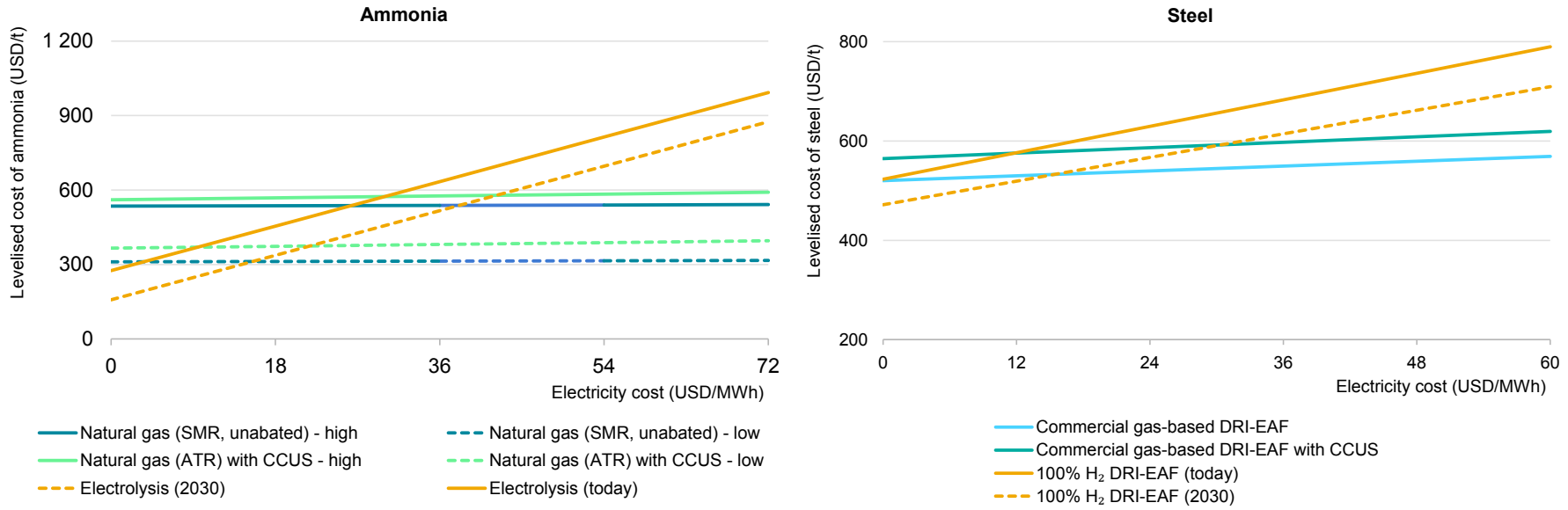
Cost considerations

Today, fossil fuels are the lowest-cost source of industry feedstocks, reduction agents and high-temperature heat for industry in virtually all regions. With carbon prices rising in several markets and the cost of generating electricity from renewables falling rapidly, methods for using low-carbon hydrogen to produce iron and steel as well as chemicals are approaching the competitiveness threshold, with commercial routes currently deployed.

The cost-competitiveness of a low-carbon hydrogen application in industry is determined primarily by capital expenditures and energy costs (particularly for natural gas and electricity). For both ammonia and DRI-EAF steelmaking, low-carbon hydrogen can be produced using either natural gas or electricity. In ammonia production, at 2030 costs for capital equipment (electrolysers and other core process equipment) and natural gas prices of USD 2-10/MBtu with no carbon price, the electrolysis pathway competes with the natural gas with CCUS route at electricity costs of USD 20-40/MWh. For the hydrogen-based DRI-EAF route, the electricity cost range at which it is competitive with natural gas with CCUS is similar, i.e. around USD 30/MWh, when considering natural gas prices of USD 6/MBtu.

These electricity price ranges correspond to high capacity factors (95%) and are very low compared with those for typical industrial consumers in many parts of the world or expected electricity prices in the fully decarbonised grids of the future. Ongoing development in the direct use of variable renewable electricity in electricity-intensive processes (including the use of hydrogen buffer storage and enhanced process flexibility) and declining core equipment (particularly electrolyser) costs are likely to make these methods more competitive as the realised cost of electricity and subsequent hydrogen costs approach these ranges.

Cost sensitivities for ammonia and steel production



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Notes: SMR = steam methane reforming. ATR = autothermal reforming. DRI-EAF = direct reduced iron - electric arc furnace. CCUS = carbon capture, utilisation and storage. Techno-economic assumptions available in the Annex.

Transport

Greater hydrogen use is necessary to decarbonise transport

The transport sector is responsible for over 20% of global GHG emissions and one-quarter of final energy demand, with oil products supplying 90% of the energy it consumes. To date, hydrogen use in the sector has been limited, representing less than 0.01% of energy consumed. Nevertheless, hydrogen and hydrogen-based fuels can offer emissions reduction opportunities, especially in hard-to-electrify transport segments (e.g. long-haul, heavy-duty trucking, shipping and aviation).

In the Announced Pledges Scenario, hydrogen and hydrogen-based fuel consumption in transport climbs to 520 PJ or 0.4% of transport energy demand in 2030. Almost 60% of this demand is for road vehicles, as fuel cell vehicle stock expands to over 6 million. Shipping represents almost one-fifth of the demand, with hydrogen and ammonia constituting 1% of shipping fuel consumption in 2030. Similarly, hydrogen and synthetic fuels account for almost 1% of rail energy consumption. In aviation, hydrogen-based synthetic fuel use remains low, making up less than 1% of consumption. By 2050, demand for hydrogen and hydrogen-based fuels across all transport end-uses is over 15 times higher than in 2030, meeting 6% of the sector's energy demand.

In the Net zero Emissions Scenario, hydrogen and hydrogen-based fuel deployment is accelerated and demand reaches 2.7 EJ in 2030, representing 2.6% of transport energy demand. As in the Announced Pledges Scenario, the greatest share of demand (over 45%) is for road vehicles. In shipping, hydrogen accounts for almost 2% and ammonia almost 8% of fuel consumption in 2030. Synthetic fuels make up 1.6% of aviation fuel consumption in 2030 in the Net zero Emissions Scenario. By 2050, hydrogen and hydrogen-based fuels meet over one-quarter of total transport energy demand in this scenario.

Status of hydrogen and fuel cells for transport

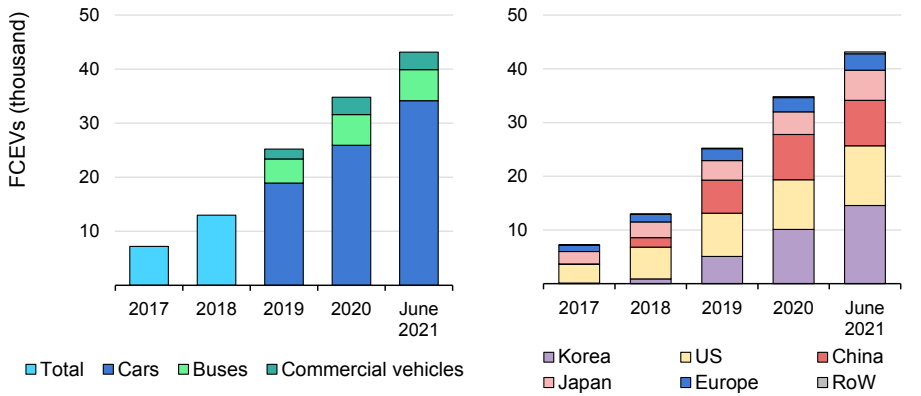
Road transport

More than 40 000 FCEVs were on the road globally by the end of June 2021.[12] Stocks grew an average 70% annually from 2017 to 2020, but in 2020 stock growth fell to only 40% and new fuel cell car registrations decreased 15% (<10 000 new vehicles), mirroring contraction of the car market overall due to the Covid-19 pandemic. However, more than 8 000 FCEVs were sold in the first half of 2021, with record-high monthly sales recorded in California (759 in March) and Korea (1 265 in April).

Global FCEV deployment has been concentrated largely on passenger light-duty vehicles (PLDVs), constituting 74% of registered FCEVs in 2020. Three commercial fuel cell PLDV models are on the market[13] (Hyundai NEXO, Honda Clarity[14] and second-generation Toyota Mirai), with other original equipment manufacturers (OEMs) announcing plans to launch models over the next few years.

Buses, despite being deployed earlier and offering a greater number of fuel cell models (12 according to Calstart's Zero-Emission Technology Inventory tool), currently represent only 16% of total FCEV stock. Almost 95% are in China, which has also led deployment of fuel cell trucks, with >3 100 in operation in 2020.

Fuel cell electric vehicle stock by segment and region, 2017-June 2021



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Notes: FCEV = fuel cell electric vehicle. RoW = rest of world.
Sources: AFC TCP provided data on stocks from 2017-2020; 2021 new registrations are based on IPHE Country Surveys, Korea Ministry of Trade, Industry and Energy, and the California Fuel Cell Partnership.

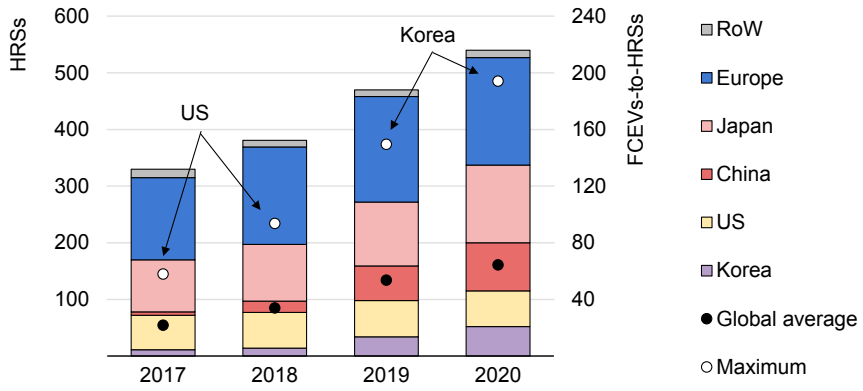
Only 5 fuel cell truck models are currently available, but 11 are expected by 2023. Daimler Truck AG and Volvo Group announced a joint venture, cellcentric, to develop, produce and commercialise fuel

[12] For comparison, EV stock totalled 11 million at the end of 2020.
[13] 350 EV models were available in 2020.
[14] Honda announced discontinuation of the Clarity series (both plug-in hybrid and fuel cell models) as of August 2021, though the Clarity fuel cell will remain available for lease through 2022.

cell systems for long-haul trucking, among other applications. Along with IVECO, OMV and Shell, both companies also signed the H2Accelerate agreement to collaborate on large-scale hydrogen truck deployment in Europe.

Some OEMs, such as Cummins and MAN, are building and testing prototype hydrogen-fuelled internal combustion engines for commercial vehicle applications, which are at a lower technology readiness level than hydrogen fuel cells.

Hydrogen refuelling stations by region and ratio of hydrogen refuelling stations to fuel cell electric vehicles, 2017-2020



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Notes: HRS = hydrogen refuelling station. FCEV = fuel cell electric vehicle. RoW = rest of world.
Source: AFC TCP Deployment Status of Fuel Cells in Road Transport: 2021 Update.

At an average year-on-year increase of almost 20% during 2017-2020, the number of hydrogen refuelling stations (HRSs) is growing more slowly than that of FCEVs. The ratio of FCEVs to HRSs[15] is thus increasing, particularly in countries with the highest FCEV sales. In 2020, this ratio reached almost 200:1 in Korea and 150:1 in the United States, compared with just 30:1 in Japan.[16] This reflects, in part, excess HRS capacity, as stations are built anticipating FCEV growth.

Recent stations tend to have higher capacities than initial stations. In 2020, California unveiled a 1 200 kg/day station and allocated funding to construct stations of up to 1 620 kg/day; this is 2.5-3.5 times the average station size funded since 2012. In July 2021, the largest hydrogen station to date opened in Beijing, with a capacity of 4 800 kg/day.

Station refuelling pressure varies according to the vehicle market served. In most countries, the majority of stations dispense hydrogen at 700 bar to serve fuel cell cars. In China, most stations dispense at 350 bar to serve bus and truck fleets. Work is ongoing on station and component design and on fuelling protocols to enable high-throughput dispensing for trucks with 700-bar onboard storage, which will support a range of ~800 km – almost double that of current fuel cell trucks (~400 km). Some stakeholders, including Daimler, Hyzon

[15] In the absence of complete data on station capacity and dispensing, this ratio aims to provide some indication of station utilisation.

[16] For reference, the gas/diesel vehicle to station ratio in the United States is about 1 800:1.

and Chart Industries, are exploring onboard liquid hydrogen storage and refuelling to enable truck ranges of >1 000 km.

Rail

Hydrogen and fuel cell technologies have been demonstrated in rail applications, including mining locomotives, switchers and trams, since the early 2000s. In 2018, the first commercial service of a hydrogen fuel cell passenger train (developed by Alstom) began a 100-km route in Germany. Two Alstom trains in Germany have since driven >180 000 km, and more countries have started testing and adopting fuel cell trains.

In 2020, a hydrogen train entered regular passenger service in Austria, and trials began in the United Kingdom and the Netherlands. In Europe, France, Italy and the United Kingdom have all placed orders for hydrogen fuel cell trains, while the largest fleet – 27 hydrogen trains – is slated to begin permanent, regular operations in Germany in 2022.

Countries such as China, Korea, Japan, Canada and the United States are also showing interest in hydrogen fuel cell trains. In addition to passenger trains, hydrogen trams, line-haul and switching locomotives are in various stages of development and deployment. Where direct electrification of lines is difficult or too costly, deploying fuel cell rail applications can help decarbonise the sector.

Shipping

Hydrogen fuel cells have been demonstrated on several coastal and short-distance vessels since the early 2000s. None are yet commercially available, but the commercial operation of fuel cell ferries is expected to begin in 2021 in the United States and Norway. Most hydrogen-fuelled vessels currently under demonstration or planned for deployment in the next few years are passenger ships, ferries, roll-on/roll-off ships and tug boats, typically with fuel cell power ratings of 600 kW to 3 MW. Furthermore, a recent EU partnership aims to build a hydrogen ferry with 23 MW of fuel cell power.

Past and ongoing projects span both gaseous and liquid onboard hydrogen storage. Due to the low volumetric density of hydrogen (whether in gaseous or liquid form), direct use of hydrogen will be limited to short- and medium-range vessels, especially those with high power requirements that cannot be met through battery electrification.

Hydrogen-based fuels are also attracting attention for use as maritime fuels for large oceangoing vessels. Green ammonia in particular can be used in internal combustion engines to eliminate vessel CO_2 emissions. Major industry stakeholders have announced plans to make 100% ammonia-fuelled maritime engines available as early as 2023 and to offer ammonia retrofit packages for existing vessels from 2025.

The CEM Global Ports Hydrogen Coalition

Launched at the 12th Clean Energy Ministerial (1 June 2021), the CEM Global Ports Hydrogen Coalition aims to strengthen collaboration between government policymakers and port representatives to scale up low-carbon hydrogen use.

The IEA's The Future of Hydrogen identifies ports and coastal industrial hubs (where much of the refining and chemical production that currently uses hydrogen is concentrated) as opportune places to support the near-term scale-up of low-carbon hydrogen production and use. The shift from fossil-based to low-carbon hydrogen by industries in these clusters would boost hydrogen fuel demand by ships and trucks serving the ports as well as by nearby industrial facilities (e.g. steel plants), which would drive down costs.

To enlarge dialogue on hydrogen potential for port operations, the Coalition convenes numerous ports and stakeholders, including the International Association of Ports and Harbours and the World Ports Climate Action Program as well as regional associations (e.g. the European Sea Ports Organisation). The Hydrogen Council, the world's leading industry initiative, will also participate in Coalition activities along with other industry stakeholders.

Methanol has also been demonstrated as a fuel for the maritime sector and is relatively more mature than hydrogen and ammonia. Given its compatibility with existing maritime engines, methanol could be a near-term solution to reduce shipping emissions, but ultimately ammonia offers deeper decarbonisation potential.[17]

Aviation

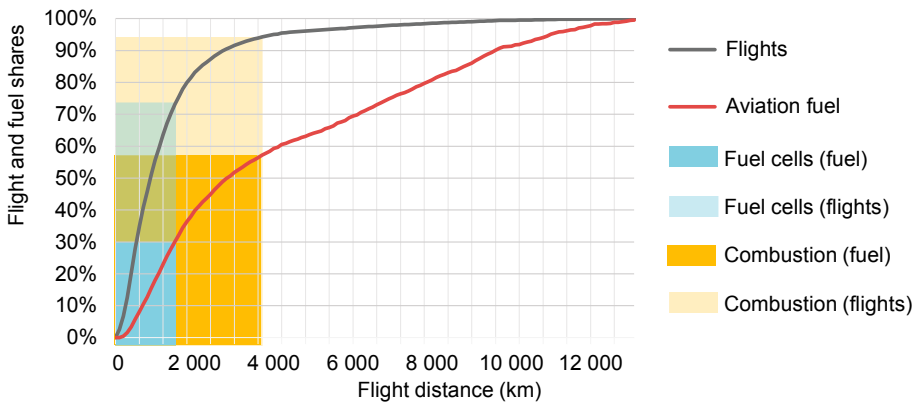
Interest in using hydrogen for aviation has also been growing. The industry group ATAG sees a role for hydrogen fuel cells for flights of up to 1 600 km, and hydrogen combustion for short flights and potentially for medium-haul ones. Assuming the technology is developed successfully, hydrogen fuel cells could be used in 75% of commercial flights but account for only ~30% of aviation fuel.

Technically, hydrogen combustion could be used for longer flights, potentially covering almost 95% of flights and 55% of fuel consumption, but equipment would be needed to mitigate NOx emissions.[18] Sustainable drop-in aviation fuels, including hydrogen-based fuels and biofuels, will be needed to decarbonise at least longer-haul flights, although means to mitigate non-CO_2 climate-warming effects may be required.

[17] However, ammonia combustion results in N_2O and NOx emissions that may require additional equipment to mitigate climate and air pollution impacts.

[18] A recent McKinsey & Company study prepared for the Clean Sky 2 JU and FCH JU is more optimistic about hydrogen use in aviation and provides a comparison of its climate impacts with those of synthetic fuels.

Hydrogen potential, by share of flights and fuel use in commercial passenger aviation



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Note: Shading indicates shares of aviation fuel use (solid) and flights (transparent) that could theoretically be offset by hydrogen aircraft, given successful technology development to meet industry targets.

Source: IEA analysis based on OAG flight database.

Whether used with fuel cells or directly combusted, using hydrogen will require new aircraft system designs. Airbus is exploring various hydrogen aircraft concepts, focused on a capacity of up to 200 passengers and a 3 700-km range, with the goal of having a commercial aircraft available by 2035. Smaller companies working on hydrogen aircraft solutions include ZeroAvia, which targets the first commercial offering of a hydrogen plane with a 900-km range in 2024, and Universal Hydrogen, which aims to develop hydrogen storage solutions and conversion kits for commercial aircraft.

Boeing recently partnered with Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) to publish a roadmap for hydrogen in the aviation industry that considers opportunities for hydrogen use in aircrafts and airport applications (buses, stationary power, ground support equipment, taxis, trains and freight trucks). Remaining technical challenges include light-weighting cryogenic storage tanks (with minimal boil-off) and developing hydrogen infrastructure for delivery (likely pipelines with near- or on-site liquefaction) and high-flowrate liquid refuelling.

Deployment of hydrogen in other mobile applications

Material handling equipment

Deploying zero-emissions material handling equipment, which includes forklifts and other machinery, is particularly important for indoor operations. Quick refuelling (~2 minutes) is cited as a benefit of fuel cells: in contrast with battery electric equipment, which forces drivers to return to a central location during a shift to swap out batteries, hydrogen refuelling can be situated more strategically throughout a warehouse. Fuel cells also perform particularly well in refrigerated environments, whereas cold temperatures degrade batteries.

Forklifts have proven to be an early commercial application for fuel cells. The United States currently has >40 000 hydrogen forklifts, with Plug Power being the major provider. Japan targets 10 000 by 2030, an ambitious scale-up from its current 330, and Belgium, Canada, France and Germany also each have fuel cell material handling equipment numbering in the hundreds. In Chile, Walmart has announced plans to convert 150 battery forklifts to fuel cell, powered by green hydrogen.

Mining and agricultural equipment

Hydrogen fuel cells may also be used to help decarbonise heavy off-road applications such as mining and agricultural equipment. As part of its national decarbonisation policy and Green Mining Plan, Chile supports projects to investigate and develop hydrogen-fuelled mining trucks, and the mining industry in general is investing in hydrogen technologies for mining equipment.

Anglo American expects to begin testing the first fuel cell mining truck in the second half of 2021 at a platinum group metal mine in South Africa. Komatsu, the Japanese construction equipment maker, plans to develop a fuel cell mining dump truck, aiming to commercialise it by 2030. While electric mining trucks powered by catenary lines already exist, fuel cell trucks offer decarbonisation potential for routes that power lines do not reach.

Agricultural equipment company New Holland, which showcased a fuel cell tractor in 2011, has now developed (as a transitional technology) a dual-fuel tractor that runs on a hydrogen-diesel blend. Other companies such as H2X and H2Trac are also developing fuel cell tractors.

Insights into regional strategies for hydrogen fuels in transport

China

China currently has the third-largest FCEV stock. Unlike other countries, it has focused on deploying fuel cell buses and trucks, and it now has the highest number in the world. Owing to a previous subsidy scheme, which set the fuel cell requirement at just 30 kW to qualify, fuel cells have been used mainly as range extenders. A new rewards-based policy framework aims to accelerate hydrogen demonstration at the regional (or city-cluster) level and focuses on the FCEV operation and supply chain, including hydrogen production and vehicle hydrogen consumption.

China has not yet approved type-IV hydrogen tanks used for 700-bar onboard storage, which partially explains its past emphasis on deploying mainly buses and trucks. While trucks and buses are expected to dominate FCEV sales in the next few years, regulatory approval and deployment of fuel cell cars will likely be needed to reach targets outlined in China's Technology Roadmap 2.0. The Society of Automotive Engineers is aiming for 50 000-100 000 FCEVs in 2025 and 1 million between 2030 and 2035.

In non-road applications, China has developed a hydrogen tram and hybrid locomotive. An ammonia fuel-ready tanker now being built could become the first maritime vessel to operate on this fuel.

Europe

At the end of 2020, over 2 600 FCEVs were operating in Europe, with more than 1 000 in Germany. More than 90% of Europe's FCEVs are light-duty, and about 130 are fuel cell buses. Germany also leads in the number of HRSs, with 90 operating at the end of 2020 (of 190 across Europe).[19]

The Fuel Cell and Hydrogen Joint Undertaking (FCH JU) has supported a wide variety of FCEV demonstration and deployment projects, including taxis, delivery vans, buses and refuse trucks. As a result, the deployment of fuel cell taxis in Europe has been relatively high, most notably in Paris (100), the Hague (~40), Copenhagen (~10) and London (>50). Madrid has announced plans to deploy 1 000. Several European countries (the Czech Republic, France, the Netherlands, Portugal and Spain) have set FCEV targets, together aiming for ~415 000 FCEVs by 2030.

[19] The European Commission's Fit for 55 package's revisions to the Alternative Fuels Infrastructure Directive aims to ensure the HRS network is dense enough to "allow for seamless travel" of FCEVs, with an emphasis on heavy-duty vehicles.

Europe has been a leader in commercialising fuel cell trains. Additionally, the European Union has funded demonstrations of fuel cell-powered maritime vessels, including EUR 5 million (~USD 5.9 million) for the FLAGSHIPS project, which is deploying a hydrogen cargo transport vessel in France and a hydrogen passenger/car ferry in Norway, and EUR 10 million (~USD 11.8 million) for the ShipFC project, which will install a 2-MW ammonia fuel cell on an offshore vessel.

In July 2021 the European Commission presented the ReFuelEU Aviation proposal, which would require a minimum share of sustainable aviation fuel at all EU airports, including a continually increasing minimum share of synthetic aviation fuel. It aims to increase the share of synthetic aviation fuel from 0.7% in 2030 to 28% in 2050.

Additionally, the German government recently released a power-to-liquids (PtL) roadmap targeting the consumption of 200 000 tonnes of hydrogen-based sustainable aviation fuel in 2030. Meanwhile, as part of its *Plan de relance aéronautique* (a programme to help the aerospace industry recover from Covid-19 impacts), the French government has granted EUR 800 000 for development of a small (two-seat) hybrid hydrogen aircraft. The FCH JU has also funded the HEAVEN project, aimed at developing and integrating a high-power fuel cell and cryogenic hydrogen storage system into an existing small aircraft.

Japan

At the end of 2020, Japan had 4 100 fuel cell cars and 100 fuel cell buses, and by mid-2021 the total had surpassed 5 500. With 137 HRSs at the end of 2020, Japan currently has the most in the world. Future (2030) targets include 800 000 PLDVs, 1 200 buses, 10 000 forklifts and ~1 000 HRSs (recently revised upwards from 900 as part of Japan's Green Growth Strategy).

To support targeted level of FCEV adoption, Japan aims to make them price-competitive with comparable hybrid EVs, particularly by reducing the cost of fuel cells and hydrogen storage systems. Japan is also targeting HRS cost reductions;[20] to date, prescriptive regulations have contributed to stations costing twice that in other parts of the world. Current HRS development and operations are financially supported through Japan Hydrogen Mobility (JHyM), a consortium of 26 private companies, financial institutions and the government.

[20] HRS cost reduction targets include reducing capital expenses from JPY 350 million (~USD 3.2 million) in 2016 to JPY 200 million (~USD 1.8 million) around 2025.

The East Japan Railway Company, partnering with Hitachi and Toyota, has announced plans to develop a hydrogen train, with testing to begin in 2022. To meet International Maritime Organisation (IMO) standards on GHG emissions for international shipping, Japan is also investigating hydrogen- and ammonia-fuelled vessels. In 2020, the government published the Roadmap to Zero Emissions in International Shipping, which targets introduction of a first-generation zero emissions ship by 2028.

Korea

Korea took the lead in FCEVs in 2020, with >10 000 cars and >50 buses on the road. Its FCEV stock doubled from 2019 to2020, and by the end of June 2021 an additional 4 400 fuel cell cars had been registered. Purchase subsidies from central and local governments cover about half of the purchase price of the popular, domestically produced Hyundai NEXO. In the Hydrogen Economy Roadmap, FCEV targets are set at 2.9 million cars, 80 000 taxis, 40 000 buses and 30 000 trucks by 2040. In the 2020 New Deal, the government set an interim target of 200 000 FCEVs in 2025.

Korea had 52 operational HRSs at the end of 2020, and the government is targeting 310 by 2022 and 1 200 by 2040. The Hydrogen Energy Network (HyNet) was therefore established in 2019 with an investment of USD 119 million to build ~100 HRSs by 2022.

According to Korea's hydrogen roadmap, the government plans to expand its focus to include hydrogen ships, trains and drones once the road vehicle market has matured. In fact, the government recently provided funding (USD 13 million) to the Korean Railroad Research Institute to develop the world's first liquefied hydrogen-based locomotive, slated for testing at the end of 2022.

United States

The United States currently has the second-largest FCEV fleet, with >9 200 at the end of 2020. Most are in California, where the state government has supported HRS construction with funding of USD 166 million. At the end of 2020, there were 45 retail stations open in California and a total of 63 public and private HRSs across the country.

The California Energy Commission estimates the state will have 179 HRSs by 2027 with capacity to support 200 000 FCEVs, though this would miss the target of 200 HRS by 2025. Despite industry plans to expand the FCEV market to the north-eastern US states, regulatory barriers in some states are impeding deployment.

To date, the US government has not established federal targets for FCEV deployment. However, the California Fuel Cell Partnership, an industry and government collaboration, has announced its ambition to have 1 million FCEVs and 1 000 HRSs in the state by 2030.

To guide R&D efforts, the US Department of Energy has set cost and performance targets for fuel cells for light- and heavy-duty vehicles. In 2019, the DOE published heavy-duty long-haul truck targets, including reducing the cost of the fuel cell system to USD 60/kW and increasing its durability (i.e. lifetime) to 30 000 hours. To support R&D to meet these targets, the DOE established and funded the Million Mile Fuel Cell Truck Consortium.

California government agencies have also supported vehicle deployments, including the first fuel cell ferry (launch expected in 2021), development of a hydrogen fuel cell switching locomotive and the deployment of heavy-duty hydrogen trucks.

Outlook for hydrogen in transport

Road transport

Road vehicles account for the highest share of hydrogen and hydrogen-based fuel consumption in transport in 2030 under both the Announced Pledges (58%) and Net zero Emissions scenarios (45%). FCEV stock, across all modes, reaches >6 million in the Announced Pledges Scenario and >15 million in Net zero Emissions, with most being LDVs. The share of cars within the total FCEV stock remains at about 75% from 2020 to 2030 in the Announced Pledges Scenario, but decreases to 70% in the Net zero Emissions Scenario.

Generally, EVs are expected to be the dominant zero emissions vehicle powertrain in road transport, reflecting higher efficiency and a lower TCO in most cases. FCEV sales in 2030 reach 1% in the Announced Pledges Scenario (compared with 29% for EVs) and 3% in the Net zero Emissions Scenario (against almost 60%) owing to supportive government policies and subsidies, as well as consumer preference for non-cost factors (e.g. refuelling or charging time).

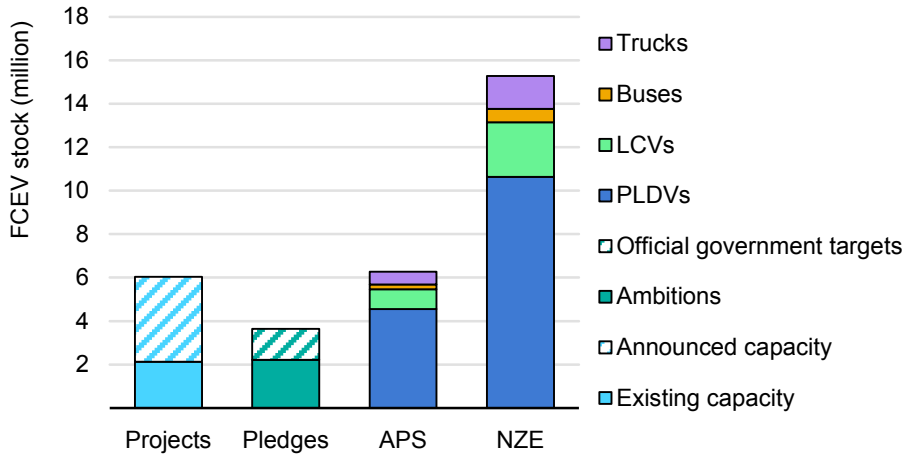
In the Announced Pledges Scenario in 2030, the sales share of fuel cell buses (3.7%) is the highest of all road transport modes, mainly because they offer advantages over battery electric technology for intercity buses. Fuel cells can also compete in the long-haul-trucking sector, as their range, refuelling time and payload capacity can enable performance and operations similar to current diesel trucks.

Similarly, fuel cell buses reach the highest sales share (6.1%) in 2030 in the Net zero Emissions Scenario. In addition, rapid technology and infrastructure development is assumed to support fuel cell truck deployment, which reaches a sales share of 4.7% in 2030. Use of synfuels for road transport is limited due to a higher TCO than for other zero- or low-emission alternatives.

In 2019, the Hydrogen Energy Ministerial published the Global Action Agenda targeting 10 million fuel cell-powered systems (including road vehicles, trains, ships and forklifts) by 2030. Annual fuel cell production capacity doubled from 2019 to 2020, but FCEV deployment in 2020 was ~20% lower than in 2019 – and well below the annual average needed to achieve the target. Even including the deployment of material handling equipment such as forklifts (~10 000 in 2020), accelerated scale-up is needed (likely beyond Announced Pledges projections) to achieve such an ambitious target.

Announced annual fuel cell manufacturing capacity by 2030 (~1.3 million systems/yr) could meet 75% of required fuel cell production for road vehicle sales in the Announced Pledges Scenario but would satisfy only less than one-third of Net zero Emissions sales. Notably, announced capacity exceeds the FCEV stock targets and ambitions stated by governments and other groups (e.g. the China Society of Automotive Engineers and the California Fuel Cell Partnership).

FCEV stock in the Announced Pledges and Net zero Emissions scenarios in 2030 vs current and announced cumulative fuel cell manufacturing capacity and FCEV deployment targets



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Notes: FCEV = fuel cell electric vehicle. LCV = light commercial vehicle. PLDV = passenger light-duty vehicle. APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. FCEV ambitions include non-government targets such as from the China Society of Automotive Engineers and the California Fuel Cell Partnership. Sources: IEA Mobility Model (projections); E4tech (fuel cell projects).

To support FCEV deployment in 2030, an estimated 27 000 HRSs would be needed in the Announced Pledges Scenario and 18 000 in the Net zero Emissions. These estimates are highly sensitive to station capacity and utilisation assumptions. As station size and utilisation are expected to grow more slowly in the Announced Pledges than in the Net zero Emissions Scenario, the former requires a higher number of HRSs despite a lower number of vehicles.

In the Net zero Emissions Scenario, installed station capacity reaches >50 kt/day in 2030, compared with <20 kt/day in the Announced Pledges Scenario.

Non-road transport

Shipping becomes the second-largest consumer of hydrogen and hydrogen-based fuels among transport modes in 2030 in both the Announced Pledges and Net zero Emissions scenarios. Demand for hydrogen and ammonia in shipping remains limited in the Announced Pledges Scenario, together meeting about 1% of fuel demand. In the Net zero Emissions Scenario, ammonia meets 8% of total shipping fuel demand and hydrogen meets 2%.

To enable hydrogen and ammonia fuel use in shipping, ports will need to build corresponding bunkering infrastructure. It is expected that ports with hydrogen bunkering infrastructure will remain fairly limited until 2030, with most being “first movers” such as the signatories of the Global Ports Hydrogen Coalition and others that have already begun investigating and testing hydrogen solutions (e.g. the Port of Valencia, Port of Honolulu, Ports of Auckland, Port of Los Angeles and Port of Antwerp).

As hydrogen continues to displace fossil fuels in relatively short-range vessels (especially when battery electrification is difficult), in the long term every port serving ferries, cruise ships and inland and coastal vessels will likely need hydrogen infrastructure. In the Net zero Emissions Scenario, about ten ports are projected to be first

movers in providing ammonia bunkering services (fewer in the Announced Pledges Scenario), all having high maritime cargo throughput and either existing ammonia bunkering or plans to integrate new fuels. Included in the first movers are the ports of Rotterdam and Singapore (both ranking in the top ten by container throughput), as well as the Keihin ports along Japan's Tokyo Bay.

In rail, hydrogen is expected to mainly replace current diesel lines that are expensive to electrify due to relatively low utilisation.[21] Hydrogen constitutes 0.7% of rail energy consumption in 2030 in the Announced Pledges Scenario and 2% in the Net zero Emissions.

Passenger aircraft, for commercial aviation, designed to use hydrogen directly are not expected to be commercially available until the mid-2030s or later. Use of hydrogen-based synfuels (or power-to-liquids [PtL]), which can be dropped into an existing aircraft, could make inroads by 2030. In the Announced Pledges Scenario, PtL meets <0.6% of aviation fuel demand in 2030, but this share almost triples to >1.6% in the Net zero Emissions Scenario.

Given the limited availability of sustainably sourced carbon, the bulk of synfuels are consumed in the aviation sector where battery electrification and direct use of hydrogen are restricted to relatively short flights, especially in the near to medium term.

[21] See The Future of Rail for further analysis.

Transport industry announcements for FCEVs

Company	Target	Target year	Vehicle category
BMW	Limited-series fuel cell SUV release	2022	PLDV
Jaguar Land Rover	Prototype testing of fuel cell SUV	End of 2021	PLDV
Great Wall Motor	Fuel cell SUV release	2021	PLDV
Toyota Motor Corp.	Deployment of 600 FCEV taxis in greater Paris region	End of 2024	PLDV
Riversimple	Production target of 5 000 fuel cell coupes/yr	2023	PLDV
Riversimple	Light goods vehicle model release	2023	LCV
Stellantis	Fuel cell van models release	2021	LCV
Renault and Plug Power	Light commercial vehicle models release	2021	LCV
Symbio and Safra	Availability of 1 500 buses	2021	Bus
Symbio and Safra	Construction of largest EU fuel cell plant (60 000 units/yr)	Unspecified*	Bus
H2Bus Consortium	Deployment of 600 fuel cell buses	2023	Bus
Daimler	Testing of GenH2 truck with liquid hydrogen onboard storage	2021	Truck
Air Products and Cummins	Conversion of ~2 000-truck fleet to hydrogen fuel cells	2022+	Truck
Nikola	Purchase order of up to 800 fuel cell trucks to US Anheauser-Busch	2023+	Truck
MAN	Deployment of hydrogen fuel cell demonstration fleet	2024	Truck
Hyzon	Purchase orders for 1 500 fuel cell trucks to Hiringa Energy in New Zealand; 20 to Jan Baaker and Millenaar & van Schaik in the Netherlands; and 70 to JuVE/MPREIS in Austria	2024	Truck
Hyundai	Purchase order of 1 600 fuel cell trucks to Switzerland	By 2025	Truck
Daimler and Volvo	Large-scale series production of fuel cell trucks	2025+	Truck
Industry Coalition	Deployment of 100 000 heavy-duty fuel cell trucks in Europe	From 2030	Truck

* Although plant construction has already begun, the target date for operations is unspecified.

Notes: PLDV = passenger light-duty vehicle. LCV = light commercial vehicle.

Cost and supply chain analysis

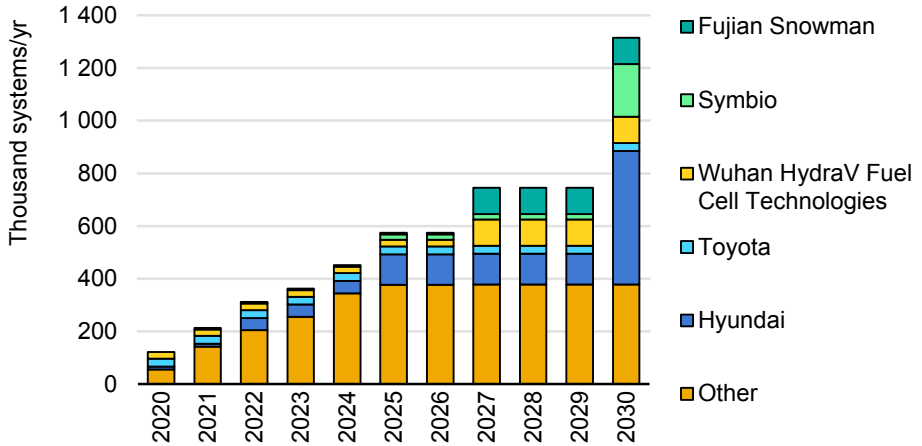
Fuel cells

The cost of automotive fuels cells has fallen ~70% since 2008. Depending on the vehicle segment, current system costs are USD 250-400/kW, but further reductions are needed to make FCEVs cost-competitive with internal combustion engine vehicles and other low- or zero emission vehicles. Analysis suggests that scaling up manufacturing capacity from 1 000 to 100 000 systems/yr would slash costs by >70%, but significant investment is needed to boost manufacturing throughput and capacity.

To this end, new and incumbent fuel cell manufacturers have announced expansion plans. Global fuel cell manufacturing capacity is expected to reach >200 000 systems/yr by the end of 2021, with supply spread among over 40 manufacturers. Toyota can currently produce 30 000 systems/yr, and Hyundai is building a second plant to bring capacity to >40 000 systems/yr in 2022 and aims reach 500 000 systems/yr by 2030. Manufacturing capacity announcements for 2030 total 1.3 million systems/yr, with an estimated annual production potential of 90 GW.

Technological advances are needed to improve fuel cell durability (which is particularly vital for heavy-duty transport applications) and reduce costs while maintaining or improving efficiency. Key areas for R&D include the fuel cell catalyst, currently based on platinum group metals; membranes and electrolytes; and bipolar plates.

Announced annual automotive fuel cell manufacturing capacity, 2020-2030



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Source: E4tech.

Since 2008, average platinum loading in fuel cells has decreased 30%. Toyota reports reducing platinum loading in the Mirai fuel cell by about one-third from first- to second-generation models.

In addition to lowering costs, reducing platinum loading mitigates potential supply chain risks associated with highly geographically concentrated supplies, as more than 70% of platinum group metals are sourced from South Africa.

According to the IEA's critical minerals report, global demand for platinum group metals is expected to grow as FCEVs displace conventional vehicles, though this is mitigated by lower palladium required for ICEV catalytic converters. Overall platinum demand is expected to increase despite further reductions in the platinum loading of automotive fuel cells.

Hydrogen refuelling stations

While economies of scale in station component manufacturing are expected to reduce the delivered cost of hydrogen for vehicles, HRSs with higher capacities will also have a lower levelised cost of dispensed hydrogen. Increasing station size from 350 kg/d to 1 000 kg/d could cut the cost of dispensed hydrogen by over 30%, according to US DOE analysis. As both station capacity and vehicle demand increase, pipeline delivery will become more profitable and could further reduce the overall cost of dispensed hydrogen.

Station utilisation is another important factor. While utilisation tends to align with vehicle deployment, early FCEV fleet deployment can help ensure a certain level of utilisation, lowering hydrogen prices. Stations designed to serve both LDVs and HDVs may be able to increase utilisation and reduce overall capital expenditures, though serving both vehicle types will require more equipment to fuel at different pressures or flowrates.

The number of suppliers for key HRS components is currently limited, which can restrict station roll-out and prevent the cost reductions that come with market competition. For example, just two companies (WEH and Walther) dominate the HRS nozzle market.

Novel component designs (including for high-throughput compressors, cryogenic hydrogen pumps, hoses and nozzles) and refuelling protocols are needed for fast fuelling of heavy-duty trucks, marine vessels and aircraft.

Total cost of ownership

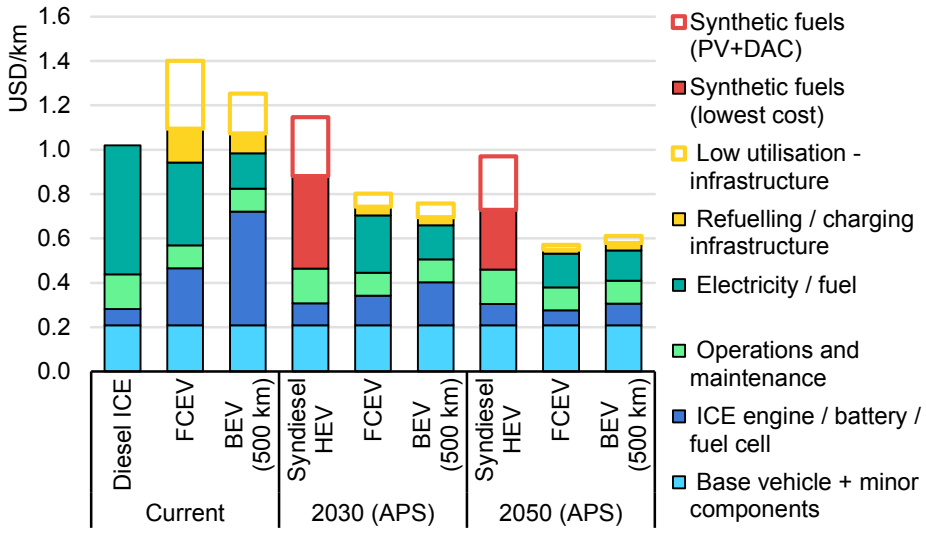
Adoption of FCEVs, especially buses and commercial vehicles, will be determined by how their TCO compares with other vehicle and fuel technologies. The main TCO factors for FCEVs are the delivered hydrogen and fuel cells costs, and station utilisation. In comparison with BEVs, daily range is another key consideration.

For long-haul HDVs, enabling a sufficient driving range may require additional battery capacity; however, the associated weight could limit payload and add to BEV cost. Fuel cell trucks begin to have a TCO advantage over battery electric at a range of 400-500 km, as shown in the IEA's Energy Technology Perspectives 2020.

The TCO for fuel cell heavy-duty trucks is currently 10-45% higher than for internal combustion diesel trucks. In the Announced Pledges Scenario, as the manufacturing of fuel cells, station components and hydrogen production technologies scales up – while station utilisation also increases – the TCO of fuel cell heavy-duty trucks drops 30-40% by 2030 and 50-60% by 2050.

Comparing decarbonisation options for this sector, the TCOs of both battery electric and fuel cell trucks are expected to be lower than for hybrid electric trucks running on synthetic diesel. In the medium term, fuel cell and battery electric trucks have comparable TCOs at a 500-km driving range, depending on refuelling or charging infrastructure utilisation. By 2050 in the Announced Pledges Scenario, fuel cell electric trucks are expected to be the lower-cost option at that range.

Current and future total cost of ownership of fuel/powertrain alternatives for heavy-duty trucks.



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Notes: APS = Announced Pledges Scenario. ICE = internal combustion engine. FCEV = fuel cell electric vehicle. BEV = battery electric vehicle. HEV = hybrid electric vehicle. PV = photovoltaic (solar electricity for synthetic fuel production). DAC = direct air capture. Techno-economic assumptions available in the Annex.

Source: Based on input from McKinsey & Company and the Hydrogen Council.

Buildings

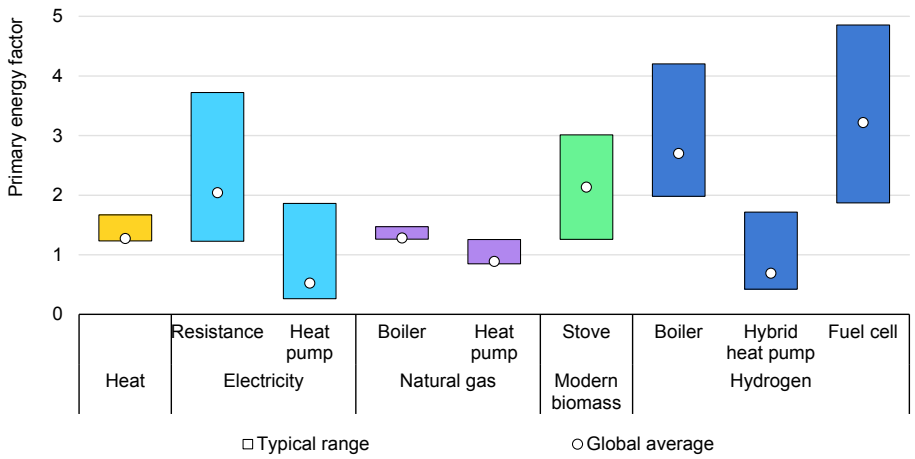
Hydrogen and fuel cell opportunities are limited in buildings but worth exploring

With consumption of almost 70 EJ, space and water heating in buildings accounts for nearly 55% of energy use in buildings globally and 4.3 Gt CO_2 of emissions. In very cold areas such as in Russia, the Caspian region and Iceland, heating can make up >80% of total energy demand in buildings. Improving the thermal performance of building envelopes and integrating clean, efficient low-temperature equipment are priorities to decarbonise heating in buildings. Several options for efficient heating are currently available, including heat pumps and clean district energy.

Prospects for deploying hydrogen in this sector remain limited, reflecting the high efficiency of electricity-based solutions and the energy losses that result from converting and transporting hydrogen. For instance, PV-powered heat pumps require 5-6 times less electricity than a boiler running on electrolytic hydrogen to provide the same amount of heating. Furthermore, ensuring safe operations and converting gas infrastructure are both capital-intensive and socially challenging.

The heating sector is difficult to decarbonise, with existing (old) multi-family buildings and very cold climates being particularly challenging because integrating efficient low-temperature solutions depends on space availability, energy system layout and overall building performance, in addition to logistical and economic costs for building occupants.

Primary energy factors of heat production by equipment and fuel, 2020



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Notes: Hybrid heat pumps are assumed to use 25% hydrogen. Heat refers to district heating. Assumptions available in the Annex

Nevertheless, since hydrogen equipment can be compatible with existing buildings' energy systems,[22] localised hydrogen applications

[22] In terms of deliverable temperature range and operational schedules, but pipework, metering and verification interventions are required.

could support decarbonisation in very specific contexts where gas infrastructure already exists. Co-existence of hydrogen and other heat production technologies can also add flexibility to the electricity grid to facilitate demand-side response, particularly in very cold regions where BEVs and other storage devices would likely fall short.

Hydrogen can be blended with or replace a portion of natural gas, which currently meets 35% of global energy demand for heating. Depending on the region, such blending (at volumes of 5-20%) can leverage current natural gas infrastructure without requiring major network modifications.

Blending hydrogen at 20% would reduce carbon intensity by 7% at most – well short of the level needed for long-term buildings sector decarbonisation. It would also affect gas prices for end users. While decarbonising established hydrogen use remains a priority, blending options could help guarantee demand for low-carbon hydrogen.

In the longer term, hydrogen-specific infrastructure could be expanded (by building up dedicated networks or retrofitting existing ones) to further displace natural gas. Space and water heating equipment will also need to be upgraded or replaced, then verified as operational.

Deployment of hydrogen equipment needs to be specifically targeted to applications where it is cost-effective compared with switching to other options, and it takes roughly five days to adapt a building's energy system.

Four main groups of technologies can operate on hydrogen at the building level:

- **Hydrogen boilers** can be practical where gas networks exist because consumers will be familiar with the basic technology and its upfront capital costs. From a lifecycle perspective, however, higher fuel consumption than more efficient technologies makes this option less attractive overall for most buildings.
- **Fuel cells that co-generate**[23] **heat and electricity** include solid oxide fuel cells (SOFCs) and polymer electrolyte membrane fuel cells (PEMFCs). SOFCs require a high temperature but also provide high electrical efficiency and a more stable load compared with PEM cells, which work at a lower temperature (60-80°C) on intermittent load schedules but offer lower electrical efficiency. As SOFC efficiency typically declines when operated with pure hydrogen, optimising the system layout to address this issue is a key research focus. Natural gas field testing in Europe shows micro-cogeneration unit electrical efficiencies of 35-60% for SOFCs and 35-38% for PEMFCs, with corresponding cogeneration system efficiencies of 80-95% (SOFCs) and 85-90% (PEMFCs).

[23] Co-generation refers to the combined production of heat and power, also known as CHP.

- **Hybrid heat pumps** combine a boiler with an electric heat pump. The boiler operates only when the heat pump cannot meet heating demand. Hybrid heat pumps are an interesting option in cold climates where hydrogen can be used to cover peak demand during very cold periods, but they have additional capital costs and require both electricity and hydrogen connections.
- **Gas-driven heat pumps** have a gas engine that produces electricity to run a heat pump. Thousands of units are already operating in Asia and Europe, primarily in non-residential buildings.

Status of hydrogen and fuel cells for buildings

In 2020, hydrogen's share in heating energy demand was extremely limited (at less than 0.005%) even though countries began supporting demonstration projects and programmes to deploy hydrogen-compatible technologies, spark market adoption and reduce upfront consumer costs as early as the 2000s. Largely focused on stationary fuel cells, these programmes have tended to rely on natural gas, but their lessons are applicable to the use of pure hydrogen. These projects are sited in countries that together cover ~40% of global heat demand, with significant heating seasonality and where natural gas covers a large share of heat production in buildings.

Stationary fuel cells

Deployment of micro-cogeneration stationary fuels cells (<1 kW of electrical output [kW_e] for residential applications, and up to 5 kW_e) has been greatest in Japan (more than 350 000 units operating) and Europe, especially in Germany (15 000), Belgium and France. Korea has 15.7 MW_e (units of <100 kW_e) installed in buildings (CEM H2I surveys), while US installations are primarily industrial-scale units (>100 kW_e).

Fuel cells have been deployed in almost all building types – from residential to commercial/public building applications, including military installations, hospitals and data centres – to provide primary or backup power, or co-generation. Most run on natural gas. Fuel cells for residential applications are mostly PEM and tend to be relatively small (0.7-1.5 kW_e but also up to 5 kW_e), with several governments offering financial incentives to support their deployment.

Homeowners in the United States can qualify for federal tax credits (>USD 3 300/kW_e) when installing residential units of >0.5 kW_e. Other government schemes offer subsidies for fuel cell technologies, such as New Jersey's Clean Energy Program for micro-cogeneration technologies. Korea is among the countries using renewable energy certificates and subsidies. Support generally covers the upfront costs of installation, or rewards power generation rather than heat production.

Hydrogen blending and pure hydrogen applications

There are a number of projects around the world at various stages for exploring the impact of hydrogen blending in existing gas networks. Frontrunner, launched in 2007 on the Dutch island of Ameland, tested injection volumes of up to 20% for heating and cooking using standard appliances. More recently in France (June 2018 to March 2021), the GRHYD project tested injection (max. 20%) for >100 dwellings, while the three-phase UK HyDeploy project aims

to prove the safety of blending up to 20%. The first phase, concluded in 2021, involved a live demonstration in the Keele gas network to assess what level of blending is safe with existing domestic appliances.

Other initiatives aiming to demonstrate hydrogen use in dedicated networks in a few hundred dwellings are now under development, particularly in north-western Europe. These include H100 Fife (300 households starting in 2022) in the United Kingdom and Hoogeveen and Stad aan 't Haringvliet (600 households from 2025) in the Netherlands. Larger projects, such as the United Kingdom's H21, are at early stages of development.

The UK government also supports the Hy4Heat project to assess the technical, economic and safety aspects of replacing natural gas with hydrogen in residential and commercial buildings and in gas applications. Under this programme, a Worcester Bosch 100% hydrogen-ready prototype boiler – which can be converted to run on hydrogen by modifying just two or three components – won Best Heating Innovation in the 2021 Green Home Awards.

In a first trial in single-family, semi-detached and terraced houses, the project found that 100% hydrogen use is as safe as natural gas for heating and cooking. More research is needed to assess safety in multi-family homes and houses with limited natural ventilation, and to determine the safety of supplying homes through gas networks. The project is also assessing the first home (in Low Thornley, Gateshead) to be entirely fuelled by hydrogen, from boilers to cookers.

The WaterstofWijk Wagenborgen project (in the Netherlands) is a pilot that will connect 1970s buildings to a hydrogen network. Wagerborgen hybrid heat pumps will be installed in each house, running as much as possible on electricity and switching to hydrogen during cold periods only; houses will also be equipped with solar panels and induction cooking.

Natural gas use in the buildings sector and selected key projects, initiatives, programmes, announcements for deploying hydrogen or hydrogen-compatible equipment by country or region, 2020

Region	Share of global heating consumption (%)	Share of water heating in heating consumption (%)	Share of natural gas in:		Initiative details
			Heating (%)	Cooking (%)	
United States	17	19	65	60	New Jersey's Clean Energy Program provides financial incentives for co-generation and fuel cell installations.
United Kingdom	2.5	21	70	50	HyDeploy for hydrogen blending applications. H21 Leeds City Gate and H21 Network innovation for 100% hydrogen application. Hy4Heat project.
Korea	1.5	22	48	63	Announced intentions to create three hydrogen power cities by 2022, in line with hydrogen roadmap goal of providing households and other buildings 2.1 GW of power from fuel cells.
European Union	15	20	40	32	Ene.field project, Europe-wide field trials for residential fuel cells, concluded in 2017.
					PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market), ends in 2021. ComSos, (Commercial-scale SOFC systems), ends in 2022. National innovation Programme for hydrogen and fuel cell technology (Germany), 2007-16. KfW433 (Germany), dedicated fuel cell programme since 2016;
					overall impact: >15 000 fuel cells deployed in EU.
					GRHYD (France): power-to-gas testing with hydrogen blending rates of up to 20% per volume, 2018-21. WaterstofWijk Wagenborgen planned project (Netherlands): demonstration project for hybrid heat pumps for 40 residents.
Japan	3	35	32	39	Ene.Farm project, >350 000 commercial fuel cells deployed.

Notes: Listed projects include concluded as well as ongoing and announced initiatives related to buildings. Heating consumption includes space and water heating.

Regional insights on hydrogen in buildings

Japan

With more than 350 000 units installed as of March 2021, Japan leads global deployment of micro-cogeneration fuel cells in buildings. The ENE-FARM programme is the main contributor to uptake, recently reporting sales of 40 000 units/yr. Models on the market are mostly fuelled by natural gas; most are PEMFC units, but SOFCs have also emerged recently. ENE-FARM subsidies were eliminated in FY2019 for PEMFCs as they reached maturity, but SOFCs remained eligible for subsidies until FY2020 (March 2021).

In 2020, to support the next phase of subsidiary projects and show that fuel cells can be a source for Japan's electricity market, 300 kW of domestic fuel cells were successfully tested to generate electricity at prices similar to those of the electricity retailer. Decarbonising buildings will require a fuel shift for fuel cells, from natural gas to low-carbon gases (such as hydrogen or synthetic methane produced with CO_2 from sustainable sources). Already Panasonic is deploying pure hydrogen fuel cell generators to power streetlights and air conditioning units at the HARUMI FLAG residential complex in Tokyo.

In both the Announced Pledges and Net zero Emissions scenarios, fuel cells in the Japanese market operating on pure hydrogen reach ~1 million installed units by 2030, requiring the development of hydrogen infrastructure.

Korea

The Korean Ministry of Trade, Industry and Energy is currently subsidising fuel cells (as well as solar power and heat, and geothermal and wind energy) to power residential and commercial buildings, with subsidies covering up to 80% of equipment installation costs. As further incentive, the government reduced the price of grid gas used in fuel cells by 6.5% from typical consumer prices, both in buildings and at utility scale.

Total installed stationary fuel cell capacity within buildings was 15.7 MW_e in 2021 according to CEM H2I surveys, largely PEMFC units with capacities ranging from 600 W to 10 kW for residential and commercial buildings. Doosan and S-FuelCell dominate the market, and market attention is shifting towards SOFC units and the use of fuel cells (equivalent to battery power) to boost flexibility in the electricity grid. The Hydrogen Economy Roadmap of Korea targets the cumulative installation of at least 2.1 GW_e of stationary fuel cells by 2040.

Europe

Several European countries are testing fuel cell applications and exploring the technical feasibility of hydrogen blending or pure hydrogen for buildings sector applications. Demonstration projects

are ongoing to verify the technology and gain the technical experience necessary to build a regulatory framework.

To date, stationary fuel cell deployment for buildings has been concentrated primarily in domestic units (commercial and industrial systems are less common). The market for fuel cells for residential applications has been supported mainly by projects co-funded by the FCH JU and the European Union, and by the German KfW 433 programme, which aims to enable manufacturers to eventually industrialise this technology.

The ene.field project (concluded in 2017) deployed >1 000 small fuel cell applications (~1.15 MW_e operating on natural gas) in ten countries, in different climates and dwelling types. The subsequent PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market) project aims to deploy >2 800 fuels cells by 2021. In the framework of this project, nearly 740 units were installed in Belgium and more than 710 in Germany.

Commercial-scale units (10-60 kW) are currently being demonstrated through the EU-funded ComSos project, which focuses solely on SOFC units and aims to install 25 in non-residential buildings such as supermarkets.

Germany

With >15 000 units operating, Germany has been the most successful market for stationary fuel cell installations in Europe, according to CEM H2I. Of the >1 000 units demonstrated by the Ene.field project, >750 were installed in Germany.

Fuel cell ramp-up was spurred by Germany's KfW 433 programme, launched in 2016 by the Federal Ministry for Economics and Energy and still ongoing. The programme provides a combination of grants and output-related subsidies of up to USD 3 400 for units with a capacity of 250 W to 5 KW_e, in both new and existing residential and non-residential buildings.

The Netherlands

Although the Netherlands has traditionally relied heavily on natural gas for residential heat, in 2018 the Gas Act was amended to ban gas connections for new homes and buildings. Subsequently, the Natural Gas-Free Districts Programme was implemented to help the country become natural gas-free by 2050. Forty-six municipalities are currently participating as test sites and to map how the transition can be scaled up, with a total of 1.5 million homes to shift from natural gas to low-carbon heating by 2030.

The Netherlands' Government Strategy on Hydrogen and Green Gas Roadmap aim to accelerate large-scale production and use of low-carbon hydrogen and biogas, with the government supporting pilot projects to demonstrate hydrogen. Meanwhile, the Green Deal H2 Neighbourhoods project aims to improve understanding of the techno-economic, safety, social, legal and administrative aspects of using existing gas infrastructure for hydrogen distribution.

Pilot projects in Hoogeven (100 new buildings and 427 existing households converted to run on hydrogen for heating) and Stad aan 't Haringvliet (600 existing buildings disconnected from natural gas by 2025) will help identify barriers and operational needs to scale up hydrogen use in buildings.

United Kingdom

Driving low-carbon hydrogen growth is part of the UK government's Ten Point Plan for a Green Industrial Revolution. To support the buildings sector, it proposes a timescale to have hydrogen heating trials in a neighbourhood by 2023 and to launch larger village trials by 2025, which could lead to a hydrogen town by the end of the decade. Completion of testing to support up to 20% hydrogen injection in the gas network for all homes by 2023 is among the project's target milestones.

In addition to the Hy4Heat and H21 projects (see above), the H100 Fife project (Scotland) intends to deliver an end-to-end 100% hydrogen demonstration using the gas network, to prove its technical viability. Initially, some 300 domestic properties are targeted to be connected and operational for 4.5 years (i.e. until 2027), with each provided with boilers, cookers and hobs.

Another demonstration, the BIG HIT project (Building Innovative Green Hydrogen Systems in Isolated Territories, 2016-2022), is under way in the Orkney Islands (Scotland). Hydrogen produced from local curtailed renewable energy generation on smaller islands is transported to Orkney, where it is used to demonstrate several end-use applications, including heating in buildings. The project is funded by the FCH JU and involves 12 partners from the United Kingdom, Italy, France, Denmark, Spain and Malta.

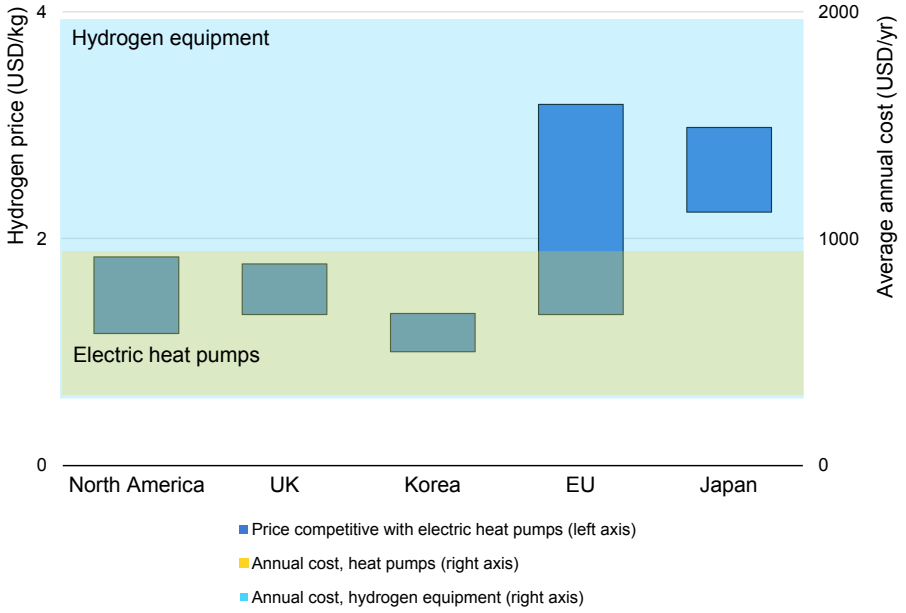
Outlook for hydrogen in building applications

At present, the main markets for fuel cell deployment in buildings are Japan, Europe and Korea, the last having a target of 2.1 GW_e installed by 2040 and focusing mostly on fuel cells for power applications. In these markets, fuel cell deployment is not focused explicitly on hydrogen but more broadly on scaling up and reducing the capital costs of these systems.

Hydrogen uptake in buildings will depend on many factors, including equipment, infrastructure and hydrogen production costs. Competition among direct electrification, hydrogen and district heating affects other factors such as the retrofit potential of buildings; building footprints and heat demand densities; hydrogen and electricity prices in relation to equipment costs; consumer preferences; the potential to supply hydrogen; and requirements for renewable capacity. The flexibility and demand-response potential that hydrogen could provide to energy systems are also key considerations.

In the Announced Pledges Scenario, in major markets hydrogen would need to be priced at USD 0.9-3.5/kg in 2030 to compete with electric heat pumps in buildings. Assuming these price ranges and considering the capital costs of equipment and of using hydrogen equipment in existing buildings, the cost to heat a home of 100 m^2 could range from USD 350/yr to USD 2 000/yr in those markets. This range might be broader than for electric heat pumps due to the wide variability of efficiencies and capital cost of hydrogen equipment.

Potential spread of competitive hydrogen prices and annual cost per household of running heating equipment in selected regions in the Announced Pledges Scenario, 2030



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Note: Techno-economic assumptions available in the Annex.

Demonstration projects over the next decade will be vital to define cost uncertainties and better understand the implications of using

hydrogen in buildings, ultimately helping to shape solutions for the direct use of pure hydrogen. Testing in dense urban centres will be needed to understand potential barriers, overcome operational constraints, address consumer safety concerns and train operators.

In the Announced Pledges Scenario, heating demand in 2030 is 20% lower than in 2020 thanks to better building envelopes and enhanced equipment efficiency. In parallel, hydrogen demand grows to more than 2 Mt H_2 (around 0.5% of global heat demand) but remains limited as planned actions are not strong enough to accelerate blending in gas networks.

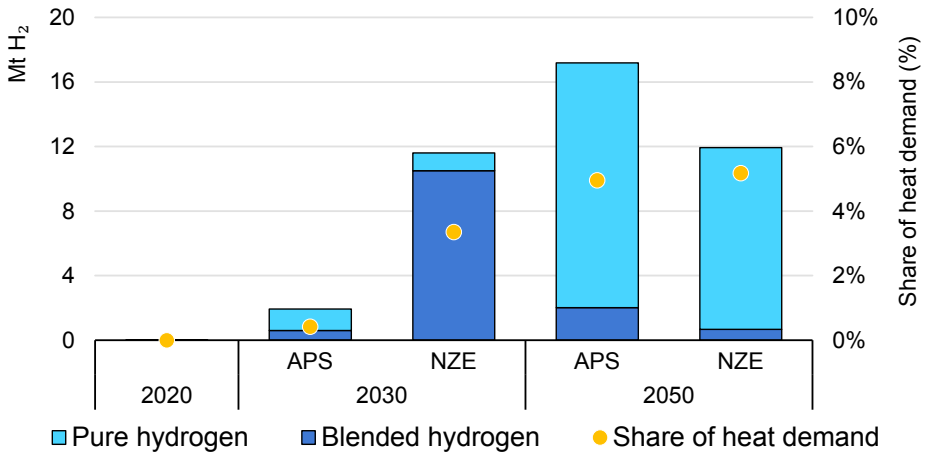
With pure hydrogen applications making inroads post-2030, this share jumps to 5% by 2050. Almost all installations are in existing buildings and are largely aligned with retrofits to ensure that replacing conventional fossil fuel-fired equipment with heat-driven units has minimal impact on building structure and heating distribution systems.

Hydrogen blending rates ramp up much more rapidly by 2050 in the Net zero Emissions than in the Announced Pledges Scenario. Due to its limited decarbonisation potential, blended hydrogen volumes in gas networks decrease after 2030 at the same time as most gas furnaces and boilers are phased out.

In 2050, pure hydrogen makes up 95% of hydrogen demand in buildings – in absolute value lower than in the Announced Pledges Scenario – as larger economies of scale, higher efficiency rates and more developed electricity demand management options are deployed.

In the Net zero Emissions Scenario, hydrogen accounts for 3.5% of final energy use for heating in 2030. Due to its lower efficiency, however, hydrogen meets slightly more than 5% of global heating needs in 2050.

Hydrogen use in buildings and shares of heat demand in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Electricity generation

Greater hydrogen penetration can help expand renewable electricity generation

Current uses of hydrogen in the power sector

Hydrogen use in power generation is negligible at present. It accounts for less than 0.2% of the electricity supply, linked mostly to the use of mixed gases with high hydrogen content from the steel industry, petrochemical plants and refineries, and to the use of by-product pure hydrogen from the chlorine-alkali industry.[24]

Hydrogen can be used as fuel in reciprocating gas engines and gas turbines. Today's reciprocating gas engines can handle gases with a hydrogen content of up to 70% (on a volumetric basis), and various manufacturers have demonstrated engines using 100% hydrogen that should be commercially available in upcoming years.

Gas turbines can also run 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 20 years. Manufacturers are therefore confident of delivering standard gas turbines that can run on pure hydrogen by 2030.

A key consideration, however, is that as hydrogen generates a higher combustion temperature than natural gas, its use in gas turbines can drive up NOx emissions, requiring a larger or more efficient selective catalytic reduction (SCR) system to avoid them. Dry, low-emission combustion systems are an alternative to minimise NOx emissions from hydrogen in gas turbines, and systems with up to 50% hydrogen blends have been demonstrated.

Fuel cells can convert hydrogen into electricity and heat, producing water but no direct emissions. Fuel cell systems can achieve high electrical efficiencies (over 60%) and can maintain high efficiency even operating at part load, making them particularly attractive for flexible operations such as load balancing.

The main fuel cell technologies for electricity and heat generation are:

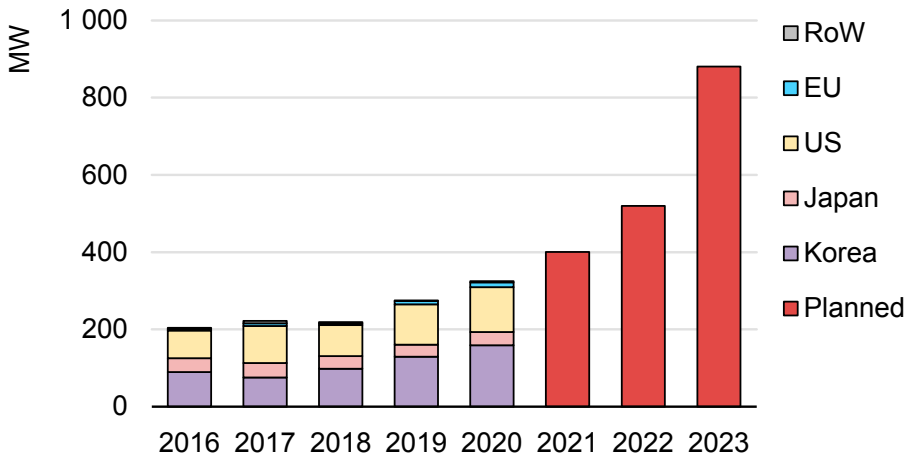
- **Polymer electrolyte membrane fuel cells (PEMFCs),** which operate at low temperatures and are used as micro-cogeneration units.
- **Phosphoric acid fuel cells (PAFCs),** used as stationary power generators with outputs in the range of 100-400 kW.
- **Molten carbonate fuel cells (MCFCs)** and **solid oxide fuel cells (SOFCs**), which operate at higher temperatures (600°C and 800-1 000°C, respectively) and can be used for heating and cooling in buildings and industry.

[24] Though mentioned here, the hydrogen content of mixed gases and by-product hydrogen from the chlorine-alkali industry are generally not included in hydrogen supply and demand presented in this report.

- **Alkaline fuel cells (AFCs),** which operate at low temperatures and can be used in stationary applications, although very few units have been deployed to date.

Global installed capacity of stationary fuel cells has grown rapidly over the past ten years, reaching ~2.2 GW in 2020. At present, only 150 MW use hydrogen as fuel; most run on natural gas. Of the 468 000 units installed globally, micro-cogeneration systems dominate. Japan's ENE-FARM initiative accounts for the majority, with 350 000 such systems.

Stationary fuel cell capacity deployment, 2016-2023



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Notes: EU = European Union; RoW = rest of world: US = United States. Data for 2020 estimated based on Q1-Q3 information. Planned capacity (2021-23) based on capacity increases and historic trends.
Source: E4tech.

Stationary fuel cells can also provide backup power (e.g. for data centres and hospitals) and off-grid electricity, applications that currently rely on diesel generators. As switching to fuel cells can reduce local air pollution and eliminate the need to potentially import diesel, many countries use fuel cells with a capacity of a few kW, fuelled by methanol, liquefied petroleum gas (LPG) or ammonia, as backup or off-grid electricity for radio and telecom towers. In 2020, Ballard Power was awarded a contract for 500 fuel cell systems for digital radio towers in Germany to ensure backup power for 72 hours.

Ammonia could also become a low-carbon fuel option for the power sector, either through imports to countries with limited options for low-carbon dispatchable generation or by being used as a medium to store electricity over longer periods to balance seasonal variations in renewable electricity supplies or electricity demand. Ammonia can be converted to hydrogen for use in gas turbines, used directly in internal combustion engines or fuel cells (AFCs and SOFCs), or fed into coal power plants in a co-firing arrangement.

Co-firing a 1% share of ammonia was successfully demonstrated by Chugoku Electric Power Corporation (Japan) at a commercial coal-fired power station in 2017. JERA, Japan's largest utility company, has started work on demonstrating a 20% co-firing share of ammonia at a 1-GW coal-fired unit, with the aim of completing tests by 2025.

To date, the direct use of ammonia has been successfully demonstrated only in micro gas turbines (up to 300 kW capacity). Its

low combustion speed and flame stability issues have been identified as barriers to using ammonia in larger gas turbines (along with increased NOx emissions). However, Mitsubishi Power recently announced plans to commercialise a 40-MW gas turbine directly combusting 100% ammonia by around 2025.

Hydrogen and hydrogen-based fuels (such as ammonia and liquid organic hydrogen carriers) also offer seasonal and large-scale storage options for the power sector. While being immensely more cost-effective, these options have low round-trip efficiencies (around 40%) compared with batteries (around 85%), limiting their use for storing energy over longer periods.

Salt caverns, being well sealed and having low contamination risk, are already used to store pure hydrogen underground (see Chapter Infrastructure and trade). Alternately, hydrogen-based fuels (e.g. ammonia) can be used for storage in regions lacking access to salt caverns – i.e. surplus electricity can be converted to ammonia, which can be burned in power plants when solar PV and wind generation drop.

Another option is the large, refrigerated liquid ammonia tanks (e.g. 50-m diameter and 30-m height) typically used in the fertiliser industry, which can store 150 GWh of energy, comparable to the annual electricity consumption of a city of 100 000. Siemens demonstrated the use of ammonia for electricity storage in 2018 in the United Kingdom, using electrolysis to convert wind electricity into hydrogen and then into ammonia for storage. The stored ammonia was later burned in an internal combustion engine as needed to produce electricity.

Future hydrogen trends

Very few countries have explicit targets for using hydrogen or hydrogen-based fuels in the power sector. Japan is one of the exceptions: it aims to use 0.3 Mt H_2/yr in electricity generation by 2030, corresponding to 1 GW of power capacity, rising to 5-10 Mt H_2/yr (15-30 GW) in the longer term. Meanwhile, Korea's hydrogen roadmap targets 1.5 GW of installed fuel cell capacity in the power sector by 2022 and 8 GW by 2040.

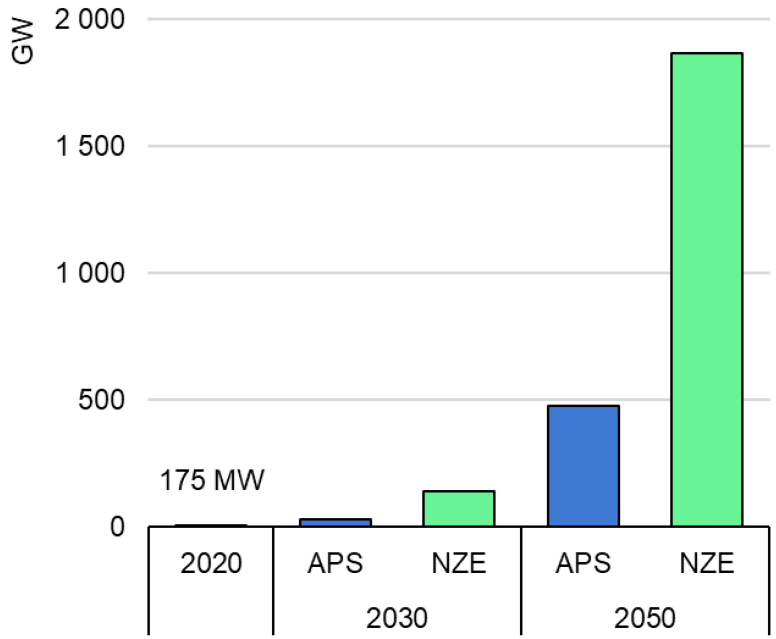
Several countries recognise hydrogen's potential as a low-carbon option for co-generation and for providing flexibility as they reach high shares of variable renewable power. Germany's National Hydrogen Council's action plan envisions 0.6 Mt H_2 of power sector hydrogen demand by 2030, increasing to 9 Mt H_2 by 2040.

Co-firing with hydrogen and ammonia can be a means to reduce the emissions of existing gas- and coal-fired power plants in the near term. In the longer term, as variable renewable energy shares increase, hydrogen- and ammonia-fired power plants can be a low-carbon flexibility option.

Capacity linked to hydrogen-based fuels reaches 30 GW by 2030 and 480 GW by 2050 in the Announced Pledges Scenario, and 140 GW

(by 2030) and 1 850 GW (by 2050) in the Net zero Emissions Scenario. Still, in 2050, hydrogen-based fuels account for only 1-2% of total global generation in the two scenarios. With modest additional investments (but relatively high fuel costs), co-firing of hydrogen-based fuels is targeted towards reinforcing power system stability and flexibility rather than providing bulk power.

Hydrogen- and ammonia-fired electricity generation capacity in the Announced Pledges and Net zero Emissions scenarios, 2020-2050

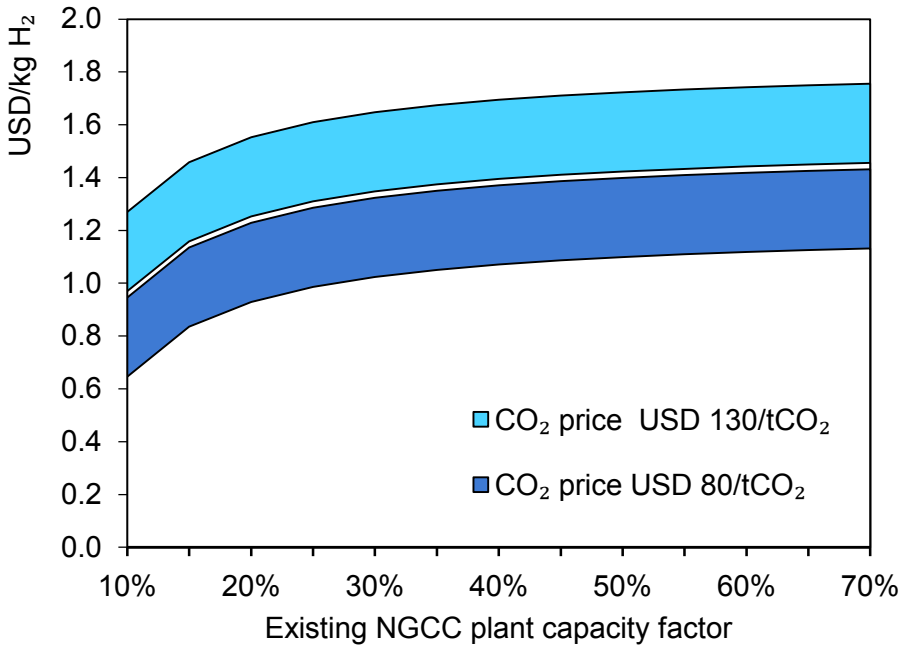


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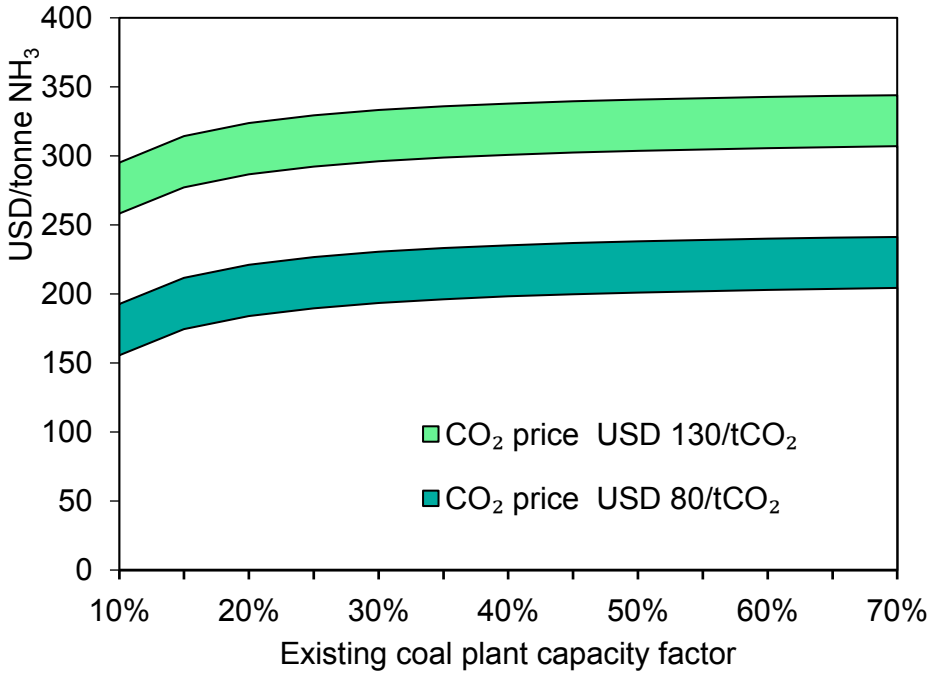
Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Economic analysis of co-firing hydrogen and ammonia in fossil fuel power plants

Break-even hydrogen price for an existing natural gas power plant, 2030



Break-even ammonia price for an existing coal power plant, 2030



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Notes: NGCC = natural gas combined cycle. Techno-economic assumptions available in the Annex.

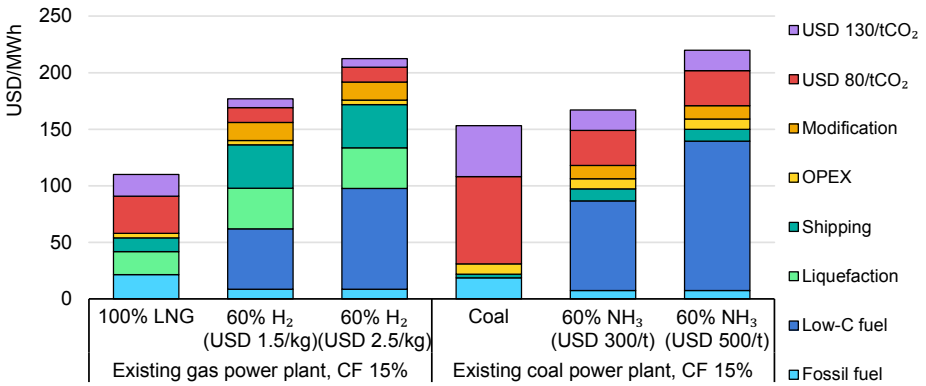
A basic condition must be met to make switching to low-carbon fuel economically attractive for existing thermal power plants: the combined cost of required plant modifications and of low-carbon fuel must be lower than the combined cost of the fossil fuel and any penalties for CO_2 emissions from combustion. Due to coal's higher carbon content, coal plants are more sensitive to carbon prices than natural gas plants, but both cases would require very high carbon prices and/or cheap low-carbon fuels to incentivise a switch. While relatively small modifications are required to enable co-firing of hydrogen or ammonia in existing gas or coal power plants, the cost of such modifications is more consequential if power plants operate at low capacity factors. However, the value of the energy produced can be much higher when operations are similar to peaking plants, which can compensate for the increased costs.

In some cases, fuel transport costs also affect overall co-firing costs significantly. This is especially the case for waterborne transport of hydrogen, which is currently at a low technology readiness level and requires expensive preparation (e.g. liquefaction). Similar cost impacts are associated with transporting natural gas as liquefied natural gas (LNG), although they are moderated somewhat by the wider availability of large-scale LNG tankers and the higher liquefaction temperature of natural gas (compared with hydrogen), which requires less energy.

Ammonia (compared with hydrogen and natural gas) has the highest vaporisation temperature, and the commercial availability of ammonia ship carriers makes transport costs lower. Although converting hydrogen to ammonia incurs thermal losses and greater capital investment, if marine transport is required, the higher levelised cost of ammonia (compared with hydrogen) can be offset (in part or fully) by lower transportation costs.

Despite the costliness of low-carbon hydrogen and ammonia, high carbon prices can largely counterbalance the additional cost of co-firing by reducing CO_2 emissions and associated carbon price penalties. This is especially the case for existing coal-fired plants. The IEA's forthcoming report The Role of Low-Carbon Fuels in Clean Energy Transitions of the Power Sector will provide more details on the potential use of hydrogen and ammonia in electricity generation.

Existing thermal power plants' levelised cost of energy with co-firing, 2030



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Notes: LNG = liquefied natural gas. CF = capacity factor. Low-C fuel = low-carbon fuel. Techno-economic assumptions available in the Annex.

Electricity sector hydrogen projects under development

Power plant/project	Location	Start-up date	Capacity (MW)	Description
Daesan Green Energy	Korea	2020	50	PAFCs fuelled by by-product hydrogen from petrochemical industry
Long Ridge Energy Terminal	US	2021	485	Initially blending 15-20% hydrogen with natural gas at new CCGT; moving to 100% hydrogen in next 10 years
Magnum	Netherlands	2023	440	Conversion of existing natural gas-fired CCGT; hydrogen from natural gas + CCUS; currently on hold
Keadby Hydrogen	United Kingdom	2030	1 800	Being developed together with Keadby 3, a natural gas-fired power plant + CCUS
JERA-Hekinan	Japan	2024	200	20% co-firing of ammonia in 1-GW Unit 4 of coal-fired Hekinan power plant
Air Products' Net zero Hydrogen Energy Complex	Canada	n.a.	n.a.	Hydrogen produced from natural gas-fuelled ATR + CCUS
Ulsan	Korea	2027	270	Conversion of CCGT from natural gas to hydrogen
Hyflexpower	France	2023	12	Combining hydrogen production from renewables, hydrogen storage and electricity generation from hydrogen in a gas turbine
Intermountain Power Project	United States	2025	840	Conversion of a 1.8-GW coal power plant into 840-MW CCGT with gradually increasing hydrogen co-firing, from 30% in 2030 to 100% by 2045

Notes: ATR = autothermal reformer. CCGT = combined-cycle gas turbine.

Hydrogen supply

Overview and outlook

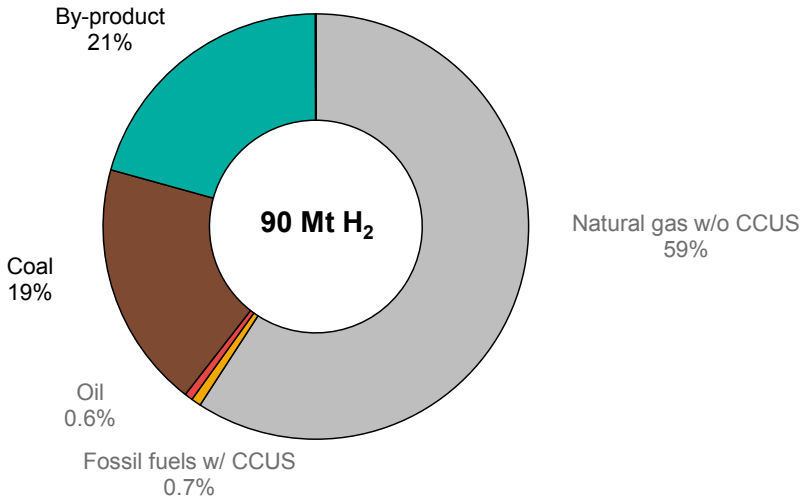
Hydrogen production in 2020

Global hydrogen demand of 90 Mt in 2020 was met almost entirely by fossil fuel-based hydrogen, with 72 Mt H_2 (79%) coming from dedicated hydrogen production plants. The remainder (21%) was by-product hydrogen produced in facilities designed primarily for other products, mainly refineries in which the reformation of naphtha into gasoline results in hydrogen. Pure hydrogen demand, mainly for ammonia production and oil refining, accounted for 72 Mt H_2, while 18 Mt H_2 was mixed with other gases and used for methanol production and DRI steel production.

Natural gas is the main fuel for hydrogen production, with steam methane reformation being the dominant method in the ammonia and methanol industries, as well as in refineries. Using 240 bcm (6% of global demand in 2020), natural gas accounted for 60% of annual global hydrogen production, while 115 Mtce of coal (2% of global demand) accounted for 19% of hydrogen production, reflecting its dominant role in China. Oil and electricity fuelled the remainder of dedicated production.

The dominance of fossil fuels made hydrogen production responsible for almost 900 Mt of direct CO_2 emissions in 2020[25] (2.5% of global CO_2 emissions in energy and industry), equivalent to the emissions of Indonesia and the United Kingdom combined. For a clean energy transition, emissions from hydrogen production must be reduced.

Sources of hydrogen production, 2020



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Note: CCUS = carbon capture, utilisation and storage.

[25] This includes 265 Mt CO_2 emitted through the use of hydrogen-derived products (e.g. urea and methanol) that capture carbon only temporarily.

Various technology options exist to produce low-carbon hydrogen: from water and electricity via electrolysis; from fossil fuels with carbon capture, utilisation and storage (CCUS); and from bioenergy via biomass gasification. However, they account for very small shares of global production: at 30 kt H_2, water electrolysis made up ~0.03%, and 16 fossil fuel with CCUS plants produced just 0.7 Mt H_2 (0.7%).[26]

Water demand for hydrogen production

In addition to energy, hydrogen production requires water. Water electrolysis has the smallest water footprint, using about 9 kg of water per kg of hydrogen. Production from natural gas with CCUS pushes water use to 13-18 kg H_2O/kg H_2, while coal gasification jumps to 40-85 kg H_2O/kg H_2, depending on water consumption for coal mining.

In the Net zero Emissions Scenario, global water demand for hydrogen production reaches 5 800 mcm, corresponding to 12% of the energy sector's current water consumption. While total water demand for hydrogen production is rather low, individual large-scale hydrogen production plants can be significant consumers of fresh water at the local level, especially in water-stressed regions.

Using seawater could become an alternative in coastal areas. While reverse osmosis for desalination requires 3-4 kWh of electricity per m^3 of water, costing around USD 0.70-2.50 per m^3, this has only a minor impact on the total cost of water electrolysis, increasing total hydrogen production costs by just USD 0.01-0.02/kg H_2. As the direct use of seawater in electrolysis currently corrodes equipment and produces chlorine, various research projects are investigating ways to make it easier to use seawater in electrolysis in the future.

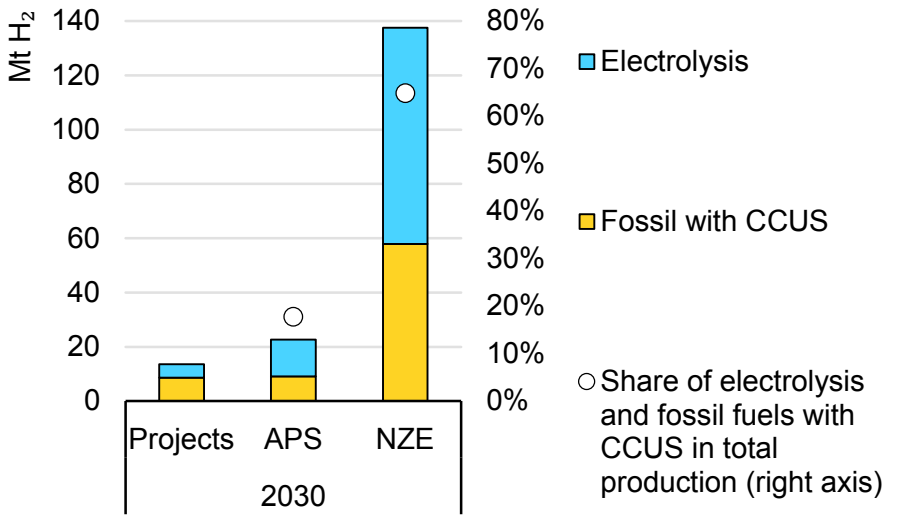
[26] These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale; CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

Low-carbon hydrogen production projects are multiplying rapidly, but fall short of climate ambitions

Judging by projects under construction or planned, low-carbon hydrogen production could grow rapidly to 2030.[27] Some 350 projects could push electrolytic hydrogen production to 5 Mt H_2, while 56 projects for fossil fuels with CCUS could reach 9 Mt H_2 (including the 16 existing plants). Taking into account another 40 projects at an early development stage, electrolytic hydrogen production could reach 8 Mt H_2 by 2030.

Although production from electrolysers falls far short of the 12 Mt H_2 needed in the Announced Pledges Scenario in 2030, the 9 Mt H_2 from natural gas with CCUS is on target. Together, however, expected production from planned projects is only two-thirds of what is needed. This gap widens significantly in the Net zero Emissions Scenario, which requires electrolytic hydrogen production of 80 Mt H_2 and 60 Mt H_2 from natural gas with CCUS in 2030. Nevertheless, more projects are likely to be developed in upcoming years, reducing shortcomings of the current project pipeline.

Electrolysis and fossil fuel + CCUS hydrogen production in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2030



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCUS = carbon capture, utilisation and storage. Hydrogen from fossil fuels with CCUS does not include production that uses the CO_2 to produce urea; this production totals 13 Mt H_2 in 2030 in both the APS and NZE.

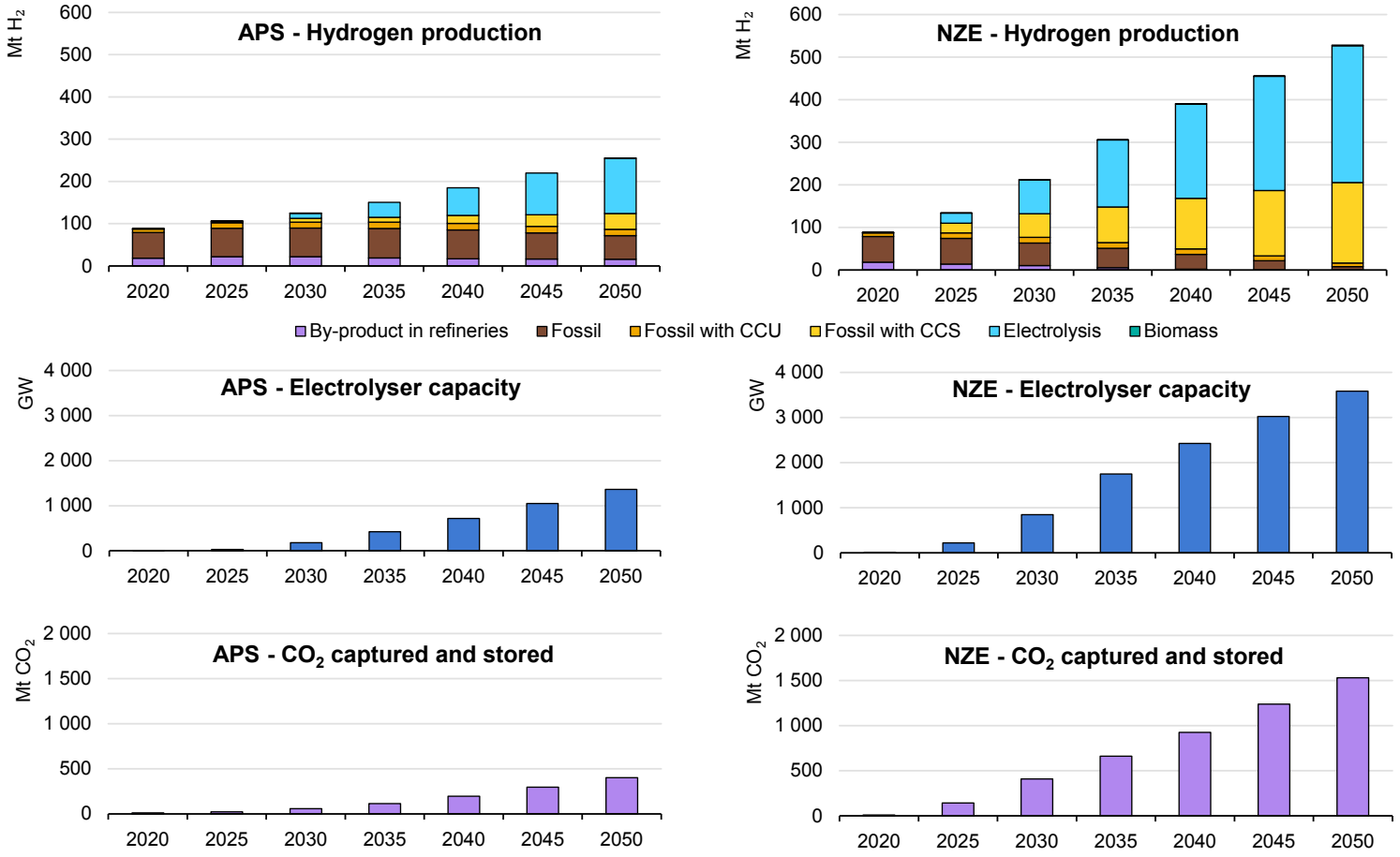
[27] If not otherwise specified, planned projects are those for which a final investment decision (FID) has been taken or a feasibility study is in progress.

By 2050, global hydrogen production reaches 250 Mt H_2 in the Announced Pledges Scenario, with 51% provided by electrolysis, 15% by fossil fuels with CCUS and the remainder by fossil fuels without CCUS. This corresponds to global electrolyser capacity of 1 350 GW and the capture of 0.4 Gt CO_2/yr.

In the Net zero Emissions Scenario, global production doubles compared to the Announced Pledges Scenario, with shares of 60% from electrolysis and 36% from fossil fuels with CCUS as installed electrolyser capacity reaches 3 600 GW and the capture rate climbs to 1.5 Gt CO_2/yr. Notably, this corresponds to electricity consumption of almost 15 000 TWh (20% of global generation) and 925 bcm of natural gas (50% of global natural gas demand).

Decarbonising hydrogen production will require rapid electrolysis and CCUS roll-out

Global hydrogen production, installed electrolysis capacity and CO_2 captured and stored in the Announced Pledges and Net zero Emissions scenarios



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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCS = carbon capture and storage; CCU = carbon capture and use. Hydrogen production from fossil fuels with CCU refers to ammonia production in which captured CO_2 is used to produce urea fertiliser. When urea fertiliser is applied to soil, it breaks down again into ammonia and CO_2, with the latter released into the atmosphere.

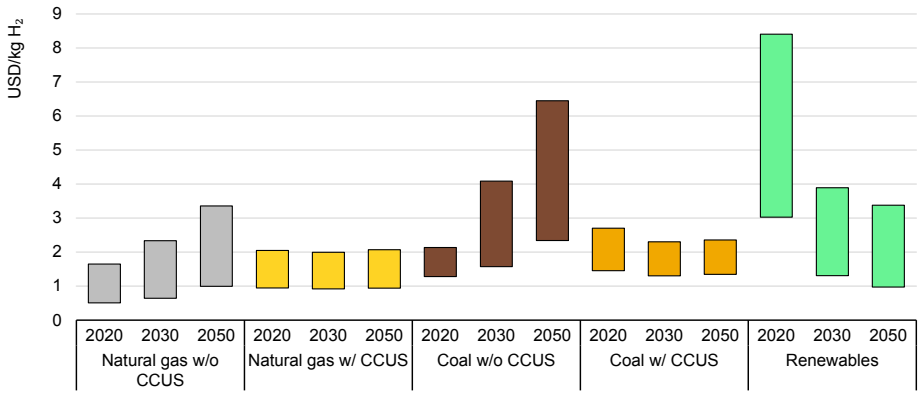
The cost challenge of low-carbon hydrogen

In most parts of the world, producing hydrogen from fossil fuels is currently the lowest-cost option. Depending on regional gas prices, the levelised cost of hydrogen produced from natural gas is in the range of USD 0.50-1.70/kg H_2. Using renewables is much costlier in most places, at USD 3.00-8.00/kg H_2. In fact, renewable electricity costs can make up 50-90% of total production expenses, depending on both electricity costs and the full-load hours of the renewable electricity supply.

As both renewable electricity and electrolyser costs fall, however, the price gap between production methods is expected to shrink quickly. Pricing CO_2 emissions (e.g. through carbon prices) could further narrow the gap by pushing up the cost of hydrogen produced from fossil fuels. For example, a carbon price of USD 100/t CO_2 corresponds to a cost increase of USD 0.90/kg H_2 for natural gas-based production without CCUS, or USD 2.00/kg H_2 for coal gasification without CCUS.

At high capture rates (90-95%), the impact of CO_2 prices on hydrogen production costs from fossil fuels with CCUS can be drastically reduced. Depending on gas prices, natural gas with CCUS entails a production cost of USD 1.00-2.00/kg H_2 – about USD 0.50/kg H_2 higher than without CCUS. A CO_2 price of USD 70/t CO_2 would therefore be needed to close this cost gap.

Levelised cost of hydrogen production by technology in 2020, and in the Net zero Emissions Scenario, 2030 and 2050



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Notes: CCUS = carbon capture, utilisation and storage. Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions.

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

Meanwhile, reducing the cost of low-carbon electricity will be critical to bring down the expense of producing hydrogen from electrolysis. Hydrogen production costs of USD 1.00/kg H_2 – the 2030 goal of the US Hydrogen Earthshot initiative – translate into electricity prices of USD 20/MWh, without any CAPEX or fixed OPEX (at 70% efficiency, lower heating value). To reach this targeted hydrogen production cost, electricity prices must therefore be sufficiently below USD 20/MWh to allow for additional CAPEX and OPEX costs.

In regions with good solar resources – and thus relatively high full-load hours for the electrolyser – solar PV can fall below this cost threshold. In fact, tenders for utility-scale solar PV in the Middle East in 2019 and 2020 secured bids of USD 14-17/MWh (though these prices are very market-specific and reflect favourable financing conditions).

Furthermore, technology improvements to boost electrolyser efficiency moderate how electricity costs affect hydrogen production costs. Efficiency improvements are not limited to the electrolyser itself; optimising components such as rectifiers and inverters for anticipated operation at part load (i.e. not nominal load) is vital if variable renewables are the main electricity source. The projected cost of hydrogen production after 2030 is therefore very uncertain and will depend on the impacts of scaling up, learning by doing and other technological progress.

Electrolysis

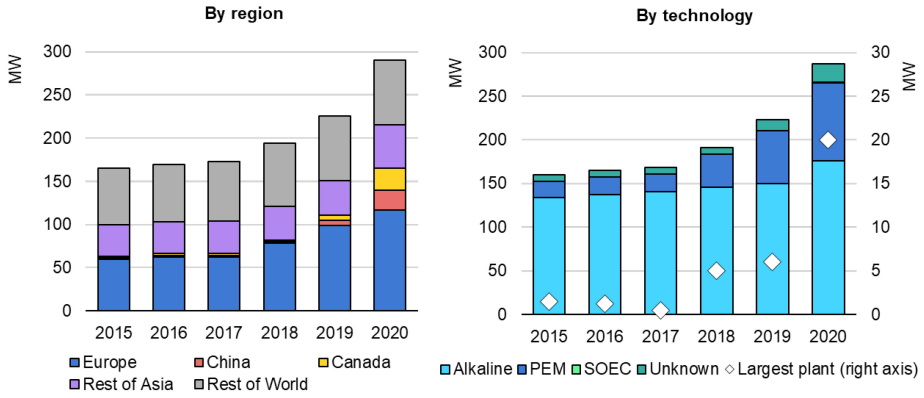
Electrolysis deployment is expanding quickly

Water electrolysis is an electrochemical process that uses electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). In 2020, this process accounted for ~0.03% of hydrogen production for energy and chemical feedstocks.[28] Of installed global electrolyser capacity of 290 MW, more than 40% is based in Europe with the next-largest capacity shares in Canada (9%) and China (8%).

Four main electrolyser technologies exist today: alkaline; proton exchange membrane (PEM); solid oxide electrolysis cells (SOECs); and anion exchange membranes (AEMs) (see Emerging Technologies below for more on SOECs and AEMs). Alkaline electrolysers dominate with 61% of installed capacity in 2020, while PEMs have a 31% share. The remaining capacity is of unspecified electrolyser technology and SOECs (installed capacity of 0.8 MW).

Used since the 1920s for hydrogen production in the fertiliser and chlorine industries, alkaline electrolysis is a mature commercial technology. The operating range of alkaline electrolysers covers a minimum load of 10% to full design capacity. As they do not require precious materials, capital costs are relatively low compared with other electrolyser technologies.

Global installed electrolysis capacity by region and technology, 2015-2020



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Notes: PEM = proton exchange membrane; SOEC = solid oxide electrolysis cell.
Source: IEA (2021), Hydrogen Projects Database.

The area requirements of PEM electrolyser systems are relatively small, making them potentially more attractive than alkaline electrolysers in dense urban or industrial areas. Current materials for electrode catalysts (platinum, iridium), bipolar plates (titanium) and membrane materials are expensive, however, so overall costs for

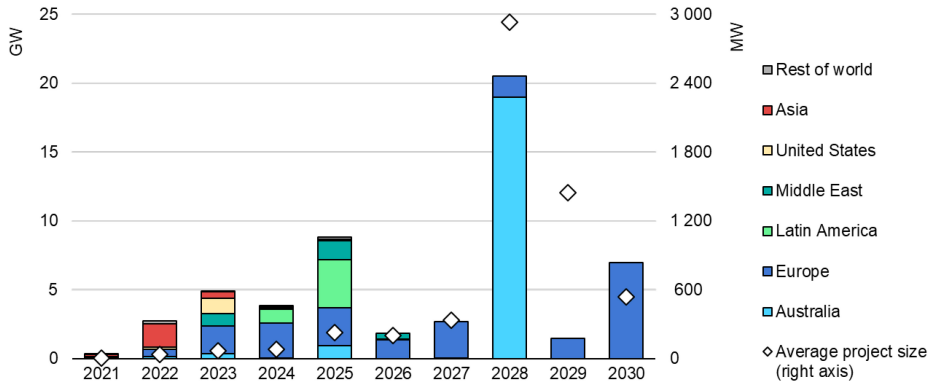
[28] If not otherwise specified, electrolysis refers to water electrolysis, i.e. excluding chlor-alkali electrolysis.

PEMs (USD 1 750/kW) are higher than for alkaline electrolysers (USD 1 000-1 400/kW). Additionally, PEM systems currently have a shorter lifespan.

By 2030, global installed electrolyser capacity could climb to 54 GW, given capacity under construction and planned. If all projects at the very early planning stages are counted, capacity could even reach 91 GW by 2030. Geographically, Europe and Australia lead with 22 GW[29] and 21 GW of projects under construction or planned, followed by Latin America (5 GW) and the Middle East (3 GW).

Many projects are linked to renewables as a dedicated electricity source, and around a dozen demonstration projects (combined electrolyser capacity of 250 MW) explore using nuclear power for hydrogen production (Canada, China, Russia, the United Kingdom and the United States). Not all these projects will be realised, however. So far, only 4 GW (7%) are linked to projects under construction or with a final investment decision, leaving 50 GW still at various earlier stages of development (e.g. at the front-end engineering design, feasibility study and concept phases).

New installed electrolyser capacity based on projects under construction or planned, 2021-2030



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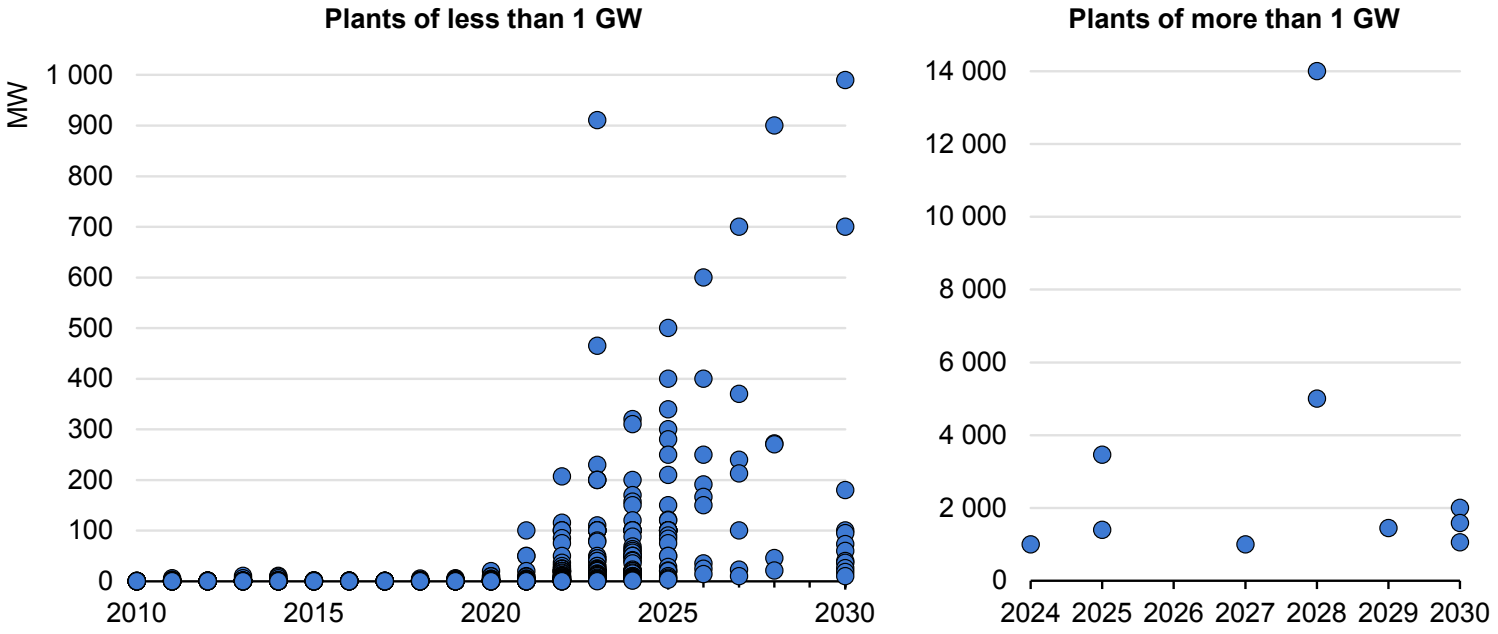
Notes: Based on ~350 projects under construction or planned. Only projects with a known start year of operation are considered.
Source: IEA (2021), Hydrogen Projects Database.

As global electrolyser capacity scales up, the average project size increases. Notably, the average of 0.6 MW in 2020 includes the largest alkaline electrolyser plant in operation (the 25-MW Industrial Cachimayo plant in Peru, which is connected to the electricity grid) and the largest PEM electrolyser plant in operation using dedicated renewables (20 MW using hydropower, inaugurated in 2020 by Air Liquide in Bécancour, Canada).

[29] For Europe, some projects with unknown completion dates (e.g. the 67-GW HyDeal project) are not included. If realised, they could push electrolyser capacity well beyond 23 GW by 2030.

Some 80 projects under construction or being planned have capacities of >100 MW, and 11 projects reach ≥1 GW. The planned Western Green Energy Hub (Australia) is in the GW scale: with a solar PV and wind capacity of up to 50 GW, it will produce 3.5 Mt H_2/yr for conversion into 20 Mt of ammonia for export. As the average project size increases to 230 MW by 2030, economies of scale and learning effects are expected to bring down electrolyser costs.

Size of electrolyser projects (existing, under construction and planned), 2010-2030



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Note: Years refer to the planned start of operations; only projects with a known start year are considered.
Source: IEA (2021), Hydrogen Projects Database.

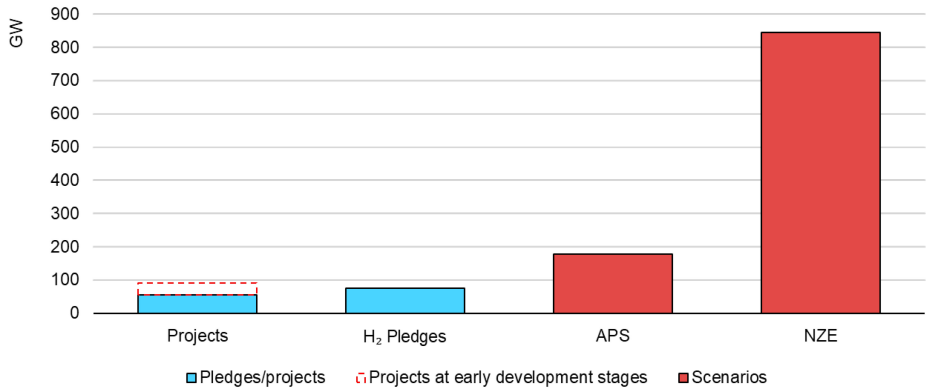
Deployment must accelerate further to meet climate targets

Several countries, as well as the European Union, include electrolyser capacity deployment goals in their hydrogen strategies. Together, these pledges could result in installed capacity of 75 GW by 2030, with the majority linked to the targets of the European Union (40 GW) and Chile (25 GW). However, planned projects do not necessarily match national or regional targets. In the EU case, only 22 GW are currently under construction or planned – barely half of the targeted 40 GW by 2030.

In the Announced Pledges Scenario, global installed electrolyser capacity increases to 180 GW by 2030, twice as much as national targets and three times the projects under construction and planned, and still 70% higher when including in the Projects case also projects at earlier development stages.

In the Net zero Emissions Scenario, capacity requirements in 2030 are 850 GW, some nine times the project pipeline when including projects at early development stages. Despite such significant gaps, current efforts are a good basis from which to expand and accelerate deployment, raising ambition as new projects are developed and more countries build hydrogen into their national strategies.

Electrolysis capacity in the Announced Pledges and Net zero Emissions scenarios in 2030 compared with the current project pipeline and government deployment pledges



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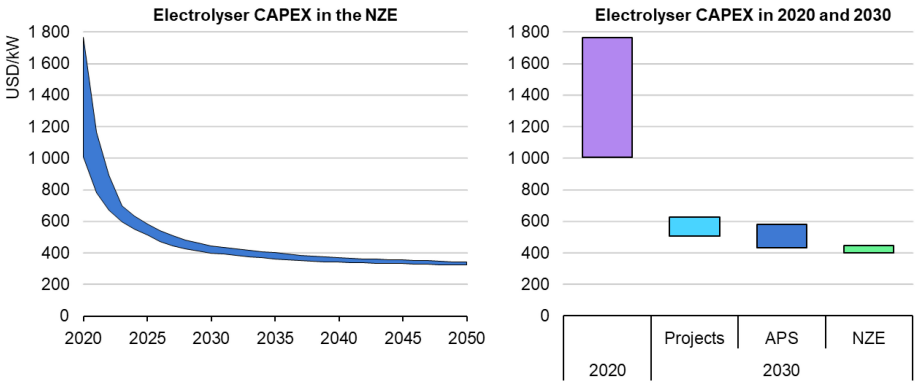
Greater electrolyser deployment will speed cost declines

Projections for hydrogen costs reflect the IEA cost database, recently updated with input from a range of industry participants under the Hydrogen Council and through collaborations with researchers in China. In 2020, costs fell within the range of USD 1 000-1 750/kW (including electric equipment, gas treatment, plant balancing, and engineering, procurement and construction [EPC]), with the lower cost applying to alkaline electrolysers produced in China and the upper representing PEM electrolysers.

The cost of alkaline electrolysers in China – USD 750-1 300/kW, with some sources reporting as low as USD 500/kW[30] – falls well below the average of USD 1 400/kW in the rest of the world. Although concerns over the reliability and durability of Chinese electrolysers have been raised in the past, manufacturing is improving quickly. As recently as a few years ago, Chinese manufacturers had to import several components, limiting their ability to reduce costs through industrial clustering and economies of scale. Local component manufacturing is expanding, however, so cost savings should be realised soon.

Learning effects in manufacturing and economies of scale will also drive down electrolyser costs. A component-wise learning-curve approach was used to analyse future electrolyser costs as a function of cumulative capacity deployment. Based on a literature review, a learning rate of 15% is assumed for the electrolyser stack, which also takes account of learning rates for fuel cells that rely on the same electrochemical processes.

Evolution of electrolyser capital costs under the Projects case, Announced Pledges and Net zero Emissions scenarios



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Notes: APS = Announced Pledges Scenario. NZE = Net Zero Emissions Scenario.
Sources: Based on data from McKinsey & Company and the Hydrogen Council.

[30] Based on CAPEX for the electrolyser system itself of USD 200/kW (China EV100, 2020; MOST, 2021). Including inverter and EPC the overall CAPEX increases to USD 500/kW.

The cumulative capacity deployment of projects under construction and planned would reduce capital expenses by almost 60% by 2030. With capacity deployment in the Announced Pledges Scenario being almost triple the current project pipeline, costs may be 65% lower in 2030 than in 2020. This is not very different from the Net zero Emissions Scenario, for which larger capacity deployment could bring capital expenses down almost 70% from 2020, to USD 400-440/kW.

Shortfalls in electrolysis manufacturing capacity could impede deployment of all projects currently under development, which could derail long-term government climate ambitions (those reflected in the Announced Pledges Scenario) and the Net zero Emissions Scenario. Global electrolysis manufacturing capacity was ~3 GW/yr in 2020, with alkaline designs accounting for 85% and PEMs for less than 15%, plus some very small, artisanal manufacturing of SOECs and AEMs.

The largest shares of manufacturing capacity are in Europe (60%) and China (35%). Interest in the technology is growing among major companies such as Thyssenkrupp, Nel Hydrogen, ITM, McPhy, Cummins and John Cockerill, all of which have announced plans to expand their manufacturing capacities. If all announced expansions are realised, manufacturing capacity could reach ~20 GW/yr, with process automation or improved procurement driving down manufacturing costs.

A dedicated industrialised supply chain and a corresponding industrial supplier landscape will be essential to meet capacity demands to 2030 and beyond. If available soon, this manufacturing capacity could meet the deployment needs of the current pipeline of projects and government pledges (an average of 6-8 GW/y from 2022 to 2030) and approach Announced Pledges Scenario needs (20 GW/yr). But projections still show a shortfall in meeting Net zero Emissions requirements (>90 GW/yr).

Increased electrolyser production will affect demand for minerals, particularly nickel and platinum group metals (depending on the technology type). While alkaline electrolysis does not require precious metals, current designs use 800-1 000 t/MW of nickel. Even if alkaline electrolysis dominates the market by 2030, in the Net zero Emissions Scenario this would entail nickel demand of 72 Mt (which is actually much lower than the amount needed for batteries).

The catalysts in PEM electrolysers require 300 kg of platinum and 700 kg of iridium per GW. Therefore, if PEMs supplied all electrolyser production in 2030 in the Net zero Emissions Scenario, demand for iridium would skyrocket to 63 kt, nine times current global production. Experts believe, however, that demand for both iridium and platinum can be reduced by a factor of ten in the coming decade. Recycling PEM electrolyser cells can further reduce primary demand for these metals and should be a core element of cell design.

Meanwhile, SOEC production requires nickel (150-200 t/GW), zirconium (40 t/GW), lanthanum (20 t/GW) and yttrium (<5 t/GW). Better design in the next decade is expected to halve each of these quantities, with technical potential to drop nickel content to below 10 t/GW. Due to the higher electrical efficiency of SOECs, these mineral requirements are not directly comparable with alkaline and PEM electrolysers.

Low-cost electricity can boost electrolysed hydrogen production

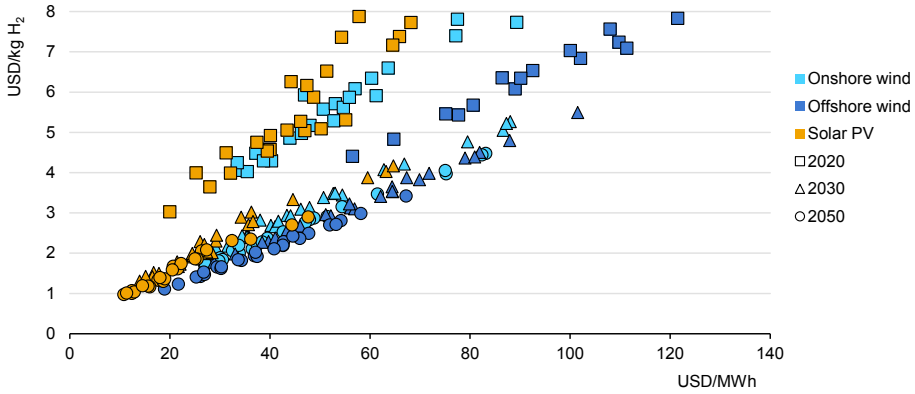
Of the various technical and economic factors that determine how much it costs to produce hydrogen from water electrolysis, the most pertinent are electricity costs, capital expenses, conversion efficiency and annual operating hours.

Electricity costs are the most important consideration, as they account for 50-90% of the overall levelised cost of hydrogen production. Using grid electricity is often rather expensive, with electricity prices of USD 50-100/MWh resulting in hydrogen production costs of USD 3.00-5.00/kg H_2 (at an electrolyser capacity factor of 90% and CAPEX of USD 500/kW).

With shares of variable renewables increasing, surplus grid electricity may be available at low cost to produce hydrogen and to store it for later use. Unfortunately, even if surplus electricity were available at zero cost for 750 hrs/yr, the hydrogen cost would remain at USD 3.00/kg H_2 (CAPEX of USD 500/kW). Running an electrolyser solely on surplus grid electricity therefore may not be an economical way to produce hydrogen and may fail to provide the volumes needed for some demand cases.

However, co-locating hydrogen production with dedicated electricity generation from renewables or nuclear power often avoids or minimises electricity transmission costs. Renewable electricity is thus the dominant source for hydrogen projects currently under construction or being planned.

Hydrogen production costs in the Net zero Emissions Scenario as a function of renewable electricity costs for solar PV and onshore and offshore wind, 2020, 2030 and 2050



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Notes: Points represent electricity and hydrogen production costs for different regions around the world, taking local renewable resource conditions into account.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020).

Solar PV has become one of the most affordable energy sources for electricity generation. In locations with excellent solar conditions (i.e. relatively high capacity factors such as the Middle East), solar PV generation costs can be USD 20/MWh or lower, corresponding to

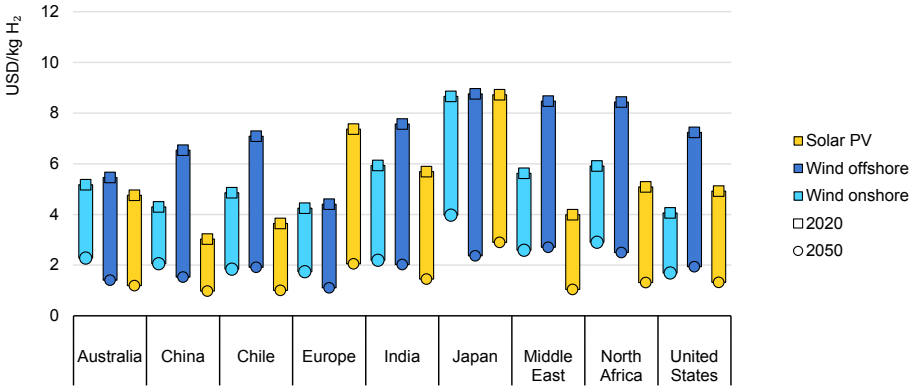
hydrogen production costs of USD 3.00/kg H_2 (at an electrolyser capacity factor of 32% and CAPEX of USD 1 000/kW).

With solar PV and electrolyser costs declining in the Net zero Emissions Scenario, hydrogen produced from solar PV in the Middle East at USD 17/MWh could cost less than USD 1.50/kg H_2 in 2030 (at a CAPEX of USD 320/kW), a level comparable to production from natural gas with CCUS. By 2050, with a solar PV cost of USD 12/MWh, hydrogen costs could fall to USD 1.00/kg H_2 (CAPEX of USD 250/kW), making hydrogen from solar PV cost-competitive with natural gas even without CCUS.

Several projects in Europe target offshore wind as an electricity source for hydrogen production. In fact, producing hydrogen offshore and transporting it to shore by pipeline is an alternative to the rather expensive use of electricity cables. Several current and planned pilot and demonstration projects (e.g. the Oyster project in Denmark) are therefore exploring this approach, and the Dutch NorthH_2 project aims to reach 4 GW of offshore electrolysis by 2030 while Germany's AquaVentus targets 10 GW by 2035.

Opportunities exist to further reduce costs by repurposing oil and gas assets, for instance by using platforms for electrolyser installations or oil and gas pipelines for hydrogen transport. There are still some uncertainties, however, about the suitability of using certain oil and gas assets for these purposes and the challenges of simultaneously phasing out oil and gas activities while ramping up electrolysis.

Levelised cost of hydrogen production from renewables by technology and region in the Net zero Emissions Scenario, 2020 and 2050



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Notes: Higher values of the ranges correspond to 2020, lower values to 2050.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020).

At USD 60/MWh, electricity generation from offshore wind was relatively costly in 2020, resulting in hydrogen costs of USD 4.50/kg H_2 (at a 50% capacity factor). With declining costs for offshore electricity generation (USD 30/MWh) and larger turbines resulting in higher capacity factors (57%), hydrogen production costs in the North Sea in the Net zero Emissions Scenario could fall to USD 2.00/kg H_2 by 2030 and to below USD 1.50/kg H_2 by 2050 (based on electricity costing USD 25/MWh and a capacity factor of 60%).

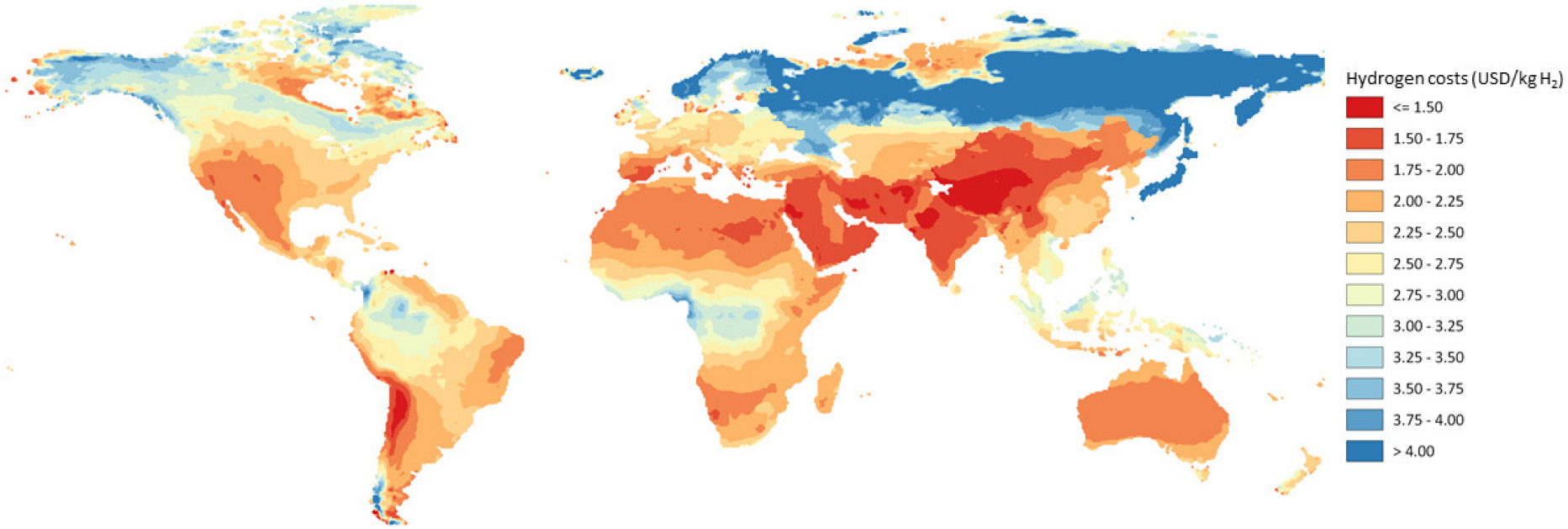
While production costs using offshore wind in Europe remain higher than for solar PV in the Middle East or North Africa, accounting for hydrogen transport costs could make sourcing domestic supplies from offshore wind a more economically feasible option for some parts of Europe.

However, considering solely the levelised cost ignores three other important factors: the number of hours the electrolyser operates; the volume of hydrogen produced throughout the year; and costs that may arise from needing to smooth out 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 other fuels and feedstocks) generally require supply stability. In such cases, hydrogen storage is likely needed to ensure supply constancy.

For the production of hydrogen-based fuels, however, it may be more economical – despite higher hydrogen production costs and fewer full-load hours – to choose a renewable electricity supply with variability patterns that requires less storage, e.g. solar PV (which typically requires daily storage) over wind power (which often requires capacity for several days or weeks of storage). Combining renewable resources in a hybrid plant (e.g. solar PV and onshore wind) may be a cost-effective way to stabilise the hydrogen supply and achieve higher full-load hours, minimising the volume of hydrogen storage needed.

Hydrogen from electrolysis starts to compete with hydrogen from natural gas with CCUS by 2030

Hydrogen production cost from hybrid solar PV and wind systems in 2030



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Notes: 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. For each location, production were derived by optimising the mix of solar PV, onshore wind and electrolyser capacities, resulting in the lowest costs and including the option to curtail electricity generation.

Sources: Based on hourly wind data from Copernicus Climate Change Service and hourly solar data from Renewables.ninja.

Fossil fuels with carbon capture

Hydrogen production from fossil fuels, and current CCUS status and adoption

Hydrogen produced from natural gas using reforming processes and from coal using gasification are well-established technologies. As noted earlier, these methods dominate hydrogen production and are the sector's primary source of CO_2 emissions.

CCUS is important in the production of low-carbon hydrogen from fossil fuels for two reasons. First, it can reduce emissions from existing hydrogen plants in the refining and chemical sectors, which account for 2.5% of global emissions; and second, it is a low-cost option to scale up production for new hydrogen demand in countries where the conditions are conducive.

CCUS refers to a suite of diverse technologies expected to be important in helping countries meet their energy and climate goals. In its first stage, CCUS involves the capture of CO_2 from large point sources (including power generation or industrial facilities that use fossil fuels or biomass for fuel) or directly from the atmosphere.

Many opportunities exist to use CO_2 captured through CCUS technologies. Urea synthesis with CO_2 captured at ammonia plants (>130 $MtCO_2$/yr in 2020) is currently the only large-scale application, but its anticipated future uses include cement and synthetic fuel production.

Storage refers the practice of injecting captured CO_2 into deep geological formations (typically depleted oil and gas reservoirs or saline formations) where it will be permanently absorbed into the rock. If not being used at the capture site, CO_2 can be compressed and transported to other facilities by pipeline, ship, rail or truck – for either use or storage.

Current large-scale CO_2 capture capacity for injection into geological formations (for dedicated storage and use in enhanced oil recovery) is in the order of 40 $MtCO_2$/yr. Around two-thirds of this capacity is in natural gas processing facilities, with the remainder distributed in roughly equal shares in power generation, synthetic fuel, ammonia and hydrogen applications, with smaller quantities captured from bioethanol and steel production.

In natural gas-based hydrogen production, steam methane reforming (SMR), the leading production route, creates direct CO_2 emissions of 9 kg CO_2/kg H_2 while upstream methane emissions from natural gas production and transport can add another 1.9-5.2 kg CO2eq/kg H2 (global average of 2.7 kg CO2eq/kg H2), reflecting regional variations. Efforts need to be taken to address them. Technologies to reduce upstream methane emissions are already available and are often cost-effective without additional support.

Among direct emissions of the SMR process, 30-40% arise from using natural gas as the fuel to produce steam and heat, giving rise to a "diluted" CO_2 stream. The rest of the natural gas used in this process is split (with the help of the steam) into hydrogen and more concentrated "process" CO_2. While capturing CO_2 from the concentrated process stream can reduce overall emissions by 60%, capturing the more diluted gas stream can boost overall emissions reductions to 90% or higher. The cost of capturing both combined is USD 50-70/t CO_2.

Autothermal reforming (ATR) is an alternative technology in which the process itself produces the required heat. This means that all related CO_2 is produced inside the reactor, resulting in a more concentrated flue gas stream that, when compared with the SMR process, allows for higher CO_2 capture rates (95% or higher) or for the same capture rate at lower capture costs.

ATR uses oxygen instead of steam, which requires electricity (rather than methane) as its fuel input. A large share of global ammonia and methanol production already uses ATR technology, though without CCUS. Two projects in the United Kingdom – HyNet and H2H Saltend – plan to combine ATR with CCUS.

Partial oxidation (POx) is a technology option that supports hydrogen production from gaseous or liquid fuels. The process does not require a catalyst (unlike ATR) and can accept feedstock impurities. POx uses oxygen (similar to ATR), requiring electricity as the energy input. Traditionally, the process has been deployed where it is possible to use low-value waste products or heavy feedstocks to produce hydrogen or syngas (e.g. in refineries).

The technology is available at commercial scale but has been modified only recently with the express aim of producing hydrogen from natural gas with CCUS. Several projects based on POx are under development and show CO_2 capture rates of up to 100%. A POx hydrogen plant at a Dutch refinery (using oil residues) that has been operating since 1997 began capturing CO_2 in 2005 for use in greenhouses (at a rate of 0.4 $MtCO_2$/yr, not fully utilising the installed capture capacity of 1 Mt CO_2/yr, which may be exploited by the Porthos project).

Meanwhile, coal gasification is a mature technology used mainly in the chemical industry to produce ammonia, particularly in China. At 20 t CO_2/t H_2, unabated hydrogen production from coal is very emissions-intensive. Though some technical challenges remain to be overcome, coal gasification can be combined with CCUS. However, since gas separation technologies focus on either hydrogen or CO_2 removal, few can produce both high-purity hydrogen and CO_2 pure enough for other uses or storage.

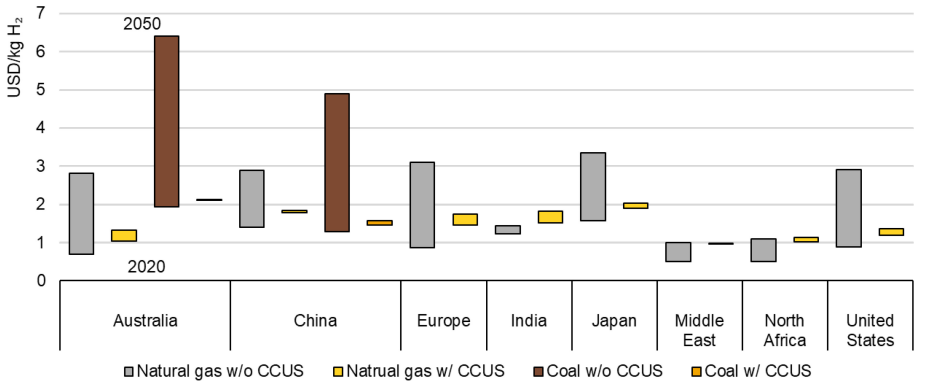
The choice and design of capture technology therefore depends on the hydrogen end-use and production costs. With the aim of producing hydrogen for export to Japan, the planned Hydrogen Energy Supply Chain project (Australia) seeks to produce it from

brown coal using gasification, with CO_2 being transported and stored via the CarbonNet project.

Sixteen projects are currently generating hydrogen from fossil fuels with CCUS; with annual combined production of just over 0.7 Mt H_2, they also capture close to 10 Mt CO_2. Ten are commercial-scale plants with CO_2 capture capacity above 0.4 Mt CO_2/yr: four are at oil refineries and three are at fertiliser plants.[31] Notably, six are retrofits of existing sites, with scales ranging from <100 MW_{H2} to >1 GW_{H2}, with 1 GW_{H2} corresponding to annual production of 0.25 Mt H_2. Planned projects reach a capacity of up to 20 GW_{H2}.

In regions with low-cost domestic coal and natural gas, where CO_2 storage is available – e.g. the Middle East, North Africa, Russia and the United States – the use of fossil fuels with CCUS is currently the most affordable option to produce low-carbon hydrogen and ammonia. Depending on local gas prices, costs for producing hydrogen from natural gas with CCUS were in the range of USD 1.00-2.00/kg H_2 in 2020 – about USD 0.50/kg H_2 higher than for natural gas without CCUS, due to CO_2 capture, transport and storage costs. As the CO_2 price penalty on uncaptured CO_2 emissions (5-10%) rises over time, production costs from fossil fuels with CCUS will increase slightly.

Levelised hydrogen production costs from natural gas and coal by region in 2020 and in the Net zero Emissions Scenario in 2050



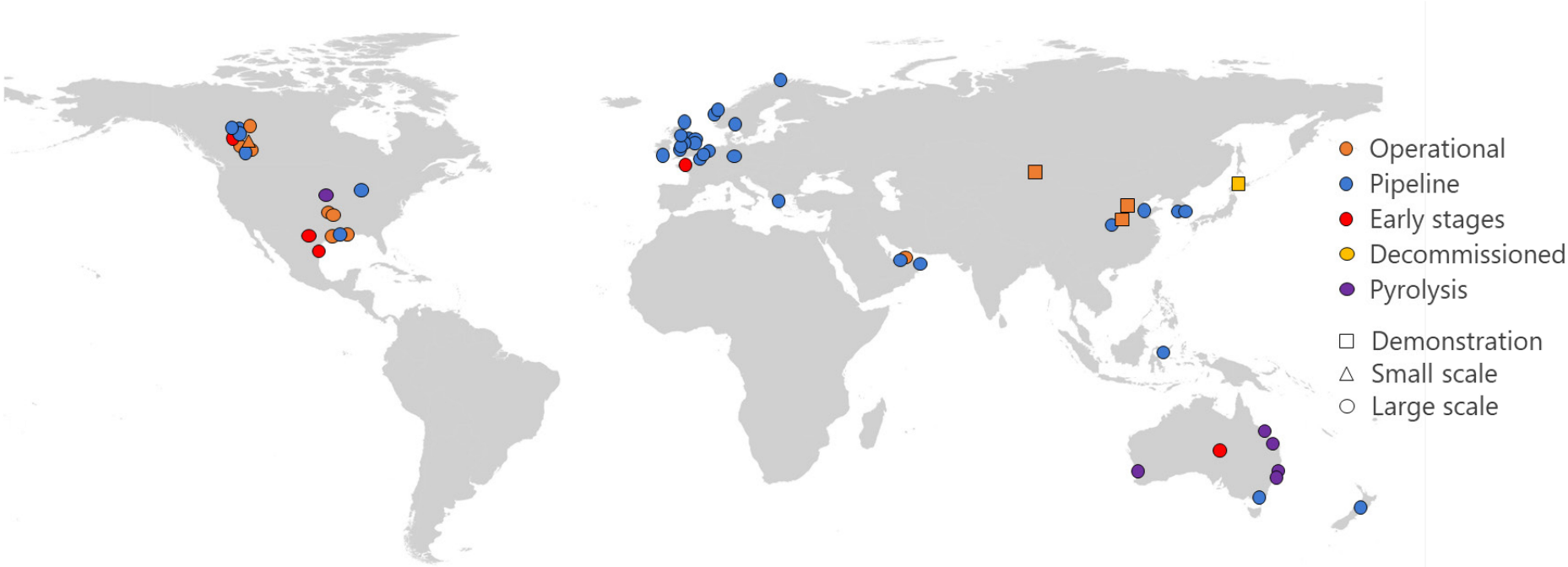
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Notes: The lower values of the ranges correspond to 2020, higher values to 2050.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; and Element Energy (2018).

[31] These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale. CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

Hydrogen production from fossil fuels with CCUS is gaining momentum

Projects for producing hydrogen from fossil fuels with CCUS, operational or under development



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Notes: 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. Mature projects are projects under construction or for which a final investment decision has been taken.

Source: IEA (2021), Hydrogen Projects Database.

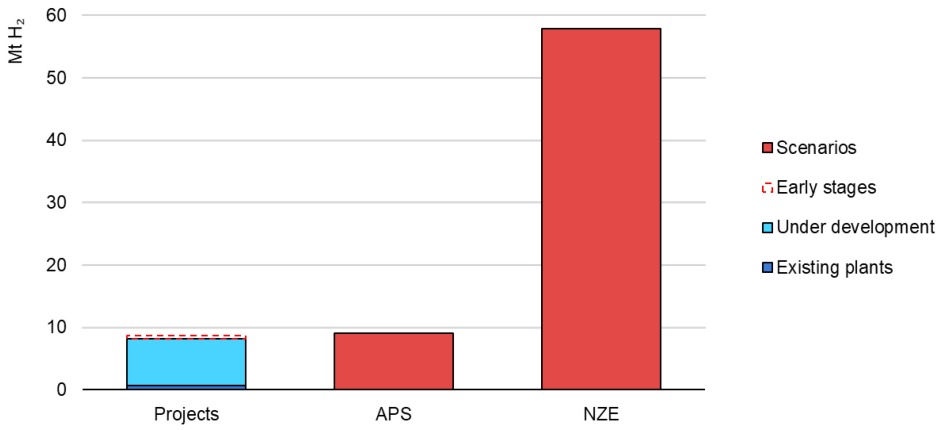
Outlook for hydrogen production with CCUS

Globally, 40 projects for producing hydrogen with CCUS are under development, with a total of four currently under construction in China and the United States. Of these, 35 rely on natural gas with CCUS, four are linked to coal and one to oil. Geographically, Europe hosts 19 projects (largely in the Netherlands and the United Kingdom), while North America hosts 7 and China has 2.

Based on planned projects and existing plants, global hydrogen production from fossil fuels with CCUS could reach 9 Mt by 2030. While several national strategies and roadmaps consider this a low-carbon hydrogen production option, almost none define deployment targets for hydrogen with CCUS, in contrast to electrolysis. Exceptions are the United Kingdom, with a technology-neutral target of domestic low-carbon production capacity of 5 GW_{H2} by 2030, and the low-carbon supply targets of Japan (420 kt H_2) and the Czech Republic (10 kt H_2). Assuming these targets were fulfilled solely by hydrogen production with CCUS, it would correspond to 1.7 Mt H_2 annually.

Estimated production of 9 Mt H_2 in 2030 from planned and existing plants aligns with the Announced Pledges Scenario. The jump to 58 Mt H_2 from fossil fuels with CCUS in the Net zero Emissions Scenario is around seven times the project pipeline, implying that – by 2030 – some 230 hydrogen plants with capacity of 1 GW_{H2} need to be newly built or retrofitted with CCUS. While this number may seem huge, it corresponds to roughly 80% of current unabated production capacity from fossil fuels.

Hydrogen production from fossil fuels with CCUS in the Announced Pledges and Net zero Emissions scenarios, compared with the project pipeline and government pledges, 2030



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Source: IEA (2021), Hydrogen Projects Database.

Industrial ports – where a large share of unabated fossil hydrogen production plants for refining and the petrochemical industry is located – could become hubs for scaling up hydrogen production. In addition to offering offshore storage potential, they could share CO_2 transport and storage infrastructure across different industries, benefitting from economies of scale that could reduce investment risks. Active examples are the Port of Rotterdam (Porthos) project

inthe Netherlands, the Zero Carbon Humber project in the United Kingdom, and CarbonNet in Australia.

Growing momentum for CCUS

Interest in CCUS is expanding globally, as strengthened climate commitments – including ambitious net zero targets – from governments and industry drive renewed momentum. In the first eight months of 2021, more than 40 new commercial projects were announced, reflecting an improved investment environment. A variety of CCUS projects are operating or in planning across several sectors:

- **Industry:** CO_2 capture is already an integral part of urea manufacturing and other industrial processes. Deployment is expanding to chemical products, the steel sector (with one commercial plant operating) and the cement sector (construction to retrofit a plant in Norway has commenced).
- **Electricity and heat:** Two coal-fired power plants equipped with CCUS (in Canada and the United States) have a capture capacity of 2.4 Mt CO_2/yr. Globally, plans exist to equip around 30 coal, gas, biomass or hydrogen power facilities with CCUS.
- **Fuel supply:** Most existing commercial CCUS facilities are linked to natural gas processing, which has relatively low capture costs; collectively, they currently capture almost 30 Mt CO_2/yr. A wide range of CCUS projects are planned, associated with production of low-carbon hydrogen and biofuels, refining, and LNG; several are linked to development of regional CCUS and/or hydrogen hubs.
- **Direct air capture:** A number of small pilot and demonstration DAC plants are currently operating around the world, including some in commercial operation to provide CO_2 for beverage carbonation and greenhouses, and a large-scale (1 Mt/yr) facility is in development in the United States.

CCUS technologies and applications are at various stages of development. Several capture technologies, such as chemical absorption of CO_2 during hydrogen production in ammonia plants, are mature and have high (85-90%) average capture rates (e.g. of CO_2 in the gas stream). Boosting capture rates to 99%, which would substantially decrease residual emissions from CCUS operations, is technically possible with minimal additional cost, but requires incentives such as sufficiently high CO_2 prices or low-carbon standards.

As urea applied on soils breaks back down into ammonia and CO_2 and synthetic fuels are combusted to extract embedded energy, it must be noted that CO_2 used for urea production or for synthetic fuels will eventually be released into the atmosphere. For hydrogen to be considered low-carbon, CO_2 captured during

production would need to be permanently stored (rather than used).

A well-selected and well-managed geological storage site can retain stored CO_2 for more than 1 000 years, with minimal risk of leakage. Theoretically, global CO_2 storage resources are vast; however, some reservoirs will not be suitable or accessible. In many regions, detailed site characterisation is still needed to assess the feasibility and scope of permanent CO_2 storage. At present, a relatively low share of captured CO_2 – only 20% the 40 Mt quoted above – is directed into permanent geological storage (80% is used for EOR).

Hydrogen-based fuels

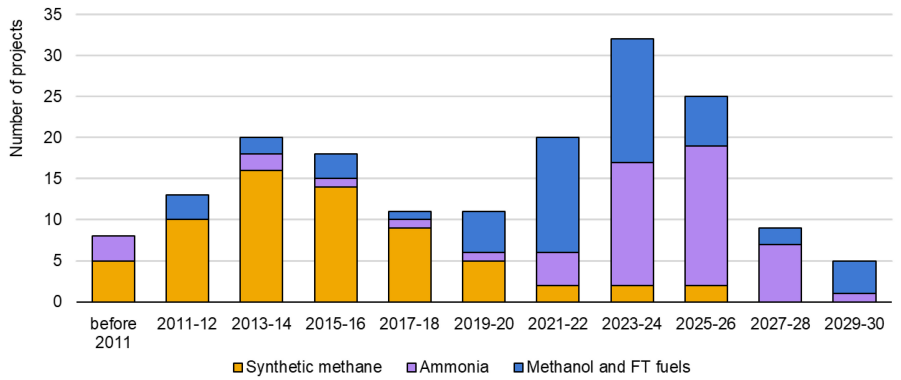
Hydrogen-based fuels are often compatible with existing infrastructure, but cost more

Hydrogen produced through the methods described above has a low volumetric energy density, which makes it more challenging to store and transport than fossil fuels. It can, however, be converted into hydrogen-based fuels and feedstocks (e.g. synthetic methane, synthetic liquid fuels and ammonia) that can be transported, stored and distributed through existing infrastructure for fossil fuels. In fact, some synthetic hydrocarbons from hydrogen can directly substitute for fossil equivalents. The potential benefits and opportunities of these fuels and feedstocks must be weighed against additional conversion losses and related costs.

In 2020, 81 pilot or demonstration projects were in operation, converting electrolytic hydrogen into synthetic methane (59), synthetic methanol (7), synthetic diesel or kerosene (7) and ammonia (8).. Geographically, most are in Europe, and most are at a relatively small scale to demonstrate technologies and supply chains.

Besides hydrogen, synthetic hydrocarbon fuel production requires CO_2 as an input. Initially, the CO_2 may be sourced from hard-to-abate emissions sources. But to ensure the CO_2 neutrality of the produced fuel in the long term, CO_2 supplies should be captured at bioenergy conversion plants or directly from the atmosphere. The Power2Met project (Denmark) uses CO_2 from biogas upgrading, while the Troia plant (Italy) uses DAC for CO_2 to produce synthetic methane.

New projects to produce hydrogen-based fuels from electrolytic hydrogen, by start year



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Notes: FT = Fischer-Tropsch. Figure includes eight synthetic methane and five FT fuel projects decommissioned before 2020. Ammonia includes projects in the chemical industry, where ammonia is used as a feedstock.
Source: IEA (2021), Hydrogen Projects Database.

Several projects planned for upcoming years are expected to advance to the commercial scale. With an electrolyser capacity of 2 GW, the Haru Oni project for methanol (Chile) has a planned final production capacity of 550 million litres per year (by 2026). The Helios Green Fuels project (Saudi Arabia), based on electrolyser capacity of 1.5-2.0 GW, has a planned annual production capacity of 235 kt hydrogen and 1.2 Mt ammonia.

In parallel, the focus of projects under construction or planned shifts from synthetic methane to synthetic liquid fuels (ammonia, methanol and Fischer-Tropsch fuels), with the last accounting for >90% of future projects. This may reflect that using hydrogen-based liquid fuels is an important pathway to decarbonise long-distance transport, particularly aviation and shipping. In the Net zero Emissions Scenario in 2050, ammonia covers 45% of global shipping fuel demand while synthetic kerosene accounts for one-third of global aviation fuel consumption.

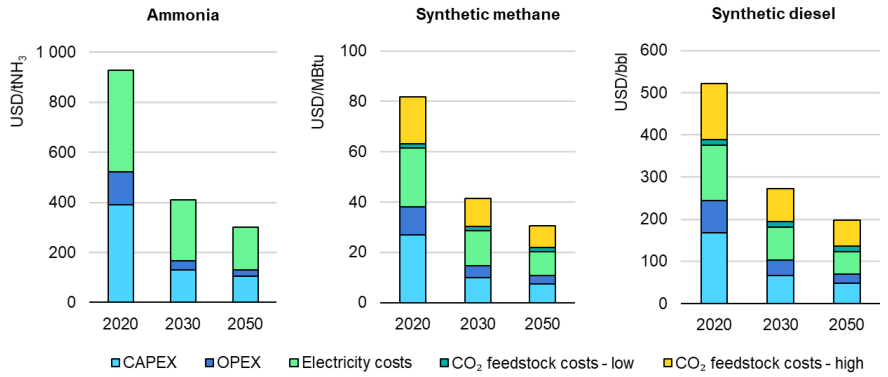
The economics of producing clean ammonia and synthetic hydrocarbon fuels depend on various factors, the cost of hydrogen being key. Fossil fuel and CO_2 storage prices will affect the cost of producing hydrogen using CCUS, whereas for the electrolytic hydrogen route, the availability of low-cost and low-carbon electricity is critical.

In the case of synthetic hydrocarbon fuels, the availability and cost of CO_2 feedstocks is another important factor. CO_2 costs currently range from USD 30/t CO_2 from ethanol plants to USD 150-450/t CO_2 from DAC (but as DAC technology is at an early stage of development, costs could fall to USD 70-240/t CO_2 by 2050). With CO_2 feedstock costs at USD 30-150/t CO_2, production costs for synthetic liquid fuels fall in the range of USD 15-75/bbl.

Current production costs for synthetic liquid hydrocarbon fuels from electrolytic hydrogen are in the range of USD 300-700/bbl. With cost declines for renewable electricity, electrolysers and DAC, they fall to USD 120-330/bbl by 2050 in the Net zero Emissions Scenario, which is still much more expensive than conventional fossil liquid fuels. The situation for synthetic methane is similar.

To support use of these fuels in parts of the energy system with limited low-carbon options (e.g. long-distance transport in aviation or shipping), policy measures are needed to close the cost gap by either pushing up the cost of using of fossil fuels (e.g. CO_2 prices) or incentivising low-carbon fuel use (e.g. clean fuel standards). To close the cost gap with fossil kerosene at USD 25/bbl, a CO_2 price of USD 230-750/t CO_2 would be needed to deliver synthetic liquid hydrocarbon fuels at USD 120-330/bbl.

Levelised cost of ammonia, synthetic methane and synthetic liquid fuels for electricity-based pathways in the Net zero Emissions Scenario, 2020, 2030 and 2050



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Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020); Agora (2018); Danish Energy Agency (2021); IFA (2021).

Emerging technologies

Hydrogen production technologies of the future hold promise

Solid oxide electrolyser cells (SOECs)

SOECs use steam instead of water for hydrogen production, a key departure from alkaline and PEM electrolysers. Additionally, as they use ceramics as the electrolyte, SOECs have low material costs. While they operate at high temperatures and with high electrical efficiencies of 79-84% (LHV), they require a heat source to produce steam. Therefore, if SOEC hydrogen were used to produce synthetic hydrocarbons (power-to-liquid [PtL] and power-to-gas [PtG]), it would be possible to recover waste heat from these synthesis processes (e.g. Fischer-Tropsch synthesis, methanation) to produce steam for further SOEC electrolysis. Nuclear power, solar thermal and geothermal heat systems, as well as industrial waste heat, could also be heat sources for SOECs.

SOEC electrolysers can also be operated in reverse mode as fuel cells to convert hydrogen back into electricity, another feature that is distinct from alkaline and PEM electrolysers. Combined with hydrogen storage facilities, they could provide balancing services to the power grid, increasing the overall utilisation rate of equipment. SOEC electrolysers can also be used for co-electrolysis of steam and CO_2, thereby creating a syngas mixture (carbon monoxide and hydrogen) for subsequent conversion into a synthetic fuel.

SOECs are still in the demonstration phase for large-scale applications (TRL 6-7[32]). Operational systems, often linked to the production of synthetic hydrocarbon fuels, currently have capacities of <1 MW. The largest system in operation (720 kW capacity) uses renewable electricity and waste heat to produce hydrogen for a DRI steel plant. However, a 2.6-MW SOEC system is being developed in Rotterdam, and several companies (e.g. Bloom, Sunfire) are manufacturing SOEC systems, mainly in Europe. Denmark plans to launch a manufacturing plant with an annual capacity of 500 MW by 2023.

Methane pyrolysis

Methane pyrolysis (also known as methane splitting, cracking or decomposition) is the process of converting methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite), without creating any direct CO_2 emissions. The reaction requires relatively high temperatures (>800°C), which can be achieved through conventional means (e.g. electrical heaters) or using plasma. Per unit

[32] A technology's technology readiness level indicates its current maturity within a defined scale, ranging from the definition of basic principles (TRL 1) to full commercial operation in a relative environment (TRL 9). See https://www.iea.org/articles/etp-clean-energy-technology-guide.

of hydrogen produced, methane pyrolysis uses three to five times less electricity than electrolysis; however, it requires more natural gas than steam methane reforming.

The overall energy conversion efficiency of methane and electricity combined into hydrogen is 40-45%. Notably, the process could create additional revenue streams from the sale of carbon black for use in rubber, tyres, printers and plastics, though the market potential is likely limited, with global demand for carbon in 2020 being 16 Mt of carbon black, which corresponds to hydrogen production from pyrolysis of 5 Mt H_2. Carbon from pyrolysis could be used in other applications such as construction materials or to replace coke in steelmaking.

Several methane pyrolysis technology designs under development show TRLs of 3 to 6. Monolith Materials (in the United States) uses thermal plasma to create the high temperatures required. After operating a pilot plant for four years, the company launched an industrial plant in 2020 (in Nebraska) and is planning a commercial-scale plant for ammonia production. To convert biogas into hydrogen and graphite, Hazer Group (Australia) is building a demonstration plant for its catalytic-assisted fluidised bed reactor technology, and BASF (Germany) is developing an electrically heated moving-bed reactor process. Together with RWE, in 2021 the company announced a project to use electricity from offshore wind to produce hydrogen from electrolysis and for a methane pyrolysis plant. Gazprom (Russia) is developing a plasma-based process for methane pyrolysis. The start-up C-Zero (United States) is working on an electrically heated molten-metal reactor for methane pyrolysis.

Anion exchange membranes (AEMs)

AEM electrolysis combines some of the benefits of alkaline and PEM electrolysis. Using a transition metal catalyst (CeO_2-La_2O), it does not require platinum (unlike PEM electrolysis). A key advantage is that the anion exchange membrane itself serves as solid electrolyte, avoiding the corrosive electrolytes used in AEL. AEM technology is still at an early stage of development (TRL 4-5), but Enapter (Germany) is developing kW-scale AEM electrolyser systems that can be combined to form MW-scale systems.

Electrified steam methane reforming (ESMR)

SMR is a widely used process to produce hydrogen from natural gas, and it can be combined with CCUS to reduce CO_2 emissions. To achieve capture rates of 90% or higher, CO_2 capture needs to be applied to two gas streams: the synthesis gas stream after the steam methane reformer (characterised by relatively high CO_2 concentrations) and a more diluted flue gas stream caused by steam production from natural gas. Because the latter has a lower CO_2 concentration, capture requires more energy.

An alternative to capturing CO_2 from flue gas, which accounts for 40% of CO_2 emissions from natural gas SMR, is to use an alternative heat source to produce the steam. Haldor Topsoe (Denmark) is using low-carbon electricity (hence SMR becomes ESMR) at a level of 8 kWh/kg H_2. The technology has been demonstrated at only the laboratory scale (TRL 4) to date, but a pilot plant is under construction to use biogas as a feedstock in ESMR to produce hydrogen and carbon monoxide, which will then be converted into methanol.

Infrastructure and trade

Infrastructure

Efficient development of hydrogen infrastructure requires analysis at the system level

Large-scale hydrogen deployment will need to be underpinned by an effective and cost-efficient system for storage and transport, strategically designed to connect supply sources to demand centres and thereby establish a deep liquid market. While there is generally consensus on the need to expand the penetration of hydrogen in the energy system to decarbonise certain hard-to-abate sectors, uncertainty remains about how its production, consumption and geographical distribution will evolve.

This uncertainty in turn influences how infrastructure for hydrogen storage and transport is developed. Efficient infrastructure design will depend on several aspects, including demand volumes; the location of infrastructure relative to resources for producing low-carbon hydrogen (renewables and CO_2 storage sites); technologies used for production; and existing natural gas and electricity networks, as well as their future development. In some cases, transporting electricity for decentralised electrolytic hydrogen production may be the most economical choice, but under different circumstances, centralised production relying on hydrogen transport can be preferable.

The final use of hydrogen can also dictate how it is transported. In certain cases, hydrogen could be used locally to produce end products (chemical products, fertiliser or steel) or to produce other fuels (ammonia or synthetic fuels) that could be transported more cost-efficiently. In other cases, pure hydrogen would be the final product (for use in transport or high-temperature heating) and its transport as pure hydrogen (gaseous or liquefied) or using a hydrogen carrier (ammonia or a liquid organic hydrogen carrier [LOHC]) would depend on the total cost of transport (including conversion/reconversion, storage and transport).

Although hydrogen's high versatility makes a wide range of possibilities and solutions available across diverse sectors, inadequate planning could result in the construction of inefficient and costly infrastructure. Thus, integrated analysis at the system level is needed to design efficient infrastructure for producing hydrogen and transporting it to end users.

More pipeline transport is needed to reach hydrogen targets

Hydrogen can be transported either in gaseous form by pipelines and tube trailers or in liquefied form in cryogenic tanks. IEA analysis indicates that pipeline is generally the most cost-efficient option for distances of <1 500-3 000 km, depending on pipeline capacity. For longer distances, alternatives such as transporting liquefied hydrogen, ammonia or LOHCs by ship could be more attractive (see also Hydrogen Trade below).

Transmitting hydrogen by pipeline is a mature technology. The first hydrogen pipeline system was commissioned in the Rhine-Ruhr metropolitan area (Germany) in 1938 and remains operational. Historically, carbon steel or stainless steel have been used for hydrogen-line pipes, as higher grades (>100 ksi) present a higher risk of hydrogen embrittlement. Hydrogen pipelines currently cover more than 5 000 km, with >90% located in Europe and the United States. Most are closed systems owned by large merchant hydrogen producers and are concentrated near industrial consumer centres (such as petroleum refineries and chemical plants).

Similar to natural gas pipeline systems, hydrogen pipelines are capital-intensive projects that have high upfront investment costs. Due to the inflexible and durable nature of these assets, investments become sunk as soon as the pipeline is laid. High initial capital costs and associated investment risks can therefore impede hydrogen pipeline system development significantly, especially when demand is nascent and regulatory frameworks have not been established.

Moreover, because thicker pipeline walls are required at larger diameters, construction costs for new-build hydrogen pipelines are typically higher than for natural gas pipelines. At a similar diameter, the CAPEX of hydrogen-specific steel pipelines is 10-50% higher than for natural gas.

Reaching the targets set in hydrogen strategies will necessitate much faster hydrogen transmission development. IEA analysis shows that by 2030, the total length of hydrogen pipelines globally will need to double to 10 000 km in the Announced Pledges Scenario and quadruple to >20 000 km in the Net zero Emissions Scenario.

Fortunately, existing natural gas infrastructure can act as a catalyst to scale up hydrogen transportation. In the short to medium term, blending hydrogen into natural gas can facilitate the initial development of trade, while repurposing gas pipelines can significantly reduce the cost of establishing national and regional hydrogen networks.

Hydrogen blending can be a transitionary solution

By providing a temporary solution until dedicated hydrogen transport systems are developed, blending hydrogen in gas networks can support initial deployment of low-carbon hydrogen and trigger cost reductions for low-carbon hydrogen production technologies. While several pilot projects have been launched in recent years, blending still faces several technical and regulatory barriers. Parameters related to natural gas quality (composition, calorific value and Wobbe index) – as regulated in different countries – can limit (or completely prevent) injection of hydrogen into gas grids.

The hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering. To avoid interoperability issues arising from the changing quality of gas, hydrogen blending will require that adjacent gas markets co-operate more closely.

Hydrogen can be injected into gas networks either directly in its pure form or as "premix" with natural gas. Due to its chemical properties, however, it can cause embrittlement of steel pipelines, i.e. reactions between hydrogen and steel can create fissures in pipelines. Depending on the characteristics of the gas transmission system, hydrogen can be blended at rates of 2-10 vol%H_2[33] without substantial retrofitting of the pipeline system. The hydrogen tolerance of polymer-based distribution networks is typically greater, potentially allowing blending of up to 20 vol%H_2 with minimal or possibly no modifications to the grid infrastructure.

The injection of low-carbon hydrogen into gas grids has grown sevenfold since 2013, but volumes remain low. In 2020, ~3.5 kt H_2 were blended, almost all in Europe and mainly in Germany, which accounted for close to 60% of injected volumes. In France, the GRHYD demonstration project is testing injection of up to 20 vol%H_2 into the natural gas distribution grid of Cappelle-la-Grand (near Dunkirk). In Italy, the Snam project demonstrated the feasibility of blending up to 10% hydrogen in its transmission grid, while in the United Kingdom, the HyDeploy demonstration project tested injection of up to 20 vol%H_2 into Keele University's existing natural gas network (the project became fully operational in early 2020).

Interest in blending is growing in other regions as well. In Australia, pipeline network operators are developing demonstration projects allowing 5-10% volH_2 blend injections starting in 2021 or 2022. Australia Gas Infrastructure Group (AGIG) launched the country's

[33] The energy density of hydrogen is about one-third that of natural gas.

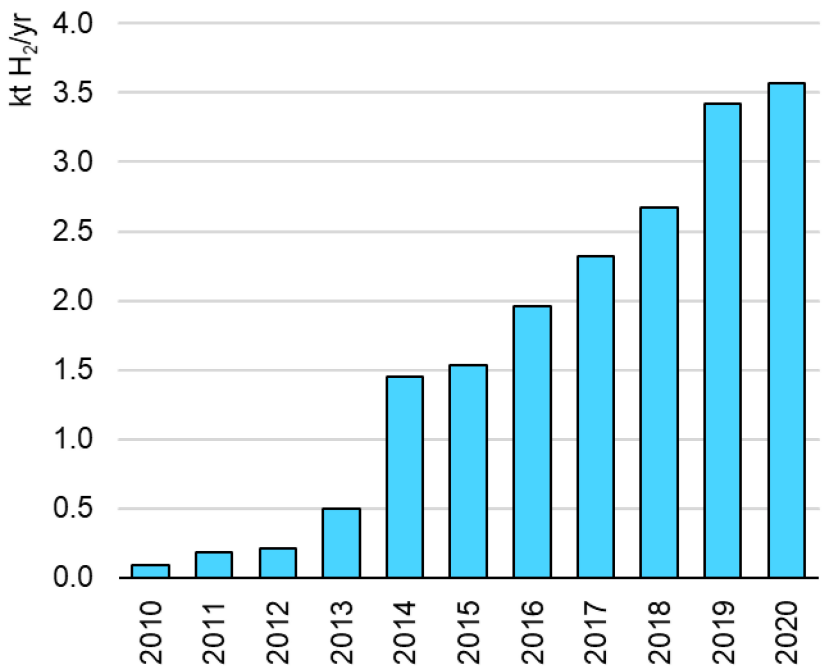
first hydrogen blending pilot project (Hyp SA) in May 2021. Under this project, AGIG will blend about 5 vol% green hydrogen into South Australia's gas distribution network, supported by a 1.25-MW electrolyser operating on solar and wind energy.

In the United States, a first demonstration project on polymer-based distribution pipelines is expected to be launched in California in 2021, with its initial blend level of 1 vol% potentially rising to 20 vol%H_2. In Canada, a hydrogen demonstration project in Ontario is set to start in 2021, allowing for a maximum hydrogen blended content of up to 2% of the natural gas supplied.

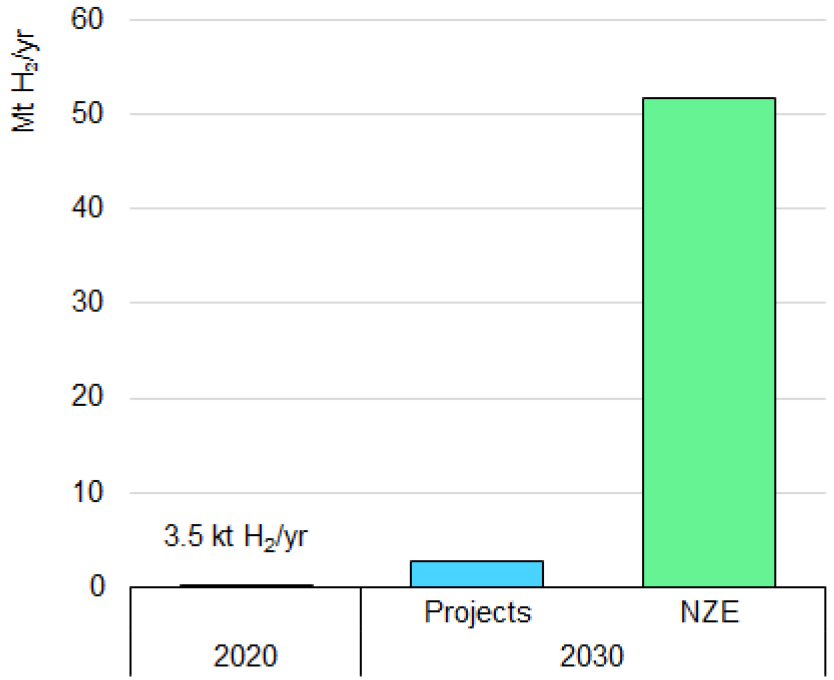
Based on projects that have reached final investment decision (FID) or are under construction, hydrogen blending could increase by a factor of 1.3 by 2030 (>4 kt H_2). However, if all proposed grid-connected hydrogen projects are realised, it could rise by over 700 times to >2 Mt H_2. Still, this falls massively short of the 53 Mt H_2 that need to be blended into gas grids globally in 2030 in the Net zero Emissions Scenario.

Supportive policies and regulatory mechanisms, including blend certificates and/or guarantees of origin, could spur hydrogen trading and pipeline transport development. While the costs associated with hydrogen blending are relatively low, emissions savings are rather limited, with only a ~10% CO_2 reduction at a blending rate of 30%. Consequently, in terms of climate change action, blending is a transitionary solution than can help build up stable sources for low-carbon hydrogen demand until a dedicated hydrogen transport system is developed.

Estimated low-carbon hydrogen injected into gas networks, 2010-2020



Low-carbon hydrogen injected into gas networks in the Projects case and Net Zero Emissions Scenario, 2020-2030



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Note: NZE = Net zero Emissions Scenario.

Source: IEA (2021), Hydrogen Projects Database.

Old but gold: Repurposing gas infrastructure can catalyse hydrogen network development

Compared with building new hydrogen pipelines, repurposing existing natural gas pipeline systems as dedicated hydrogen networks can be substantially less costly and the lead times can be much shorter. Ultimately, this could translate into lower transport tariffs and improve the cost-competitiveness of hydrogen.

Pipeline repurposing can range from simple measures (e.g. replacing valves, meters and other components) to more complex solutions, including replacing/recoating pipeline segments (which entails pipe excavation). Also, considering that hydrogen has a higher leakage rate and an ignition range about seven times wider than that of methane, it may be necessary to upgrade leak detection and flow control systems.

Based on technical analysis of Germany's gas transmission system, Siemens estimates that compressor stations can generally be used without major changes up to 10 vol%H_2; beyond 40 vol%H_2, they have to be replaced, driving up initial investment costs. Notably, the compressor power required per unit of hydrogen transportation is about three times higher than for natural gas, resulting in higher operating expenses. The amount of total compressor power required will ultimately depend on market demand for hydrogen.

Practical experience of gas-to-hydrogen pipeline conversion is rather limited, with several crude oil and product pipelines repurposed to carry hydrogen in the 1970s and 1990s. The first conversion of a natural gas pipeline for full hydrogen service in the Netherlands was put into commercial service in November 2018 by Gasunie (12 km with throughput capacity of 4 kt H_2/yr). Repurposing took six to seven months.

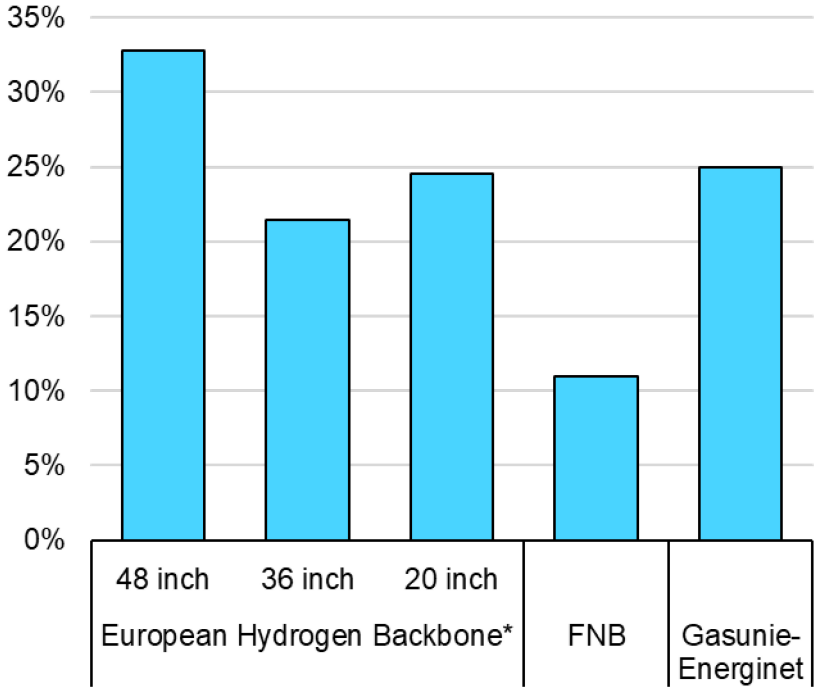
In Germany, as part of its H2HoWi R&D project, E.ON announced the conversion of a natural gas pipeline with an investment cost of EUR 1 million (works started at the end of 2020). In addition, GRTgaz and Creos Deutschland launched the MosaHYc project to convert two existing natural gas pipelines into a 70-km pure hydrogen infrastructure along the border where Germany, France and Luxembourg intersect (FID expected by 2022). In Australia, APA announced the repurposing of 43 km of its Parmelia pipeline in Western Australia as a demonstration project, with testing to be completed by the end of 2022.

The cost benefits of gas pipeline repurposing can be substantial. The European Hydrogen Backbone (EHB) study suggests conversion costs are 21-33% the cost of a new hydrogen pipeline. Of an expected ~40 000 km of hydrogen pipelines in Europe by 2040, the study estimates 75% will be repurposed. The latest draft network development plan of Germany's Transmission System Operator (TSO) Association estimates new-build hydrogen pipeline costs to be almost nine times higher than for gas pipeline conversion.

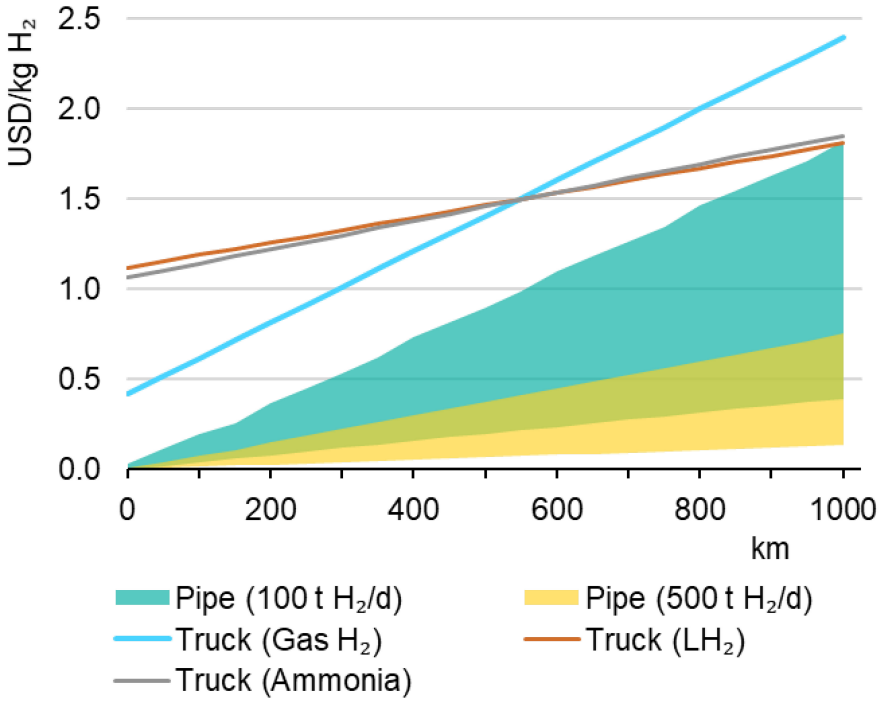
Most recently, the pre-feasibility study for a Danish-German Hydrogen Network estimated repurposing costs to be just 25% of those for new construction. Furthermore, the HyWay27 study, published in the Netherlands (June 2021), estimates that reusing existing natural gas pipelines is four times more cost-effective than laying new hydrogen pipelines. Lower construction costs would translate into more cost-competitive transport tariffs, further supporting deployment of low-carbon hydrogen.

Therefore, of the >1 200 km of hydrogen pipelines foreseen by 2030 in the German TSO Association's Ten-Year Network Development Plan (2020-2030), >90% is repurposed natural gas pipelines. At the end of June 2021, Gasunie announced that the Netherlands' State Secretary for Energy and Climate had requested it to develop a roll-out plan for a national hydrogen transport infrastructure by 2027. Project costs are estimated at EUR 1.5 billion with a throughput capacity of 10 GW, and the hydrogen network would consist of around 85% repurposed natural gas pipes. In September 2021, the Dutch government announced an investment of EUR 750 million (as part of a wider EUR 6.8 billion package on climate measures) to convert parts of the existing gas network into hydrogen transport infrastructure.

Construction cost comparison of repurposing natural gas pipelines vs building new hydrogen pipelines (%)



Estimated transport costs per unit of hydrogen via different types of transport



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* Including compressor station CAPEX costs.

Notes: FNB = Vereinigung der Fernleitungsnetzbetreiber (TSO Association of Germany). LH_2 = liquefied hydrogen. In the right graph, the lower limit for pipeline costs corresponds to repurposing existing pipelines, the upper one to building new pipelines. Truck transport costs are based on a capacity of 10 t H_2/d; in the case of liquefied hydrogen and ammonia, they include conversion and reconversion costs.

Sources: Based on FNB (2020), Netzentwicklungsplan 2020; Gas For Climate (2021), European Hydrogen Backbone 2021; Gasunie-Energinet (2021), Pre-feasibility Study for a Danish-German Hydrogen Network.

Underground hydrogen storage in salt caverns and other geological formations

Availability of hydrogen as an energy vector could, like natural gas, enhance overall energy system flexibility by balancing short-term supply variability and meeting seasonal demand swings, thereby improving energy supply security. To fulfil this role, low-carbon hydrogen deployment will need to be coupled with development of cost-effective, large-scale and long-term storage solutions.

Global gas storage totalled >400 bcm in 2020 (10% of total consumption), with porous reservoirs (depleted fields and aquifers) accounting for >90% of storage capacity and the rest located in salt and rock caverns. Assuming global hydrogen demand reaches 530 Mt and a similar storage-to-consumption ratio, hydrogen storage requirements in the Net zero Emissions Scenario could amount to ~50 Mt (~550 bcm) by 2050.

Used by the petrochemical industry since the early 1970s, storing hydrogen underground in salt caverns is a proven technology. Because salt caverns support high injection and withdrawal rates, storing hydrogen there can provide short-term energy system flexibility. Their development, however, depends on geological conditions, i.e. the availability of salt formations. In addition, the injection-withdrawal periodicity of the petrochemical industry's use of underground hydrogen storage may differ from that of other applications, which could require faster cycles.

Four hydrogen salt caverns sites are currently operational. The first was commissioned in in 1972 at Teesside (United Kingdom) by Sabic Petrochemicals, and three are operational in Texas, including Spindletop (commissioned in 2016), the world's largest hydrogen storage facility.

Several pilot projects are under development in Europe: in the Netherlands, testing of hydrogen storage in the borehole of a future cavern in Zuidwending began in August 2021, with the first cavern to be operational in 2026. In Germany, EWE began building a smaller-scale salt cavern storage site at Rüdersdorf at the beginning of 2021, with first test results expected by mid-2022. In Sweden, a rock cavern hydrogen storage facility is under construction, with pilot operations expected to start in 2022. Several pilot projects are also in various stages of development in France and the United Kingdom.

In the United States, the proposed large-scale Advanced Clean Energy Storage (Utah) is targeting start-up in the mid-2020s. While there is no practical experience in repurposing methane caverns for hydrogen service, it is estimated that such an approach would require about the same amount of time as developing a new salt cavern.

While experience storing hydrogen in porous reservoirs such as depleted fields or aquifers is limited, demonstration projects in Austria (the Underground Sun Storage project) and Argentina (HyChico)

show it is feasible to store a blend of 10% hydrogen and 90% methane in depleted fields without adversely affecting the reservoirs or equipment. Water aquifers are the least mature of the three geological storage options, and evidence of their suitability is mixed. The feasibility and cost of storing pure hydrogen in depleted reservoirs and aquifers still must be proven, requiring further research.

Another potential barrier is public opposition due to concerns about subsidence and induced seismicity, which should be investigated in depth to minimise risks. In parallel, adequate and transparent communication should address public concerns before large-scale storage site development begins. The IEA Hydrogen TCP is establishing a new task for underground hydrogen storage that will focus on research and innovation to prove its technical, economic and societal viability.

Existing hydrogen storage facilities and planned projects

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

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Hydrogen trade

First steps under way to develop supply chains for international hydrogen trade

With the transition to sustainable energy systems boosting demand for hydrogen and hydrogen-based fuels, international trade in hydrogen will be an important part of the hydrogen supply chain. Countries that have limited domestic capabilities to produce low-carbon hydrogen from renewables, nuclear energy or fossil fuels with CCUS – or that find these processes too expensive – can benefit from importing more affordable low-carbon hydrogen.

For countries with excellent renewable resources, international trade in hydrogen can provide an opportunity to export renewable resources that otherwise may not be exploited. Similarly, gas- or coal-producing countries could join the market by exporting hydrogen produced from fossil fuels with CCUS. In the Net zero Emissions Scenario, international trade in hydrogen and hydrogen-based fuels covers ~15% of global demand for these fuels in 2030.

Transporting energy over long distances is typically easier in the form of molecules (i.e. liquid, gaseous or synthetic fuels) than as electricity because fuels are characterised by high (volumetric) energy densities and lower transport losses. Most natural gas is moved worldwide in large-scale pipelines or as LNG via ships, and similar methods could be employed for hydrogen and hydrogen carriers. Hydrogen can also be transported in storage tanks by trucks, which is currently the main option to distribute it at the local level, but it is generally very expensive. For longer distances, pipelines and seaborne transportation are more economical, with the best option dependent on distance and volume (among other factors).

At present, hydrogen is generally stored as a compressed gas or in liquefied form in tanks for small-scale local use. However, a much wider variety of storage operations will be required to achieve uninterrupted international hydrogen trading. At import terminals, hydrogen storage is likely necessary as a contingency measure in case of supply disruptions, similar to the approach for LNG.

Various solutions are being explored for long- or short-distance seaborne hydrogen transport. One option is to transport it in liquefied form, which is drastically more dense than the gaseous state. However, as hydrogen liquefaction requires a temperature of -253°C (i.e. 90°C lower than for LNG), it is energy-intensive. Plus, current liquefaction processes have a relatively low efficiency and consume about one-third of the energy contained in the hydrogen. Some reports indicate that scaling up liquefier capacity could cut energy requirements to around one-fifth.

Another option for high-density transport is to convert hydrogen into another molecule such as ammonia or LOHC. Ammonia is already traded internationally as a chemical product, but as it is toxic, increased transport and use may raise safety and public acceptance issues, restricting its handling to professionally trained operators.

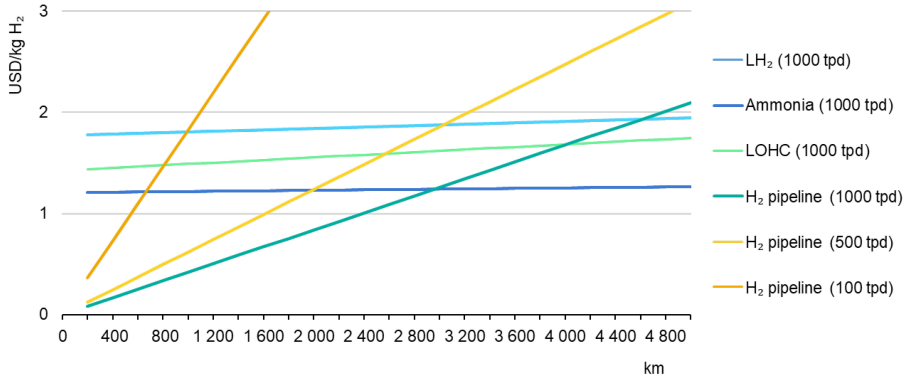
Converting hydrogen into ammonia and reconverting it back to hydrogen after transport is possible, but additional energy and purification steps will be required for some end uses. Still, the advantage of ammonia is that it liquefies at -33°C (at ambient pressure), a much higher temperature than hydrogen, resulting in a lower energy needs.

LOHCs have properties similar to crude oil and oil products, and their key advantage is that they can be transported without liquefaction. As with ammonia, conversion/reconversion and purification processes are costly, and depending on an LOHC's basic molecular makeup, toxicity issues could be a consideration. Furthermore, an LOHC's carrier molecules are often expensive and, after being used to transport hydrogen to its destination, need to be shipped back to their place of origin.

The high cost of hydrogen transmission and distribution for many trade routes means it may cost less to produce low-carbon hydrogen domestically than to import it – i.e. the higher cost of clean hydrogen production could still be less than the supply costs incurred for imports. This depends heavily on local conditions. Countries with constrained CO_2 storage or limited renewable resources will be more dependent on imports to meet hydrogen demand.

In 2020, significant progress was made in demonstrating international hydrogen trade. The Advanced Hydrogen Energy Chain Association for Technology Development successfully produced and traded hydrogen by LOHC technology from Brunei to Japan using container shipping, for use as a gas turbine fuel. Meanwhile, Saudi Aramco and the Institute of Energy and Economic of Japan collaborated to import 40 t of ammonia produced in Saudi Arabia from natural gas with CCUS to Japan for direct use as an electricity generation fuel. For liquefied hydrogen (LH_2), the first planned shipment from Australia to Japan in the Hydrogen Energy Supply Chain (HESC) pilot project was postponed to the first quarter of 2022 due to the Covid-19 pandemic. Still, the import terminal and hydrogen production plant were commissioned, and the hydrogen was successfully produced and liquefied in Australia.

Costs of delivering GH_2 by pipeline and LH_2, LOHC and ammonia by ship, 2030



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Notes: GH_2 = gaseous hydrogen. LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. tpd = tonnes per day. Includes conversion, export terminal, shipping, import terminal and reconversion costs for each carrier system. Storage costs are included in import and export terminal expenses. The pipeline cost assumes construction of a new pipeline.

Sources: Based on IAE (2016); Baufumé (2013).

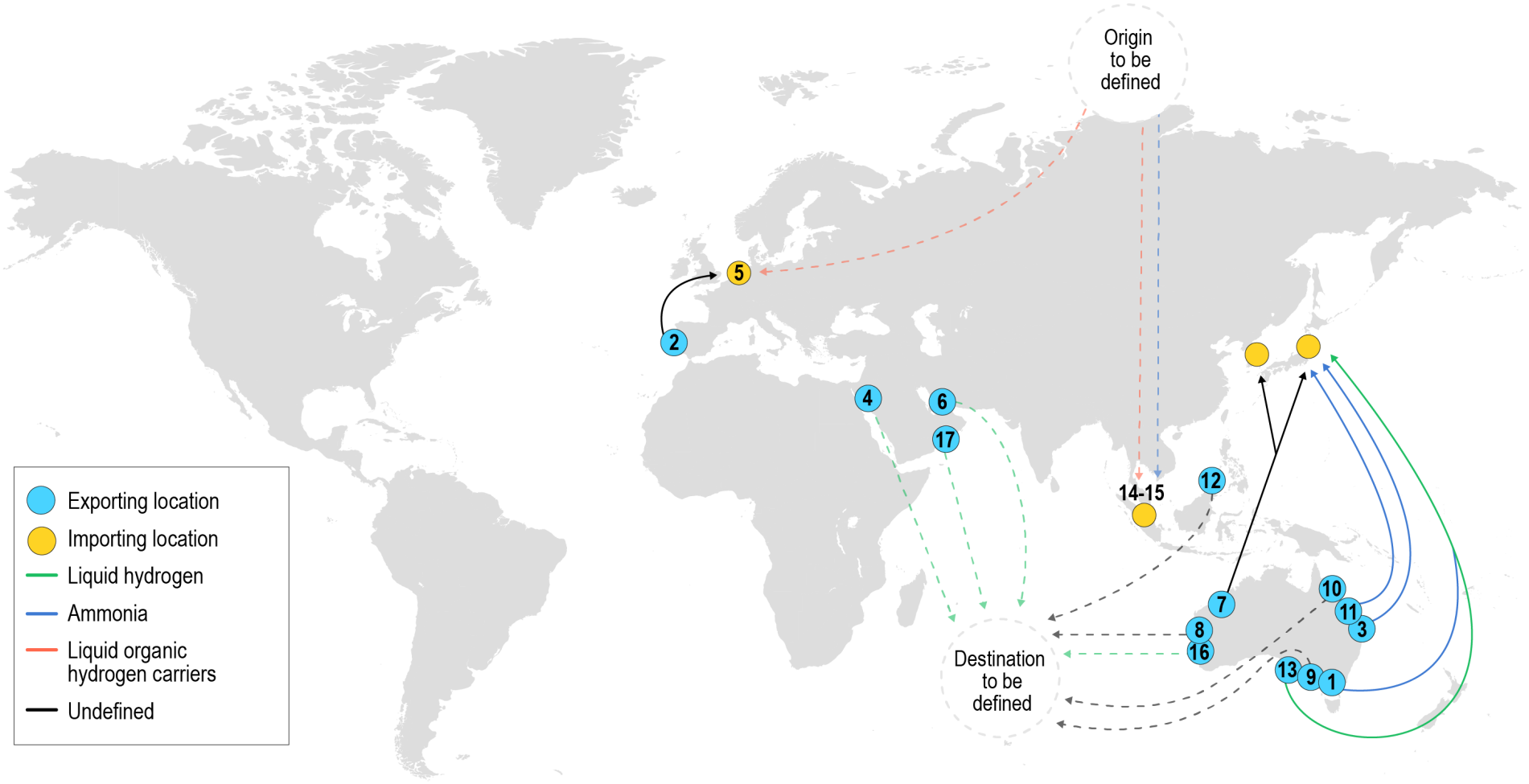
Governments and private companies have also announced several other international collaborations and projects for hydrogen trade. Germany, which stated the importance of importing hydrogen in its national strategy, signed an agreement for a joint feasibility study with Australia and Chile. Meanwhile, the Netherlands signed an MOU with Portugal, the Port of Rotterdam signed one with Chile, and Japan signed a memorandum of collaboration (MOC) with the United Arab Emirates. Around 60 international hydrogen trade projects have been announced and feasibility studies are under way for half of them. The total reported volume of these projects is 2.7 Mt H_2/yr.

Selected international hydrogen trade projects

Project	Export country	Import country	Volume	Carrier	Expected first shipping year	Map Reference
Hydrogen Energy Supply Chain	Australia	Japan	225 540 tpa	LH_2	2030	1
H2 Sines	Portugal	Netherlands	TBD	TBD	TBD	2
Stanwell - Iwatani Gladstone project	Australia	Japan	280 000 tpa	LH_2	2026	3
Helios Green Fuels	Saudi Arabia	TBD	650 tpd	Ammonia	2025	4
H2Gate	TBD	Netherlands	1 000 000 tpa	LOHC	TBD	5
ADNOC - TA'ZIZ industrial hub	United Arab Emirates	TBD	175 000 tpa	Ammonia	2025	6
Asian Renewable Energy Hub	Australia	Japan or Korea	TBD	LH_2 or ammonia	2028	7
Murchison	Australia	TBD	TBD	TBD	TBD	8
Crystal Brook Energy Park	Australia	TBD	25 tpd	TBD	TBD	9
Pacific Solar Hydrogen	Australia	TBD	200 000 tpa	TBD	TBD	10
Origin Energy - Kawasaki Heavy Industries Townsville project	Australia	Japan	36 000 tpa	LH_2	2025	11
KBR SE Asia feasibility study	Southeast Asia	TBD	TBD	TBD	TBD	12
Eyre Gateway	Australia	Japan or Asia	7 000 tpa	Ammonia	TBD	13
Unnamed	TBD	Singapore	TBD	LH_2	TBD	14
Unnamed	TBD	Singapore	TBD	LOHC	TBD	15
Project Geri	Australia	TBD	175 000 tpa	Ammonia	TBD	16
Green Mega Fuels Project	Oman	TBD	175 000 tpa	Ammonia	2032	17
Western Green Energy Hub	Australia	TBD	34 000tpa	Ammonia	TBC	18

Notes: LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. SE Asia = Southeast Asia. TBD = to be determined. tpa = tonnes per annum. tpd = tonnes per day.

Most hydrogen trade projects under development are in Asia-Pacific



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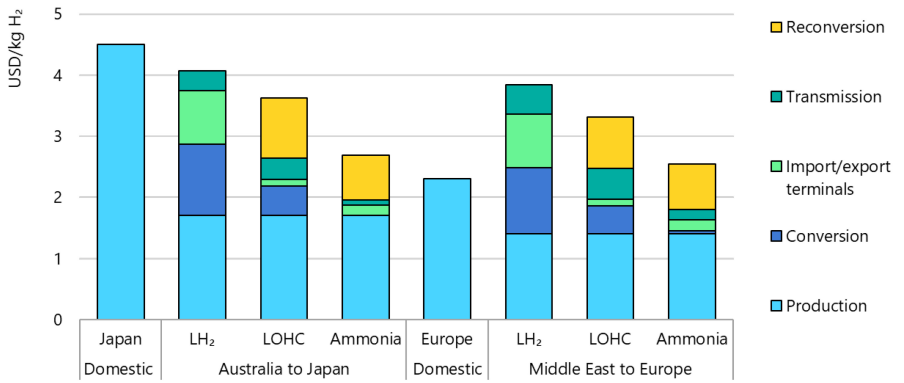
Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

As part of its JPY 2-trillion (about USD 18.7-billion) Green Innovation Fund, the Japanese government has allocated JPY 255 billion (about USD 2.4 billion) to establish the first commercial international hydrogen trade. Its intent is to support LH_2 and LOHC supply chain development to reduce costs and improve the maturity of the technologies involved.

Any country deciding whether to produce hydrogen domestically or import must consider all delivery costs across the entire supply chain, from production and transport to end-use application. The IEA estimates that by 2030, importing hydrogen produced from solar PV in Australia into Japan (<USD 4.20/kg H_2) will cost slightly less than producing it domestically from renewables (USD 4.50/kg H_2). While producing natural gas-derived hydrogen with CCUS in Japan could cost even less (USD 1.85/kg H_2), access to CO_2 storage may be a limiting factor.

In the case of exporting hydrogen from the Middle East to Europe, imported hydrogen (USD 2.60-3.80/kg H_2) is unlikely to be competitive with domestic production (USD 2.30/kg H_2) in 2030. However, if ammonia can be used directly (e.g. in the chemical industry or as a shipping or power sector fuel), reconversion losses can be avoided and the supply cost could be reduced to USD 1.80/kg H_2 for these trade links, which would be competitive. In the long term, further efficiency improvements and process optimisation could reduce transport and thus total supply costs for all carriers. In some regions, this could eventually make imports more attractive than domestic production, potentially boosting international trade after 2030.

Projected costs of delivering LH_2, LOHC and ammonia in selected regions, 2030



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Notes: LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. Assumes distribution of 1 000 t H_2/d. Storage costs are included in import and export terminal expenses. Hydrogen is produced from electrolysis using renewable electricity.

Source: Based on IAE (2016).

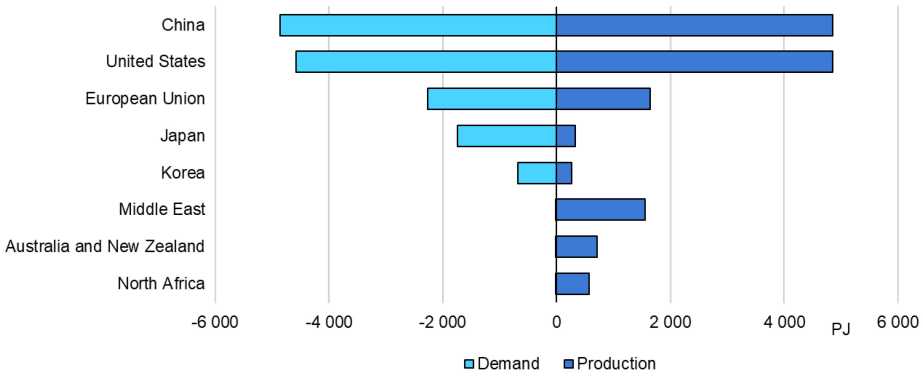
Long-term potential of international hydrogen trade

In the Announced Pledges Scenario in 2050, trade in hydrogen and hydrogen-based fuels accounts for 20% of global demand, with 8% of hydrogen demand being traded, 50% of ammonia and 40% of liquid synfuels. This reflects the comparatively lower transport costs of ammonia and synfuels. While several countries (e.g. China and the United States) manage to cover growing demand for low-carbon hydrogen and hydrogen-based fuels domestically, others (e.g. Japan, Korea and parts of Europe) rely on imports, at least in part. By 2050 in the Announced Pledges Scenario, Japan and Korea are importing each around 60% of their domestic demand for hydrogen and hydrogen-based fuels.

Australia, Chile, the Middle East and North Africa emerge as key exporting regions in the Announced Pledges Scenario, benefitting from the low cost of producing hydrogen from renewables or from natural gas with CCS. By 2050, North Africa, the Middle East and Chile export ~600 PJ of hydrogen and hydrogen-based fuels to Europe. For Asia, the important hydrogen suppliers are the Middle East, Australia and Chile. By 2050, these exporters meet 1 800 PJ of Asian demand for hydrogen and hydrogen-based fuels in the Announced Pledges Scenario.

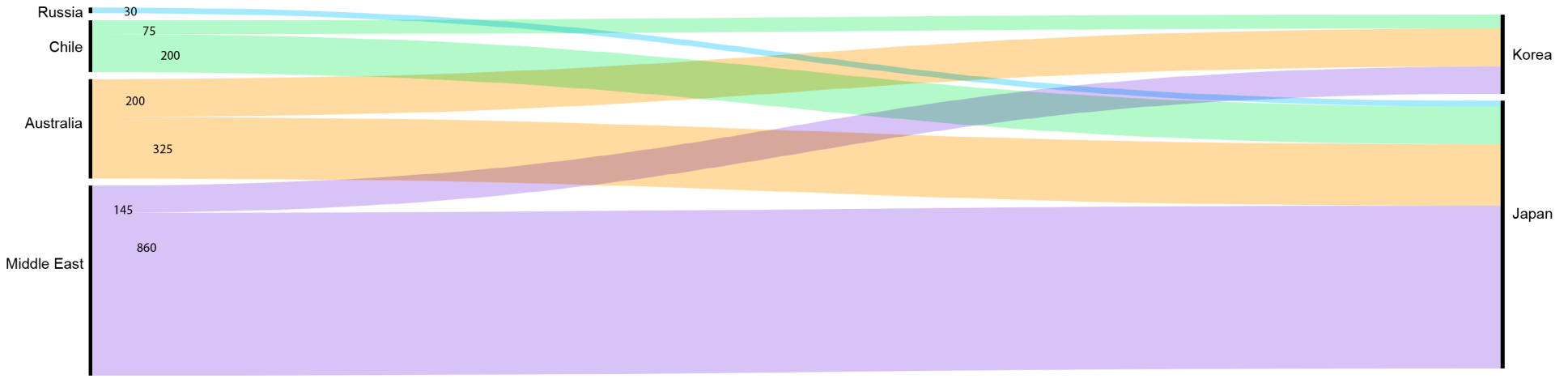
However, many of these major future exporters do not yet have net zero pledges in place, so importing countries will need to engage with trading partners to encourage and guarantee relevant supply investments if they want their hydrogen imports to be low-carbon.

Announced Pledges Scenario hydrogen and hydrogen-based fuel demand and production in selected regions, 2050



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Hydrogen trade flows to Japan and Korea in the Announced Pledges Scenario in 2050



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Investments and innovation

Hydrogen investments rising despite Covid-19 pandemic, with unprecedented private fundraising, mostly for manufacturing and to meet project demand

Hydrogen has proven remarkably resilient during the economic slowdown induced by the global pandemic. Companies specialised in producing, distributing and using hydrogen raised almost USD 11 billion in equity between January 2019 and mid-2021 – a considerable increase from prior years – and contracts funded by government recovery packages are expected to raise project investments substantially. Nevertheless, funding is grossly insufficient to accelerate innovation to the level required to realise hydrogen's 60 Gt of CO_2 emissions reduction potential modelled in the Net zero Emissions Scenario.

Overview of recent company fundraising

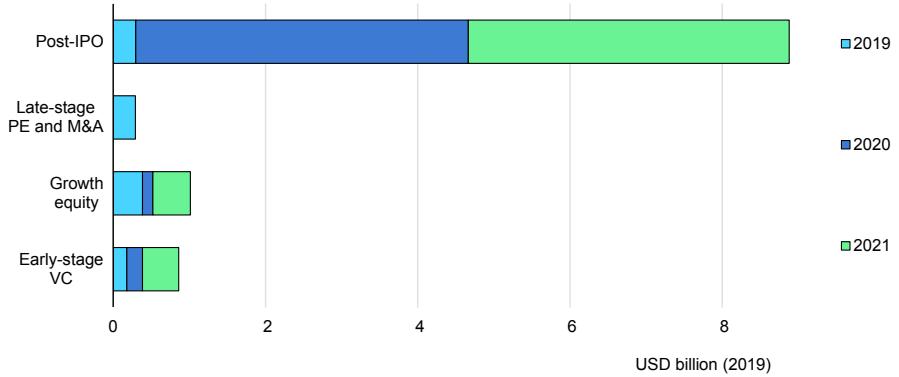
Most new funding for hydrogen in 2020 and 2021 was raised by companies already listed on a stock exchange. They issued new shares to investors, primarily to secure capital for expanding manufacturing facilities to meet expected or contracted demand for electrolysers and fuel cells. Investor confidence in hydrogen companies continued into the first half of 2021, partly in anticipation of contracts to be supported by government recovery packages.

Having sold USD 4.8 billion in new shares since 2019, the largest fundraiser was Plug Power, a US company (est. 1997) that makes electrolysers, fuel cells and refuelling equipment. Other electrolyser manufacturers – including Nel, ITM Power, McPhy Energy, Green Hydrogen Systems and Sunfire – collectively raised USD 1.5 billion. Nikola, a company developing a fuel cell truck, raised USD 250 million in 2019, then listed on the Nasdaq in 2020, raising USD 700 million. In November 2020, however, a deal to sell 11% of its shares to GM for USD 2 billion fell through. Investors have since become increasingly concerned about Nikola's ability to meet its development schedule.

Two notable acquisitions occurred in this period. US engine manufacturer Cummins bought the Canadian electrolyser company Hydrogenics for USD 290 million. In Germany, engine manufacturer MAN Energy Solutions acquired the PEM electrolyser maker H-Tec for an undisclosed sum.

Several investment funds targeting hydrogen were launched in 2021. The most recent, HydrogenOne Capital Growth Fund, raised USD 150 million in an initial public offering including USD 35 million from the petrochemical company INEOS. Other funds established since 2018 include Ascent, FiveT, H-Mobility, Klima and Mirai. In China, Shanxi Hydrogen Energy Industrial Fund, a government-guided fund, was launched in 2021.

Hydrogen company fundraising by stage of funding, January 2019 to mid-July 2021



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Notes: PE = private equity. M&A = mergers and acquisitions. VC = venture capital. Post-IPO includes private investment in public equity (PIPE) transactions and other new share sales. Early-stage VC includes seed, Series A and Series B. Only deals with disclosed values are included, which notably excludes certain M&A deals with undisclosed values.
Sources: Calculations based on Cleantech Group (2021) and Prequin (2021).

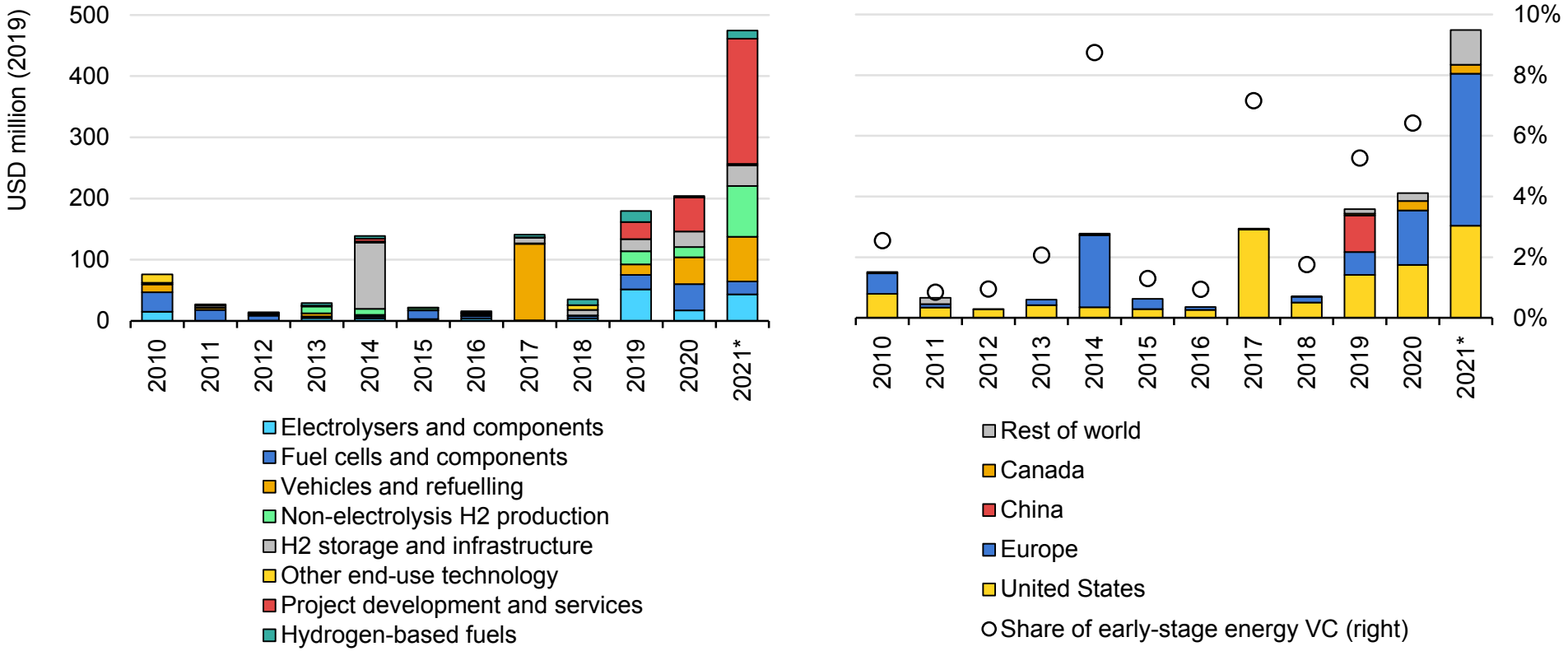
Investment in riskier early-stage hydrogen start-ups is also on the rise. In contrast to the clean energy venture capital (VC) boom around 2010, which involved few hydrogen companies, the current investment surge delivered record amounts in 2019 and 2020, with these sums surpassed in just the first six months of 2021. As electrolyser companies become more established in the market, start-up activity is shifting to focus on newer non-electrolysis routes, such as pyrolysis for extracting hydrogen from methane. Transform Materials and Syzygy Plasmonics have raised USD 50 million since 2019, while Monolith Materials raised USD 100 million in 2021 in later-stage financing.

The fact that start-ups providing project development and integration services for hydrogen projects are securing funding indicates a maturing sector. In May 2021, H2 Green Steel raised over USD 100 million, the first major deal for a project developer for hydrogen use in the steel industry. Aiming to start production by 2024, the Swedish company plans follow-up funding of USD 2.5 billion in mixed debt and equity within the next year. HTEC, an early-stage Canadian integration services firm, raised USD 170 million in September 2021.

Regionally, many start-ups in these newer areas are European. For the first time, in fact, European hydrogen start-ups are expected to raise more early-stage funds in 2020 and 2021 than their US counterparts. China has also emerged as a source of hydrogen technology start-ups and venture capital for scale-up. In 2019, Jiangsu Guofu Hydrogen Technology's fundraise of USD 60 million was the main early-stage deal in China, with the money coming from a state-backed Shanghai fund.

More early-stage capital flowing to start-ups, especially in Europe; fastest growth in companies offering project development services or non-electrolysis supply solutions

Early-stage venture capital deals for hydrogen-related start-ups by technology area and region, 2010-2021



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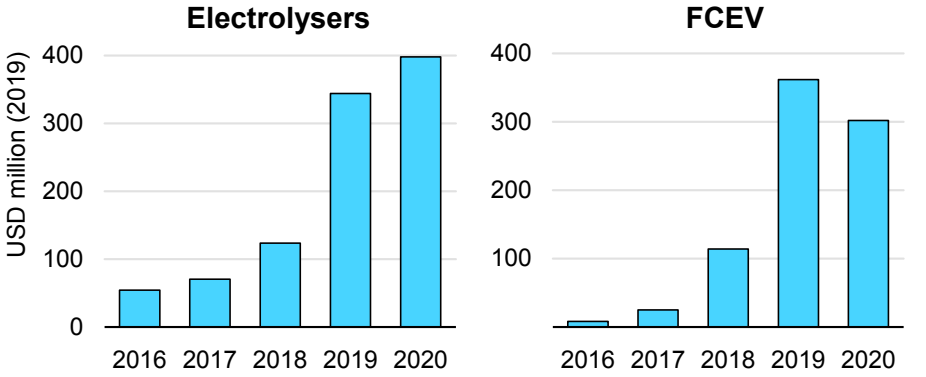
Notes: 2021* data up to mid-June. H2 = hydrogen. Early-stage VC includes seed, Series A and Series B. The share of early-stage energy VC excludes outlier deals above USD 150 million that distort trends (no such deal was recorded for hydrogen start-ups). Other end-use technology includes stationary turbines and non-transport mobile applications that do not involve proprietary fuel cell stacks.

Source: Calculations based in part on Cleantech Group (2021).

Evolution of investment in technology deployment

Investment in hydrogen technology deployment is also increasing. Despite near-term uncertainty about market-led uptake, hydrogen prospects look stronger than before the Covid-19 pandemic. Projects expected to deploy electrolysis capacity in 2021 raised more than USD 400 million in 2020, nearly four times the investments in 2018. In mobility, 2020 funding decreased slightly from 2019, likely reflecting impacts of the pandemic; investment is more than recovering in 2021, however, and deployments up to June point to a new record year.

Annual investments in electrolysers and FCEVs, 2016-2020



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Note: FCEV = fuel cell electric vehicle.
Sources: Based on IEA Hydrogen Project Database and annual data submissions of the AFC TCP to the IEA Secretariat.

Clearly, government action – including funding in Covid-19 recovery plans and long-term signals embedded in national hydrogen strategies – is spurring the strong momentum behind hydrogen investment. Public investment is expected to leverage much higher private spending, which could further accelerate hydrogen technology deployment. For example, as part of its national hydrogen strategy, Germany announced a EUR 9-billion package, which the German government expects to trigger an additional EUR 33 billion of private investment. Globally, the industry sector is responding with an impressive investment appetite: according to the Hydrogen Council, the private sector has announced more than USD 300 billion of investments through 2030, although funding of only USD 80 billion has been committed.

Investment outlook for the Announced Pledges and Net zero Emissions scenarios

While recent hydrogen investments are encouraging, realising government climate ambitions will require significant ramp-ups across the entire production, end-use and infrastructure value chains. The Announced Pledges Scenario models investments totalling USD 250 billion for 2020-2030, leading to an accumulated investment of USD 3.2 trillion in 2050. This is lower than announced industry stakeholder investments to 2030, but significantly larger than those for which funding has already been committed.

Investments over the next decade could be critical in determining long-term outcomes. Every year until 2030, investments of USD 7 billion in electrolysers will be required (30 times recent record investments) and USD 4 billion in FCEV deployment will be needed (14 times record investments). To achieve net zero emissions by

2050, global cumulative investments must increase to USD 1.2 trillion by 2030 and USD 10 trillion by 2050.

Building up low-carbon hydrogen production capacity accounts for 25% of global cumulative investments to 2050 in the Announced Pledges Scenario and 27% in the Net zero Emissions. The need to deploy capacity for both new production and to decarbonise existing uses (which requires limited investments in end uses and infrastructure) means the share of investments in hydrogen production must be higher before 2030 than after. Although investment in production capacity continues to grow to 2050, its share declines as investments in new end-uses and infrastructure development increase.

End-use technologies account for about 60% of global cumulative investments to 2050 in both the Announced Pledges and Net zero Emissions scenarios, with the share increasing continuously. Investments in end-use technologies are already considerable in 2020-2030, projected at USD 8 billion/yr in the Announced Pledges Scenario and USD 30 billion in the Net zero Emissions. After 2030, several end-use technologies advance from early-stage development to commercialisation and deployment at scale, unlocking new hydrogen demand, particularly in the transport sector. Consequently, investments increase substantially to USD 90 billion/yr to 2050 in the Announced Pledges Scenario and to USD 270 billion/yr in the Net zero Emissions.

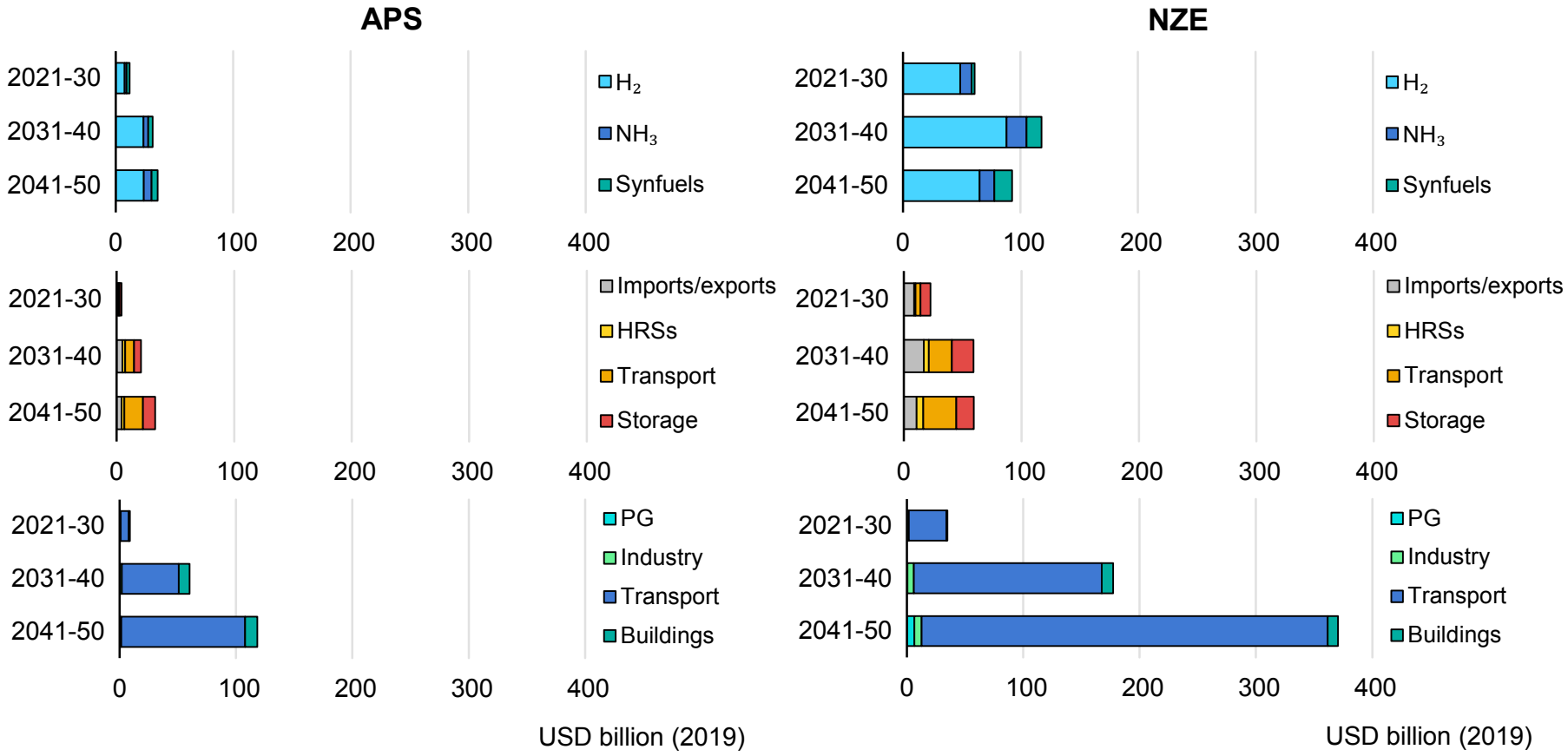
To distribute hydrogen to end users, significant investments are also required to develop infrastructure (i.e. refuelling stations, pipelines, storage and import/export terminals). In fact, infrastructure accounts for 18% of global cumulative investments to 2050 in the Announced Pledges Scenario (USD 575 billion) and 14% in the Net zero Emissions (USD 1 400billion).

Although modelling shows this share increasing nearly fivefold after 2030 in the Announced Pledges Scenario and more than twofold in the Net zero Emissions, this does not mean that infrastructure development can be delayed another decade. Rather, developing hydrogen storage capacity will be critical to ensure supply security in the short term and to provide balancing for the integration of renewable energy in the longer term. In parallel, progress can be made by blending hydrogen in the gas grid and repurposing natural gas pipelines. As hydrogen demand grows, greater investments in new pipeline infrastructure may be required, depending on regional conditions. Furthermore, the development of international hydrogen supply chains can spur investment in import/export terminals and hydrogen transport vessels.

Notable opportunities may exist to minimise expenditures by repurposing current infrastructure. With minimal modification, infrastructure for oil-derived products could be used to import/export liquid synfuels, while some parts of LNG and LPG infrastructure could be upgraded to import/export hydrogen and ammonia.

Investment on hydrogen must increase to USD 1.2 trillion by 2030 to put the world on track to meet net zero emissions by 2050

Global annual hydrogen investment needs by sector in the Announced Pledges and Net zero Emissions scenarios

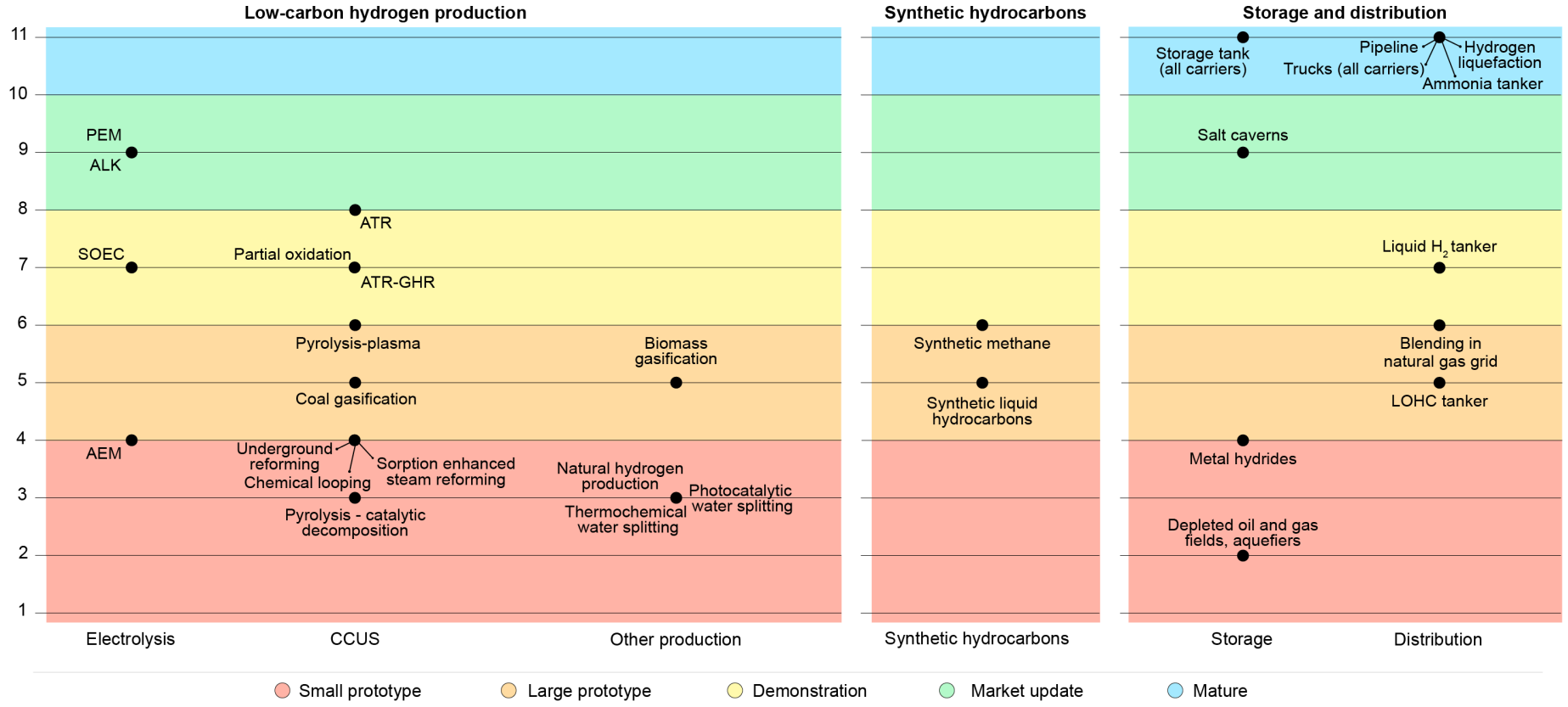


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Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. HRSs = hydrogen refuelling stations. PG = power generation.

Several hydrogen technologies not yet commercially available

Technology readiness levels of key hydrogen production, storage and distribution technologies

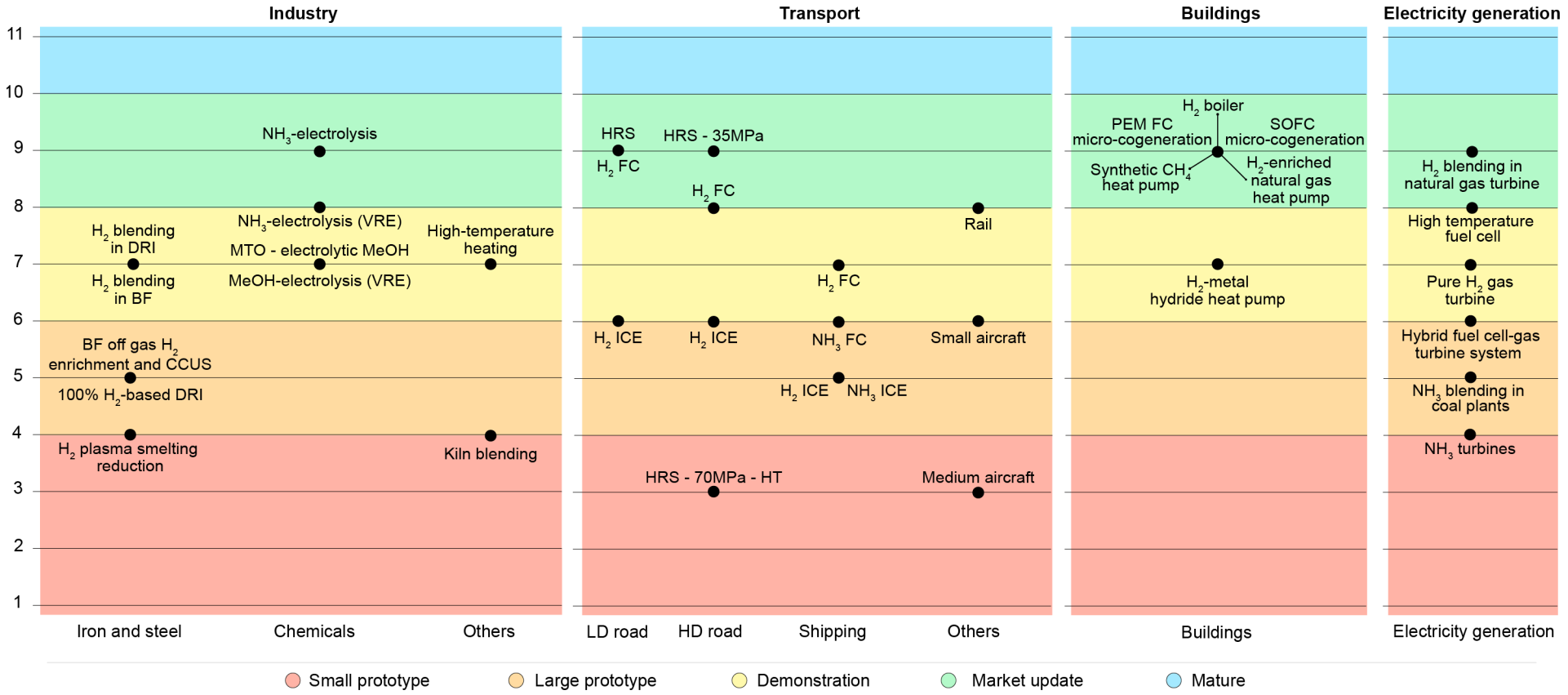


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Notes: AEM = anion exchange membrane. ALK = alkaline. ATR = autothermal reformer. CCUS = carbon capture, utilisation and storage. GHR = gas-heated reformer. LOHC = liquid organic hydrogen carrier. PEM = polymer electrolyte membrane. SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. For technologies in the CCUS category, the technology readiness level (TRL) refers to the overall concept of coupling these technologies with CCUS. TRL classification based on Clean Energy Innovation (2020), p. 67.

Source: IEA (2020), ETP Clean Energy Technology Guide.

Technology readiness levels of key hydrogen end-use technologies



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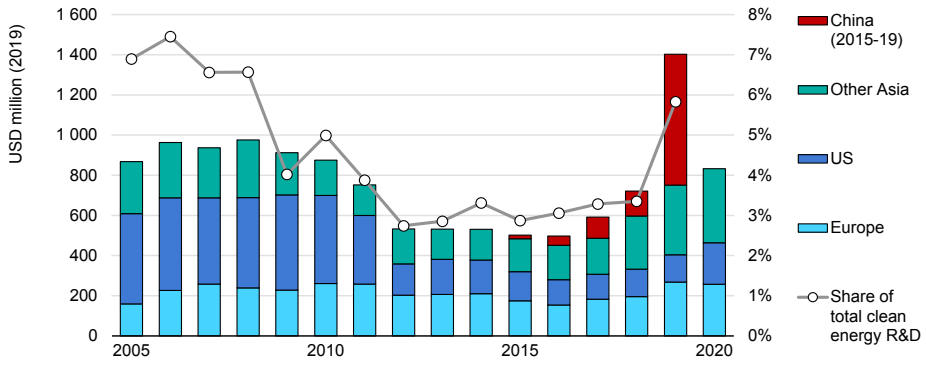
Notes: BF = blast furnace. DRI = direct iron reduction. FC = fuel cell. HRS = hydrogen refuelling station. HD = heavy-duty. HT = high throughput. ICE = internal combustion engine. LD = light-duty. MeOH = methanol. MTO = methanol to olefins. PEM FC = polymer electrolyte membrane fuel cell. SOFC = solid oxide fuel cell. VRE = variable renewable electricity. Co-generation refers to the combined production of heat and power. Technology readiness levels based on Clean Energy Innovation (2020), p. 67.

Source: IEA (2020), ETP Clean Energy Technology Guide.

Innovation in hydrogen technology is lagging

Except for well-established technologies for fossil-based production and conventional uses in industry and refining, much of the hydrogen value chain is yet to be fully developed at commercial scale. It is therefore vital that innovation efforts for all hydrogen technologies be stepped up to avoid bottlenecks in using them as a key lever for decarbonisation. In its Net zero by 2050 roadmap, the IEA estimates that USD 90 billion of public money needs to be mobilised globally as quickly as possible, with around half dedicated to hydrogen-related technologies.

R&D spending in hydrogen technologies, 2005-2020



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Source: Based on IEA and Mission Innovation data. 2020 data for China not available.

Government support for hydrogen R&D was strong in the late 2000s. In fact, it accounted for 6% of all clean energy R&D, with most funding directed towards electrolyser technology and Japan being the largest funder. While a slump in R&D expenditures during 2010-2015 reflected lower overall interest in this technology family, the recent resurgence (since 2015) has focused on other hydrogen production and end-use technologies, in line with the relative maturity of fuel cell technologies. Of particular note is that the Government of China's R&D expenditures on hydrogen technologies increased sixfold in 2019.

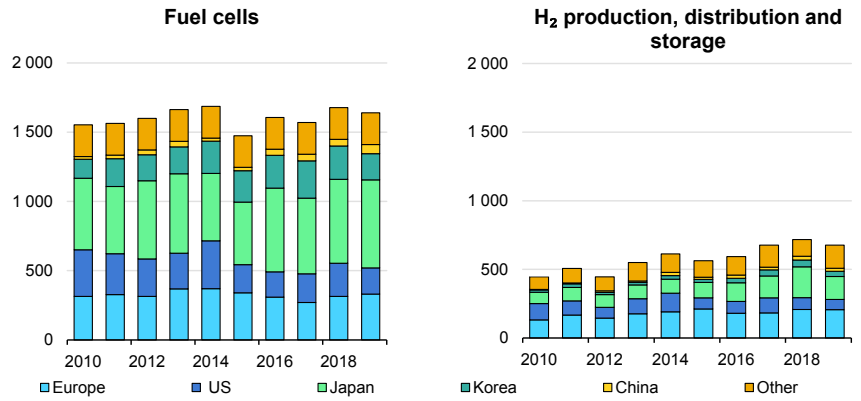
While the technology readiness levels (TRLs) of low-carbon hydrogen production technologies vary widely, analysis reveals that innovation gaps are concentrated in novel end-use industrial applications, heavy road transport, shipping and aviation. Among these technologies, the most advanced are in the early adoption stage, meaning they are ready for commercial applications but have not yet obtained significant market shares. Storage and distribution, use in buildings and light-duty road transport are all sufficiently developed for initial hydrogen use.

International patent family counts are a good proxy to measure innovation activity in any given technology. The 676 patent families registered for hydrogen production, storage and distribution technologies in 2019 reflect a 52% increase since 2010. In 2019, the highest shares of new patents were in Europe (30%) and Japan (25%).

At present, patents for fuel cell technologies outnumber those for hydrogen production, storage and distribution by a ratio of nearly 3:1, likely reflecting a higher TRL for the former as well the fact that fuel cell patent applicants include large companies (such as car manufacturers) with large R&D budgets. Japan has a clear technological lead in fuel cells, holding 39% of all patents, and the number of patent applications has been roughly constant over the past decade. Electrolyser manufacturers, in comparison, tend to be smaller companies with lower R&D budgets. Their technologies can, however, benefit from progress in fuel cells, particularly in areas such as materials or catalysts.

As public funding has been shared roughly equally between fuel cells and other applications, one can infer that the private sector has driven most of the innovation activity for fuel cells. A forthcoming study about patenting activity in hydrogen, developed jointly by the IEA and the European Patent Office, will be released in early 2022.

Patent applications by sector and region, 2010-2019



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Source: Based on European Patent Office data.

Innovation and demonstration urgently needed to unlock emissions reduction potential of hydrogen technologies

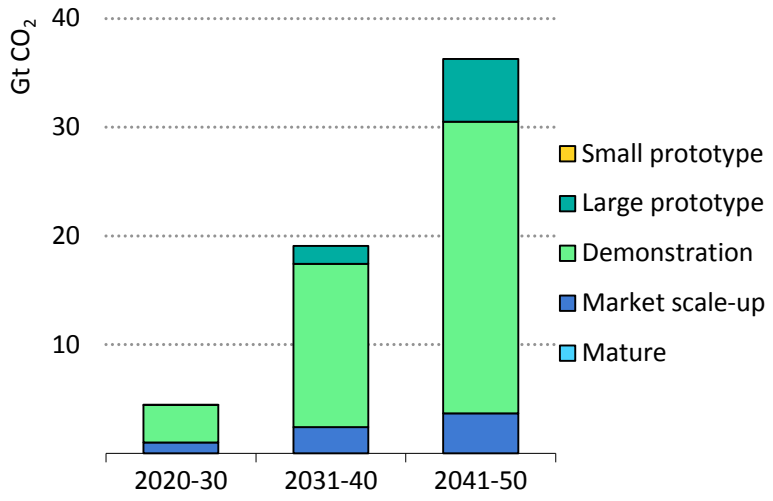
Of the 60 Gt of CO_2 emissions that hydrogen-based fuels can avoid in the Net zero Emissions Scenario, 55 Gt are achieved after 2030, reflecting that most end-use technologies for such fuels are not yet commercially available. Assessing TRLs across the entire hydrogen supply chain and in end-use sectors confirms the need to ramp up innovation to stay on track with this scenario.

Ultimately, only 12% of cumulative emissions reductions to 2050 come from technologies that are ready to enter the market and scale up production (e.g. light commercial vehicles). Most emissions reductions come from critical technologies still being developed and requiring demonstration to reach commercialisation, including co-firing ammonia and hydrogen in coal and natural gas power plants; producing chemicals using electrolytic hydrogen; using hydrogen in heavy-duty vehicles; and using hydrogen and ammonia in shipping.

In the Net zero Emissions Scenario, these technologies start delivering important CO_2 emissions reductions as early as the 2020s. While several ongoing initiatives aim to demonstrate these technologies, innovation efforts should be stepped up to ensure they reach commercialisation soon.

Other key technologies, such as using hydrogen-based DRI for steel manufacturing, are at even earlier stages of development. Their innovation cycle to reach demonstration and commercialisation should be completed as soon as possible so that they can begin effectuating CO_2 emissions reductions in the early 2030s.

Global CO_2 emissions reductions from hydrogen-based fuels by technology maturity in the Net zero Emissions Scenario, 2020-2050



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Regional insights

United States: Stepping up efforts to develop hydrogen technologies

Owing to its large refining and chemical sectors, the United States is already one of the largest producers and consumers of hydrogen. With more than 11 Mt H_2/yr of consumption, the United States accounts for 13% of global demand: two-thirds is used in refining with most of the rest going into ammonia production. Around 80% of US hydrogen production is based on natural gas reforming; practically all the remainder is met with by-product hydrogen in refineries and the petrochemical industry.

The United States has been a traditional supporter of hydrogen as an energy vector and a main advocate for the adoption of hydrogen technologies in previous waves of interest. In the early 2000s, the US government strongly promoted R&D on hydrogen and fuel cells, with federal funding peaking at USD 330 million in 2007.

After a period of lower activity, the government again stepped up efforts, and in 2016 the US Department of Energy introduced its H_2@Scale initiative to enable affordable and clean hydrogen across end-use sectors (transport, metal refining, electricity generation, heating, ammonia and fertilisers, etc.) from diverse domestic resources, including renewables, nuclear energy and fossil fuels.

Instead of setting deployment targets, this programme focuses on cost and performance targets that can enable the adoption of hydrogen technologies. In 2020, the DOE Hydrogen Program Plan established a framework to encourage R&D on hydrogen-related technologies and eliminate institutional and market barriers to adoption across multiple applications and sectors.

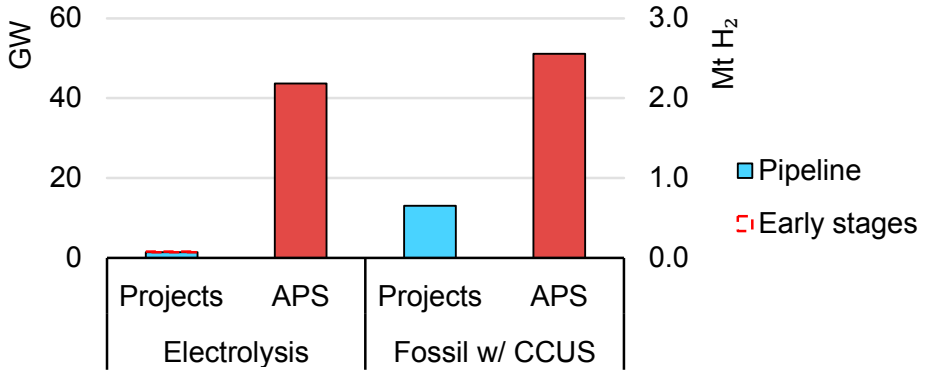
More recently (June 2021), the DOE announced Hydrogen Energy Earthshot, an ambitious initiative to slash the cost of clean hydrogen by 80% – to USD 1.00/kg H2 – by 2030. By doing this, the US government expects to unlock a fivefold increase in demand for clean hydrogen. Previous economic analysis from the National Renewable Energy Laboratory (NREL) shows detailed scenarios for expanding the US hydrogen market size to 22-41 Mt – i.e. doubling or even more than tripling current demand – even with prices of more than USD 1.00/kg H_2.

In June 2021, 17 MW of electrolysis for dedicated hydrogen production was operative in the United States,[34] with 1.4 GW of capacity in the project pipeline (300 MW under construction or with funding committed) and another 120 MW at earlier stages of

[34] The US DOE publishes regular updates on PEM electrolysers installed and under development in the United States.

development which could become online by 2030.[35] The US DOE estimates a potential deployment up to 13.5 GW based on company proposals and projections. These numbers fall short of what is needed to meet net zero goals.

US electrolysis capacity and hydrogen production from fossil fuels with CCUS in the Projects case and the Announced Pledges Scenario, 2030



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Note: APS = Announced Pledges Scenario.
Source: IEA (2021), Hydrogen Projects Database.

In the Announced Pledges Scenario, 44 GW of electrolysis capacity is deployed by 2030. US progress on deploying capacity to produce hydrogen from fossil fuels with CCUS is accelerating in response to the 45Q tax credit, which rewards CCUS projects at rates of USD 50/t CO_2 for geological storage of CO_2 or USD 35/t CO_2 if used for enhanced oil recovery. In 2021, annual US production from fossil fuels with CCUS was 0.23 Mt H_2, around one-third of global production capacity.

The largest project currently under construction in the world (Wabash Valley Resources) is in the United States and expected to become operational in 2022, which could push production capacity to over 0.3 Mt. To align with the Announced Pledges Scenario, however, capacity should expand to more than 2.5 Mt by 2030.

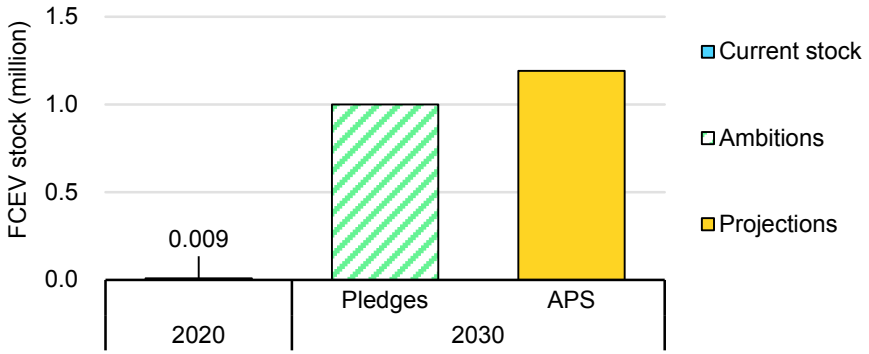
The United States led global deployment of FCEVs until 2020, when Korea pulled ahead. At the end of 2020, of the 9 200 FCEVs in the country, most were in California, which has been supporting deployment for almost a decade through the Clean Vehicle Rebate Project and by funding construction of hydrogen refuelling stations (HRSs).

In 2013, Assembly Bill 8 (AB8) required establishment of at least 100 HRSs; this target was doubled in 2018 to 200 HRSs by 2025. The main support mechanisms are grants (up to USD 115.7 million offered in GFO-19-602) and credits under the Low Carbon Fuel Standard Hydrogen Refuelling Infrastructure, which incentivise both

[35] Projects in the pipeline includes, in addition to projects already operational, projects currently under construction, that have reached final investment decision (FID) or that are undergoing feasibility studies. Projects for which there has just been an announcement or a cooperation agreement signed among stakeholders are considered projects at early stages of development.

renewable hydrogen (33-40%) and high-capacity HRSs. To support FCEV deployment, Air Liquide is building a 30-tpd renewable liquid hydrogen plant to supply HRS infrastructure in California.

FCEV deployment in the United States in the Announced Pledges Scenario, 2020-2030



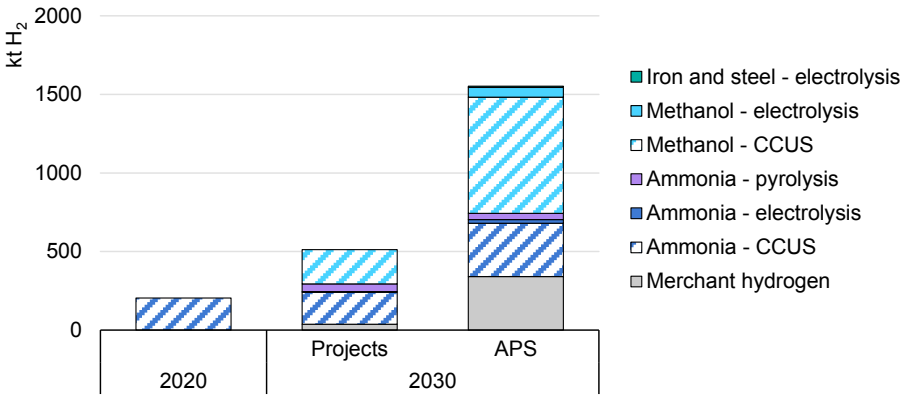
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Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. "Ambitions" refers to the California Fuel Cell Partnership target.
Source: AFC TCP.

In addition to FCEVs, a successful DOE programme has triggered commercialisation of hydrogen fuel cells for material handling equipment: in 2021, roughly 115 HRSs served over 40 000 fuel cell material handling vehicles. While the US government has not set an official federal target for FCEV deployment, the California Fuel Cell Partnership aims for 1 million FCEVs in the state by 2030. In the APS, national FCEV deployment slightly exceeds this target, reaching 1.1 million in 2030.

Opportunities to use low-carbon hydrogen in industry in the United States are mainly in the chemical sector. Low-carbon hydrogen is already produced in facilities incorporating CCUS, particularly for ammonia production. Since 2013, 1.7 Mt CO_2 have been captured every year at two fertiliser plants (Coffeyville and PCS Nitrogen), where captured CO_2 is used for EOR.

Low-carbon hydrogen demand in the US industry sector in the Announced Pledges Scenario, 2020-2030



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Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

A small number of projects for the production of hydrogen from fossil fuels with CCUS are currently in the pipeline in the United States. If all these projects become fully operational, the production capacity will meet 40% of the Announced Pledges requirement of 1.1 Mt H_2

produced from fossil fuels with CCUS in 2030. For electrolytic hydrogen use, current announced projects fall far short of the 2030 Announced Pledges level of around 85 kt H_2 for ammonia and methanol production – i.e. 25 times the capacity of the single ammonia project currently under development.

Interest is growing in the ways hydrogen can provide energy storage and be used as a means of generating on-demand electricity to balance the power grid as variable renewable generation increases. The Advanced Clean Energy Storage Project (ACES), under development in Utah by Mitsubishi Power Americas and Magnum Development, aims to pair 1 GW of electrolysers with large salt caverns to store 150 GWh of dispatchable energy. The hydrogen will be used in an 840-MW plant currently running on coal, which will initially be converted to run on natural gas and hydrogen blends, then eventually modified to operate on 100% hydrogen. While this is one of the largest project of its kind in the world, it would meet less than 12% of the nearly 1.4 Mt H_2 needed for electricity generation by 2030 (according to the Announced Pledges Scenario) to keep the United States on track with its net zero target for 2050.

The significant hydrogen uptake projected in the Announced Pledges Scenario, especially for new applications such as electricity generation and transport, would require rapid deployment of hydrogen infrastructure to facilitate delivery to end users. With more than 2 600 km of hydrogen pipelines currently in commercial operation, the United States accounts for over half of global hydrogen pipelines. Most are owned by merchant hydrogen producers and are located mainly in the Gulf Coast region where US refining capacity is concentrated.

The Hydrogen Strategy, published by the DOE in July 2020, considers blending an option to deliver pure hydrogen to downstream markets, using separation and purification technologies near the point of end-use. To help determine acceptable blending limits and material compatibility, in 2020 the DOE, together with industry and national laboratories, launched the HyBlend initiative.

In California, a first demonstration project using polymer-based distribution pipelines is expected to launch in 2021, with an initial hydrogen blend level of 1 vol% H_2, potentially rising to 20 vol% H_2. Meanwhile, Dominion Energy started a pilot project (spring 2021) to blend 5% hydrogen into a test gas distribution system. Kinder Morgan, one of North America's largest gas pipeline operators, estimates that hydrogen in 5-10% blends could be transported through natural gas transmission pipelines with little to no modification.

At present, three of the four hydrogen salt caverns storage sites operating globally are in the United States (all in Texas), including the world's largest facility in Spindletop (commissioned in 2016).

Japan: Announcement of a 2050 net zero target triggers new push for hydrogen technologies

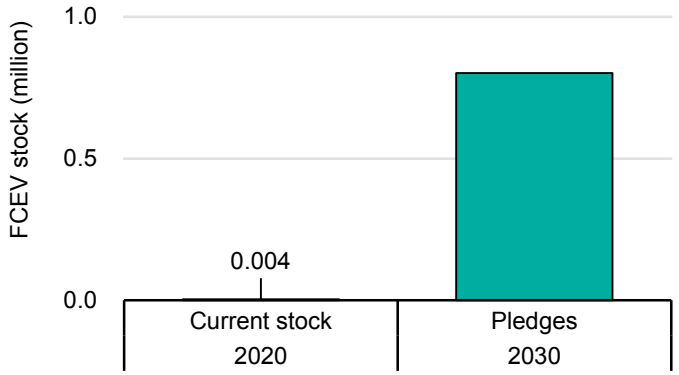
Hydrogen demand in Japan was close to 2 Mt H_2 in 2020. Refining is responsible for close to 90% of demand, with a small amount of domestic ammonia production making up the rest. Natural gas-based production accounts for more than 50% of the country's hydrogen supply, and another 45% is by-product hydrogen from refineries and the petrochemical industry and a small coal-based production meeting the remainder.

Japan has been spearheading efforts to adopt hydrogen technologies. It was the first country to release a hydrogen strategy (December 2017) and has been leading international co-operation since 2018 through its annual Hydrogen Energy Ministerial meetings. The country considers hydrogen technologies as practical options to decarbonise significant parts of its energy and industry sectors and to boost energy security.

Therefore, although Japan has yet to publish details on its plans to achieve the 2050 climate pledge announced by Prime Minister Suga (October 2020), hydrogen is likely to be an important part of its programme. The government's Green Growth Strategy (announced in June 2021) includes a target to expand hydrogen use to 3 Mt in 2030. To support this goal, the government announced a public investment plan of JPY 700 billion (~USD 6.6 billion) to develop hydrogen supply chains in Japan.

The plan includes up to JPY 70 billion (~USD 0.7 billion) for domestic hydrogen production capacity based on dedicated renewables and up to JPY 300 billion (~USD 2.8 billion) to develop international supply chains (using liquefied hydrogen and liquid organic hydrogen carriers) and to demonstrate co-firing or pure combustion of hydrogen in fossil-based electricity generation plants. In addition, JPY 330 billion (~USD 3.1 billion) have been allocated to innovation projects for hydrogen applications in aviation, shipping, steelmaking, ammonia production and CO_2 utilisation.

Current stock and 2030 target for FCEV deployment in Japan



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Note: FCEV = fuel cell electric vehicle.
Source: AFC TCP, Strategic Roadmap for Hydrogen and Fuel Cells.

Japan has been a first mover in the use of hydrogen in transport, with Honda offering the first commercial FCEV in 2008. With around 5 600 FCEVs (including cars and buses) on the road in April 2021, Japan is the fourth-largest market in the world and has ambitious targets for FCEV deployment – 200 000 by 2025 and 800 000 by 2030. Toyota

recently expanded fuel cell manufacturing capacity to 30 000 units/yr, though capacity will need to expand further if domestic original equipment manufacturers are to be relied upon to achieve government targets.

Japan has shown interest in using hydrogen to decarbonise energy demand in buildings. The ENE-FARM programme has subsidised installation of more than 350 000 micro-cogeneration[36] fuel cells, most fuelled by natural gas. Although ENE-FARM subsidies stopped in FY2019 for PEM fuel cells, more than 40 000 micro-cogeneration units were installed in 2020, similar to the number deployed annually while the programme was active. Subsidies remain in place for SOFCs until FY2020.

On the supply side, in 2020 a 10-MW solar-powered electrolysis project was inaugurated in Fukushima, the world's largest at the time. To date, Japanese stakeholders have not announced plans to deploy significant electrolysis capacity for dedicated hydrogen production; only some small projects (<5 MW) have been announced for upcoming years. This outlook may change following the government announcement of a budget of JPY 70 billion 70 (~USD 0.7 billion) to scale up and modularise electrolysers with the aim of decreasing manufacturing costs.

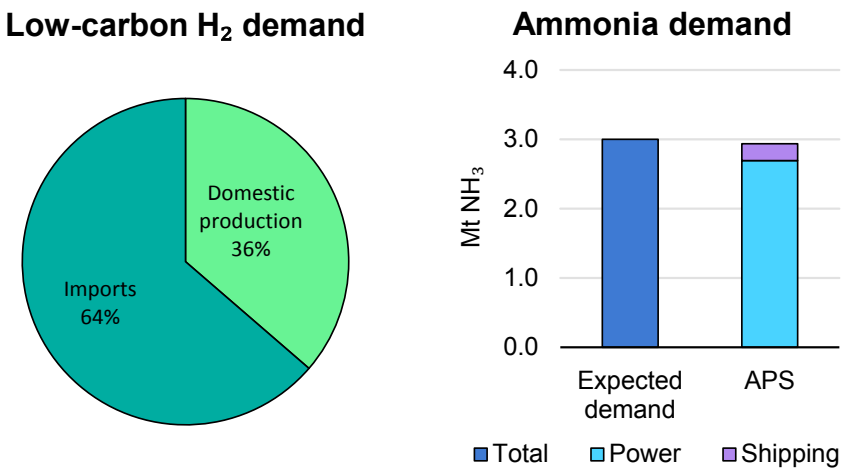
Regarding hydrogen production from fossil fuels with CCUS, the Tomakomai demonstration project was operational until 2019, and no projects for the near future have been announced. Low-carbon hydrogen production needs to be accelerated and international hydrogen supply chains must be developed to meet Japan's strategy target of 420 kt of low-carbon hydrogen by 2030. Japan is currently updating its strategy to align with its revised climate target, but it is likely that achieving the new targets will require substantial volumes of low-carbon hydrogen, with a significant portion having to be imported.

Japan has also targeted the use of ammonia as a fuel. In February 2021, the government released an Interim Report of the Public-Private Council on Fuel Ammonia Introduction highlighting its potential use in shipping and for co-firing in coal power plants to reduce their carbon intensity and avoid decommissioning them, as they are critical to Japan's electricity supply security. The concept was demonstrated at small scale by Chugoku Electric Power Corporation, and now JERA is scaling up the concept to demonstrate a 20% co-firing share of ammonia at a 1-GW coal-fired unit by 2024.

Using 100% ammonia in electricity generation is also gaining traction: Mitsubishi Power announced it is developing a 40-MW gas turbine able to run on ammonia, aiming to commercialise it in 2025. By 2030 in the Announced Pledges Scenario, Japan consumes close to 3 Mt NH_3 as fuel, mostly for co-firing in coal plants but also 0.25 Mt as fuel for maritime transport and. In addition, 0.7 Mt is used as feedstock in the chemical industry.

[36] Co-generation refers to the combined production of heat and power

Low-carbon hydrogen and fuel ammonia demand in Japan in the Announced Pledges Scenario, 2030



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Notes: APS = Announced Pledges Scenario. "Expected demand" represents the proposal of the Interim Report of Public-Private Council on Fuel Ammonia Introduction.

Japan has been very active in developing international hydrogen trade: various projects are ongoing with Australia, Brunei, Indonesia, Saudi Arabia and the United Arab Emirates. Most noteworthy is the Hydrogen Energy Supply Chain (HESC) project, led by the Hydrogen Energy Supply-chain Technology Research Association (HySTRA), which aims to establish a hydrogen supply chain between Australia and Japan. As part of this project, in 2020 Kawasaki Heavy Industries presented its Suiso Frontier, the world's first liquefied hydrogen carrier; the first demonstration shipments will take place will take place during the first quarter of 2022. The Suiso Frontier has one tank with a capacity of 1 250 m^3, which can store 75 t H_2. A future commercial supply chain between Australia and Japan would require ships with much larger capacity, estimated by HESC project developers at four tanks, each with 40 000 m^3 of capacity. Ships of similar size to Suiso Frontier could be used for shorter distances.

Japan has also spearheaded development of international fuel ammonia trade. In September 2020, the world's first shipment of ammonia produced from fossil fuels with CCUS (40 t NH_3) took place between Saudi Arabia and Japan. Plus, the Japan Oil, Gas and Metals National Corporation (JOGMEC) recently launched several initiatives with partners in Japan and around the world. With the aim of supplying low-carbon ammonia to Japan, JOGMEC, Mitsubishi Corporation, the Bandung Institute of Technology and PT Panca Amara Utama (PAU) agreed (March 2021) to conduct a joint study on producing ammonia from natural gas with CCUS in a PAU plant in Central Sulawesi (Indonesia).

Additionally, in July 2021 JOGMEC, INPEX Corporation and JERA announced a joint study agreement with the Abu Dhabi National Oil Company (ADNOC) to explore the commercial potential of low-carbon ammonia production in the United Arab Emirates and to provide a platform for ADNOC and its partners to explore supplying Japanese utility companies. Also in July 2021, JOGMEC signed a joint research agreement with Woodside Energy, Marubeni Corporation, Hokuriku Electric Power Company and Kansai Electric Power to develop a supply chain from Australia to Japan for fuel ammonia produced from natural gas with CCUS.

European Union: EU Hydrogen Strategy set the foundation in 2020, but meeting net zero targets will require ambitious action in next decade

Close to 7 Mt H_2 were produced and used in the European Union in 2020. Refining (3.7 Mt H_2) and the chemicals sector (3.0 Mt H_2) were the main consumers of hydrogen, which was produced mainly from unabated natural gas (two-thirds of total production) and as a by-product in refineries and the petrochemical sector (30%).

In November 2018, the European Commission set out its vision for reaching net zero emissions by 2050, followed in March 2020 by the proposal for the first European Climate Law, which was adopted by the European Council in June 2021. To date, most decarbonisation efforts have focused on electricity generation, but adoption of the net zero target widened the scope beyond the power sector to include industry, transport, agriculture and heating in the built environment.

In turn, interest in hydrogen has grown exponentially, with launch of the EU Hydrogen Strategy (July 2020) and the European Clean Hydrogen Alliance (November 2020) being major milestones. The strategy emphasises use of hydrogen in industry and heavy transport as well as its balancing role in the integration of variable renewables (particularly offshore wind in the northwest region and solar PV in the south). The Alliance brings together industry, national and local public authorities, civil society and other stakeholders to implement the strategy.

On the supply side, electrolytic hydrogen from renewable sources is considered the main route for hydrogen production, although the role of other low-carbon technologies in the near term is recognised as the hydrogen market develops and scales up and the cost of electrolytic hydrogen decreases. Beyond decarbonising hydrogen production, the European Union sees electrolysis as a strategic opportunity to export technology: EU countries currently hold more than 60% of global electrolysis manufacturing capacity. With the aim of creating market rules for hydrogen deployment, the Hydrogen Strategy also announced a review of the legislative framework for gases.

The strategy envisages three phases for hydrogen adoption. The first phase (until 2024) focuses on scale-up, with an interim target of 6 GW of renewable energy-powered electrolysis to decarbonise current production capacities and trigger uptake in some new uses (e.g. heavy-duty transport). In the second phase (2025-2030), hydrogen should become an intrinsic part of an integrated energy system while renewable hydrogen becomes cost-competitive and reaches new applications (steelmaking or shipping). By 2030, 40 GW of renewable energy-powered electrolysis should be installed. In the third phase

(post-2030), renewable hydrogen technologies should reach maturity and be deployed at large scale to reach all hard-to-decarbonise sectors.

In December 2020, the European Commission adopted a proposal to revise the EU rules on Trans-European Networks for Energy (the TEN-E Regulation) to end support for natural gas pipelines, instead including cross-border hydrogen networks as infrastructure eligible for EU support as Projects of Common Interest. The proposal covers both new and repurposed assets for dedicated hydrogen transport and large-scale electrolyser projects linked to cross-border energy networks.

A significant step taken by the European Commission in adopting low-carbon hydrogen technologies came from proposals to modify directives and regulations announced in July 2021 as part of the Fit for 55 package. If approved by the EU Council and the EU Parliament, these proposals will incorporate into EU legislation several targets for using hydrogen and hydrogen-based fuels in industry and transport, and for developing required infrastructure.

Some EU countries have also released national hydrogen strategies (the Czech Republic, France, Germany, Hungary, the Netherlands, Portugal, and Spain); others are under public consultation (Italy and Poland) or expected to be released soon (Austria). While focusing on each country's strengths, these strategies are very aligned with each other and with the EU Hydrogen Strategy in terms of sectors and technologies to prioritise. Practically all have deployment targets for electrolysis by 2030, amounting more than 20 GW by 2030 (with another 7 GW in the planned strategies of Italy and Poland).

Hydrogen-related targets proposed by the European Commission in the Fit for 55 package

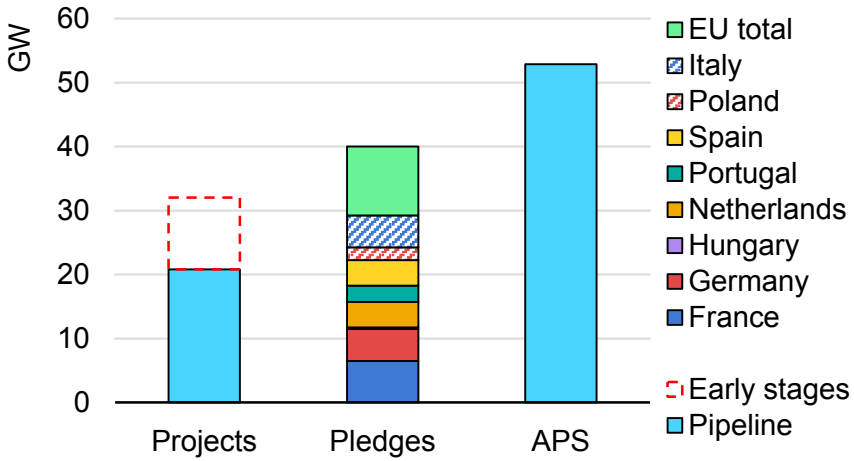
Proposal	Target
Renewable Energy Directive modification	50% renewable hydrogen consumption in industry by 2030
Renewable Energy Directive modification	At least 2.6% share of renewable fuels of non-biological origin in 2030*
ReFuelEU Aviation	0.7% share of synfuels in aviation by 2030 5% by 2035 8% by 2040 11% by 2045 28% by 2050
Regulation on deployment of alternative fuels infrastructure	1 HRS (>2 t H_2/day of capacity and 700-bar dispenser) every 150 km along major routes 1 HRS with liquid hydrogen every 450 km

* Renewable fuels of non-biological origin include hydrogen and hydrogen-based fuels produced from renewable electricity.

The European Union has registered progress in adopting hydrogen technologies. The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has played a fundamental role with its programmes to support research, innovation and demonstration. More than 140 MW of electrolysis for dedicated hydrogen production have been installed, accounting for more than 40% of global capacity. The strong signals sent by government strategies have created momentum for additional deployment, with the pipeline of projects currently under development

accounting for more than 20 GW by 2030 (11 GW more from projects at very early stages of development), although initial assessment by the Clean Hydrogen Alliance suggests that total electrolysis capacity at different stages of development could be larger.

Electrolysis capacity deployment in the EU in 2030 in the Projects case and the Announced Pledges Scenario compared with national and EU targets



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Note: APS = Announced Pledges Scenario.
Sources: IEA (2021), Hydrogen Projects Database; National Strategies, CEM H2I consultation.

Of the more than 20 GW in the pipeline, more than 1 GW is already under construction or has funding committed. While the current project slate may not meet the EU target, the number of projects is growing quickly and the gap is shrinking. However, both the current project pipeline and the EU target may fall short of the electrolysis capacity deployment needed to meet the EU pledge of net zero emissions by 2050. The Announced Pledges Scenario shows more than 50 GW of electrolysis deployed in EU countries by 2030.

Progress in deploying hydrogen production from fossil fuels with CCUS has been slower, despite its envisaged near-term importance. Two projects are already operational in the European Union, although in both cases for hydrogen production from fossil fuels and CCU: the Shell gasification project at the Pernis refinery (the Netherlands) and Air Liquide's Port Jerome project (France).

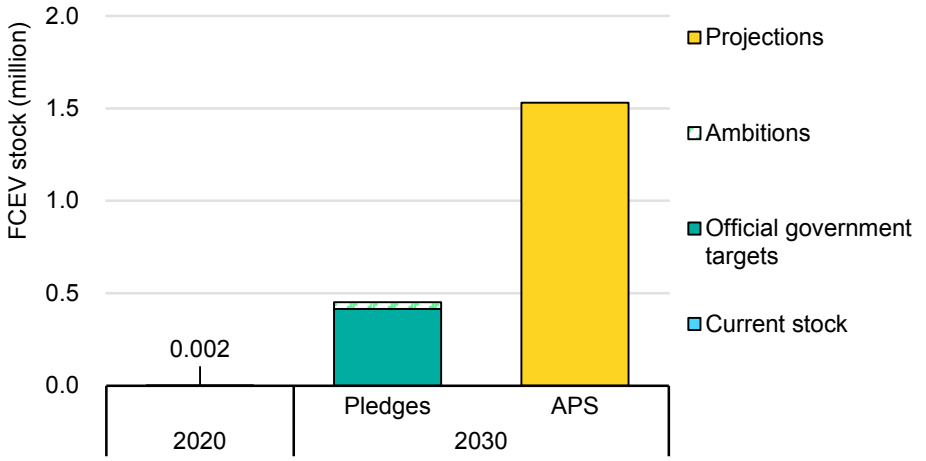
The Netherlands is the most active country in developing hydrogen production from fossil fuels with CCUS. Through its SDE++ scheme, the Dutch government recently committed EUR 2 billion to fund Porthos, a project to develop CO_2 transport and storage infrastructure in the Port of Rotterdam, which will store 2.5 Mt CO_2 annually, with a significant share coming from hydrogen production.

The current pipeline of projects for producing hydrogen from fossil fuels with CCUS will more than meet EU net zero ambitions. While in the Announced Pledges Scenario 3 Mt CO_2 are captured from hydrogen production in the European Union by 2030, currently the project pipeline amounts to more than 7 Mt CO_2 captured (plus close to 3 Mt CO_2 more from projects at early stages of development), although this figure could be significantly lower. Several projects are large CCUS hubs that will involve activities beyond hydrogen

production and, as such, it is difficult to estimate how much of the projected capture capacity would be linked to hydrogen production.

In transport, some 2 200 FCEVs were on the road in EU countries by the end of 2020 (mostly passenger cars) and around 165 HRSs were in operation. Germany has the largest number of both, but the Czech Republic, France, the Netherlands, Portugal and Spain have FCEV targets that, if achieved, would result in about 415 000 FCEVs by 2030. In the Announced Pledges Scenario, FCEV deployment reaches 1.5 million by this date.

FCEV deployment the European Union in the Announced Pledges Scenario, 2020-2030



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Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. FCEV ambitions include unpublished government targets from Italy and Slovakia.
Sources: AFC TCP; National Strategies; CEM H2I consultation.

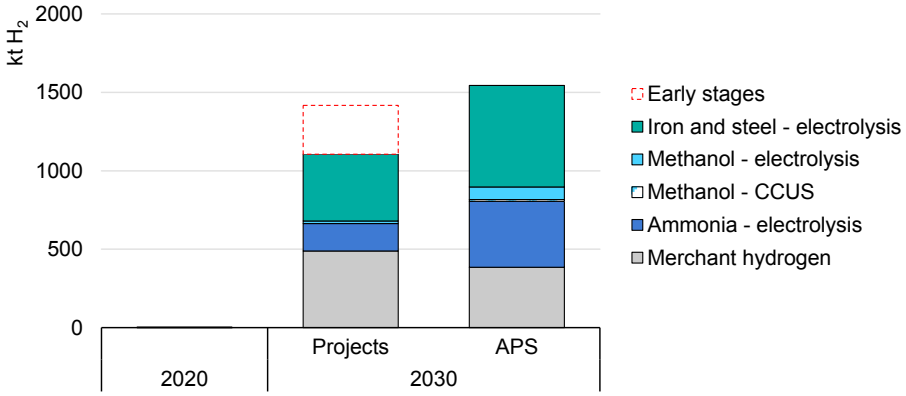
In the industry sector, EU stakeholders have been active in recent years and some significant developments are taking place. As part of the REFHYNE project, in July 2021 ITM and Shell put a 10- MW PEM electrolyser in the Rhineland Refinery (Germany) into operation. In steel manufacturing, Thyssenkrup has demonstrated using hydrogen to partially replace pulverised coal in one of the tuyeres of a blast furnace – and is working to extend this practice to other blast furnaces.

Since 2019, the H2FUTURE project has been feeding hydrogen produced in a 6 MW PEM electrolyser via the coke gas pipeline to a blast furnace of the steel works (Linz, Austria). Meanwhile, the HYBRIT project – the first attempt to produce steel from DRI using pure hydrogen – is currently at the pilot stage (4.5 MW of electrolysis capacity) but is expected to advance to a demonstration facility by 2025. Also in steel manufacturing, the largest SOEC electrolyser in the world (0.72 MW, manufactured by Sunfire) became operational in the GrinHy2.0 project.

In the chemical sector, Fertiberia and Iberdrola in Spain are building the world's largest demo project (20 MW) to produce electrolytic ammonia, expected to become operational at the end of 2021. The GreenLab Skive (Denmark) is building a 12 MW demonstrator for methanol production, to start operations in 2022. These proposed projects will not meet Announced Pledges goals for 2030, however.

Projects currently under development account for 1.1 Mt of low-carbon hydrogen use by 2030 (0.3 Mt more if early-stage projects are realised), whereas required Announced Pledges consumption is 10% higher.

Low-carbon hydrogen demand in EU industry in the Announced Pledges Scenario, 2020-2030



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Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.

Source: IEA (2021), Hydrogen Projects Database.

The first steps to develop hydrogen-specific infrastructure for delivery to end users have already been taken. Europe has more than 1 600 km of hydrogen pipelines, mostly owned and operated by industrial producers and users, but large-scale deployment of low-carbon hydrogen will require additional transmission and distribution systems.

A consortium of gas grid operators therefore presented a European Hydrogen Backbone (EHB) initiative proposal in 2020 (updated in 2021). Across 21 countries (including non-EU countries such as Switzerland and the United Kingdom), the EHB envisions 39 700 km of pipelines by 2040 – with 69% being repurposed natural gas networks and 31% newly built hydrogen pipelines. The first natural gas pipeline, 12 km with throughput capacity of 4 kt H_2/yr, has been converted and put into commercial service (November 2018) by Gasunie in the Netherlands.

In June 2021, Gasunie also announced that it had been asked by the State Secretary for Energy and Climate to develop a national infrastructure for hydrogen transport by 2027, of which 85% will be repurposed natural gas pipelines. In September 2021, the Dutch government announced an investment of EUR 750 million (as part of a wider EUR 6.8 billion package on climate measure) to convert parts of the existing gas network into hydrogen transport infrastructure. Furthermore, based on project submissions, the latest Ten-Year Network Development Plan of the European Network of Transmission System Operators for Gas assessed that roughly 1 100 km of gas pipelines could be converted to hydrogen by 2030, but FIDs have not yet been secured for these projects.

Several EU countries are also undertaking pilot blending projects, including France, Germany, the Netherlands and Portugal. In May 2021, the Government of Germany announced that 62 large-scale hydrogen projects, including pipeline transport, have been selected for further assessment for funding of up to EUR 8 billion under the Important Projects of Common European Interest (IPCEI) scheme.

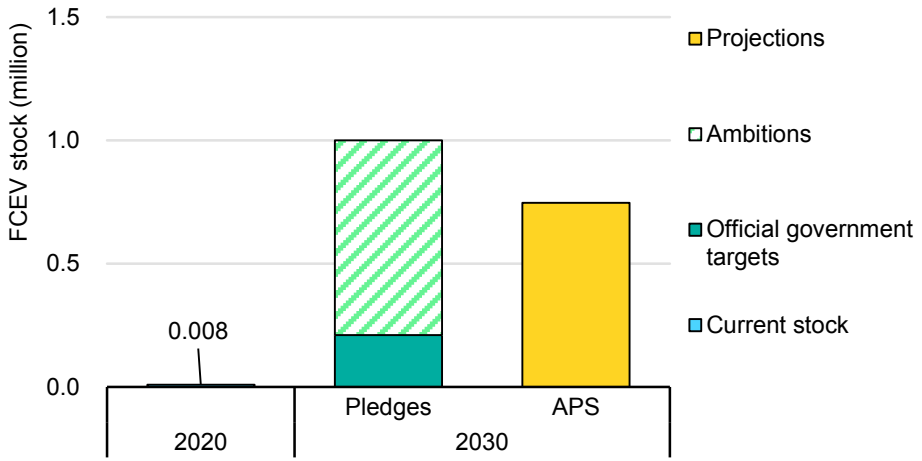
China: Hydrogen development focused on transport, but carbon-neutrality pledge will offer opportunities for other applications, particularly in industry

With annual consumption of more than 25 Mt, China is the world's largest hydrogen user, mainly in refining (9 Mt H_2) and the chemical sector (16.5 Mt H_2). This demand is met by domestic production based on fossil fuels, with coal accounting for 60% and natural gas for 25%. The remaining 15% is by-product hydrogen from refineries and the petrochemical industry.

In 2020, China announced its ambition to reach carbon neutrality by 2060. Hydrogen use will be important, especially in the country's vast industry sector, which accounts for 60% of final energy demand. Using hydrogen as an alternative to fossil fuels received attention even before China's net zero pledge, as it was seen as a means to address air quality concerns in cities.

As such, practically all developments around hydrogen adoption for new uses have focused on transport. Initial projects were based on using by-product hydrogen from coke ovens and petrochemical processes, which facilitated access to low-cost hydrogen in industrial hubs, and deploying fuel cell truck and bus fleets which maximise utilisation rates of HRSs. Thanks to these strategies and government support schemes, China has now the world's third-largest FCEV stock and leads in fuel cell truck and bus deployments. At the end of 2020, 8 400 FCEVs had been deployed, of which two-thirds were buses and one-third trucks.

FCEV deployment in China in the Announced Pledges Scenario, 2020-2030



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Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. Official government targets include city and provincial targets; ambitions refer to additional FCEV deployment needed to achieve the China Society of Automotive Engineers target.
Source: AFC TCP.

Although the government does not have an official target for FCEV adoption, the China Society of Automotive Engineers targets 1 million FCEVs by 2030. In response to China's recent pilot cities programme, which rewards city clusters for FCEV deployment and supply chain development, several city- and province-level targets have been set. Beijing and Shanghai each aim for 10 000 FCEVs by

2025, and Guangzhou envisions 100 000 by 2030. In the Announced Pledges Scenario, China's FCEV stock reaches 750 000 in 2030.

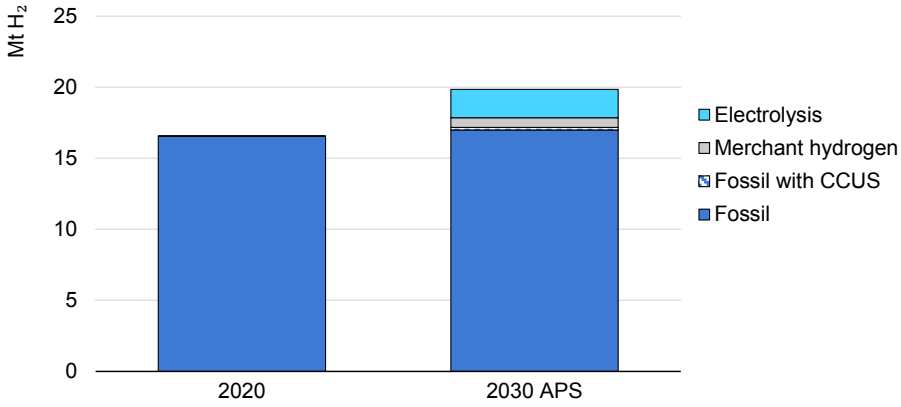
More recently, China has recognised how important hydrogen can be in transforming the energy system, and interest is growing beyond transport, particularly in industrial applications. China is the largest producer of methanol, ammonia and steel, three subsectors in which low-carbon hydrogen use could play a significant in the future. Beyond its traditional production and use in industry, low-carbon hydrogen adoption is in the early stages in China, with first steps for demonstrating new applications forthcoming.

In the chemical sector, Ningxia Baofeng Energy Group is building the world's largest electrolysis plant for dedicated production of hydrogen to provide some of the feedstock for making the methanol used in its coal-to-olefins project in Ningxia Province. The company has already installed a 30-MW electrolyser and intends to add 70 MW of electrolysis capacity by the end of 2021.

Baosteel, the country's largest steel producer, has pledged to reach net zero emissions by 2050, relying in part on developing hydrogen-based DRI production at scale by 2035. Meanwhile, Hebei Iron and Steel Group (HBIS), the second-largest producer, has taken the first step towards hydrogen steelmaking, developing a small but commercial-scale DRI project to blend 70% hydrogen (with 30% coke oven gas) for ironmaking.

These demonstration projects could lay the groundwork for low-carbon hydrogen adoption in China's industry sector. Although projects currently under development could result in 45 kt of low-carbon hydrogen production and use in industry by 2030, this is well short of the Announced Pledges projection of 2.2 Mt, produced mostly through electrolysis.

Industry hydrogen demand in China in the Announced Pledges Scenario, 2020-2030



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Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.

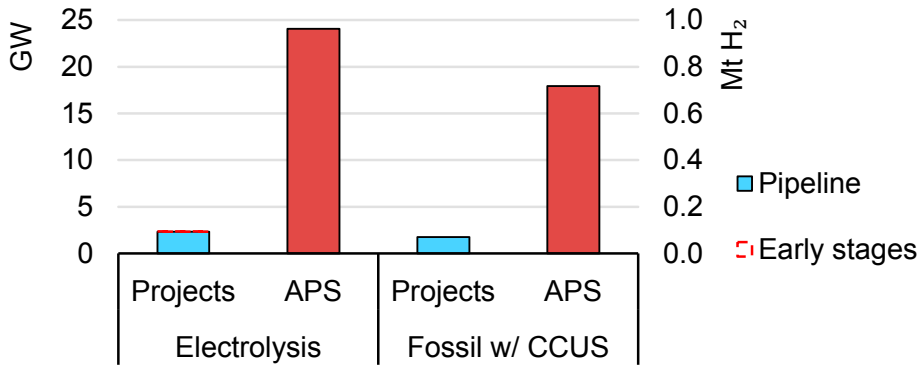
China's greatest challenge is to decarbonise existing hydrogen production while deploying new production capacity to meet demand from new applications. At present, hydrogen production creates direct

emissions of 475 Mt CO_2/yr.[37] Therefore, to stay on track with long-term climate ambitions, low-carbon hydrogen production technology deployment needs to accelerate in the next decade. By 2030 in the Announced Pledges Scenario, more than 20 GW of electrolysis is deployed in China, most of it in industrial facilities for producing methanol and ammonia. Plus, the first plant for manufacturing steel through DRI using hydrogen sequestered from coke oven gas should start operating by the end of 2021, and second-phase expansion and conversion towards electrolytic hydrogen should then begin.

Compared with other regions, China was slow to deploy electrolysis for dedicated hydrogen production; as a result, projects under development are insufficient to reach China's goals for 2030. However, several factors have triggered significant acceleration in the last two years:

- The cost of alkaline electrolysers in China is low – USD 750-1 300/kW including electrical equipment, gas treatment, plant balancing, and engineering, procurement and construction (EPC), with some sources reporting as low as USD 500/kW[38] – compared with the average of USD 1 400/kW in the rest of the world. Other factors, such as electrolyser reliability and durability, differ among regions and could strongly affect hydrogen production costs over a plant's lifetime.
- China has also deployed a huge amount of renewable energy generation capacity in recent years, especially in regions where potential is considerable but energy demand is fairly low. The resulting electricity grid congestion has forced some regional governments to limit the amount of power that can be loaded into transmission grids. Electrolysis can minimise curtailment and store energy for local use or for transport to regions with lower renewable energy potential and large energy needs.
- China accounts for one-third of global electrolyser manufacturing capacity. In response to anticipated domestic market growth, all major manufacturers have announced plans to expand their manufacturing capacity.

Electrolysis capacity and hydrogen production from fossil fuels with CCUS in China in the Projects case and the Announced Pledges Scenario, 2030



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Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

[37] This includes 115 Mt CO2 emitted through the use of hydrogen-derived products (e.g. urea and methanol) that capture carbon only temporarily.

[38] Based on CAPEX for the electrolyser system itself of USD 200/kW (China EV100, 2020; MOST, 2021). Including electrical equipment, gas treatment as well as EPC increases the overall CAPEX to USD 500/Kw.

The use of carbon capture to decarbonise current fossil fuel-based hydrogen production will also need to ramp up. This could be particularly beneficial for the chemical industry in China's north-western regions, where a very young fleet of plants currently uses coal to produce hydrogen-based ammonia and methanol. In the Announced Pledges Scenario, production capacity of 0.7 Mt H_2 in the chemical industry is retrofitted with CCUS by 2030.

Canada: Hydrogen to play a critical role in net zero ambitions and economic growth through exports

In 2020, Canada produced and used around 3 Mt H_2, almost equally split between refining and the industry sector. Around 80% of production is based on natural gas, and the remainder is by-product gas from refineries.

In December 2020, Canada released its strengthened climate plan, which lays the foundation to reach net zero emissions by 2050. Hydrogen and other clean fuels feature prominently in this plan. Also at the end of 2020, Canada released its Hydrogen Strategy with a call for action to promote investments and partnerships among national stakeholders, sub-national governments and indigenous organisations, as well as at the international level, to seize the economic and environmental opportunities that hydrogen can offer. The strategy shows that, in a net zero future, Canada's economy will be mobilised by two equally important pathways: clean power and clean fuels, with hydrogen making up to 30% of the energy mix.

The Canadian strategy addresses the role of hydrogen across a very wide range of end-use sectors, including industry, refining, transport, power and buildings. It also sees the variety of domestic energy resources available as a great opportunity to diversify the mix of technologies to produce hydrogen. This mix includes oil and gas reserves (coupled with CCUS) in Alberta, Saskatchewan, British Columbia and the East Coast, an 80% non-emitting power grid, nuclear capacity, and large renewable capacity. Based on these vast resources, Canada has an ambitious goal to become a major exporter of hydrogen-based fuels. As it is home to some of the sector's major technology developers (e.g. Ballard and Hydrogenics, recently acquired by Cummins), the potential to export hydrogen technologies is also high.

The Canadian government has already established a series of clean energy support programmes to enable the development of business cases for hydrogen technologies. In June 2021, Natural Resources Canada announced the Clean Fuels Fund, providing CAD 1.5 billion (~USD 1.1 billion) to help private investors with upfront capital costs to construct new clean fuel production capacity, including support for developing at least ten hydrogen projects. In addition, the Net zero Accelerator initiative will provide up to CAD 8 billion (~USD 6.0 billion) for projects that reduce domestic GHG emissions, including decarbonisation of large industrial emitters, fuel switching to hydrogen in industrial processes, and development of CCUS capacities for hydrogen production in heavy industries already using hydrogen.

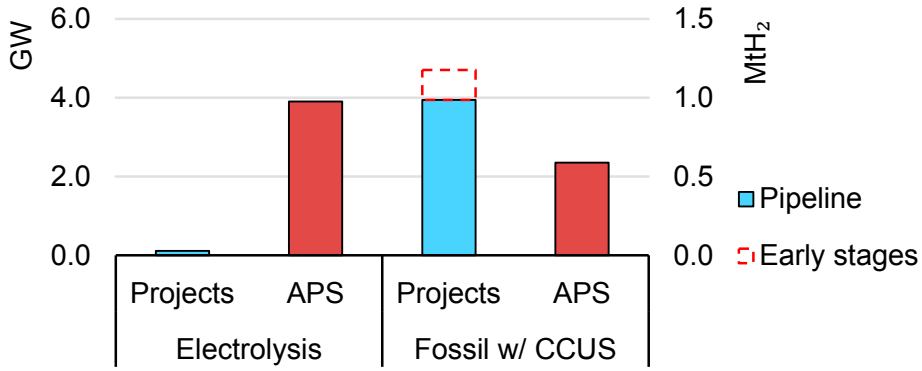
Even before the national hydrogen strategy and related programmes were launched, Canadian stakeholders had been very active. With four operative projects capturing and storing around 3 Mt CO_2/yr, Canada is the second-largest producer of hydrogen from fossil fuels with CCUS. Another four projects are under development, aiming to capture an additional 5.0 Mt CO_2/yr (1.8 Mt CO_2/yr if early-stage

projects are included). If all are realised, total hydrogen production from fossil fuels with CCUS could reach close to 1 Mt H_2/yr in 2030 (0.2 Mt H_2/yr with early-development projects) – around 70% higher than in the Announced Pledges Scenario.

However, projects under development aim to produce merchant hydrogen for diverse applications rather than decarbonise existing hydrogen production capacity in the chemical sector. Consequently, almost 200 kt H_2 (0.5 Mt H_2/yr with early-development projects) in fossil fuel with CCUS production capacity for industrial applications could be reached by 2030 – almost reaching the capacity in the Announced Pledges. Initiatives such as the Net zero Accelerator can speed deployment of low-carbon hydrogen capacity in industrial processes to better align with the Announced Pledges Scenario.

Concerning electrolysis, in January 2021 Air Liquide put into operation the world's largest PEM electrolysis plant at Bécancour. The project, which includes a 20 MW electrolyser running on hydropower, doubled the site's hydrogen production capacity. Currently, close to 100 MW of electrolysis projects are at different stages of development; if all are realised, total installed electrolysis capacity for dedicated hydrogen production could reach around 120 MW. In the Announced Pledges Scenario, electrolysis capacity in Canada reaches more than close to 4 GW by 2030, 40 times more than the capacity currently under development.

Electrolysis capacity and hydrogen production from fossil fuels with CCUS in Canada in the Projects case and the Announced Pledges Scenario, 2030



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Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.

Source: IEA (2021), Hydrogen Projects Database.

In the transport sector, Canada had a stock of around 130 FCEVs at the end of 2020. In the Announced Pledges Scenario, FCEV stock reaches close to 50 000 in 2030. Recent measures can facilitate this deployment: for instance, in December 2020 the government announced a new Clean Fuel Standard that will require liquid fuel suppliers to gradually reduce the carbon intensity of the fuels they produce and sell for use in Canada (final regulations will be published at the end of 2021). In June 2021, the government committed to a mandatory 100% ZEV sales target by 2035, followed by the announcement in August 2021 of a CAD 2.75 billion (~USD 2.1 billion) Zero Emission Transit Fund to support the purchase of zero emission public transit and school buses and associated infrastructure.

Other regions: Hydrogen momentum is building as more countries get on board

Africa

Of Africa's annual close to 3 Mt H_2 consumption, 70% is used in the chemical sector, mainly to produce nitrogen fertilisers that boost crop yields and replenish soil nutrients and are thus a critical component of food security across the continent. Without synthetic nitrogen fertilisers (together with other macro-nutrients), soil fertility would be significantly lower and land required for farming significantly higher.

Africa is one of the few places in the world where fertiliser use is projected to grow strongly in upcoming years, even as care is taken to apply it efficiently and judiciously, identifying the right fertiliser source, applying it at the right rate, at the right time and in the right place (CITE). In turn, ammonia production (the starting point of all synthetic nitrogen fertilisers) for existing agricultural and industrial uses increases 40% by 2030 in the Announced Pledges Scenario (see the IEA's forthcoming Ammonia Technology Roadmap).

Virtually all hydrogen production in Africa is currently based on fossil fuels, including the portion used to produce nitrogen fertilisers. The ability to produce hydrogen from renewables is therefore a great opportunity for African countries to replace fossil fuel-based production, which in many cases depends on imports. This is particularly important for landlocked countries that face additional challenges in distributing fertiliser and/or securing the natural gas needed to produce it.

Africa's potential to generate low-cost renewable electricity to produce low-carbon hydrogen is considerable. As electrolyser and renewable electricity generation costs continue to decline, cost parity with fossil fuel-based generation is a genuine prospect in the medium to long term in locations with the best renewable resources. In areas where the necessary transport and storage infrastructure is practical and scalable, low-cost natural gas equipped with CCUS is another option to produce low-carbon hydrogen for ammonia synthesis. Having an indigenous supply of nitrogen fertilisers made using low-carbon hydrogen would reduce CO_2 emissions from this energy-intensive industry while also boosting food security by reducing dependence on food imports.

Developing projects to produce renewable hydrogen for fertiliser manufacturing can also create high-quality jobs and spur economic growth, although project realisation will hinge on innovation and scale-up to close the cost gap with conventional production methods. Due to unfavourable economics, two large electrolysers (of 100 MW in Zimbabwe and 165 MW in Egypt) producing ammonia using renewable electricity from hydropower installations closed or switched to natural gas in the last decade, highlighting the challenges facing this technology option.

Similarly, ultra-low-cost electricity at a high capacity factor, or variable renewable electricity combined with hydrogen storage, is required for

electrolysis-based ammonia production to become competitive with natural gas, even when equipped with CCUS. Given the practical ease and relatively low cost of shipping nitrogen fertiliser products (e.g. urea produced in the Middle East), cost reductions in the production process are required to make electrolysis a viable option for a price-sensitive market segment and region.

On-site production, storage and use of renewable hydrogen in mini-grids to generate electricity in remote areas is another hydrogen application attracting great interest. In fact, this concept has already been demonstrated. Hydrogen South Africa (HySA) has been operating a hydrogen-based mini-grid installed at a high school in Goedgevonden since April 2018, and Tiger Power is developing a project to power 3 000 rural households and businesses in Kyenjojo (Uganda). This application is cost-competitive with the traditional use of diesel for remote power generation, thus facilitating electricity access while decreasing CO_2 emissions.

Some countries in the region have taken the first steps to seize the opportunities hydrogen can offer. Morocco is leading the way with its Green Hydrogen Cluster, established by the government to promote collaboration among private and academic stakeholders to support the emerging renewable hydrogen sector. With the dual objectives of collaborating in technology development and positioning Morocco as a potential exporting hub, the government has been building international partnerships with countries such as Germany and Portugal.

Some activity is also well under way in South Africa, led predominantly by the private sector. Anglo American is building a 3.5-MW electrolyser at its mine in Mogalakwena to produce hydrogen on site to fuel a hydrogen-powered fuel cell electric haul truck. Expected to become operational in 2021, the project will be a first demonstrator to gain operational knowledge and experience, and thus support replication at other mines around the world.

Australia

In November 2019, Australia launched its National Hydrogen Strategy. It explores potential for clean hydrogen production, outlines a plan for quick scale-up and details the necessary co-ordinated actions for governments, industry and communities. As part of this plan, the government has invested over AUD 1.3 billion (~USD 1.0 billion) to accelerate domestic hydrogen industry growth. The strategy also highlights the significant opportunity offered by hydrogen exports, which the government is fostering by developing international partnerships with Singapore, Germany, Japan, Korea and, more recently, the United Kingdom.

Current hydrogen demand in Australia is very small, practically all used in refining and ammonia production; moreover, growth in domestic demand is generally seen as limited. However, the country has tremendous potential to affordably produce low-carbon hydrogen, which can decarbonise production for both domestic use and export. Recognising this opportunity, the government has

invested in seven hydrogen hubs that centralise users geographically, thereby minimising infrastructure costs.

Australia's potential to produce hydrogen from renewables is considerable. Currently, nine projects with a capacity >1 GW are under development or at early stages. These include some of the world's largest projects: the Western Green Energy Hub (20 Mt NH_3/yr, equivalent to >20 GW of electrolysis capacity); the Asian Renewable Energy Hub (14 GW); HyEnergy Zero Carbon Hydrogen (8 GW); and the Murchison Project (5 GW). If all projects under development are deployed, electrolysis capacity in Australia will reach nearly 20 GW by 2030 (33 GW including early-stage ones), the vast majority aiming to export hydrogen and ammonia. However, the Asian Renewable Energy Hub recently encountered government pushback; in June 2021 its application was rejected due to potential adverse impacts on habitats and native species.

Australia has also significant fossil fuel resources, particularly Victoria's brown coal reserves. Combined with CCUS, they could be another energy source for low-carbon hydrogen production. The first facility for producing hydrogen from coal started operation (in the Latrobe Valley) in March 2021 as part of the HESC project lead by HySTRA. The facility is not incorporating CCUS in its first phase, but it will be retrofitted with CCUS capabilities by 2030, subject to successful demonstration of the economic viability of transporting liquid hydrogen from Australia to Kobe in Japan.

India

More than 7 Mt H_2 was used in India in 2020, with 45% used for refining, 35% for chemicals and almost 20% for iron and steel. India is the world's largest producer of steel using the DRI route, consuming one-quarter of global hydrogen demand for this end use. Practically all hydrogen demand is met through domestic production based on fossil fuels, with natural gas accounting for three-quarters, coal for more than 15% and by-product from refineries making up the rest.

Irrespective of the scenario context, hydrogen use in India is expected to rise substantially in the next decade as population growth and greater prosperity necessitate increased food production (requiring ammonia) and new infrastructure (requiring steel). In the Announced Pledges Scenario, hydrogen demand grows to close to 11 Mt H_2 by 2030, with DRI-based steelmaking accounting for around 30% of this increase.

India's enormous potential to expand hydrogen demand and its considerable renewable energy possibilities offer an extraordinary opportunity to decarbonise the industry sector while also reducing fossil fuel import dependency. If electrolysis were deployed at scale and the potential for cost reductions materialised, India could be one of the regions with the lowest costs for producing hydrogen from renewables.

As early as 2030, hydrogen production from renewables could cost just USD 1.4-3.7/kg H_2, competitive with production through unabated fossil fuel methods. Low production costs for renewable hydrogen could enable the export of low-carbon hydrogen and hydrogen-based fuels, particularly to other Asia-Pacific economies that are likely to require imports to meet national hydrogen demand (e.g. Japan and Korea).

The Indian government has taken the first steps to seize the energy sector decarbonisation opportunities hydrogen can offer. Early in 2021, it launched the National Hydrogen Mission (NHM) to articulate the government's vision, intent and direction for hydrogen and to outline a strategy. The NHM will also explore policy action to support the use of hydrogen as an energy vector and develop India into a global hub for hydrogen and fuel cell technology manufacturing.

The first policy actions are under way, with the government having announced the adoption of auctions (in 2021) for producing hydrogen from renewables and mandatory quotas for using renewable hydrogen in refining and ammonia production. According to the proposal, starting in 2023/24 refineries will have to meet 10% of their hydrogen demand with renewable hydrogen, increasing to 25% in the following five years. Fertiliser producers will need to meet 5% of demand with renewable hydrogen in 2023/24, increasing to 20%. This proposal is expected to be extended to the steel industry in the near future.

The Indian government also announced plans for new developments in gas grid infrastructure, connecting major demand centres with ports to help the latter become major import/export hubs. The industry sector has also become involved, with some major companies (e.g. Adani, Arcelor Mittal, the Indian Oil Corporation, NTPC, Reliance Industries and the Solar Energy Corporation of India) announcing ambitious plans to develop projects for low-carbon hydrogen production.

Korea

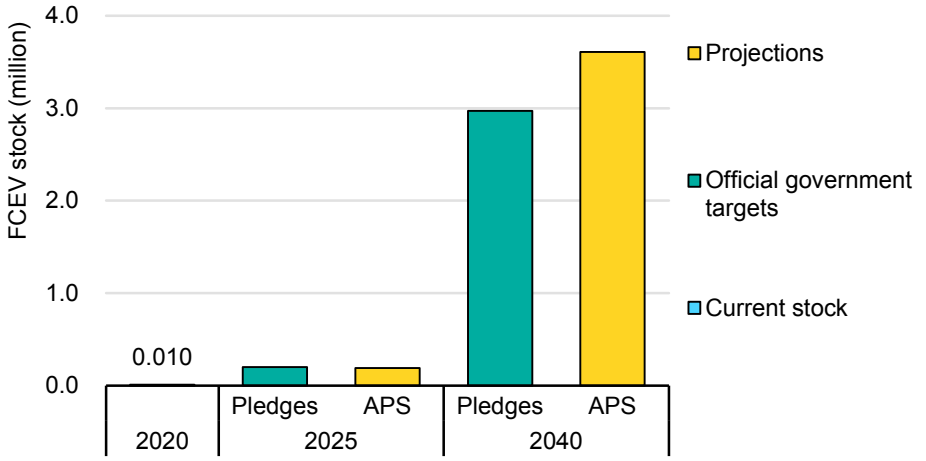
More than 1.8 Mt H_2 were produced and used in Korea in 2020, with practically all demand coming from refining and petrochemical processes. Around 60% of the hydrogen used is obtained as by-product from various sources, with the remaining 40% produced from natural gas. Korea is among the most active countries in adopting hydrogen technologies. In 2019 the government launched its Hydrogen Economy Roadmap, which outlines a vision for the role of hydrogen in the energy sector. The roadmap highlights two priorities: creation of a hydrogen market; and the development of hydrogen-utilising industries to create the world's largest market for fuel cells for transport and electricity generation.

In transport, Korea became the leader in FCEV deployment in 2020, with over 10 000 FCEVs on the road. In its 2020 New Deal, the government increased the 2025 FCEV target from 100 000 (set in the 2019 hydrogen roadmap) to 200 000, and for 2040 it is targeting

close to 3 million FCEVs, including 2.9 million domestically manufactured fuel cell cars, 30 000 fuel cell trucks and 40 000 fuel cell buses.

Furthermore, interest in using hydrogen in transport extends beyond decarbonising domestic transport. As fuel cell development is also considered an important technology export opportunity, the roadmap established targets for exporting 3.3 million FCEVs by 2040. Hyundai's announced fuel cell manufacturing capacity of 500 000 units/yr in 2030 largely aligns with the production target of 6.2 million fuel cell cars by 2040.

FCEV deployment in Korea in the Announced Pledges Scenario, 2020-2040



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Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. Source: AFC TCP; Korea 2020 New Deal; Hydrogen Economy Roadmap.

Regarding stationary fuel cells, Korea currently has 620 MW of installed capacity – almost double what it had at the end of 2018, according to its Hydrogen Economy Roadmap. Most of this capacity is used for electricity generation (605 MW), but a small fraction (15 MW) is used in buildings. Practically all this capacity is fuelled by natural gas, but stakeholders are taking steps to operate fuel cells with 100% hydrogen.

By 2040 in the Announced Pledges Scenario, Korea consumes 1.9 Mt H_2 to generate 33 TWh of power. This will require an installed capacity of 18 GW – far more than the Korean government's target of 8 GW. This 18 GW also includes other hydrogen technologies for electricity generation, such as co-firing hydrogen with natural gas in gas turbines. The Korean government also considers stationary fuel cells a technology export opportunity, so the Hydrogen Economy Roadmap targets 7 GW of stationary fuel cell exports by 2040.

Korea is also giving considerable attention to producing low-carbon hydrogen and developing hydrogen infrastructure. So far, hydrogen demand for fuel cell applications has been met with by-product hydrogen or unabated natural gas-based production. In the transition to 2040, the Hydrogen Economy Roadmap prescribes greater hydrogen production from water electrolysis and from natural gas with CCUS, and more hydrogen imports.

The first projects to develop low-carbon hydrogen production are already under way: in 2021, SK E&S and Hyundai Oilbank

announced plans to develop two projects for hydrogen production from natural gas with CCUS, for a combined production capacity of 350 kt H_2/yr. Plus, the Korea National Oil Corporation and Korea East-West Power have announced the potential incorporation of a 100-MW electrolysis plant into the Donghae 1 offshore wind project, expected to be completed by 2025. On the infrastructure side, Linde and Hyosung partnered in 2021 to build Asia's largest hydrogen liquefaction plant (30 t H_2/day) to supply hydrogen for use in transport.

Latin America

Latin American countries consumed 3.5 Mt H_2 in 2020, of which 2.5 Mt H_2 was used in industry and the rest in refining. The vast majority of the production (90%) was based on natural gas, with by-product hydrogen from refineries making up the rest.

A combination of factors has spurred increased interest in hydrogen in the region. The major economies (Argentina, Brazil, Chile, Colombia and Mexico) already produce large volumes from unabated fossil fuels for use in oil refineries and in the chemical and iron and steel industries, and Trinidad and Tobago is among the world's largest producers of ammonia and methanol.

Latin America also has one of the world's highest shares of renewables in electricity generation, with Costa Rica, Paraguay and Uruguay producing practically all their electricity from renewables. Plus, the region has significant oil and gas resources, particularly in Venezuela, Brazil and Mexico.

This combination of factors can create complementarities and synergies across the region. Establishing effective co-operation among the countries could therefore help the region meet the challenges of adopting hydrogen as a clean fuel while generating economic growth.

Chile has taken the lead in announcing hydrogen developments. Having enormous renewable energy potential – well exceeding its energy demand – it can produce renewable hydrogen at costs that are among the lowest in the world. The government published its Green Hydrogen Strategy in November 2020 with the ambition of becoming the top destination in Latin America for renewable hydrogen investment by 2025 and one of the world's largest exporters of hydrogen-based fuels by 2030. The strategy also targets 25 GW of electrolysis operational or under development by 2030.

Chile's private sector has responded to the government's call for action by launching some major initiatives. For instance, the Haru Oni project, led by HIF, aims to demonstrate synthetic methanol production using hydrogen produced by wind-powered electrolysis in Magallanes. The first phase is expected to be operational by 2022, and if successfully demonstrated, the project will be expanded in subsequent phases to produce 550 million litres of synthetic fuels

annually by 2026 (with 2 GW of installed electrolysis capacity). The objective is to export these hydrogen-based fuels.

Meanwhile, in 2020 ENAEX and Engie announced the HyEx project to deploy up to 780 MW of electrolysis by 2030 to produce ammonia in Antofagasta, starting with a pilot of 50 MW of electrolyser capacity to be implemented by 2024. ENAEX, a company that produces explosives for the mining sector, imports 350 kt of fossil fuel-based ammonia annually, subject to high price volatility. The company therefore aims to secure and internalise its ammonia feedstock supply while also reducing its CO_2 emissions.

Chile's national hydrogen strategy also highlights the usefulness of electrolysis in decarbonising existing uses (in the chemical industry and refining), and especially heavy road transport. In a noteworthy activity in the mining sector, a major contributor to the economy, stakeholders are developing as many as 13 different initiatives for using hydrogen in mining, particularly for trucks used at mines.

The release of the Chile's strategy stimulated hydrogen-related policy discussions across the region. In Argentina, an inter-ministerial group was created to develop a hydrogen roadmap and update existing laws to promote hydrogen, and in February 2021, Brazil's Energy Research Office (EPE) released its first technical document laying the foundation for a national hydrogen strategy. Colombia announced the launch of its national strategy at the end of September 2021 and the governments of Panama, Paraguay, Trinidad and Tobago, and Uruguay are also developing hydrogen strategies and roadmaps.

In turn, the private sector is taking action to leverage hydrogen opportunities. For example, in early 2021 Energix announced the Base One project to deploy around 3.4 GW of electrolysis capacity powered by renewable energy (at Ceará, north-eastern Brazil). All hydrogen produced will be exported from the Port of Pecem (a founding member of the Global Ports Hydrogen Coalition).

In 2017, Costa Rica was the first country in the region to deploy a fuel cell bus and four FCEVs. The government, in collaboration with the private sector, presented an institutional plan to facilitate the use of hydrogen in transport in 2018 and is currently developing a national strategy. Meanwhile, Panama's strategic location at the crossroads of major shipping routes makes it a global hub for maritime transport and a centre for regional trade. While current hydrogen production and use are very limited, in 2021 the government presented its vision for Panama to become a logistics and distribution centre for low-carbon hydrogen-based fuels, initially focusing on the maritime shipping industry.

More details about hydrogen's status and opportunities in Latin America can be found in the IEA's August 2021 report Hydrogen in Latin America.

Middle East

Countries in the Middle East consumed around 11 Mt H_2 in 2020, using close to 4 Mt H_2 in refining, more than 5 Mt H_2 in the chemical industry and 1.5 Mt H_2 in steel production. Natural gas accounts for close to 90% of production, with by-product hydrogen from refineries making up the remainder.

The Middle Eastern region has a formidable combination of oil and gas reserves and tremendous renewable energy potential (particularly solar) that can enable low-carbon hydrogen production at significantly lower cost than in most parts of the world. Plus, Middle Eastern countries have considerable experience in exporting LNG. Owing to all these factors, the countries aim to become major international suppliers of low-carbon hydrogen. Oman, Saudi Arabia and the United Arab Emirates have been the most active to date, having several projects under development and participating in various international co-operations.

In Saudi Arabia, Air Products, Acwa Power and Neom signed an agreement in 2020 to develop a USD 5-billion project to produce 650 t H_2/day using electrolysis powered by 4 GW of solar PV and wind. Part of the hydrogen produced will be transformed into ammonia for export to Air Products clients globally. The project has already reached FID and the design and early work are now under way, with the expectation that it will be operational in 2025. Thyssenkrupp and Haldor Topsoe are involved as technology providers.

Saudi Arabia has been quite active in the international sphere, seeking to develop potential supply chains through which it could become a major exporter, particularly to Europe and Japan. In September 2020, Saudi Aramco, the Institute of Energy Economics, Japan and SABIC successfully carried out the world's first shipment of ammonia produced from fossil fuels with CCUS, shipping 40 t of ammonia from Saudi Arabia to Japan for use in electricity generation while captured CO_2 was used in EOR and chemical production in Saudi Arabia. In March 2021, the Saudi government signed a collaboration agreement with Germany to lay the groundwork for developing an international hydrogen (or ammonia) supply chain.

In 2020, DEME announced the first initiative to develop a large-scale electrolysis plant (250-500 MW) in Oman. The number and size of projects announced has since grown significantly. For instance, a USD 2.5-billion collaboration between ACME Solar and the Oman Company for the Development of Special Economic Zone will produce 2 400 t/day of green ammonia. Furthermore, in May 2021 an international consortium of companies announced plans to develop the Green Fuels Mega Project, a 14-GW electrolysis project powered by 25 GW of wind and solar PV, with construction planned to start in 2028 and full operations expected by 2038. As most of these projects aim to produce low-carbon hydrogen or ammonia for export, the Port of Duqm (a founding member of the Global Ports Hydrogen Coalition) is a cornerstone of the initiatives being developed in Oman.

In the United Arab Emirates, Emirates Steel has been operating the Al Reyadah CCUS Project since 2016, capturing 800 kt CO_2/yr from DRI-based steel production. In 2021, DEWA and Siemens inaugurated Expo 2020 Dubai (delayed because of the Covid-19 pandemic), the region's first renewable energy-powered electrolysis project.

In addition, by signing an agreement with Japan to collaborate on hydrogen production technologies and create an international supply chain, the Emirates have taken the first steps to becoming hydrogen exporters. ADNOC announced a joint study agreement with two Japanese companies (INPEX, JERA) and a government agency (JOGMEC) to investigate the potential of producing ammonia from fossil fuels with CCUS to supply Japanese utilities. ADNOC is already developing a large-scale low-carbon ammonia production facility (capacity of 1 Mt NH_3/yr) at the TA'ZIZ Industrial Chemicals Zone and exploring opportunities to commercialise this product.

Kuwait and Qatar have also taken the first steps in developing their hydrogen strategies, in preparation to capture opportunities to exploit their natural resources to produce hydrogen.

Policy recommendations

Attaining climate goals will require ambitious, decisive action in the next decade

The IEA's Net zero by 2050 roadmap shows that achieving net zero targets will require immediate action to make the 2020s the decade of clean energy expansion through massive deployment of available low-carbon technologies and accelerated innovation of those still under development. Hydrogen technologies are a key example, with a considerably higher pace of progress and deployment required from now until 2030. The three overarching goals are to significantly expand hydrogen use while bringing new technologies onto the market; make hydrogen production much cleaner (i.e. shift away from unabated fossil fuel-based routes); and reduce the costs of technologies for hydrogen production and use.

To inform decision-making, this report presents a series of milestones that need to be reached by 2030 to unlock hydrogen's potential to address climate change. These markers cover the entire hydrogen value chain, including its production, infrastructure requirements, transformation into other fuels and end uses. Ultimately, the milestones are a call for action to governments. The implementation of policies to support their achievement can help build confidence among investors, industry, citizens and other countries, in turn prompting collaboration to trigger uptake of hydrogen as a new energy vector.

Key milestones to stay on track with the Net zero Emissions scenarios by 2030

	2020	NZE 2030	Development status
Total H_2 demand (Mt H_2)	90	212	-
Electrolysis capacity (GW)	0.3	850	Mature
CO_2 captured and stored in H_2 production (Mt CO_2)	10	410	Mature
Total road FCEVs (million vehicles)	0.035	15.3	Market scale-up
HRSs (1 000s of stations)	0.54	18	Market scale-up
NH_3 demand in shipping (Mt NH_3)	0	47	Demonstration
H_2 demand in electricity generation (Mt H_2)	0	43	Demonstration
Low carbon H_2 demand in DRI (Mt H_2)	0.1	5.7	Demonstration
Synfuel demand in aviation (mb/y)	0	38	Prototype
Export terminals (number of terminals)	0	60	Prototype

Near-term policy recommendations to enable the required transformation

To achieve the Net zero Emissions milestones, governments must take a lead role in facilitating the clean energy transition by establishing policy frameworks that stimulate integrated action. In The Future of Hydrogen, the IEA identified a series of recommendations for near-term policy action. Here, this Global Hydrogen Review expands on these policies and explains how they can facilitate attainment of the milestones.

Policies should centre on the need to:

- Develop strategies and roadmaps on hydrogen's role in energy systems.
- Create strong incentives for using low-carbon hydrogen to displace fossil fuels.
- Mobilise investment in production assets, infrastructure and factories.
- Provide strong innovation support to ensure critical technologies reach commercialisation quickly.
- Establish appropriate certification, standardisation and regulation regimes.

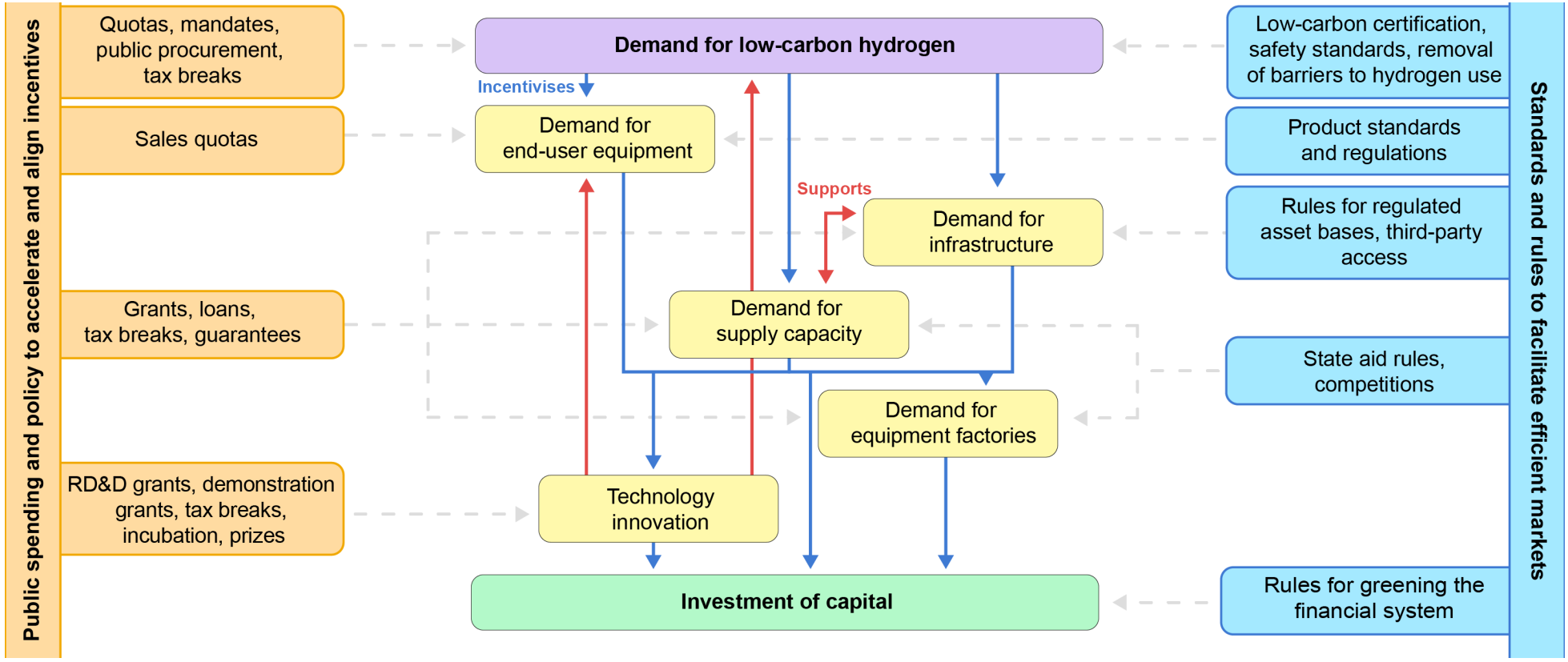
As all these policies are interconnected, implementation of one will impact the potential outcomes of the others. Some are natural first steps, such as defining the role of hydrogen in national energy strategies. However, it is unlikely this role can be realised without sufficient stimulus measures to create demand and mobilise investments for the infrastructure needed to connect hydrogen producers and users in the initial adoption stages. Developing such infrastructure requires planning among diverse stakeholders, with local authorities playing a key role as co-ordinators. Co-ordination of efforts can be facilitated if the roles of the different stakeholders are clearly and properly defined in hydrogen strategies and roadmaps.

In turn, the extent to which demand can be created will depend on increased effort in two main areas: support for innovation to ensure technologies are developed and become competitive; and establishment of standards and certification schemes to ensure the interoperability of these technologies globally and provide certainty to end users about the products they are acquiring on the market. Market development will also depend on adequate regulation to guarantee fair competition.

Ultimately, these features all work together like gears in one system: they all need to be in place and function in a co-ordinated fashion to ensure the effective adoption of hydrogen technologies at the required levels, within the next decade. The success of these policies will also depend on other measures, such as the development of training programmes to create a skilled workforce, ready to deploy and operate novel hydrogen technologies.

In the long term, consumer demand will drive investment in low-carbon hydrogen value chains. In the short term, however, it is up to policymakers to pull various levers to attract capital to the right places to create such demand.

How policy and regulatory interventions can amplify and steer incentives across hydrogen value chains



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Develop strategies and roadmaps on hydrogen's role in energy systems

National hydrogen strategies and roadmaps with concrete milestones for implementation and specific targets for producing and using hydrogen are essential to signal government commitment to expanding hydrogen supply and use. Ideally, they should be part of wider government strategies to achieve climate targets, thereby anchoring hydrogen as part of the expected energy future. Developing strategies and roadmaps is thus critical to build stakeholder confidence in the potential marketplace of low-carbon hydrogen and related technologies.

More and more countries have taken the vital first step of establishing national strategies in the last couple of years, creating momentum for the hydrogen industry and triggering new investments. Nevertheless, IEA analysis of stated targets detects a widening supply-demand gap due to strong policy focus on expanding low-carbon hydrogen supplies and relatively little action designed to increase market demand.

Clearly, emphasising the "push" for low-carbon hydrogen by increasing production capacity without creating sufficient market "pull" for the end product can create imbalances – and even bottlenecks – in the hydrogen value chain. Lack of demand can impede the emergence of supply projects, making it more difficult to achieve government targets for low-carbon hydrogen production.

Scenario analysis in this report suggests a growing need for more ambition to boost demand for low-carbon hydrogen, to both replace current demand for fossil fuel-based hydrogen (in refining and industry) and create demand for new applications such as heavy-duty transport, energy storage, new industrial applications, shipping and aviation.

Specific targets must therefore be adopted for using low-carbon hydrogen in existing applications and for deploying new hydrogen applications within this decade. Endorsing these aims at the national level can facilitate co-ordinated global action to achieve the milestones for 2030 proposed in this report.

Including hydrogen demand and production as well as hydrogen technology deployment in national energy statistics and reporting is also advisable. Tracking demand by sector, production through different routes, and other parameters related to hydrogen technology deployment (e.g. the number of HRSs, installed electrolysis capacity and the number of FCEVs on the roads by vehicle type) is critical to assess progress in meeting strategy and roadmap targets.

The IEA is ready to apply its analytical capabilities to help governments around the world define the role hydrogen can play in meet their climate goals and advance their strategies and roadmapping efforts.

Create strong incentives for using low-carbon hydrogen to displace fossil fuels

Demand creation is a key lever to stimulate adoption of hydrogen as a clean energy vector. However, using low-carbon hydrogen is more costly than employing incumbent technologies, whether one compares with fossil-based hydrogen in traditional uses or the combustion of fossil fuels in potential new hydrogen applications.

Although an increasing number of countries now impose carbon pricing or taxation, current carbon prices are not high enough to close the cost gap between low-carbon hydrogen and fossil-based alternatives. Carbon prices are expected to rise in some countries and jurisdictions (e.g. Canada, Norway and the European Union), but this can take many years and, while helpful, may not drive transformation at the speed required.

To help industry de-risk investments and improve the bankability of projects, governments should design policy frameworks and financial support schemes that are transparent and predictable. Three key policy instruments already show strong potential for this purpose:

- Carbon contracts for difference. Already proposed by the European Union and Germany, this is a new policy instrument to bridge the gap between current carbon prices and the price needed to trigger fuel switching in target industries (e.g. refining, iron and steel, and chemicals). Using auctions to support the most competitive projects can be an effective way to hasten low-carbon hydrogen adoption (particularly for traditional refining and industrial applications).
- Mandates/quotas. Gradually rising mandatory quotas for low-carbon technologies, both for existing hydrogen uses (e.g. refineries and fertiliser production) and new-use sectors, can be a powerful instrument to stimulate the adoption of low-carbon hydrogen-based fuels in some jurisdictions (e.g. California's Zero-Emission Vehicle [ZEV] mandate). Such demand-pull policies can strengthen the business cases of hydrogen projects without expending significant public funds. For example, demand for low-carbon hydrogen can be stimulated through mandates for ZEVs; blending quotas for low-carbon gases in natural gas grids or low-carbon fuels in power generation; and mandates for synfuel use in aviation. Mandates can also be reinforced by relevant disincentives, such as a ban on the sale of internal combustion engine vehicles; sunset clauses for conventional industrial equipment; and regulations for deploying combustion equipment (e.g. domestic appliances and industrial boilers and turbines) compatible with low-carbon fuels.
- Public procurement. All levels of government and public agencies can help create demand for low-carbon hydrogen by modifying public procurement contracts to require its use for public transport, taxi services, waste collection, trucks, ferries and barges, and by stipulating the use of low-carbon steel and cement in infrastructure projects. For example, the Norwegian government recently decided that the largest ferry connection in the country (Bodø-Værøy-Røst-Moskenes) should be fuelled by hydrogen. In some countries, governments have direct influence on the strategies and investment allocations of state-owned companies.

International engagement will help extend the impact of such policies. Some governments will be first movers, reaping the positive outcomes these policies can deliver while also learning lessons about

their inherent challenges. Recognising that the scale of the challenge requires co-ordinated global action and the positive effects of replicating success are multiple. The CEM Hydrogen Initiative has created an unparalleled platform for sharing knowledge and best practices with this purpose.

Mobilise investment in production assets, infrastructure and factories

A policy framework that effectively stimulates demand can in turn trigger investment in low-carbon production plants, infrastructure deployment and manufacturing capacity. Meeting ambitious climate goals will require additional policy action to accelerate the use of electrolysers and carbon capture in hydrogen production, develop hydrogen-specific infrastructure and ramp up manufacturing capacity for key hydrogen technologies (e.g. fuel cells and electrolysers).

On the production side, the pipeline of sizeable low-carbon hydrogen projects is impressive, with private companies and investors committing considerable investments. These projects are encountering a bottleneck, however, as governments still need to design and implement support schemes and relevant regulations, risking the loss of valuable time.

Providing tailor-made support for selected, shovel-ready flagship projects through grants, loans and tax breaks (ensuring due diligence to guarantee fair competition), while establishing the support schemes and regulations that will be needed later, can kick-start low-carbon hydrogen expansion. Tailored support for flagship projects can also unlock significant funding to scale up manufacturing capacity for key hydrogen technologies as well as prompt infrastructure development, from which later projects in the region can benefit. This requires flexible regulations that can help de-risk investment, for example through public-private partnerships designed to fit specific projects.

It can be expected that the hydrogen market will initially develop as integrated supply chains from producer to customer, as in the early days of LNG. Transitioning quickly to a liquid market that supports scale-up and widespread hydrogen adoption will require timely development of hydrogen-specific infrastructure, which implies adequate planning and mobilisation of sufficient investment.

Governments face the challenge of balancing rapid development – to ensure that lack of infrastructure does not impede creation of new demand – with the risk of deploying infrastructure too quickly and having it under-utilised or even stranded if demand does not develop sufficiently, particularly for new applications. To avoid such a scenario, infrastructure development should begin with interconnection of major industrial clusters – a low-regret option, since the hydrogen demand of such hubs is more certain than potential demand from new applications. These hubs are also natural locations for establishing hydrogen valleys, where new demand can be developed.

As these hubs typically have natural gas infrastructure in place, repurposing gas pipelines to serve as dedicated hydrogen pipelines is a low-cost option to initiate hydrogen infrastructure development (in fact, timely gas pipeline can accelerate hydrogen system establishment). Then, beyond these initial deployments to support transmission and distribution, governments should begin planning the development of future hydrogen infrastructure, including storage.

Provide strong innovation support to ensure critical technologies reach commercialisation quickly

While key hydrogen technologies are ready to start scaling up, continuous innovation is critical to drive down costs and increase competitiveness. Strong efforts are therefore needed in the near term to demonstrate several emerging technologies at scale to ensure that they reach commercialisation early this decade and unlock the full potential of hydrogen demand. Pertinent demonstration projects include using hydrogen in the DRI process for iron- and steelmaking; producing ammonia and methanol using electrolytic hydrogen produced from variable renewable energy; using hydrogen in heavy-duty transport; and using ammonia in shipping.

Governments should also take policy action now to stimulate funding for (and incentivise development of) next-generation technologies, such as use of hydrogen in shipping; transform hydrogen into synfuels; and use hydrogen to provide high-temperature heat in industrial processes (e.g. in cement kilns). Robust R&D and innovation programmes are necessary to ensure these technologies mature enough in the upcoming decade to be ready for deployment at scale in 2030.

In reality, public budgets for R&D and innovation in low-carbon hydrogen technologies do not offer the support needed to ensure the development pace required to meet long-term climate goals. Governments therefore need to take decisive action against these budget shortfalls.

In its Net zero by 2050 roadmap, the IEA estimates that USD 90 billion of public money needs to be mobilised globally as quickly as possible, with around half dedicated to hydrogen-related technologies. This could reduce investment risks for the private sector and help attract private capital for innovation. Furthermore, it is important for government departments managing R&D portfolios to work closely with national hydrogen research labs and other research centres, as well as with industry, to recognise and respond to the needs of the private sector.

International co-operation will be critical in this area. Implementing the agreed doubling of public R&D within the Mission Innovation initiative can be a first step. In parallel, the convening power of the IEA Hydrogen and Advanced Fuel Cells Technology Collaboration Programmes should be leveraged to facilitate international R&D and information exchange.

Establish appropriate certification, standardisation and regulation regimes

Since adopting hydrogen as a clean fuel is expected to stimulate the development of new markets and value chains, regulatory frameworks, certification schemes and standards will be required to reduce barriers for stakeholders.

In the short term, it is particularly important to develop standards in three domains:

- **International trade**. Standards are required in several areas to develop a global low-carbon hydrogen market. International agreement on a methodology for calculating the carbon footprint of hydrogen production is critical, as it is the basis from which a global certificates market could develop. Importing countries, regions and companies would then be able to decide what carbon footprint threshold they deem acceptable for imported clean hydrogen, although a commonly agreed international standard is vital to avoid future impediments to cross-border trade in hydrogen.
- **Safety**. Safety is a critical topic for low-carbon hydrogen and hydrogen-based fuels. Industry has been able to produce and use hydrogen safely over several decades, but as its use is now expected to expand beyond industry to reach domestic consumers in their vehicles and homes, ensuring safety across all levels is essential. Gaining public acceptance will require the establishment of high safety standards through international co-operation and harmonisation.
- **Technology adoption**. New applications for hydrogen use will result in deployment of new technologies to operate refuelling stations, storage sites and combustion appliances. Internationally harmonised standards for nozzles, valves, burners and storage tanks are therefore necessary to ensure consistent operability around the world.

The IPHE has been leading international efforts in these areas for many years. Governments and industry should thus leverage its progress and collaborate to ensure all required standards are developed quickly enough to prevent the lack of them becoming a barrier to hydrogen adoption. For example, an internationally agreed standard to measure the carbon footprint of hydrogen production on a lifecycle basis will be needed to account for the emissions of the whole hydrogen supply chain, including from electricity generation (where applicable) and fossil fuel production.[39]

Certification is the natural follow-on step after the development of standards. Certification schemes aim to ensure that manufacturers comply with standards adopted internationally to inspire confidence among low-carbon hydrogen users. Furthermore, low-carbon premium markets that rely on product certification can help create demand, mobilise investments and stimulate innovation.

For instance, a car certified to have been manufactured with low-carbon steel (i.e. steel produced in a factory where low-carbon hydrogen has replaced fossil fuel inputs) may have a small price

[39] See the IEA Methane Tracker for estimates on methane emissions from fossil production."

premium over a standard car, which can make it an attractive option for a significant number of consumers across diverse income levels. The same may apply to other consumer products manufactured with low-carbon commodities, such as fertilisers, cement and solvents. For a low-carbon premium market to function effectively, however, it must be founded on a dedicated and reliable system of certificates and labels to provide certainty to consumers about the low-carbon attributes of products they are acquiring.

In addition, a clear, transparent and supportive regulatory framework is necessary to enable development of a robust hydrogen market. As demand rises and suppliers respond, and entirely new value chains and partnerships emerge, regulatory systems will need to be flexible to adapt to market evolution without jeopardising the solidity of business cases needed to attract investment in production assets and infrastructure.

Clear rules for regulated assets and to ensure third-party access will also be needed to avoid new monopolies and market fragmentation in low-carbon hydrogen. However, given the embryonic stage of hydrogen market development, it is premature to apply rigid regulatory principles that work in other mature markets, since they could create a serious risk of regulatory failure or regulatory disconnect. Rather, a gradual and dynamic regulation approach, carefully calibrated to periodic market monitoring (as suggested by the Council of European Energy Regulators and the Agency for the Cooperation of Energy Regulators) can help minimise the risk of failure.

Governments should also consider ways to align other regulatory aspects and policy domains not directly linked to hydrogen markets but that can affect the business case to ensure that, at the very least, they do not render hydrogen projects unappealing. Some examples are:

- Grid fees and levies, which are often developed independently for electricity and gas and can hamper sector coupling.
- State aid rules, which are of critical importance to ensure fair competition. In some jurisdictions, they may need to be adjusted to facilitate initial deployment of low-carbon hydrogen technologies.
- Spatial planning and licensing, which in some countries can be a long and cumbersome process. Current planning and approval processes do not yet include hydrogen and may need to be revised. Governments and local authorities can help co-ordinate infrastructure planning processes among public agencies, industry and citizens.
- Possible tariff and non-tariff trade barriers, which can hamper hydrogen trade. A strong case exists for striving for uninhibited and smooth global trade in hydrogen, facilitated by early identification of potential barriers and, where necessary, undertaking international efforts to harmonise and tackle them.
- Energy taxation, which ideally should follow the “polluter pays principle” and systematically favour zero-/low-carbon solutions over fossil fuel alternatives.
- Fossil fuel subsidies, which still exist in several countries and can distort the developing hydrogen market. The IEA has long been recommending timely phase out of such subsidies.

Finally, financial market regulations for sustainable financing and initiatives for environmental, social and corporate governance – both national and international – are increasingly helpful to nudge investors towards clean energy, including low-carbon hydrogen. Governments should actively encourage these trends (e.g. by mandating that multilateral banks help fund hydrogen scale-up) to leverage their own public investments.

Annexes

Abbreviations and acronyms

AEM	anion exchange membrane
AFC	alkaline fuel cells
AFC TCP	Advanced Fuel Cell Technology Collaboration Programme
ALK	alkaline
APS	Announced Pledges Scenario
ATR	autothermal reforming
AUD	Australian dollar
BEV	battery electric vehicle
BF	blast furnace
CAD	Canadian dollar
CAPEX	capital expenditure
CCfD	carbon contracts for difference
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CEM H2I	Clean Energy Ministerial Hydrogen Initiative
CNY	Chinese yuan
CO_2	carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DRI	direct reduced iron
DRI-EAF	direct reduced iron - electric arc furnace
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 Scheme
EUR	Euro
EV	electric vehicle
FC	fuel cell
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FID	final investment decision
FT	Fischer-Tropsch
GBP	British pound sterling
GH_2	gaseous hydrogen
GHG	greenhouse gases
GHR	gas-heated reformer

H_2	hydrogen
HDV	heavy-duty vehicle
HEM	Hydrogen Energy Ministerial
HEV	hybrid electric vehicle
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
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
IPCEI	Important Projects of Common European Interest
JHyM	Japan Hydrogen Mobility
JPY	Japanese yen
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
LNG	liquefied natural gas
M&A	mergers and acquisitions
MCFC	molten carbonate fuel cell
MeOH	methanol
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
NZE	Net zero Emission Scenario
OEM	original equipment manufacturer
OPEX	operating expenditure
PAFC	phosphoric acid fuel cell
PE	private equity
PEM	proton exchange membrane
PEMFC	proton exchange membrane fuel cell
PIPE	private investment in public equity
PLDV	passenger light-duty vehicle

POx	partial oxidation
PtG	power-to-gas
PtL	power-to-liquids
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
SCR	selective catalytic reduction
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
SOFC	solid oxide fuel cell
SUV	sport utility vehicle
TCO	total cost of ownership
TCP	Technology Collaboration Programme
TRL	technology readiness level
TSO	transmission system operator
UK	United Kingdom
UN	United Nations
US	United States
USD	United States dollar
VC	venture capital
VRE	variable renewable energy
WEF	World Economic Forum
ZEV	zero emissions vehicle

Units of measure

°C	degree Celsius
bbl	barrel
bcm	billion cubic metres
EJ	exajoule
Gt	gigatonnes
Gt CO_2	gigatonnes of carbon dioxide
GW	gigawatt
GWh	gigawatt-hour
kg	kilogramme
kg H_2	kilogramme of hydrogen
kg CO_2eq	kilogrammes of carbon-dioxide equivalent
kt	kilotonnes
kt H_2	kilotonnes of hydrogen
kW	kilowatt
kWh	kilowatt-hour
mcm	million cubic metres
MBtu	million British thermal units
MJ	megajoule

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