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Global Hydrogen Review 2024

International Energy Agency

INTERNATIONAL ENERGY AGENCY

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Abstract

The *Global Hydrogen Review* is an annual publication by the International Energy Agency that tracks hydrogen production and demand worldwide, as well as progress in critical areas such as infrastructure development, trade, policy, regulation, investments and innovation.

The report is an output of the Clean Energy Ministerial Hydrogen Initiative and is intended to inform energy sector stakeholders on the status and future prospects of hydrogen. Focusing on hydrogen's potential role in meeting international energy and climate goals, the Review aims to help decision makers fine-tune strategies to attract investment and facilitate deployment of hydrogen technologies at the same time as creating demand for hydrogen and hydrogen-based fuels. It compares real-world developments with the stated ambitions of government and industry.

This year's report has a special focus on Latin America and includes analysis on recent developments of low-emissions hydrogen projects in the region and how to unlock demand and move towards project implementation. In addition, the report assesses in detail the greenhouse gas emissions associated with different hydrogen supply chains.

Acknowledgements, contributors and credits

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Executive summary

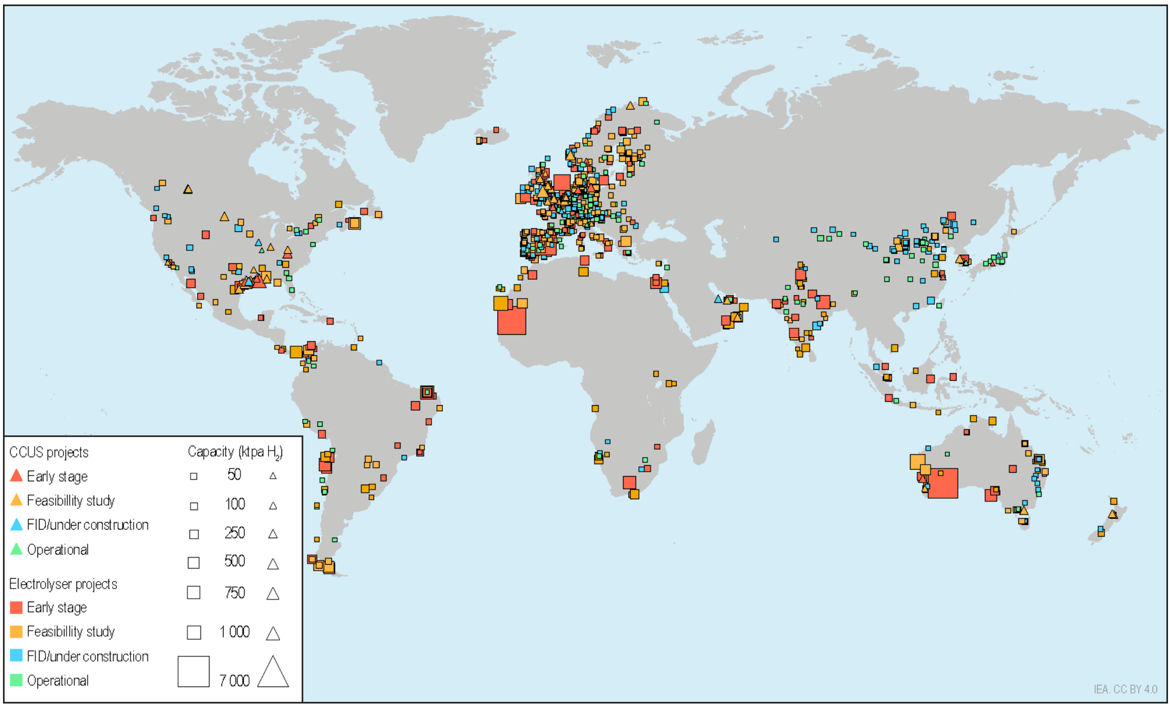
More projects and more final investment decisions, but setbacks persist

Global hydrogen demand reached 97 Mt in 2023, an increase of 2.5% compared to 2022. Demand remains concentrated in refining and the chemical sector, and is principally covered by hydrogen produced from unabated fossil fuels. As in previous years, low-emissions hydrogen played only a marginal role, with production of less than 1 Mt in 2023. However, low-emissions hydrogen production could reach 49 Mtpa by 2030 based on announced projects, almost 30% more than when the Global Hydrogen Review 2023 was released. This strong growth has been mostly driven by electrolysis projects, with announced electrolysis capacity amounting to almost 520 GW. The number of projects that have reached a final investment decision (FID) is also growing: Announced production that has taken FID doubled compared with last year to reach 3.4 Mtpa, representing a fivefold increase on today's production by 2030. This is split roughly evenly between electrolysis (1.9 Mtpa) and fossil fuels with carbon capture, utilisation and storage (CCUS) (1.5 Mtpa).

Hydrogen production from fossil fuels with CCUS has gained ground over the past year – although the total potential production from announced projects grew only marginally compared with last year, there were several FIDs for previously announced large-scale projects, all of which are located in North America and Europe. As a result, the potential production in 2030 from projects using fossil fuels with CCUS that have taken FID more than doubled in the last year, from 0.6 Mtpa in September 2023 to 1.5 Mtpa today.

Overall, this is noteworthy progress for a nascent sector, but most of the potential production is still in planning or at even earlier stages. For the full project pipeline to materialise, the sector would need to grow at an unprecedented compound annual growth rate of over 90% from 2024 until 2030, well above the growth experienced by solar PV during its fastest expansion phases. Several projects have faced delays and cancellations, which are putting at risk a significant part of the project pipeline. The main reasons include unclear demand signals, financing hurdles, delays to incentives, regulatory uncertainties, licensing and permitting issues and operational challenges.

Map of announced low-emissions hydrogen production projects, 2024



Source: IEA Hydrogen Projects database (October 2024).

China and electrolysers – the sequel to solar PV and batteries?

Announced electrolyser capacity that has reached FID now stands at 20 GW globally, of which 6.5 GW reached FID over the last 12 months alone. China is strengthening its leadership, accounting for more than 40% of global FIDs in capacity terms over the same period. China's front-running position is backed by its strength in the mass manufacturing of clean energy technologies: it is home to 60% of global electrolyser manufacturing capacity. China's continued expansion of manufacturing capacity is expected to drive down electrolyser costs, as has occurred with solar PV and battery manufacturing in the past. Moreover, several large Chinese manufacturers of solar panels have entered the business of manufacturing electrolysers, and today they account for around one-third of China's electrolyser manufacturing capacity. However, other regions are also stepping up efforts: in Europe, FIDs for electrolysis projects quadrupled over the last year to reach more than 2 GW, while India has emerged as one of the key players thanks to a single FID for 1.3 GW.

Technology innovation is making headway, with signs pointing to accelerated progress in the near term

Government investment in hydrogen technology RD&D has been growing since 2016, and this effort is starting to bear fruit. To date, progress has occurred mostly on the supply side, and numerous technologies are either already commercially available or close to this point. Promising results are also being seen for end-use technologies, with several applications in industry and electricity generation reaching demonstration stage, as well as significant progress in transport applications, particularly in the shipping sector. In addition, the number of patent applications leapt up 47% in 2022, with most of the growth coming from technologies that are primarily motivated by climate change concerns. Increased activity around patenting suggests that additional public funding for R&D and growing confidence in future market opportunities, backed by supportive policies, are stimulating more new ideas and product designs with commercial potential.

Low-emissions hydrogen will remain expensive in the short term, but costs are expected to fall significantly

Low-emissions hydrogen is an emerging sector and, as such, there is uncertainty about costs. Today's electrolyser costs have been revised upwards for this report, based on newly available data from more advanced projects. The future cost evolution will depend on numerous factors, such as technology development, and particularly on the level and pace of deployment. With the deployment seen in the IEA's Net Zero Emissions by 2050 Scenario (NZE Scenario), the cost of low-emissions hydrogen production from renewable electricity falls to USD 2-9/kg H_2 by 2030 – half of today's value – with the cost gap with unabated fossil-based production shrinking from USD 1.5-8/kg H_2 today to USD 1-3/kg H_2 by 2030. Deployment levels in the Stated Policies Scenario (which considers existing policies only) mean that the cost range would fall only around 30%. As natural gas prices fall in many regions, low-emissions hydrogen production from natural gas with CCUS is also set to experience cost reductions.

Cost reductions will benefit all projects, but the impact on the competitiveness of individual projects will vary. For example, full development of the entire electrolyser project pipeline of almost 520 GW would achieve similar global cost reductions as in the NZE Scenario. In China, global deployment at such a level would mean that the vast majority of the production from its current electrolyser project pipeline (1 Mtpa) would be cheaper than hydrogen produced from unabated coal. Globally, by 2030, more than 5 Mtpa could be produced at a cost competitive with production from unabated fossil fuels, and up to 12 Mtpa with a cost premium of USD 1.5/kg H_2.

This cost gap will remain an important challenge in the short term for project developers, but for final products for which hydrogen is an intermediate feedstock, the impact is likely to be manageable in many cases. The cost premium of low-emissions hydrogen production decreases along the value chain, meaning that consumers often see only a modest price increase in final products. For example, using steel produced with renewable hydrogen today in the production of electric vehicles (EVs) would increase the total price of an EV by around 1%.

Progress is being made in creating demand for low-emissions hydrogen, but this still needs to scale up

Efforts to stimulate demand for low-emissions hydrogen (and hydrogen-based fuels) are now gaining traction as governments begin implementing key policies (such as Carbon Contracts for Difference in Germany and the EU mandates in aviation and shipping). These measures have also triggered action on the industry side, with a growing number of offtake agreements signed and the launch of tenders to purchase low-emissions hydrogen. However, the overall scale of these efforts remains inadequate for hydrogen to contribute to meeting climate goals.

Policies and targets for hydrogen demand set by governments add up to around 11 Mt in 2030, nearly 3 Mt lower than last year due to the downward revisions of some targets for hydrogen use in industry, transport and power generation. Yet the amount of low-emissions hydrogen production that has taken FID (3.4 Mtpa) or is already operational (0.7 Mtpa), at 4 Mtpa, is well below that level. The gap constitutes a call for action to industry and governments to facilitate offtake agreements that can help unlock investment on the supply side.

At the same time, government policies and targets for demand are well behind the production targets by governments (which add up to 43 Mtpa in 2030) and are even lower than the potential supply that could be achieved from announced projects (49 Mtpa). Policy measures are still insufficient to create the level of demand needed to scale up production to meet government expectations. In addition, some more ambitious actions (like the EU targets in industry applications or the refining quotas in India) have not yet been translated into national legislation. Moreover, from the around USD 100 billion of policy support for low-emissions hydrogen adoption announced by governments over the past year, support on the supply side is 50% larger than on the demand side. Stronger government action will be needed to stimulate demand for low-emissions hydrogen as an essential requirement to underpin investments on the supply side. Industrial hubs, where low-emissions hydrogen could replace the existing large demand for hydrogen met today by unabated fossil fuels, remain an important untapped opportunity for governments to stimulate demand.

The next steps for certification and mutual recognition

Governments are accelerating the development of regulations on the environmental attributes of low-emissions hydrogen, particularly regarding greenhouse gas (GHG) emissions. Clear and predictable regulations can strengthen certainty for long-term investments. Yet these frameworks, and the associated certification schemes, remain unaligned across different regions, creating potential for market fragmentation. In response, at COP 28, 37 governments committed to mutual recognition of national certification schemes, while Latin America launched “CertHiLAC”, a regional certification framework. In addition, the International Organization for Standardization (ISO) has released a methodology for determining GHG emissions associated with hydrogen production, transport and conversion/reconversion. This will be the basis for a full standard expected by 2025 or 2026, which could serve as a common methodology to enable the mutual recognition of certificates. However, some questions related to the assessment of GHG emissions in hydrogen supply chains remain unresolved, such as how to account for emissions from the construction and manufacturing of production assets. In the case of fossil-based production, there is a need for better data on upstream and midstream emissions of fossil fuel supply available in national inventories in order to ensure robust assessment of the GHG emissions associated with these production routes.

Hydrogen can be an opportunity for Latin America in the new energy economy, but is facing challenges

This year’s report includes a special focus on Latin America and the Caribbean, following the launch of the IEA’s Latin America Energy Outlook in 2023. Latin America is well-positioned to emerge as a major producer of low-emissions hydrogen, capitalising on its abundant natural and renewable energy resources and largely decarbonised electricity mix. Based on announced projects, by 2030, Latin America could produce more than 7 Mtpa of hydrogen with a carbon intensity below 3 kg CO_2-eq/kg H_2 (3-4 times lower than using unabated natural gas), in line with the requirements of several existing regulations around the world (e.g. the EU Taxonomy, Japan’s Hydrogen Society Promotion Act and the US Clean Hydrogen Production Standard). However, achieving this potential in full would require a significant increase in electricity generation capacity – equivalent to 20% of the region’s current power output – and substantial investments in enabling infrastructure, such as transmission lines.

Many Latin American countries already have hydrogen strategies with a strong focus on export opportunities. However, these plans may need to be updated in light of uncertainty about the size of the global hydrogen market. At the global level, there has been no growth in announced projects linked to trade of hydrogen and hydrogen-based fuels in the past year, suggesting that project developers have instead focused on domestic opportunities. In the case of Latin America, these opportunities are mostly in refining and ammonia production, which offer immediate large-scale applications. In the case of ammonia, developing domestic production capacities would help to reduce import dependency for fertilisers in a region where agriculture makes a significant contribution to national gross domestic product.

As the market develops, new applications in steel, shipping and aviation will emerge, together with the establishment of hydrogen hubs. These hubs can open an opportunity to scale up hydrogen use and production for domestic needs, while also providing the opportunity to export hydrogen-based fuels, as well as materials produced with low-emissions hydrogen, such as hot briquetted iron, allowing countries that are today large exporters of iron ore, like Brazil, to develop new industrial capacities and scale up in the value chain. A phased approach to supply in the region, starting with smaller-scale projects, will help mitigate risks, reduce capital investment, and provide valuable experience for scaling up in the future. Infrastructure planning and development, especially in long-lead projects like power transmission, should begin immediately to support future hydrogen production.

Recommendations

Accelerate demand creation for low-emissions hydrogen by leveraging industrial hubs and public procurement

Governments should take bolder action to stimulate demand for low-emissions hydrogen. The implementation of policies such as quotas, mandates and carbon contracts for difference has already started, but remains limited in geographical coverage and scale. Governments can capitalise on the opportunity offered by existing hydrogen users and high-value sectors such as steel, shipping and aviation, which are often co-located in industrial hubs. Pooling demand in these hubs can create scale and reduce offtake risks for producers. Additionally, making use of public procurement for final products that consume low-emissions hydrogen in their production, and encouraging the development of markets where consumers are willing to pay small premiums for low-emissions hydrogen-based products, can help drive early adoption.

Support project developers to scale up low-emissions hydrogen production and drive cost reductions

Governments should provide targeted support to project developers in the scale-up phase to bridge the cost gap between low-emissions hydrogen and unabated fossil-based hydrogen. Timely support is critical to unlock investment decisions, as experienced in Europe with a wave of FIDs after the confirmation of funding for several large projects. Governments should also provide long-term visibility over the level and form of support so developers have clarity over future business cases and can attract investors. While initial projects may require substantial financial backing, support levels will decrease as the sector matures and costs decline. In addition to grants and subsidies, governments can explore other policy options such as loan guarantees, export credit facilities, and public equity investments which can help to reduce investment risk and lower the cost of capital, which is crucial for these capital-intensive projects.

Strengthen regulation and certification of environmental attributes for low-emissions hydrogen

The release of the ISO methodology provides a standardised approach to assessing GHG emissions. It is now time for governments to implement clear regulations that set thresholds for acceptable emissions levels in hydrogen production. Ensuring regulatory consistency with the ISO methodology and forthcoming standards can facilitate global interoperability. However, in addition, governments should intensify efforts to assess and verify upstream emissions from fossil fuel supply, ensuring transparency by making this data accessible to market participants and the public.

Identify opportunities to start developing hydrogen infrastructure

Governments should strengthen efforts to accelerate the development of hydrogen infrastructure to avoid further delays that risk slowing the scale-up of low-emissions hydrogen production and demand. Without timely infrastructure deployment, the link between supply and demand cannot be established, hindering market growth and creating uncertainty for both producers and consumers. Immediate action can include early planning, a focus on repurposing existing natural gas pipelines and storage facilities to minimise cost, streamlining regulatory frameworks to speed up permitting, and fostering cross-border co-operation on hydrogen networks. Public-private partnerships can also be leveraged to de-risk investments, ensuring that infrastructure keeps pace with hydrogen market development.

Support emerging markets and developing economies (EMDEs) in expanding low-emissions hydrogen production and use

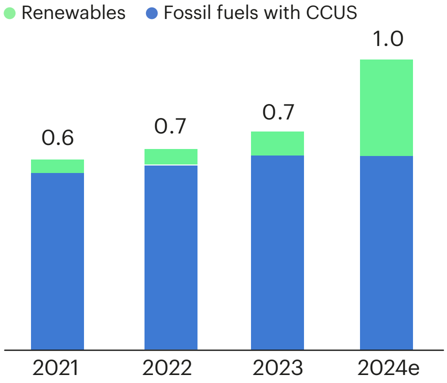
EMDEs, particularly in regions such as Africa and Latin America, hold significant potential for low-cost, low-emissions hydrogen production. To unlock this potential, governments of advanced economies and multilateral development banks should provide targeted support, including grants and concessional financing, to address key challenges such as access to financing, which is a major barrier for project developers in EMDEs. Developing these projects can help to cover domestic needs, reduce import dependencies and potentially enable the export of hydrogen or hydrogen-based products like hot briquetted iron and fertilisers.

Global Hydrogen Review Summary Progress

Production

Low-emissions hydrogen

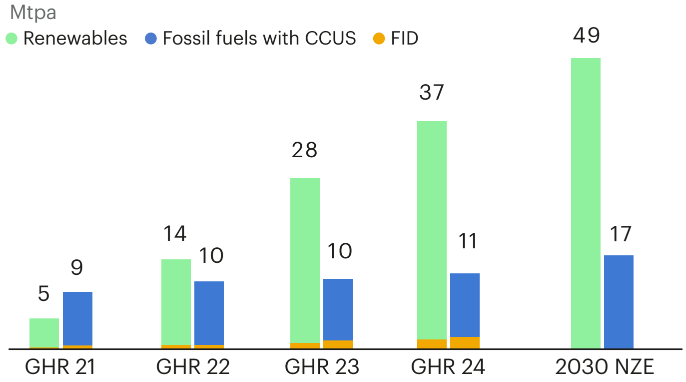
Mtpa



50%
growth
since 2021

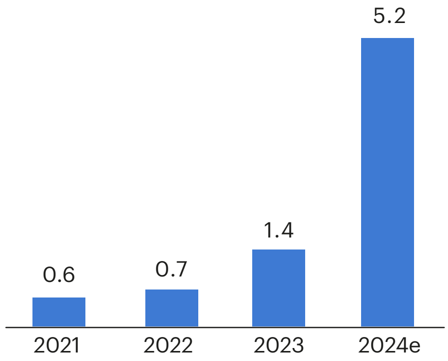
Low-emissions hydrogen production from announced projects by 2030

Mtpa



Electrolyser installed capacity

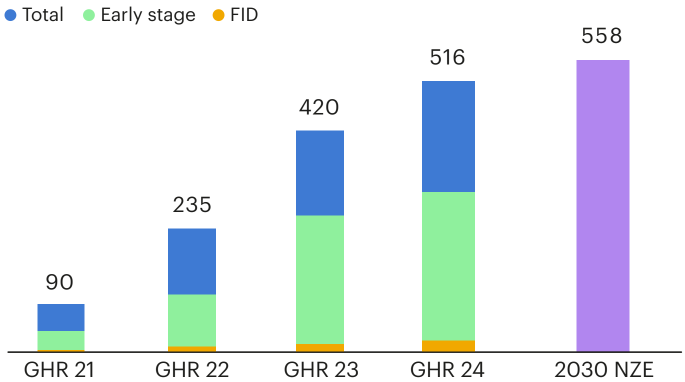
GW



9x
growth
since 2021

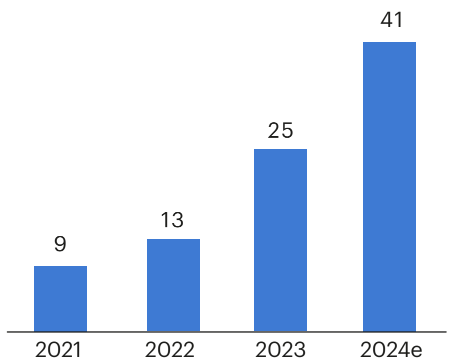
Announced electrolyser projects by 2030

GW



Electrolyser manufacturing capacity

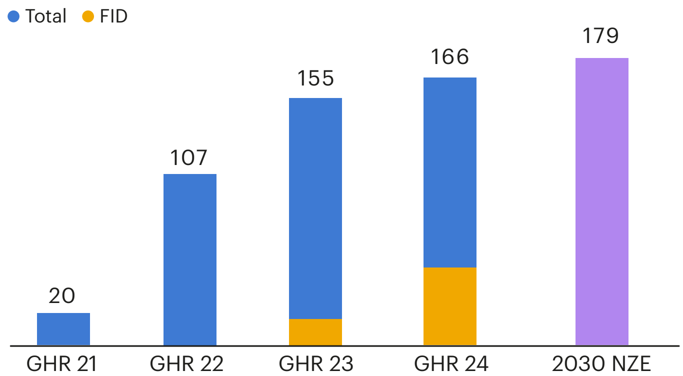
GW/yr



4x
growth
since 2021

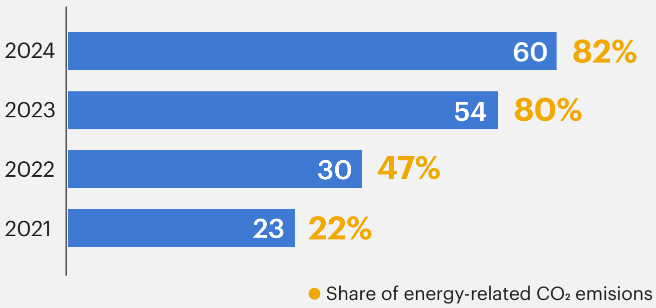
Announced electrolyser manufacturing capacity by 2030

GW/yr



Policies

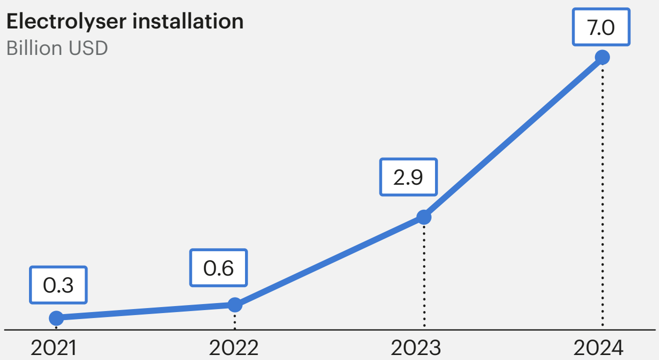
Number of hydrogen strategies



Investment

Electrolyser installation

Billion USD



Note: 2024e = Estimated based on announced projects. FID = Final Investment Decision.

Chapter 1. Introduction

Overview

The global energy sector is experiencing a profound transformation as efforts to tackle climate change and bolster energy security drive the shift toward cleaner, more sustainable energy sources. In this evolving landscape, interest in low-emissions hydrogen has grown rapidly due to a combination of drivers. First, it is widely recognised as a key solution for decarbonising sectors where emissions are hard to abate and other options are limited, such as in heavy industry, shipping and aviation. Second, the recent global energy crisis has further accelerated the push for low-emissions hydrogen, thanks to its potential to enhance energy security; as a consequence of the crisis, governments have intensified their net zero emission commitments, integrating low-emissions hydrogen into their strategic plans. Third, several major economies have recently introduced new industrial policies in which hydrogen technologies are prominently featured. However, despite this progress, the adoption of low-emissions hydrogen is yet to take off and there are still significant challenges to be overcome to fully realise its potential.

This fourth edition of the IEA Global Hydrogen Review assesses the advances within the hydrogen sector in the past year, focusing on the critical role of low-emissions hydrogen in the clean energy transition. By examining developments since the release of the Global Hydrogen Review 2023 (in September 2023) and pinpointing areas that need further attention, the report aims to guide governments, industries, and other stakeholders on the steps needed to ensure that hydrogen contributes effectively to a sustainable energy system.

The report begins with an analysis of the current state of hydrogen use and production. While global hydrogen use is on the rise, it remains heavily concentrated in traditional applications like refining and the chemical industry, with most production still based on unabated fossil fuels. Low-emissions hydrogen production has grown marginally over the past 2 years. Project developers are slowly starting to take investment decisions, although they are still facing significant barriers.

The report also assesses the situation of trade and infrastructure development. Several shipments of low-emissions hydrogen-based fuels, particularly ammonia, occurred last year; however, overall traded volumes remain small, and most projects are still in the early stages of development. Activities to develop hydrogen infrastructure remain concentrated on project announcements, with a very limited number of projects moving ahead to construction stage. The Global Hydrogen

Review also presents trends in investment and innovation in the hydrogen sector. Investment is growing, stimulated mostly by policy action, but it is still well below the levels needed for a successful energy transition. Progress in the development of key technologies is starting to accelerate as a result of the growing efforts made by governments to support innovation in the last decade.

The parts of the report devoted to tracking developments conclude with a policy chapter that summarises the main new policies adopted since the previous edition of the Global Hydrogen Review.

Finally, this year's Global Hydrogen Review includes two special focus chapters. The first presents an update of the analysis on the GHG emissions of hydrogen production following the IEA report on this topic for the G7 in 2023. We have reassessed the different production routes with the framework established by the ISO Technical Specification 19870:2023 and have extended the analysis to cover the whole supply chain of hydrogen and hydrogen-based fuels. The second special thematic chapter is a regional focus on Latin America and the Caribbean, assessing the best short-term opportunities for the region to develop supply chains for low-emissions hydrogen, hydrogen-based fuels and other hydrogen-based products.

The CEM Hydrogen Initiative

Developed under the Clean Energy Ministerial framework, the Hydrogen Initiative (H2I) is a voluntary multi-governmental initiative that aims to advance policies, programmes and projects that accelerate the commercialisation and deployment of hydrogen and fuel cell technologies across all areas of the economy.

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"), Saudi Arabia, South Africa, the United Arab Emirates, 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. H2I has active partnerships with the Breakthrough Agenda, the Hydrogen Council, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the International Renewable Energy Agency (IRENA), the Mission Innovation Clean

Hydrogen Mission, the World Economic Forum, the United Nations Industrial Development Organization (UNIDO), and the IEA Advanced Fuel Cells and Hydrogen Technology Collaboration Programmes (TCPs), all of which are part of the H2I Advisory Group and participate in various activities of the H2I. In addition, several industrial partners actively participate in the H2I Advisory Group's biannual meetings, including Ballard, Enel, Engie, Nel Hydrogen, the Port of Rotterdam Authority and thyssenkrupp nucera.

Chapter 2. Hydrogen demand

Highlights

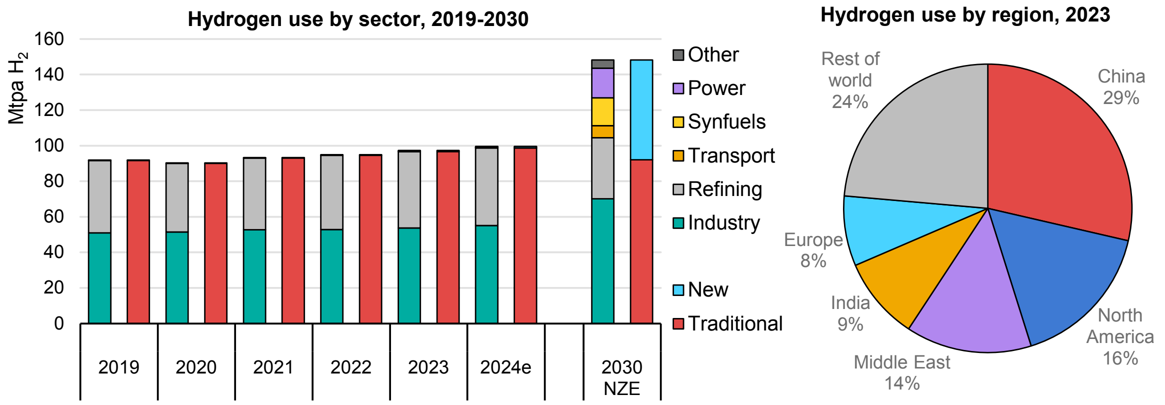
- Global hydrogen demand reached more than 97 Mt in 2023 and could reach almost 100 Mt in 2024. However, this increase should be seen as a consequence of wider economic trends rather than the result of successful policy implementation.
- Hydrogen demand remains concentrated in refining and industry applications, where it has been used for decades. Its adoption in new applications where hydrogen should play a key role in the clean energy transition – heavy industry, long-distance transport and energy storage – accounts for less than 1% of global demand, despite 40% growth compared with 2022.
- Demand for low-emissions hydrogen grew almost 10% in 2023, but still accounts for less than 1 Mt. Government action has intensified recently, through implementation of mandates, incentive schemes and market development tools. This could boost demand to over 6 Mtpa by 2030, although this would equal around one-tenth of the needs of the Net Zero Emissions by 2050 Scenario (NZE Scenario).
- Industry is responding to these policy efforts and signing a growing number of offtake agreements. Moreover, these agreements are moving from Memoranda of Understanding to firm contractual arrangements. Chemical, refining and the shipping sectors present the largest amount of contracted demand, as well as the largest share of firm agreements.
- Industry is also making other efforts to facilitate uptake, such as tenders and co-operative initiatives for demand aggregation of hydrogen and hydrogen-based fuels and feedstocks.
- Several large-scale projects for the production of low-emissions hydrogen for use in refining, chemicals production and steel manufacturing reached final investment decisions (FID) last year. The committed projects in these sectors could lead to a demand for 1.5 Mtpa of low-emissions hydrogen by 2030, 3 times more than today.
- There are contrasting trends in different transport subsectors. In road transport, the market is slowing down, with the focus shifting from cars to heavy-duty vehicles. In shipping and aviation, the use of hydrogen and hydrogen-based fuels is gaining interest, especially where policy support is in place, though slow market penetration has led to the cancellation of some ambitious projects for the supply of these fuels.
- In the power sector, progress is particularly strong in Japan and Korea, where companies are moving forward with several major demonstrations, and the governments have established the first auctions for hydrogen and ammonia-based electricity generation.

Overview and outlook

Global hydrogen demand continued to grow in 2023 to reach a new high of more than 97 Mt, a 2.5% increase compared with 2022 (Figure 2.1). Demand has been growing continuously for several decades, with the exception of 2020, when the Covid-19 pandemic led to an economic slowdown. We estimate that growth will continue in 2024 and global hydrogen demand could reach close to 100 Mt.

The regional distribution of demand remained largely unchanged from 2022: China was again the largest hydrogen user, accounting for nearly one-third of global demand (close to 28 Mt), more than double that of the second largest user, the United States, with 13 Mt (14% of global demand). Hydrogen demand grew modestly in all major regions, apart from in the Middle East, where growth was much steeper (more than 6% growth year-on-year, due to an increase in demand in refining and methanol production) and India (more than 5% growth year-on-year due to larger demand in refining and the steel sector).

Figure 2.1 Hydrogen demand by sector and by region, historical and in the Net Zero Emissions by 2050 Scenario, 2019-2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. "Other" includes buildings and biofuels upgrading. 2024e = estimate for 2024. The estimated value for 2024 is a projection based on trends observed until June 2024.

Hydrogen demand reached 97 Mt in 2023 but remained highly concentrated in traditional applications in industry and refining.

Hydrogen demand remains concentrated in traditional applications (Box 2.1), namely refining, the chemical sector (ammonia and methanol production) and steel manufacturing (to produce iron via the direct reduced iron [DRI] route using fossil-based synthesis gas). This demand is almost completely met with hydrogen produced from unabated fossil fuels. As in previous years, the growth in global hydrogen demand was not a result of policy support, but rather of global industry trends, and had no benefit in terms of mitigating climate change. On the contrary:

CO_2 emissions associated with hydrogen production and use increased to reach 920 Mt CO_2,[1] 1.5% more than in 2022 and equivalent to the annual emissions of Indonesia and France combined.

In the transition to a net zero emissions energy system, demand for hydrogen produced with unabated fossil fuels will need to be replaced with demand for low-emissions hydrogen. Furthermore, use of low-emissions hydrogen will also need to expand to new applications in sectors in which emissions are hard to abate, such as heavy industry, long-distance transport, the production of hydrogen-based fuels or electricity generation and storage. Uptake of hydrogen in these new applications grew nearly 40% in 2023 compared with 2022, although they still account for less than 1% of global demand (and less than 0.1% if excluding biofuels upgrading). In the Net Zero Emissions by 2050 Scenario (NZE Scenario), hydrogen demand reaches close to 150 Mtpa by 2030, 45% of which is low-emissions hydrogen. Almost 40% of global demand comes from new applications, meaning that demand in these new applications needs to grow more than 80-fold by 2030.

Box 2.1 Reporting hydrogen demand in the Global Hydrogen Review

In this report, demand includes hydrogen that has been intentionally produced for utilisation, including more than 75 Mt H_2 which is used as pure hydrogen in ammonia production and refining, and more than 20 Mt H_2 which is mixed with carbon-containing gases in methanol production and steel manufacturing. It excludes around 30 Mt H_2 which is present in residual gases from industrial processes (e.g. coke ovens and steam crackers), which is used for heat and electricity generation. This hydrogen is not deliberately produced for a specific application, rather its use is linked to the inherent presence of hydrogen in these residual streams. In addition, in this report we do not include estimations of historical use of small amounts of hydrogen in glassmaking, electronics and metal processing (which account for around 1 Mtpa).

Traditional and new applications for hydrogen

Beyond the existing applications for hydrogen in refining, the chemical industry, steel production, and other specialised applications, hydrogen can also be used in a wide range of new applications.

Hydrogen has not yet been used at scale in these applications, but decarbonisation efforts are expected to drive up hydrogen use in some of these new applications,

[1] Considering 0 kg CO_2/kg H_2 for hydrogen produced as a by-product in naphtha crackers and steam crackers. Considering a maximum of 10 kg CO_2/kg H_2 emissions would increase up to 1 070 Mt CO_2. This includes direct emissions from hydrogen production and close to 300 Mt of CO_2 utilised in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply.

particularly in sectors where emissions are hard to abate, and other low-emissions technologies are either unavailable or very difficult to implement.

Tracking total hydrogen use alone is not sufficient to assess progress on hydrogen adoption, and particularly whether it is happening in the direction and at the pace required for hydrogen to play its role in the clean energy transition. The use of hydrogen by application also needs to be tracked in order to assess uptake in new applications. For reporting purposes in the IEA's Global Hydrogen Review, we use two categories of applications for hydrogen:

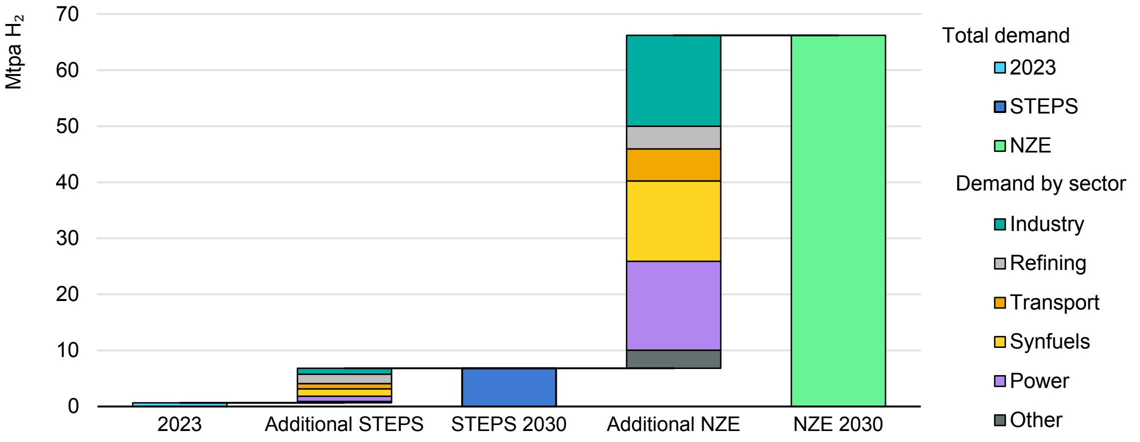
- Traditional applications, including refining; feedstock to produce ammonia, methanol and other chemicals; and as a reducing agent to produce DRI using fossil-based synthesis gas. This category also includes the use of hydrogen in electronics, glassmaking or metal processing, although these are not included in our tracking.
- Potential new applications, such as the use of hydrogen as a reducing agent in 100%-hydrogen DRI, long-distance transport, production of hydrogen-based fuels (such as ammonia or synthetic hydrocarbons), biofuels upgrading (e.g. hydrogenation of fats and oils), high-temperature heating in industry, and electricity storage and generation, as well as other applications in which hydrogen use is expected to be very small due to the existence of more efficient low-emissions alternatives.

Demand creation for low-emissions hydrogen

Demand for low-emissions hydrogen grew almost 10% in 2023 compared to 2022 but remains very low – accounting for less than 1% of global demand. Low-emissions hydrogen is more costly than hydrogen from unabated fossil fuels, which is preventing its adoption among most existing hydrogen users. This premium is also hindering its uptake in new applications in which low-emissions hydrogen could replace the direct use of fossil fuels. Without policy action that can help close the cost gap or stimulate market players to commit to using low-emissions hydrogen, demand will remain limited to small efforts from companies that have ambitious sustainability goals, or want to familiarise themselves with the technology through demonstration efforts before a larger market emerges.

Against this backdrop, demand-side policies are now starting to attract more attention (see Chapter 6. Policies), following several years in which governments have prioritised the supply side. With the current policy landscape, demand for low-emissions hydrogen could grow ten-fold by 2030, reaching more than 6 Mtpa. While this would represent significant progress compared with today, it is a far cry from the 65 Mtpa needed by 2030 in the NZE Scenario.

Figure 2.2 Low-emissions hydrogen demand by sector in 2023, and in the Stated Policies Scenario and the Net Zero Emissions by 2050 Scenario, 2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. STEPS = Stated Policies Scenario. "Other" includes buildings and biofuels upgrading.

Demand for low-emissions hydrogen could exceed 6 Mtpa by 2030 with current policy settings, but would need to reach 65 Mtpa, across many applications, to align with the NZE Scenario.

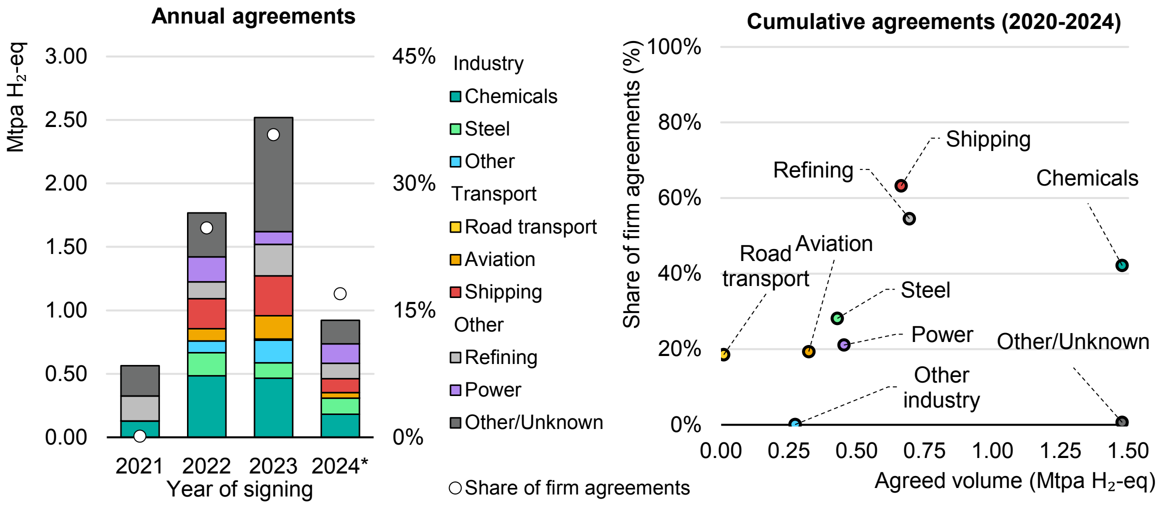
In the private sector, the number and size of offtake agreements between companies have grown in recent years.[2] These offtake agreements are crucial for helping to derisk investment in projects to produce low-emissions hydrogen. In 2023, companies signed agreements for more than 2 Mt of low-emissions hydrogen-equivalent per year (Mtpa H_2-eq),[3] of which nearly 40% is covered by firm agreements.[4] The largest share of agreements (35%) was related to hydrogen trade projects without a disclosed final application, although all these agreements are still at the preliminary stage. The second largest share was linked to the chemical sector, accounting for almost one-fifth of the total offtake agreed, and almost half of the agreements are firm. The chemical sector is today the sector with the largest historical offtake included in firm agreements: of the 1.7 Mtpa H_2-eq that have been included in firm offtake agreements across all sectors since 2021, nearly 0.6 Mtpa H_2-eq belong to the chemical sector. Notably, the NEOM project – the largest electrolysis project in the world currently under construction – can count on an offtake contract for its full production with Air Products. Other large projects in Canada and India that have very recently reached FID also have offtake agreements with the chemicals sector.

[2] This analysis excludes numerous small offtake agreements in the road transport sector, which altogether account for very small quantities at global level. As a reference, global demand for hydrogen in the transport sector in 2023 reached around 60 kt (see Transport), mostly produced from unabated fossil fuels.
[3] This includes agreements for offtake of hydrogen and hydrogen-based fuels.
[4] Firm agreements include contractual arrangements with binding conditions for both suppliers and offtakers, whereas preliminary agreements include other type of non-binding deals, such as MoUs.

The refining and shipping sectors, despite having agreed smaller quantities than the chemical sector, both have larger shares of firm agreements. This suggests that traditional applications for hydrogen (ammonia production, methanol production and refining) are the best-placed to adopt low-emissions hydrogen in the near term, since they present a lower technology risk than new applications.

Other sectors where there have been a significant number of offtake agreements are steel, electricity generation and aviation, with shares of firm agreements ranging from 20-30%. However, offtake agreements in these sectors are much more regionally concentrated. Most of the offtake agreements in power generation have offtakers concentrated in Japan and Korea, boosted by government plans to use hydrogen and ammonia to decarbonise power generation, although the suppliers are distributed across Australia, the Middle East, North America and Southeast Asia. In the case of steel, almost all offtake agreements (both on the supply and offtake sides) are between European companies, which have for many years spearheaded technology developments in the sector. Finally, in the case of aviation, offtakers are mostly from European companies, a trend that seems to have accelerated in response to the ReFuelEU Aviation mandates that entered into force in 2023, although suppliers include project developers in Europe and in North America.

Figure 2.3 Offtake agreements signed for low-emissions hydrogen and hydrogen-based fuels, 2021-2024



Notes: "Unknown" includes offtake agreements without a disclosed end use for hydrogen and hydrogen-based fuels. Only offtake agreements disclosing the amount agreed and stating that they will take place before 2030 have been included. 2024 data includes agreements until August. Announcements for hydrogen production and self-consumption are not included.

Sources: IEA analysis based on announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, BloombergNEF and S&P Global.

The number of offtake agreements for low-emissions hydrogen and hydrogen-based fuels is growing, with several large, firm agreements announced, albeit accounting for just 1.7 Mtpa.

The recent trend for calls for tenders is also a sign of action in the private sector: in the past year, six companies[5] have launched calls for tenders that together account for close to 1 Mtpa H_2 (Table 2.1). The largest tender was launched by TotalEnergies in September 2023, with the aim of decarbonising hydrogen used in its refining operations in Europe. The company recently reported that a large number of offers were received, though at a high average price of around EUR 8/kg H_2 (USD ~9/kg H_2).

Table 2.1 Tenders for procuring low-emissions hydrogen and hydrogen-based fuels launched since September 2023

Company	Sector	Tendered volume	Details and conditions
TotalEnergies	Refining	500 ktpa H_2	-
Salzgitter AG	Steel	Up to 141 ktpa H_2	Bidders must ensure that hydrogen complies with the EU regulations for Renewable Fuels of Non-Biological Origin or are “low-carbon” according to the EU Taxonomy. Deliveries to start from 2027.
thyssenkrupp Steel Europe AG	Steel	143 ktpa H_2	Three-phase process: request for information (February 2024), request for proposals (Q2 2024) and request for quotations (Q3 2024). 10-year contracts for hydrogen delivered from 2028 via pipeline to its Duisburg plant.
Solar Energy Corporation of India	Fertiliser	750 ktpa ammonia (NH_3) (~135 ktpa H_2)	10-year contracts, with 3 years of government subsidies. Ammonia delivered to 11 pre-selected fertiliser production sites in India.
Stahl-Holding-Saar	Steel	50 ktpa H_2	Hydrogen delivered via the MosaHYc pipeline from 2027.
National Highways	Construction	~1 ktpa H_2	Aims to buy 5.9 kt of low-emissions hydrogen over 5 years from 2027.

In addition to these initiatives, the private sector is also developing sectoral coalitions in which several companies join forces to aggregate demand for hydrogen-based fuels, thus distributing cost and risks among the members of coalition while sending larger demand signals that can facilitate scale-up on the supply side. In the aviation sector, efforts include the Sustainable Aviation Buyers Alliance and the Qantas Sustainable Aviation Fuel Coalition (see Aviation for more details). In the maritime sector, the Zero Emission Maritime Buyers Alliance (ZEMBA, launched by the Cargo Owners for Zero Emission Vessels platform in 2023) announced in April 2024 the successful completion of its first collective tender for zero-emissions shipping solutions. Although the winner of the first

[5] Two of the tenders were launched by state-owned companies: the Solar Energy Corporation of India and National Highways.

tender will use biomethane as shipping fuel, ZEMBA announced that subsequent tenders (the next is expected before the end of 2024) will focus on developing the market for hydrogen-based fuels. Also in shipping, in 2024 the Rocky Mountain Institute, the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping, the ZEMBA and Hapag-Lloyd are expected to launch a new pilot system for Maritime Book-and-Claim chain of custody. In the steel sector, in September 2023 RMI also launched a Sustainable Steel Buyers Platform to aggregate demand for low-emissions steel.

Box 2.2 Co-ordinated efforts to facilitate market development

The uncertainty surrounding demand for low-emissions hydrogen is a significant barrier to investment on the supply side. Similarly, offtakers face uncertainties about supplies being available when they plan to adopt low-emissions hydrogen. Furthermore, infrastructure developers require clear insights into potential flows of low-emissions hydrogen between producers and users in order to create viable deployment plans.

Co-ordination among stakeholders can mitigate these uncertainties by de-risking offtake for suppliers, improving visibility of supply for users, and facilitating planning for infrastructure developers. Such co-ordination can, in turn, stimulate investment flows and accelerate the adoption of low-emissions hydrogen.

To improve co-ordination, several stakeholders have launched match-making platforms that aim to facilitate market development in its early stages, connect producers with potential offtakers, assist infrastructure developers in planning, and enhance market transparency. Some platform developers also aim to facilitate price discovery.

The European Commission pioneered this effort in 2021 with the Important Projects of Common European Interest (IPCEI) Hydrogen Match-making Procedure, with the aim of connecting stakeholders for the preparation of proposals for the IPCEI Hydrogen application, although this platform only operated for a short period of time until the proposals for IPCEI were presented in 2022. The first platform to have operated continuously was the H2 Matchmaker tool of the US Department of Energy (DoE), launched in 2022. This tool helps “clean” hydrogen producers, end users and other stakeholders across the hydrogen value chain – including infrastructure developers; manufacturers; Engineering, Procurement and Construction companies; and researchers – find potential partners to build networks and develop comprehensive supply chain projects for low-emissions hydrogen production and use. The platform is now integrated with the Regional Clean Hydrogen Hubs Program, enabling stakeholders to share detailed information about their activities, forecasts and project descriptions.

In the European Union, under the decarbonised gases and hydrogen package approved in April 2024, the European Commission has created a pilot mechanism to collect, process and provide access to information on the demand and supply of low-emissions hydrogen and its derivatives. This allows European offtakers to match with both European and non-European suppliers. It is expected to be operational from mid-2025, and to run for 5 years as part of the European Hydrogen Bank.

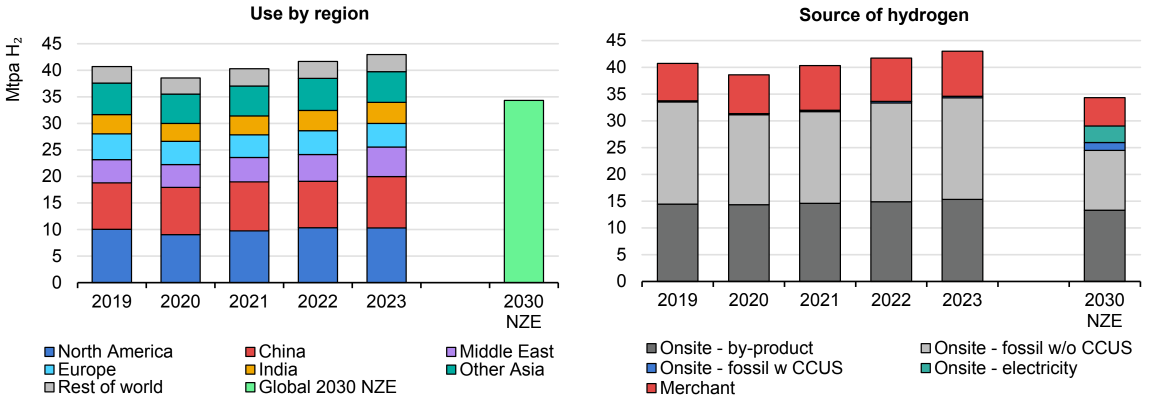
Some European Gas Transmission System Operators have also launched their own platforms. For example, Gasunie introduced its Match & Connect service in May 2023, which helps market parties connect with potential customers, producers, or shippers of hydrogen via an online platform. Fluxys launched a request for information to collect data on potential hydrogen producers and demand in Belgium, informing its infrastructure planning. Unlike Gasunie, which does not play an active role in matching market parties, Fluxys is currently facilitating regional mutual exchanges among companies that participated in the request for information process, specifically in Antwerp, Ghent, Hainaut, Liège and Limbourg.

At the international level, the Clean Hydrogen Mission has also launched a match-making tool as part of its Hydrogen Valleys platform, to help stakeholders to connect with the hydrogen valleys featured. Also noteworthy are the activities of Hintco, a subsidiary of the H2Global Foundation. While Hintco is not a match-making platform, it aims to improve market transparency by publishing information from the results of the H2Global mechanism auctions. This includes details on the companies that will be selling the hydrogen and hydrogen-based fuels, prices, and locations for production and delivery, as well as information on the companies that will buy the products, and at what price.

Refining

Hydrogen demand in refining reached 43 Mt in 2023, over 1 Mt more than the previous record from 2022. Growth in demand has been concentrated in China (+0.9 Mt) and the Middle East (+0.5 Mt), whereas demand in all the other major regions remained largely similar to 2022. Demand growth in China was a consequence of the turnaround in government policy with regards to restricting exports, and the lifting of pandemic-related measures, which led to record demand and record high refinery runs at the start of the year. However, the United States still accounts for the largest share of demand and is still expected to process more crude than China through 2024, before being overtaken.

Figure 2.4 Hydrogen use by region and source of hydrogen for refining, historical and in the Net Zero Emissions by 2050 Scenario, 2019-2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; Fossil w CCUS = fossil fuels with carbon capture, utilisation and storage. “Onsite” refers to the production of hydrogen inside refineries, including dedicated captive production and as a by-product of catalytic reformers.

Hydrogen demand in refining reached another record high in 2023, but this trend is expected to reverse soon thanks to measures that could affect demand for oil products.

As in previous years, hydrogen demand in refineries was mostly met by onsite production from unabated fossil fuels (45%) and by-production from different operations (more than 35%), such as naphtha catalytic reforming. The remainder (close to 20%) was externally sourced as merchant hydrogen,[6] and mostly produced from unabated fossil fuels.

Although demand growth for refined oil products (and therefore for hydrogen in refining) is expected to slow down in the near future, it is not expected to fall enough to get on track with the NZE Scenario, in which global demand for hydrogen in refining drops to under 35 Mt by 2030.

At the same time, the adoption of low-emissions hydrogen in refining is expected to accelerate. In 2023, demand for low-emissions hydrogen in refining reached almost 250 kt, just 4% more than in 2022. Practically all this growth came from the ramp-up of the Yanchang Integrated Carbon Capture and Storage Demonstration project (which entered into operation in mid-2022) and Sinopec’s Kuqa facility (which started partial operation in 2023), both in China. The Kuqa project is today the largest operational electrolysis plant (260 MW), but it has been experiencing operational challenges related to lower-than-expected efficiencies of the electrolysers supplied, and issues with their ability to handle power fluctuations

[6] Merchant hydrogen refers to hydrogen that is purchased from external producers who then deliver hydrogen to the end users, normally by trucking or using regional, privately owned hydrogen networks. In the case of refineries, merchant hydrogen is typically produced in plants very close to the refinery, and sometimes even in the same location, but in plants operated by another company, given that hydrogen is not a global commodity today.

from the renewable electricity generation assets.[7] This has limited its production, and it is not expected to operate at full capacity until 2025. Elsewhere, since the start of 2024, one 10 MW electrolysis (able to produce around 1.5 ktpa H_2) project has started operation, in Hungary, and some others currently under construction are expected to become operational before the end of the year. However, these additions are not expected to have a significant impact on the use of low-emissions hydrogen in refineries this year, with demand potentially reaching 260 kt. At the time of writing, projects for low-emissions hydrogen for refineries accounting for a total production of more than 220 ktpa have already reached FID or are currently under construction. Since the Global Hydrogen Review 2023 (GHR 2023), a handful of large projects for the production of low-emissions hydrogen for refineries have reached FID:

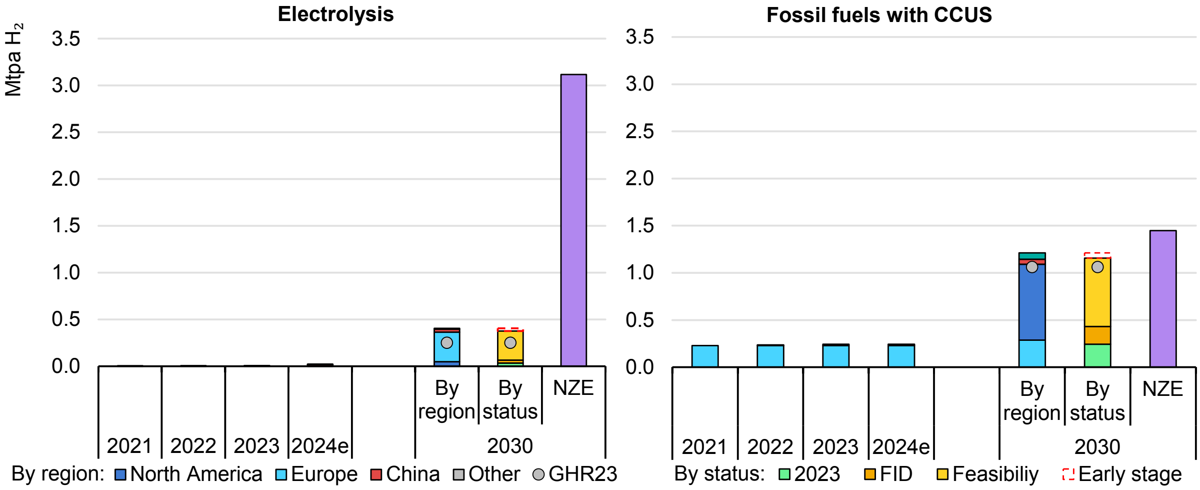
- Two 100 MW electrolysis projects, one from GALP at the Sines refinery (Portugal) and another from Shell at its refinery in Rheinland (Germany), each able to produce up to 15 ktpa of renewable hydrogen.
- The first phase of BP's HyVal project at Castellon (Spain), with a capacity of 25 MW (able to produce close to 4 ktpa H_2). This could be extended up to 2 GW in the future.
- Two projects, one from Air Liquide and one from Air Products, for the production of around 100 kt of hydrogen from natural gas with CCUS (both retrofitting existing hydrogen production units) linked to the Porthos carbon capture and storage (CCS) project in Rotterdam.
- Shell's Polaris project, with an undisclosed hydrogen production capacity, which will capture 650 kt of CO_2 from the Scotford refinery and chemicals complex (Canada).

If all the announced projects for the production of low-emissions hydrogen for use in refineries are realised on time (according to their original development plans), 1.6 Mtpa of low-emissions hydrogen could be used in refining activities by 2030 (close to 1.5 Mtpa if projects at very early stages of development are excluded). This would meet around one-quarter of the need in the NZE Scenario. Europe dominates the pipeline of announced projects, followed by North America. The majority of projects have not yet reached FID, but the adoption of targets for the use of renewable hydrogen in the EU Renewable Energy Directive (which are now in the process of being transposed to national legislation), is expected to bring about more FIDs in the region in the near future. For example, the Dutch government is working on a scheme to award tradable certificates to fuel suppliers that adopt hydrogen that complies with the renewable fuels of non-biological origin (RFNBO) regulation in refineries from 2026. Elsewhere, India has also taken first steps towards adopting low-emissions hydrogen in refining, with state-owned oil

[7] China's World-Leading Green Hydrogen Project Faces Slow Ramp Up, Bloomberg New Energy Finance, 3 January 2024; Green Hydrogen Production Technology Faces a Reality Test, Bloomberg New Energy Finance, 17 January 2024.

companies having opened tenders to build, own and operate low-emissions hydrogen production in plants in the Panipat and Numaligarh refineries.

Figure 2.5 Onsite production of low-emissions hydrogen for refining by technology, region and status, historical and from announced projects, compared to the Net Zero Emissions by 2050 Scenario, 2021-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; GHR 2023 = Global Hydrogen Review 2023; NZE = Net Zero Emissions by 2050 Scenario. 2024 values are estimates considering projects that have at least taken FID and are expected to be operational during 2024. Only planned projects with a disclosed start year of operation are included. FID includes projects that are operational, under construction or that have reached FID. GHR 2023 shows the estimated production of low-emissions hydrogen from projects that were included in the IEA Hydrogen Production Projects Database as of August 2023.
Source: IEA Hydrogen Production Projects Database (October 2024).

Based on announced projects, 1.6 Mtpa of low-emissions hydrogen could be produced in refineries by 2030, an amount that is little changed from last year.

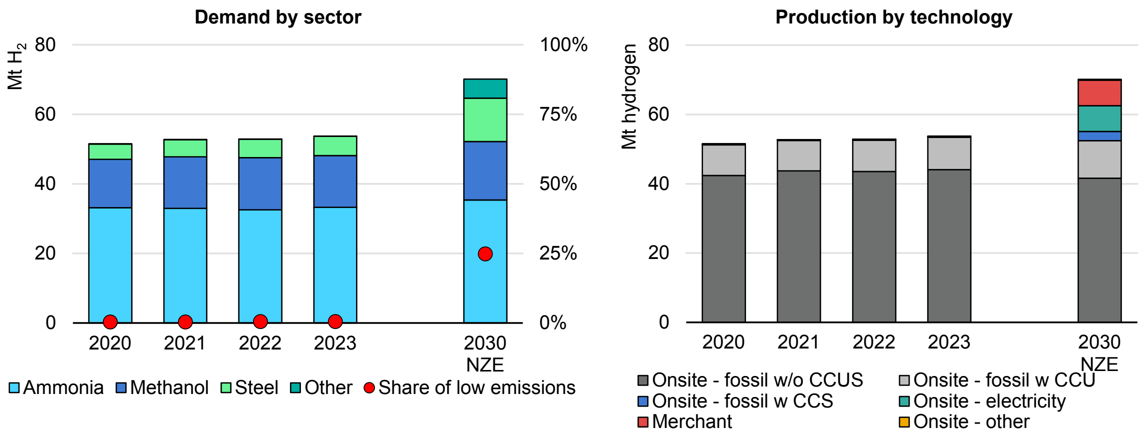
In addition to traditional oil refineries, biorefineries are attracting growing interest due to the decarbonisation potential of biofuels. Some projects under development are already considering the use of low-emissions hydrogen for upgrading these biofuels. Two plants, one in Canada (using renewable hydrogen) and one in France (using hydrogen from fossil fuels with CCUS), are expected to start operating in 2025-2026. In addition, in May 2024, OMV Petrom took an FID on a facility for the production of hydrotreated vegetable oils in its Petrobrazi refinery (Romania), which includes a 55 MW electrolysis plant to be operational from 2028. If all announced projects are realised according to their original development plants, close to 500 ktpa of low-emissions hydrogen could be used in the production of biofuels by 2030.

Finally, hydrogen and hydrogen-based fuels can also play a role in reducing emissions from high-temperature processes in refineries. Essar has completed the installation of a first-of-a-kind furnace able to operate with pure hydrogen in its Stanlow refinery (United Kingdom), although it will operate with natural gas until low-emissions hydrogen from the HyNet project can be supplied (expected in 2027). In addition, in March 2024, Idemitsu demonstrated for the first time the use of ammonia as a combustion fuel in a commercial naphtha cracking furnace at its Tokuyama complex (Japan), displacing 20% of fossil fuel consumption in the furnace.

Industry

Global hydrogen demand in industry reached 54 Mt in 2023, an increase of almost 2% year-on-year. About 60% of this demand was for ammonia production, 30% for methanol and 10% for DRI in the iron and steel subsector – the same sectoral distribution as in previous years (Figure 2.6). The majority of hydrogen used in industry is produced from unabated fossil fuels in the same facilities where it is later used. Carbon capture is a common practice in some industry subsectors, although most of the 140 Mtpa of CO_2 captured is used for other industrial applications (such as urea production) and ends up being released, with only a handful of projects storing CO_2 underground. As a result, hydrogen production in industry was responsible for around 680 Mt of direct CO_2 emissions in 2023, up 0.6% from 2022, approximately equal to the total CO_2 emissions of Türkiye.

Figure 2.6 Hydrogen use in industry by subsector and source of hydrogen, historical and in the Net Zero Emissions by 2050 Scenario, 2020-2030



Notes: Fossil w CCS = fossil fuels with carbon capture and storage; Fossil w CCU = fossil fuels with carbon capture and use; Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; NZE = Net Zero Emissions by 2050 Scenario. Ammonia and methanol exclude fuel applications. 'Other' includes dedicated hydrogen production for high-temperature heat applications.

Source: IEA analysis based on data from Argus Media Group, International Fertilizer Association, World Steel Association.

Hydrogen use in industry increased in 2023 to reach 54 Mt, mostly in ammonia, methanol and steel production.

The increase in global hydrogen demand in industry was mainly driven by use in ammonia production, with global demand rising by 2.2%, and by DRI, with 4.8% growth. China remains the main consumer of hydrogen in industrial applications, accounting for 34% of global industrial use, followed by the Middle East (15%), North America (10%), India (9%) and Europe (6%).

The Middle East is currently seeing some of the fastest growth in demand in industry, with a 4% increase in 2023. This is mainly driven by methanol production (up 8% in 2023), especially in Iran (+20%), which is investing in methanol production to satisfy the needs of the chemical industry and the transportation sector. Two projects are due to start production by the end of 2024, Dena Petrochemical and Siraf Energy, each adding 1.6 Mt of capacity. On the basis of projects that are relatively committed and those already in construction, Iran could add a further 5 Mt of fossil-based methanol production capacity in the next 5 years – accounting for a large share of global production, which currently stands at around 115 Mt.

In Europe, the 10% growth in hydrogen demand in industry in 2023 must be seen in the context of a 30% fall in demand in 2022, when ammonia production dropped by one-third as a result of the energy crisis triggered by Russia's invasion of Ukraine. Ammonia production picked up in 2023 as energy prices stabilised, growing by 10%, but remains far below pre-invasion levels. As a result, Europe's hydrogen demand in industry in 2023 was 25% lower than in 2021.

In the NZE Scenario, hydrogen use in industry grows to 70 Mtpa by 2030. Meeting this need would require close to a 4% annual increase in production, compared to just 1.3% over the past 4 years. Furthermore, about one-quarter of industrial hydrogen demand needs to be satisfied by low-emissions hydrogen by 2030, which would require most new capacity additions to be low-emissions, as well as retrofits to some existing stock. Beyond traditional applications in the chemical and steel sectors, hydrogen use also increases in new industrial applications. For example, by 2030 in the NZE Scenario, hydrogen DRI and high-temperature heating together account for around 15% of global hydrogen demand in industry.

Low-emissions hydrogen production in industrial plants in 2023 was about 280 kt, almost the same level as in 2022. More than 90% of this capacity relies on fossil fuels with CCUS, with installations spread across North America, the Middle East and China. In 2024, production is expected to grow to 370 kt on the basis of planned capacity additions. There has been relatively significant progress in the production of hydrogen from electrolysis since the publication of the GHR 2023, with over 1 GW of electrolyser capacity likely to commence production in 2024. As much as two-thirds of this capacity is in China, and of this, more than 90% is for the production of ammonia. Outside of China, Yara's Porsgrunn plant (Norway), CF's Donaldsonville plant (United States) and the Unigel project (Brazil) are the largest projects producing low-emissions hydrogen coming online in 2024.

The near-term outlook for low-emissions hydrogen production in industry continues to improve: Together, projects already under construction or which have taken an FID would be able to produce more than 750 ktpa by 2030. The vast majority are concentrated in China and Europe (with around 45% and 30% respectively). In addition, there has been an increase in projects for methanol production, particularly in China, though it is likely that this is for use as an alternative fuel (for example in shipping) rather than for industrial use. Nevertheless, despite this improving outlook, some projects planning to produce DRI using low-emissions hydrogen are reporting that availability of hydrogen is limited, and that support to improve affordability is insufficient, which might delay their planned switch to using 100% hydrogen.

The most noteworthy developments since the release of the GHR 2023 are:

- AM Green took FID for a 1.3 GW electrolysis project (India) able to produce around 1 Mtpa of ammonia for manufacturing nitrogen fertilisers. This project has been certified by CertifHy to be compliant with the EU regulation for RFNBOs.
- Shanghai Electric - Taonan Wind Power with Biomass for Green Methanol[8] (China) started construction of its plant to produce 250 kt of methanol per year using electrolytic hydrogen.
- The Hy4Chem-EI project (Germany) is beginning construction of a 54 MW electrolysis project, with an estimated production capacity of around 8 ktpa H_2 for the chemicals industry.
- Yara's green fertiliser project at Porsgrunn, Herøya (Norway) began operations in May 2024, using a 24 MW electrolyser to produce hydrogen for use in ammonia production.
- Project Oshivela (Namibia) began construction in late 2023 and is expected to come online from Q4 2024. The project initially aims to produce 15 kt of DRI per year using hydrogen from a 12 MW electrolyser (with an estimated production capacity of up to 2 ktpa H_2), with future scale-up to 1 Mtpa of DRI capacity. This is one of the first African projects aiming to use low-emissions hydrogen to have moved beyond feasibility studies.
- The Hygenco JSL plant opened in early 2024 and is India's first steel plant using hydrogen from electrolysis and renewable electricity for the annealing process.

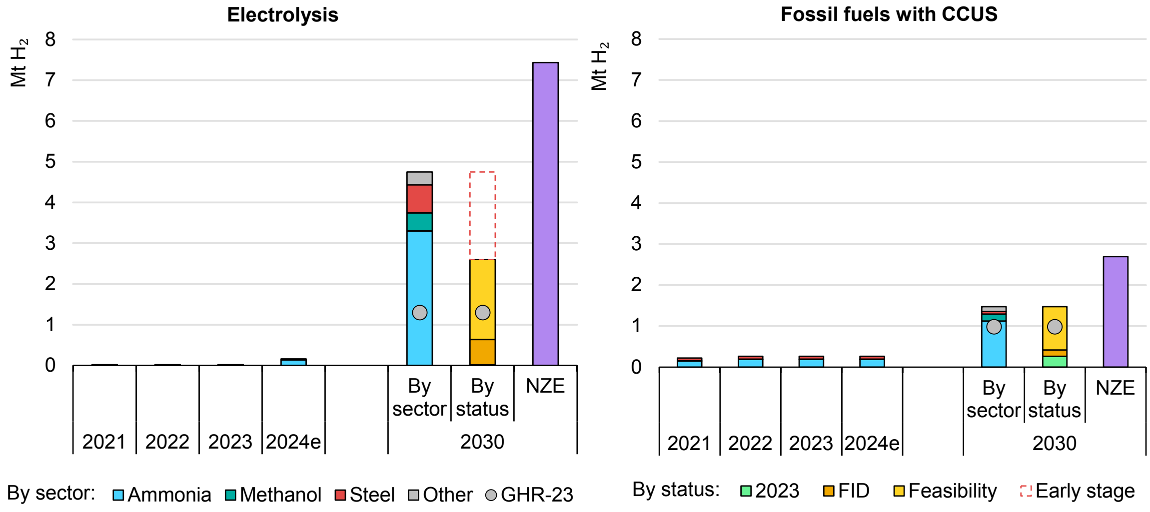
Many additional projects have been announced in the past year. If all projects come to fruition, low-emissions hydrogen production from fossil fuels with CCUS could reach 1.5 Mtpa by 2030, and production from electrolysis could reach 4.8 Mtpa by 2030 (2.6 Mtpa if projects at very early stages of development are

[8] 4 green methanol production projects began construction this year in China, China Hydrogen Bulletin, 29 April 2024.

excluded) (Figure 2.7). This is a noteworthy increase, but this growth is occurring from a very low base, and the combined 6.2 Mt of low-emissions hydrogen represents only 60% of what is required under the NZE Scenario. Some of the newly announced projects include:

- FertigHy's first plant (France), which aims to produce 500 ktpa of nitrogen-based fertilisers from electrolytic hydrogen.
- The Cormorant Clean Energy Project (United States), which will capture 1.4 Mtpa CO_2 from ammonia production.
- Waaree Odisha (India), which plans to produce 1.2 Mtpa of ammonia based on renewable hydrogen.
- Zijin Mining Renewable energy project (Serbia), which aims to produce 30 ktpa of hydrogen for use at a copper mine and smelter.

Figure 2.7 Onsite production of low-emissions hydrogen for industry applications by technology and status, historical and from announced projects, 2021-2030



Notes: GHR-23 = Global Hydrogen Review 2023; FID = Final investment decision; NZE = Net Zero Emissions by 2050 Scenario. 2024e values are estimates considering projects that have at least taken FID and are expected to be operational during 2024.
Source: IEA Hydrogen Production Projects (October 2024).

Announced projects for the onsite production of low-emissions hydrogen in industry can reach 6.2 Mtpa by 2030, meeting 60% of needs in the NZE Scenario.

Nonetheless, to align with the NZE Scenario, the onsite production of low-emissions hydrogen from electrolysis using renewable electricity, and from fossil fuels with CCUS in the industry sector, needs to reach 7.4 Mtpa and 2.7 Mtpa of hydrogen, respectively, nearly double the production potential of the current project pipeline (and almost tripling it if projects at very early stages of development are excluded).

In addition to hydrogen produced onsite in industrial facilities, a significant number of projects aim to produce merchant hydrogen for delivery to industrial consumers. Merchant hydrogen projects can have certain advantages, such as producers partnering with multiple industrial clients to spread risk, but transport infrastructure is required. We estimate that these projects could supply an additional 0.8 Mtpa of hydrogen to industrial consumers by 2030 (0.7 Mt if projects at very early stages of development are excluded). Some key merchant hydrogen projects that have been announced are the Baytown project (United States), Sinopec's Ordos development (China), Project Catalina (Spain), the HyDeal project (Spain) and the Actis-Fortescue project (Oman). However, the realisation of these projects depends on their ability to secure offtakers for all their potential production (which in turn depends on their ability to reduce current production costs), and on the prospects for new or reused infrastructure to transport hydrogen to end users. These challenges have already led some of these projects to revise their originally announced plans.

Use of hydrogen for heating applications in industry

Putting the world on a pathway consistent with net zero emissions by 2050 will require new technologies that are still at the R&D phase today, such as for the use of hydrogen for high-temperature heating in industry, which is currently being investigated across new use cases in R&D projects. Notably, several projects have recently been started (Table 2.2) with the aim of demonstrating the use of hydrogen in specialised process heating equipment and extending existing experience to industries outside of the chemical and steel sectors that are not used to working with hydrogen.

Table 2.2 Selected applications of hydrogen and hydrogen-based fuels in industry and associated research and demonstration projects

Application	Research and demonstration projects
Hydrogen in industrial Boilers	While hydrogen has been used in industrial boilers for many years, this has generally been in specialised industries with significant experience using and handling hydrogen, like the chlor-alkali industry. Projects are ongoing in the food and drink industry, such as WhiskHy in Scotland, and in the paper industry, such as KCA in Australia.
Ammonia in industrial boilers	Ammonia, a key hydrogen derivative and hydrogen carrier, could provide heat to low-temperature heating in industrial boilers in place of natural gas. The UK-based "Amburn" project aims to demonstrate a megawatt scale ammonia-fed steam boiler system at a customer site.

Application	Research and demonstration projects
Hydrogen in alumina calcination	Natural gas could be replaced with hydrogen as a fuel for the high-temperature calcination process in alumina refining. In 2023 an AUD 111.1 million (Australian dollars) demonstration project was funded by Australian Renewable Energy Agency, using a 2.5 MW onsite electrolyser and retrofitting one of the calciners in a refinery to use a hydrogen burner.
Hydrogen in glass furnaces	Hydrogen could be used in glass furnaces, potentially in combination with electricity and other fuel sources. In Germany, Saint-Gobain is using hydrogen to replace more than 30% of the fossil fuels used in flat glass production. Ardagh Group is also replacing 20% of the natural gas with hydrogen for the production of some glass bottles, and Schott has recently produced optical glass using 100% hydrogen.
Blended firing of hydrogen in direct fired equipment	Hydrogen is already used in some cases as an additive to enhance combustion properties, and could be used as part of a low-emissions fuel mix in many sectors. For example, trials in the United Kingdom have investigated hydrogen as a partial replacement for fossil fuels in cement kilns and asphalt production.
100% firing of hydrogen in direct fired equipment	Hydrogen is also being tested as a "full" replacement fuel in some pieces of equipment, in some cases using oxyfuel combustion technology. In 2023, Tokyo Gas and building materials manufacturer Lixil tested hydrogen instead of natural gas for the heat treatment of aluminium products. Findings suggested there was no effect on the quality of aluminium products. In Europe, the HyTecHeat, HyINHeat and H2Glass projects that started in 2023 are looking to develop hydrogen-fired high-temperature furnaces, and in the United States an aluminium casting and rolling facility is planning to test hydrogen firing.

Transport

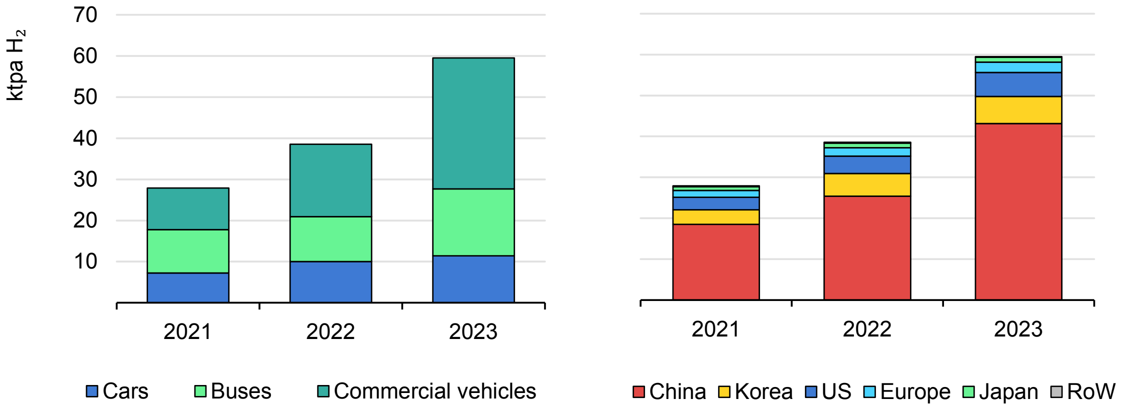
Road transport

The use of hydrogen as a means of decarbonising[9] road transport continues to expand, increasing more quickly in 2023 (by around 55%) than in 2022 (around 40%)[10] due, in particular, to growth in heavy fuel cell trucks and buses in China. In spite of this, hydrogen demand in road transport reached just 60 kt in 2023 (less than 0.1% of global demand).

[9] For decarbonisation, the hydrogen used must be low-emissions, although today hydrogen demand in transport is met with a variety of sources, including unabated fossil fuels.

[10] The estimate of year-on-year hydrogen demand growth shown in the GHR 2023 (45%) has been revised due to adjustments to historic values for average fuel efficiency and mileage.

Figure 2.8 Hydrogen consumption in road transport by vehicle segment and region, 2021-2023



Notes: RoW = Rest of World; US = United States. Commercial vehicles include light commercial vehicles and medium- and heavy-duty trucks. Assumptions on annual mileage and fuel economy come from the IEA Global Energy and Climate Model.

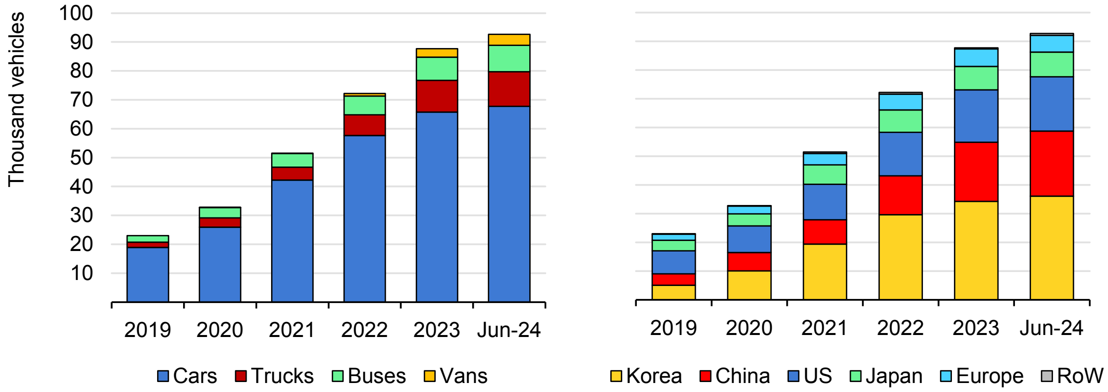
Hydrogen use in road transport increased by around 55% in 2023, with heavy-duty vehicles accounting for almost 85% of this growth.

In China, fuel cell electric vehicle (FCEV) deployment has focused on heavy-duty vehicles, which have relatively high mileages, meaning that in 2023, consumption of hydrogen for road transport grew almost twice as fast as in the United States, and over three times as fast as in Europe. In Korea and Japan, the light-duty vehicle segment continues to be a focus for FCEVs, although growth in this segment is slowing down, and hydrogen use in road transport in these countries reached only around 7 kt combined in 2023.

Growth in fuel cell passenger car stock slowed significantly in the past year, falling from more than 35% in 2022 to just under 15% in 2023, with slow sales continuing into the first half of 2024. In contrast, healthier sales in fuel cell buses and trucks increased the stock by 25% and more than 50%, respectively, between 2022 and 2023. The total stock of FCEVs across all road modes, as of the end of June 2024, stands at around 93 000.[11]

[11] For comparison, there were over 40 million battery electric and plug-in hybrid electric vehicles (excluding two- and three-wheelers) at the end of 2023, as described in the Global Electric Vehicle Outlook 2024.

Figure 2.9 Fuel cell electric vehicle stock by segment and region, 2019-2024



Notes: RoW = Rest of World; US = United States. Commercial vehicles include light commercial vehicles (LCV), medium freight trucks and heavy freight trucks. Includes data until June 2024.

Sources: IEA analysis based on data from Advanced Fuel Cells Technology Collaboration Programme; Hydrogen Fuel Cell Partnership; Korea, Ministry of Land, Infrastructure, and Transport; International Partnership for Hydrogen and Fuel Cells in the Economy; and Clean Energy Ministerial Hydrogen Initiative country surveys.

Growth in FCEVs was strongest in the truck segment for the second year in a row.

Cars and vans

Korea, the United States[12] and Japan continue to lead deployment of fuel cell cars, with over 50%, more than 25%, and over 10%, respectively, of the global stock. However, sales have slowed across all regions, and global stock increased by just 15% between 2022 and 2023,[13] and by less than 5% from the end of 2023 to June 2024.

Despite this slowdown, Honda have released a fuel cell version of their best-selling CR-V in California, competing with the Toyota Mirai and Hyundai Nexo. In China, sales of passenger cars are increasing, with sales of the Maxus Euniq 7 and Hongqi H5 reaching over 500 and 150 units, respectively, though China remains unusual in that the car segment makes up the smallest share of the hydrogen fleet. BMW has been piloting their fuel cell car prototype in Japan, the United States and Europe, and is planning to begin mass producing fuel cell cars in 2028.

The taxi business continues to be an interesting use case, given the advantages of faster refuelling and longer ranges compared to battery electric vehicles, with the French FCEV taxi operator Hype expanding into Brussels. These advantages are also seen as having strong potential for decarbonising the delivery business.

Interest from original equipment manufacturers (OEMs) in the van segment was also seen with Stellantis reaffirming their commitment to produce fuel cell vans in

[12] Fuel cell electric vehicles in the United States are concentrated in the state of California.
[13] For comparison, the stock of electric cars and vans increased by around 50% from 2022 to 2023.

Europe, while Sweden is now offering subsidies for fuel cell vans. The number of fuel cell vans on Chinese roads is over four times that of cars, and accounts for over 90% of the global total, further demonstrating the focus on commercial vehicles. Nevertheless, fuel cell vans made up less than 0.5% of the combined sales and just 0.2% of the combined stock of plug-in hybrid, battery electric, and fuel cell vans globally in 2023.

Trucks

Trucks are the fastest-growing sector for fuel cell vehicles, with the stock increasing by over 50% in 2023, more than twice as fast as buses, and three times faster than cars. As of June 2024, the global stock stands at more than 12 000, but – as in 2022 – around 95% of these are in China. Nevertheless, this should not hide the substantial growth seen in both the United States and Europe, albeit from a lower base. By the end of 2022 there were around 135 fuel cell trucks in Europe, but that had increased to around 350 as of June 2024. In the United States, over the same period, fuel cell trucks increased from just 10 to around 170. The share of trucks in the global FCEV fleet has therefore risen from less than 9% in 2021 to almost 13% as of June 2024.

Commercial trials to prove the technology and gather data on performance in different use cases are being undertaken around the world, including in the United Kingdom, New Zealand and Saudi Arabia. There have also been new commitments to the technology in the United States, for example through orders for Nikola's fuel cell truck, which officially entered the market last year, with 35 units delivered in 2023. An order has been placed for a further 100 trucks in 2025, contributing to the growing hydrogen hub at the Port of Los Angeles, as well as another 50 trucks ordered by a haulier that deemed battery electric trucks insufficient for their needs after an almost 2-year-long trial. Despite this positive news, Nikola still faces considerable headwinds, having incurred losses of almost USD 1 billion in 2023. Another fuel cell truck maker from the United States, Hyzon, have halted their operations in Europe and Australia, in part due to having accumulated losses of over USD 275 million. This decision can, at least in part, be attributed to lower-than-expected demand following the cancellation of purchase announcements, such as by Glasgow City Council (United Kingdom).

Innovations to fuel cell trucking are still being made, such as through a hydrogen-electric hybrid system in which the fuel cell acts as a range extender, thereby making the powertrain technology suitable for a larger share of duty cycles. Elsewhere, Daimler and Linde have jointly developed a novel liquefied hydrogen refuelling process aimed at providing ranges of more than 1 000 km,[14] which is now being deployed in Germany. The two companies also aim to support the

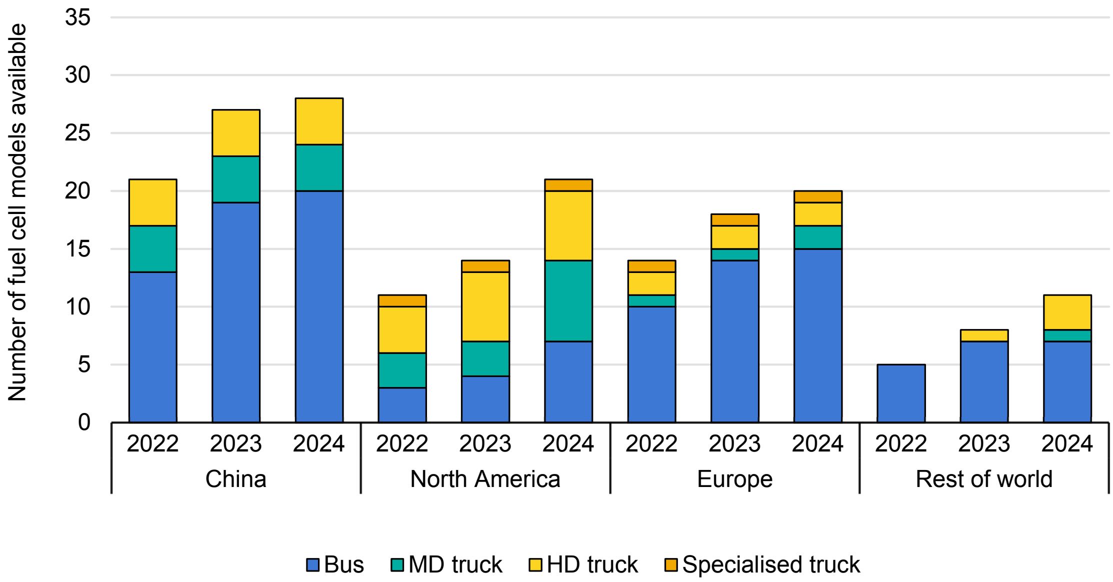
[14] The average range of fuel cell heavy-duty trucks in the Global Drive to Zero ZETI tool database is around 600 km.

establishment of a common refuelling standard for liquid refuelling, to enable commercial use of the technology. The use of hydrogen combustion engines in trucks may also support emissions reductions compared to conventional diesel trucks. MAN is due to launch such trucks in 2025, and Volvo Trucks will begin testing in 2026. This technology may have a particular role to play in the medium term, while fuel cells continue to face challenges such as high costs, lower durability in difficult operating conditions,[15] and uncertainty around the availability of skilled technicians and spare parts.

Model availability is an important factor in increasing deployment of fuel cell trucks, particularly in the short to medium term, so as to offer customers choice and options suited to their needs, and model options are expanding around the world (Figure 2.10). However, given that China has the highest sales of trucks, but a smaller number of models available than North America, it is also clear that policy – and not just model availability – is influencing uptake. Europe has fewer models available than North America or China, though new additions are being announced, such as by Symbio (expected in late 2024). Partnerships between Honda and Isuzu, and Quantron and Ford, are also expected to add to model availability in the coming years. Retrofitting of existing trucks, where the diesel engine is replaced with an electric fuel cell powertrain, can also increase vehicle availability. H2X Global, who specialise in retrofitting, have announced the development of both a smaller 3.5 t truck as well as trucks in the range of 16 t to 44 t in 2024.

[15] Internal combustion engines are more tolerant of environmental contaminants such as dust, can operate with lower fuel purity, and withstand operational vibration better than the fuel cell powertrains currently available.

Figure 2.10 Fuel cell electric vehicle models by original equipment manufacturer headquarters, type of vehicle, and release date, 2022-2024



Notes: MD = medium-duty; HD = heavy-duty. This figure is based on a continuously updated inventory and may not be fully comprehensive due to new model announcements and small manufacturers not yet captured in the database. Values for 2022 include models released between 2016 and 2022 inclusive. The database contains coaches, school buses, shuttle buses, and transit buses, categorised here as "Bus", which refers to those with more than 25 seats. "MD truck" includes medium-duty (MD) trucks, MD step vans, and cargo vans with a gross vehicle weight (GVW) of greater than 3.5 t but less than 15 t. "HD truck" includes all freight trucks with a GVW of greater than 15 t. "Specialised truck" includes garbage trucks, concrete mixers, and other specialised mobile commercial trucks. Buses with 25 seats or fewer and light commercial vehicles, which have a GVW of less than 3.5 t, are excluded from this analysis. Vehicles of the same model that appear more than once in the database, but with small variations in specifications, such as power, payload or seating, are counted as one model.
Source: IEA analysis based on the Global Drive to Zero ZETI tool database.

North American producers offer the widest range of trucks, while Chinese manufacturers lead in the bus sector, with Europe lagging behind in terms of heavy-duty fuel cell vehicle offering.

Buses

Fuel cell bus stock increased by almost 25% in 2023 compared to 2022. China again accounted for the majority of new additions, deploying over 75% of the more than 1 500 fuel cell buses added in 2023, thereby constituting a similar share of the global stock of more than 9 100 fuel cell buses as of June 2024. In terms of year-on-year stock growth, Europe and Japan have similar rates to China, between 20% and 25%, while Korea experienced an annual growth rate of 130%.

Similarly to trucks, fuel cell buses continue to be trialled, often alongside battery electric models. Many European cities have taken delivery of or placed orders for fuel cell buses, such as Barcelona (Spain), Bologna (Italy), Cottbus and Oberberg (Germany), Paris (France) and Wałbrzych (Poland). Several German cities that already have fuel cell buses in operation, such as Frankfurt and Cologne, among others, have opted to expand their fleets. In Duisburg (Germany), a previous decision to use battery electric was reversed in favour of fuel cell buses, with cost being cited as a deciding factor. The city of Cheonan, Korea, will deploy 350 fuel cell buses and the necessary refuelling infrastructure by 2027, through a partnership with SK E&S, expanding on the Incheon fleet announced last year. Both will be supplied by SK E&S's plant which liquefies by-product hydrogen for use in transport. However, there have also been several high-profile incidences of cities ending trials or retiring existing fleets, citing issues of reliability and cost. Examples include Montpellier and Pau in France, Carinthia in Austria, and Wiesbaden in Germany.

Key to the increasing sales of fuel cell buses is sufficient availability. In Europe, companies such as Solaris and Wrightbus are expanding production. In Korea, Hyundai has expanded its capacity from 500 to 3 000 units per year in order to keep pace with deployment. In North America, NFI Group are signing fuel cell supply agreements to capitalise on emerging demand. However, by far the largest range of models (and variations thereof) are being produced by a relatively small number of Chinese OEMs, in order to supply both their large domestic market and growing overseas markets, such as Australia. Hydrogen retrofits also have a role to play, as demonstrated by Green Corp, who are installing their technology in 50 coaches in France, in a segment often deemed difficult to electrify. Finally, the continued introduction of hydrogen range extenders for buses can enable the decarbonisation of routes currently deemed unsuitable for battery electric buses, and demonstrates the potential to combine the two technologies.

Hydrogen refuelling stations

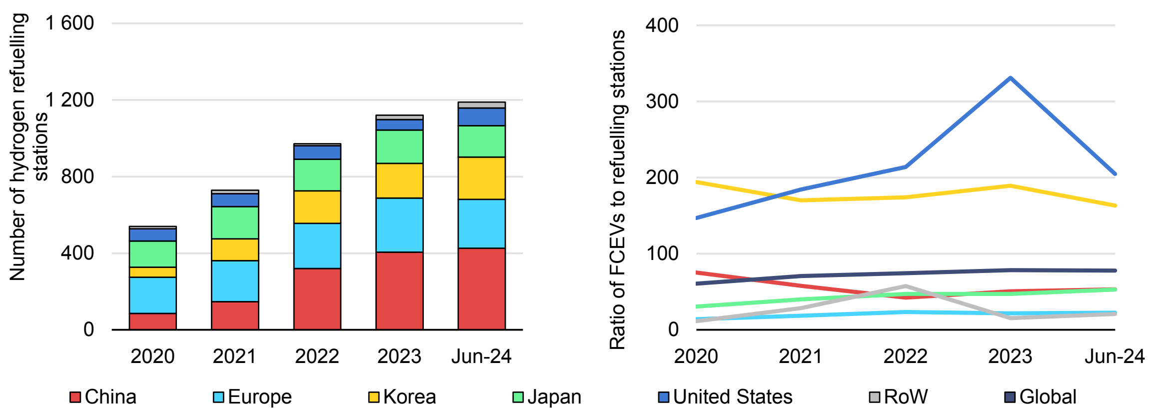
There are now close to 1 200 hydrogen refuelling stations (HRS)[16] in operation globally, but the overall total grew only marginally in the past year, as the number of new HRS being opened was partially offset by station closures around the world (see Box 2.3), and older HRS were upgraded or replaced (Figure 2.11). As in 2022, China had the largest number of stations in 2023, at over 400, followed by Europe, with 280, Korea at 180, and Japan with over 170. This pattern is reflected by stock growth from 2022 to date, with China adding more than 100 new stations, followed by Europe with over 45 additions and almost 60 in Korea. Over the past few years the stock of operating HRS in Japan has remained relatively constant and the country is now providing subsidies for the maintenance of ageing HRS, to continue to meet customer expectations. Korea has provided large subsidies to existing station owners to deal with the increasing cost of hydrogen in the country. In the United States, there were around 90 HRS in June 2024, but stock fell as

[16] As of June 2024. This includes only HRS for road mobility applications and excludes refuelling points for non-road applications, such as forklifts. There is higher level of uncertainty around HRS stock and additions in 2024 than in previous years due to the number of closures and differences in when various sources publish their figures.

low as 55 in 2023, with many stations being closed or temporarily out of service, although some new stations were added.

In the majority of the regions examined (see Figure 2.11) the ratio of FCEVs to HRS has remained steady in recent years. During periods of relatively high vehicle sales Korea has maintained a ratio of less than around 200 vehicles per HRS, in particular thanks to building around 50 HRS in 2022. The United States is a notable exception, where a number of station closures in California (where FCEV stock is concentrated) led to significant issues for customers in 2023, though many of these stations have since reopened or been replaced, as explored in Box 2.3.

Figure 2.11 Hydrogen refuelling stations by region and ratio of fuel cell electric vehicles to refuelling stations, 2020-2024



Notes: FCEV = fuel cell electric vehicle; RoW = rest of world. The number of hydrogen refuelling stations refers to both public (retail) and private stations. 2024 includes data until June 2024.

Sources: IEA analysis based on data from Advanced Fuel Cells Technology Collaboration Programme, H2stations.org by LBST, International Partnership for Hydrogen and Fuel Cells in the Economy and Clean Energy Ministerial Hydrogen Initiative country surveys.

Despite a number of station closures around the world, global stock of HRS increased in 2023, driven by growth in China and Europe.

Like Japan and Korea, Germany has also been investing in existing stations, including upgrading them to accommodate heavy-duty vehicles (HDV). This follows a wider trend: over 90% of new European HRS are capable of refuelling HDVs, in sharp contrast to 2019, when 70% of new HRS were only capable of refuelling passenger cars. The share of stations in Europe that can service HDVs has increased from 27% in 2019 to almost 40% in 2023.[17] The United States is also moving towards accommodating HDVs and has opened three truck- and four bus-specific HRS in California.

[17] Capability here could refer to either the ability to physically accommodate the larger vehicles, having a 350-bar dispenser (as is typically used by HDVs), greater hydrogen storage for the larger anticipated demand, or a combination of factors.

Outside of China, almost 340 new HRS are planned in the coming years. These include stations delivered through partnerships between OEMs and station developers to help increase demand, such as by Stellantis (Vauxhall) in the United Kingdom, Toyota and Hyundai jointly in Australia, and Nikola through their HYLA brand in the United States. Further HRS installations have also been announced by companies in Australia, Canada, France, New Zealand and the United Kingdom. However, in the coming years, by far the greatest number of stations are likely to be built in China, which has the ambition of reaching 1 200 stations in 2025. This includes 5 provinces and municipal cities each with plans to reach 100 HRS or more, and both upward and downward revisions to previously announced plans based on the progression of deployment.

Box 2.3 The past year proves difficult for hydrogen refuelling stations in Europe and North America

The past year has seen a series of announcements that suggest a slowdown in the deployment of HRS, and the closure of many existing stations in a number of countries. Everfuel announced the closure of their Danish stations in September 2023, and Shell followed by closing their California stations in February 2024, after having closed their UK stations in October 2022. Everfuel reported low demand as being behind the closures, leaving a fleet of 100 Danish hydrogen taxis without access to hydrogen refuelling, while Shell cited hydrogen supply issues, but common to both was a refocusing away from cars to the HDV segment. Even in the relatively strong bus sector, HRS plans are being cancelled due to lack of demand, such as in Edmonton, Canada, or are experiencing substantial delays, such as in Crawley, United Kingdom.

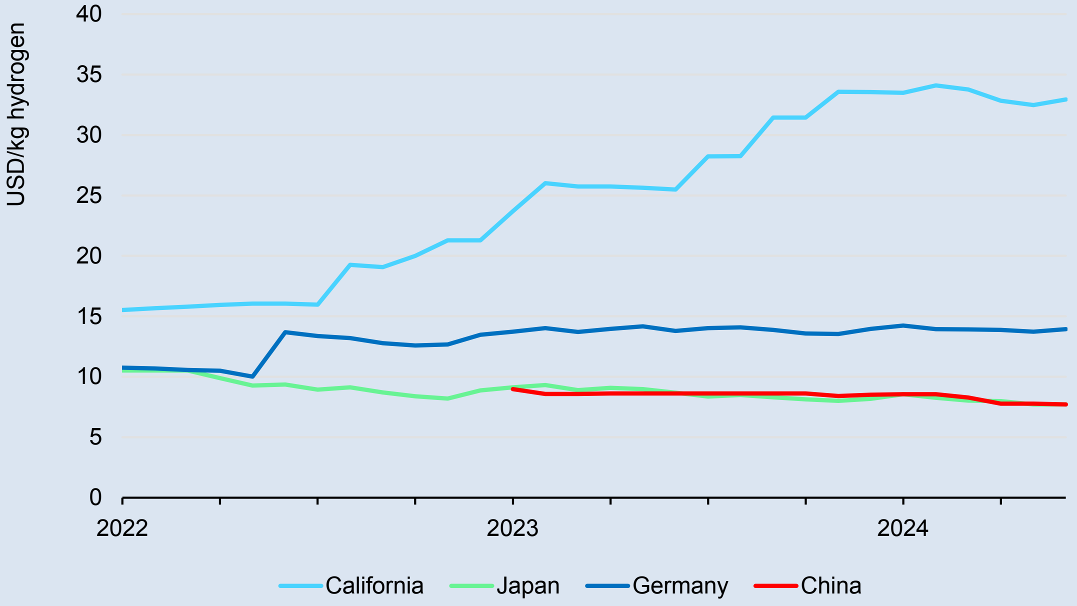
Another sign that the industry may be struggling to grow was the number of selloffs of hydrogen refuelling businesses. In October 2023, UK-based ITM Power sold its joint venture Motive Fuels, and in July 2024, French company McPhy finalised the sale of their HRS business. In June 2024, Norway-based Nel spun off their HRS business into a separate entity, Cavendish Hydrogen, which will focus on HDV refuelling. These companies all noted that the changes were motivated by a desire to concentrate on their core business of electrolysers.

Shaping these trends are three main challenges – low demand, reliability issues and drastic increases in hydrogen prices – which apply across all regions to differing extents.

Sales of fuel cell passenger cars have not taken off in Europe, leaving much of the costly infrastructure underutilised, and in California, where sales have been more substantial, frequent station downtime has damaged consumer sentiment. However, it is the widely reported jump in hydrogen price that may be most damaging: in California, hydrogen pump price increased by over 100% between

2021 and the end of 2023. This issue was most serious in California, but to mitigate similar issues occurring in Europe, H2 Mobility introduced dynamic pricing, whereby the price varies by the origin of the hydrogen, as well as the size and pressure level of the station. This allowed their renewable hydrogen sale price (approximately USD 10.3/kg for trucks and buses, or USD 11.9/kg for cars and vans), to be 25-30% cheaper than the standard price as of October 2023.

Monthly hydrogen pump prices



Notes: Values for Japan are an average of values from Chubu, Chugoku, Kinki, Kyushu, Tohoku, and Japan Metropolitan. In Japan, value for June 2024 is assumed equal to May 2024.

Sources: Data for California, Germany, and Japan was provided by Platts, S&P Global Commodity Insights, ©2024 by S&P Global Inc. Data for China is taken from the Hydrogen Observations monthly newsletter and refers to the consumption-side price.

Shipping

Hydrogen-based fuels are anticipated to play an important role in reaching the targets of the recently revised International Maritime Organization (IMO) GHG strategy, including that zero or "near-zero" emissions fuels account for 5-10% of international shipping fuel consumption in 2030. A significant fraction of those fuels are expected to be biofuels, but if all this demand were met with hydrogen-based fuels, it could represent 4-9.3 Mtpa in hydrogen-equivalent terms (Mtpa H_2-eq).[18] Given that these targets will come into force in 2027, it may be difficult to achieve the necessary ramp-up in production to achieve the volumes of

[18] Assuming that 9 700 PJ of fuel is consumed in international shipping in 2030 as in the IEA Stated Polices Scenario. The lower bound of the range represents the demand for hydrogen needed to meet the 5% target with hydrogen directly and the upper bound represents the demand for hydrogen needed to produce methanol to meet the 10% target.

low-emissions fuels required. However, the orderbook for alternative-fuel-ready[19] vessels has been growing, with over 290 methanol-fuelled vessels, almost 30 ammonia-fuelled vessels, and around 30 hydrogen vessels[20] on order as of September 2024. The majority of methanol vessels on order are container ships, whereas bulk carriers and tankers dominate orders for ammonia-fuelled vessels. The orderbook for hydrogen-fuelled vessels is characterised by smaller vessels such as tugs, cruise ships and ferries.

Each of the top ten largest shipping companies by market capitalisation now has emissions reductions targets of varying levels. In addition, at COP 28, the Green Hydrogen Catapult (a non-profit organisation working to leverage multi-sector opportunities to simultaneously scale supply and demand of renewable hydrogen) partnered with the UN High-Level Climate Champions to co-ordinate a Call to Action with Shipping Leaders. This includes a non-binding commitment to increase maritime fuels derived from renewable hydrogen to 11 million tonnes by 2030.

Governments have also started to take action on this front, with the most noteworthy example being the adoption of the FuelEU Maritime regulation, although the effect on near-term demand for e-fuels[21] is uncertain, given that the policy does not mandate their use before 2030. Instead, the regulation by the European Council establishes a potential sub-target of 2% of RFNBOs in shipping by 2034.[22] Meeting this target would represent demand for 90-105 kt H_2-eq in that year.[23] The inclusion of shipping in the EU Emissions Trading Scheme also creates incentives for deploying low-emissions fuels for both domestic and international shipping voyages that originate or terminate in the region.

Beyond the deployment of vessels and the supply of hydrogen-based fuels, the development of technologies and regulations to support alternative fuel bunkering are also needed.[24]

[19] "Fuel-ready" refers to vessel designs that have the flexibility and capability to enable a future conversion to an alternative fuel. Such designs are meant to facilitate future modifications; fuel-ready vessels may still require installation of the new fuel system.
[20] Includes both hydrogen internal combustion and hydrogen fuel cell vessels.
[21] E-fuels are produced using electrolytic hydrogen and include e-ammonia, e-methanol, and others.
[22] FuelEU Maritime establishes targets to decrease the CO_2 emissions intensity of maritime fuels; the sub-target of 2% will enter into force only if RFNBOs do not reach 1% of total energy consumption in shipping by 2031. Even in the absence of such sub-targets, there is likely to be significant demand for these fuels due to the overarching target of a 14.5% GHG intensity reduction by 2035.
[23] Assuming that 1 100 PJ of shipping fuel consumption in the European Union in 2034 is covered by FuelEU Maritime, as per the IEA Stated Policies Scenario. The lower bound of the range represents the demand for hydrogen needed to meet the 2% target with hydrogen directly and the upper bound represents the demand for hydrogen needed to produce methanol to meet the 2% target. Included in the calculation, as per the regulation, is a multiplier of 2 applied to the energy content of RFNBO, reducing the actual mass of fuel required to meet the target.
[24] The upcoming Energy Technology Perspectives 2024 report examines considerations for establishing methanol and ammonia bunkering infrastructure at ports.

Methanol

Methanol ships are leading the way in terms of alternatively-fuelled vessels (excluding liquefied natural gas [LNG][25]), due to their higher technological and commercial readiness, and greater ease of handling when compared to ammonia – there are already around 50 methanol-ready vessels in operation today. About half of existing dual-fuel methanol vessels are oil/chemical tankers, but about two-thirds of the methanol-fuelled vessels on order for the future are container ships.

Today, limited supplies of low-emissions methanol limits the use of the fuel in existing dual-fuel vessels. Offtake agreements, mainly for biomethanol or methanol from unspecified sources, indicate that the supply of methanol for these vessels will grow over this decade. There have also been a few promising announcements relating to methanol produced using low-emissions hydrogen. Goldwind has signed an agreement to provide A.P. Møller-Mærsk with 500 ktpa of low-emissions methanol to be produced in China, sufficient to fuel 12 large methanol-enabled vessels, with initial production slated for 2026. Ørsted has received USD 100 million in funding from the US DoE to support an e-methanol project that could produce up to 300 kt of e-methanol in the Gulf Coast region of Texas. However, in August 2024, Ørsted scrapped the FlagshipONE e-methanol project in Sweden that they had acquired from Liquid Wind, due to a lack of long-term offtake agreements. Liquid Wind has another two similar projects under development, FlagshipTWO and FlagshipTHREE, each of which aims to produce 100 ktpa of e-methanol,[26] with operation due to start before 2030. However, given the company's change in priorities to focus on hydrogen, the successful completion of these projects is uncertain, although their original developer (Liquid Wind) has recently signed an agreement with Uniper to boost the development of facilities for the production of low-emissions methanol.

Beyond the availability of low-emissions methanol, regulations around refuelling vessels with methanol are a pre-requisite for widespread operation of methanol-fuelled vessels. In 2023, Gothenburg became the world's first port to publish operating regulations for methanol fuelling of vessels, and to perform methanol ship-to-ship bunkering of a non-tanker vessel. Two of the largest ports in terms of fuel bunkering, the Ports of Singapore and Rotterdam, have also successfully conducted methanol bunkering operations of a Mærsk-owned container ship.

[25] While LNG (which could also be produced synthetically using electrolytic hydrogen) is often considered in the definition of alternative fuels for shipping, this report focuses on methanol, ammonia and direct use of hydrogen, as these are anticipated to be the hydrogen-based fuels that play the largest role in decarbonising the shipping sector.
[26] E-methanol is produced using electrolytic hydrogen.

Ammonia

Ammonia-fuelled vessels are at an earlier stage of development than methanol-fuelled vessels, with safety regulations for the use of ammonia as a fuel for ships still to be established. While various classification societies have published guidance on the design and construction of ammonia-fuelled vessels, the IMO International Code of Safety for Ships Using Gases or Other Low Flashpoint Fuels (IGF Code) does not yet cover the use of ammonia as a fuel, though interim guidelines are nearing finalisation. Nevertheless, ammonia-fuelled engines for maritime applications have been tested, and vessel trials are already underway or being planned.

Notable developments include Wärtsilä launching the shipping industry's first commercial 4-stroke ammonia engine (see Chapter 5. Investment, finance and innovation), while engine manufacturer MAN Energy Solutions expects the commercial sale of ammonia engines to begin in 2027. In March 2024, liquid ammonia was loaded onto a dual-fuel vessel, and the first onboard combustion of ammonia and diesel was successfully trialled in Singapore. In Japan, an LNG-fuelled tugboat has been retrofitted to run on ammonia, with combustion tests indicating minimal nitrous oxide (N_2O) and ammonia slip. Another design being explored is onboard cracking of ammonia for use in proton exchange membrane fuel cells, which could allow for future direct use of hydrogen.

As ammonia is already a traded commodity, much like methanol, a number of ports have existing storage and transfer infrastructure. Ship-to-ship ammonia transfers are taking place, while in Norway, safety permits have been granted for the construction of an ammonia bunkering facility. The Port of Rotterdam also expects to be bunkering ammonia in 2027. However, further work is needed in standards development for the safe bunkering and use of ammonia as fuel for ships. Innovation in refuelling methods also continues, including a truck-to-ship refuelling system.

Hydrogen

A number of hydrogen vessels have been put into operation, particularly for short-range applications. China launched its first hydrogen fuel cell ship in 2023, and a liquefied hydrogen ferry has been commercially operating in Norway since 2023. A hydrogen fuel cell barge was launched in 2023 in the Netherlands, and another completed trials in March 2024. A US hydrogen-powered ferry has begun commercial operations following successful tests for a 6-month pilot. In Japan, a hybrid hydrogen and biodiesel vessel completed a certification voyage in April 2024. Projects have demonstrated a number of different hydrogen technologies in vessels, as well as hydrogen fuelling operations. In addition, BeHydro's dual-fuel technology has received approval in principle[27] from the classification society Lloyd's Register, a further sign that the technology is moving from demonstration to commercial application.

Additional projects are planned that will further build experience with hydrogen-powered vessels, especially larger vessels. These include two large hydrogen ferries (120-car capacity) that are being built in Norway for delivery in 2026, and a hydrogen barge demonstrator expected to be deployed in Paris in 2024. Belgium-based shipping company CMB.Tech is constructing four hydrogen-powered cargo vessels in Viet Nam, which are expected to be delivered in the second half of 2025 and be deployed on major sea routes including northern Europe, the Mediterranean, North Africa and West Africa. Elsewhere, as part of the SeaShuttle project, construction of the world's first hydrogen-powered short-sea containership, powered by 3.2 MW hydrogen fuel cells, began in February 2024 at the Cochin shipyard in India. Announcements from Switzerland and the Netherlands demonstrate the geographical diversity of projects in this space.

Aviation

In the short to medium term, hydrogen-related activity in aviation is expected to be concentrated in the production of sustainable aviation fuels (SAF).[28] The uptake of these fuels is easier than less advanced technologies (like the direct use of hydrogen) as they can be dropped-in with relatively minimal changes to fuel storage infrastructure and aircraft.

Moreover, there are a growing number of firm commitments to offtake hydrogen-based aviation fuels, with several having taken place since the release of GHR 2023. In November 2023, Air France-KLM invested USD 4.7 million in DG Fuels, including an option to purchase 75 ktpa of SAF over a period of several years starting in 2029. In January 2024, Norwegian Air Shuttle and Cargolux Airlines International S.A. committed to purchase 140 kt in total of synthetic fuels from Norsk e-Fuel. Finally, in February 2024, IAG reached an agreement with e-fuels producer Twelve to purchase 785 kt of SAF in total, with first deliveries as early as 2025. Most of these agreements involve companies operating in Europe, where policies such as the mandates established by the ReFuelEU Aviation regulation (1.2% of fuel use to be met with RFNBOs by 2030) are stimulating action in the sector, despite some concerns among aviation companies about the security of supply of these fuels. The industry also faces headwinds such as the

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

[28] Here, SAF includes both biofuels and hydrogen-based synthetic fuels which are produced from low-emissions hydrogen and a carbon source from biogenic origin or from direct air capture. Hydrogen is also considered a SAF and is used in the production of certain biofuels, such as in the case of hydrogenated vegetable oils.

announcement from Vattenfall and Shell to pause collaboration on their HySkies project in Sweden, which had aimed to produce 82 ktpa of e-SAF. Meeting the ReFuelEU Aviation mandate in 2030 would require 0.6 Mt of synthetic kerosene (0.3 Mt H_2-eq) in that year.[29] The three aforementioned projects could account for 0.25 Mt of fuel production in 2030, or close to half of the ReFuelEU target.[30]

In addition, sectoral coalitions of private companies have been launched to aggregate demand for SAF through the joint purchase of SAF certificates. Although this is not exclusively for hydrogen-based SAF (the certificates also include biofuels), it can help to scale uptake. Aggregating purchase power in this way increases the size of the funds raised, which can then be channelled to invest in new production facilities that sell their fuels in the general market. Examples include the Sustainable Aviation Buyers Alliance (which in April 2024 undertook the largest-ever collective purchase of SAF certificates, with close to 20 businesses spending nearly USD 200 million on certificates) and the Qantas Sustainable Aviation Fuel Coalition, which recently expanded its membership.

Direct use of hydrogen in aircraft is still in development, and given that the industry has strict regulations, any novel hydrogen aircraft are likely to spend a long time at the demonstration phase before seeing commercial use (see Chapter 5. Investment, finance and innovation). One of the best-known hydrogen aircraft development programmes is Airbus ZEROe, which investigates hydrogen combustion and fuel cells, and in January 2024 they opened a centre in Germany focusing on cryogenic liquefied hydrogen storage and delivery. Airbus also partners with other companies working to advance fuel cells for use in aviation. However, most announcements in this space come from start-ups such as Fokker Next Gen, which aims to build liquefied hydrogen-powered narrow-body jets, or hydrogen aircraft propulsion manufacturer ZeroAvia. Though still at the business development stage, ZeroAvia have demonstrated sufficient progress to generate orders for their fuel cell-based powertrains, which currently target retrofits of the 10-20 and 40-80 seater aircraft sizes.

However, these start-up companies face multiple challenges, as evidenced by the announced closure of the high-profile Universal Hydrogen project, in spite of having achieved significant technical milestones. Their novel approach was for a modular liquefied hydrogen fuel storage system, but developing this system while also retrofitting aircraft proved costly. The company was unable to develop a sustainable business model and failed to secure additional investment.

Although Schiphol airport (Netherlands) is aiming to facilitate the first hydrogen-powered international flight in 2024, the earliest significant use of hydrogen in the

[29] Assuming 2 200 PJ of fuel is consumed in aviation in the European Union in 2030 as per the IEA Stated Policies Scenario and that the target is met using synthetic kerosene.
[30] Assuming that the announced total volumes are delivered equally across 5 years including 2030.

aviation industry has been in powering ground vehicles. The intention is to develop infrastructure that could later benefit hydrogen planes, though the fact that applications for both gaseous and liquefied hydrogen are being developed presents a risk to this strategy. Overlapping consortia aiming to test, develop, and establish hydrogen as a fuel for use in airports have been established in New Zealand, North America, Scandinavia and the United Kingdom, where Bristol Airport has made substantial progress and had completed some tests by April 2024.

Hydrogen is also being considered for non-conventional aviation applications where it offers sufficient energy density and potential emissions reductions. Examples include a cartridge-based fuel storage solution for a prototype unmanned aerial vehicle, and two vertical take-off and landing aircraft, one in Australia and one in Switzerland.

Other non-road sectors

Rail

Hydrogen fuel cell trains are being trialled in a diverse range of settings, and a recent review includes 15 hydrogen rail trials announced between 2018 and 2024 to assess its suitability for local (Japan), intercity (India), and freight trains (Austria). Hydrogen trains also continue to set records for distance travelled on a single refuel – 2 803 km versus 244 km for a battery-powered version – demonstrating their potential advantages. In addition, rail operators in France, Italy and the United States have placed orders for battery-hydrogen trains in the past year.

However, there are still significant headwinds for hydrogen in rail, with many projects being cancelled or failing to make progress. The earliest of the aforementioned trials, by the German rail operator in Lower Saxony, has since opted for battery electric trains as the technology of choice for decarbonisation. Another operator in Austria has dropped their plans to adopt hydrogen trains in favour of battery electric less than 1 year after endorsing the technology, while tenders for hydrogen trains in Romania and the Netherlands did not receive any bids. These announcements suggest a trend towards electrification as the most common path towards decarbonising railways.

Industrial, heavy, and other machinery

Low-emissions hydrogen is an attractive option for decarbonising applications that combine the need for remote, continuous operation with a high-power demand. At the smaller end of the scale are forklifts, where hydrogen continues to see significant uptake, with approximately 69 000 in the United States alone, up from around 60 000 in 2022.[31] The technology required is mature and cost-effective, offering the higher uptime required and therefore often offering a favourable total cost of ownership (TCO) compared to alternatives, with companies such as Plug making frequent new announcements in this space.

At the other end of the scale in terms of size are machines such as excavators, with Applied Hydrogen powering a 30-tonne machine with fuel cells, in what is another step towards widespread decarbonisation of construction equipment. In the mining sector, where remote, extremely heavy operations are common, Liebherr is developing both a hydrogen-powered and battery electric version of their haul truck, while Komatsu are also developing a hydrogen haul truck based on their existing battery electric solution.

In other applications in which heavy-duty, continuous operations appear to favour hydrogen, such as in port handling equipment, the role of hydrogen is still to be seen. The Port of Valencia in Spain, and the Port of Los Angeles in the United States, are pioneering hydrogen-powered cargo-handling equipment, with the latter introducing the world's first hydrogen rubber-tyred gantry crane building on their Shore to Store project.

Buildings

The contribution of hydrogen to meeting energy demand and supporting decarbonisation in the buildings sector remains negligible, with no significant developments in 2023. Electrification, district heating and distributed renewables are well ahead of hydrogen technologies in fulfilling this need. Under current policies, the role of hydrogen is expected to remain marginal in the future, reaching just 20 ktpa by 2030 (0.002% of total energy demand in the sector), while in the NZE Scenario, global hydrogen use meets only around 0.13% of total demand in buildings by 2030.

There has been little progress in 2023 on the deployment of technologies that might run on hydrogen. Where fuel cells are installed – mostly in Europe, Japan, Korea and the United States – they predominantly run on natural gas, which is pre-reformed into hydrogen in the fuel cell before being used to produce heat and power. In Japan, thanks to the ENE-FARM project, the stock of deployed fuel cell micro-combined heat and power (CHP) units surpassed 500 000 at the end of 2023, even though yearly installations have declined by more than 15% year-on-year.

[31] Fuel cell forklifts still remain a niche technology with over 190 000 electric forklifts expected to be sold in 2024 alone.

Fuel cells running on pure hydrogen (supplied by a refinery) were installed in an apartment building complex in Korea in mid-2024, and provided 840 MWh of electricity in June 2024, as well as some heat.

Other advances in the use of pure hydrogen in buildings, mostly in boilers, are limited to a very small number of pilots and demonstration projects. In Hoogeveen, a pilot to use hydrogen to provide space heating to 12 homes received the green light from the Netherlands' Authority for Consumers and Markets after 1 year of delay. In Fife (Scotland), the 300-home hydrogen heating trial that was expected to be launched in the second half of 2024 has been delayed amid supply chain challenges. Some of these pilots face low social acceptance, which can significantly delay further demonstration projects showcasing the use of hydrogen in buildings – continuing the trend seen last year. For example, in May 2024, the UK government shelved plans for Britain's largest trial using hydrogen for heating, a decision that came after already abandoning plans for two smaller hydrogen trials, in Redcar and in Whitby, Cheshire.

Electricity generation

Hydrogen use for electricity generation currently represents less than 0.2% of the global generation mix (largely not from pure hydrogen, but rather mixed gases containing hydrogen from steel production, refineries or petrochemical plants). Hydrogen and ammonia can become an important source of low-emissions electricity system flexibility and are among only a few options for large-scale and seasonal electricity storage. The contribution to total electricity generation is, however, likely to be limited. In the NZE Scenario, hydrogen and ammonia combined account for less than 2% of global electricity generation in 2050.

Various technology options exist to use hydrogen-rich gas or even pure hydrogen for electricity (and combined heat) generation: fuel cells, internal combustion engines and gas turbines. Since the release of GHR 2023 (September 2023), the Korean company Hanwha demonstrated at the end of 2023 100%-hydrogen firing in an 80-MW gas turbine, with nitrogen oxide emissions at less than 9 ppm without any specific flue gas treatment. Earlier in 2023, the company had already achieved a 60% hydrogen co-firing share (in volumetric terms). In November 2023, a 30%-hydrogen co-firing share was demonstrated in a grid-connected 566-MW combined-cycle gas turbine in Japan. Gas turbine manufacturers aim to provide modern gas turbines (using dry low nitrogen oxides [NOx] combustion systems) operating on 100% hydrogen by 2030.

Interest in using hydrogen and ammonia as fuels in the power sector continues to grow, with several projects announced in the Asia-Pacific region, Europe and North America. In the near term, the use of hydrogen and ammonia can reduce emissions from existing plants, while in the longer term, power plants running entirely on hydrogen or ammonia could provide flexibility to the electricity system, in combination with large-scale hydrogen storage.

Co-firing of ammonia in coal-fired power plants has been successfully demonstrated in trials in Japan, China and Indonesia (see Chapter 5. Investment, finance and innovation). In June 2024, JERA, the largest power utility in Japan, successfully demonstrated 20% co-firing of ammonia at its 1-GW Hekinan coal power plant, with low NO_x emissions JERA plans to start 20% ammonia co-firing in commercial operations in 2027. At the end of 2023, China Energy Investment Corporation announced successful trials of ammonia co-firing at its 600 MW Guoneng Taishan coal power plant. Around the same time, in Indonesia, PT Indo Raya Tenaga tested ammonia co-firing at its Jawa 9 and Jawa 10 coal power plants (1 000 MW each), which are capable of co-firing up to 60% of ammonia. The direct use of 100% ammonia in gas turbines has already been demonstrated in a 2 MW gas turbine in 2022, with N_2O emissions being kept at low levels (0.1 ppm). Demonstration efforts are also underway in larger gas turbines, potentially up to 400 MW by 2030. IHI and GE Vernova are working on retrofittable ammonia combustion systems for existing gas turbines, aiming to address the formation of NO_x emissions when burning ammonia and to test the combustor at existing gas turbines in Singapore.

Projects using hydrogen and ammonia in electricity generation

At the end of 2023, global installed power capacity using hydrogen and ammonia totalled around 330 MW, with Asia-Pacific accounting for more than 50%, followed by North America with around 30% and Europe with 15% (Figure 2.12). Based on announced projects,[32] the power capacity using hydrogen and ammonia could reach 7 100 MW by 2030 (5 200 MW if projects at very early stages of development are excluded).[33] Compared to the corresponding capacity identified in the GHR 2023, this represents a 24% increase. Almost half of the announced capacity is located in the Asia-Pacific region, followed by Europe, accounting for around 40% of the announced capacity by 2030. The share of North America falls to around 10%, despite a tenfold increase in announced absolute capacity compared to today, which reaches 900 MW in North America by 2030, but is surpassed by project announcements in Europe, with 2 800 MW, and the Asia-Pacific region, with 3 400 MW.

[32] Announced projects include plants that are under construction, have reached FID, are under feasibility study or at an earlier development stages.

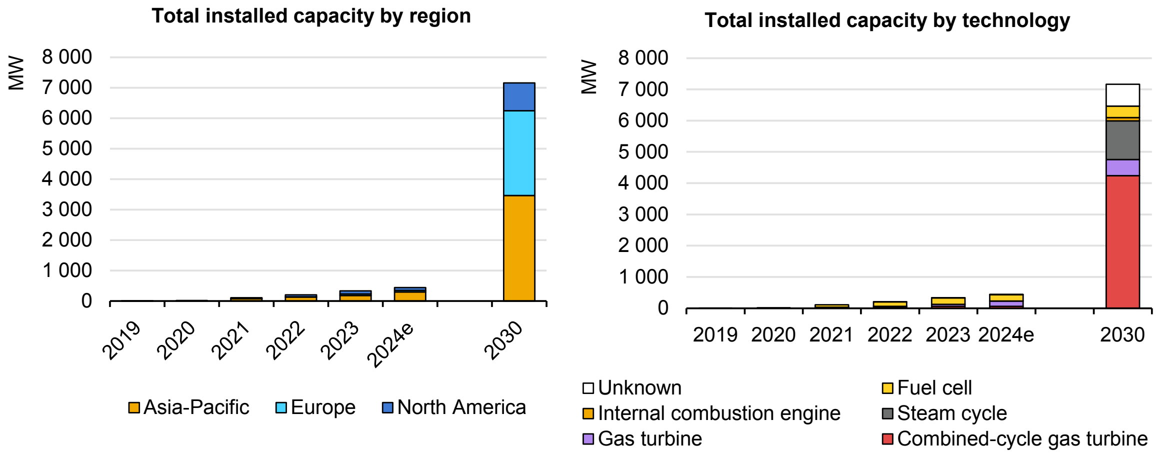
[33] In the case of co-firing hydrogen or ammonia, the capacity corresponds to the total installed capacity multiplied by the co-firing share in energy terms.

The list of announced projects includes some projects aiming to use 100% hydrogen. In the United States, Duke Energy is converting an existing 83 MW gas turbine for 100% hydrogen use. The peaking gas turbine is planned to come online in 2024 and will be linked to renewable hydrogen production from solar PV and hydrogen storage tanks. In France, the HYFLEXPOWER project demonstrated in October 2023 the operation of a 12 MW gas turbine on 100% renewable hydrogen, also linked to a local electrolyser and hydrogen storage tanks. In the United Kingdom, a 49.5 MW CHP plant has been announced for 2025, running on 100% hydrogen and being potentially extended to 125 MW by 2028.

With regards to technologies, existing hydrogen-fuelled capacity is dominated by fuel cells, representing 60% of the installed capacity, while gas turbines and combined-cycle gas turbines account for the remainder. Considering announced projects in the pipeline, gas turbines and combined-cycle gas turbines reach a share of two-thirds in 2030. Co-firing of ammonia in coal power plants is today limited to a few trials, but could represent around 15% of the announced capacity for 2030, with nine projects being developed in the Asia-Pacific region.

The global hydrogen- and ammonia-fired capacity from announced projects represents almost a quarter of the installed capacity deployed in the Announced Pledges Scenario by 2030 (30 GW), but only 6% of the capacity in the NZE Scenario (120 GW).

Figure 2.12 Power generation capacity using hydrogen and ammonia by region, historical and from announced projects, 2019-2030



Note: Values for 2024 are estimates, assuming plants with an announced start date in 2024 that are under construction or have reached FID actually start operation in 2024.
Sources: IEA analysis based on announcements from industrial stakeholders; ERM for fuel cells.

Installed hydrogen- and ammonia-fired power capacity could reach 7 100 MW globally by 2030, based on existing plants and announced projects.

Additionally, several utilities have announced plans to build new gas power plants that are "H_2-ready", or to upgrade existing plants to be able to co-fire a certain share of hydrogen, although the majority have not yet announced fixed dates for starting co-firing. The hydrogen share of this H_2-ready announced capacity would correspond to 3 900 MW,[34] but this number is likely to represent a lower range, given that it is based only on projects for which relevant information has been released. In addition, other new gas-fired power plants in planning are also likely to be able to co-fire a certain amount of hydrogen, although no information has been made available yet. Likewise, existing gas-fired power plants are able to co-fire certain shares of hydrogen, varying from 10% to 100%, depending on the gas turbine design.[35] Based on information on existing gas turbines in operation, and their maximum hydrogen blending shares as specified by gas turbine manufacturers, their hydrogen-fired capacity could amount to more than 80 GW globally.[36] As before, this represents a lower bound, given that detailed information was only available for 480 GW of the existing total gas-fired capacity of 2 000 GW in 2023.

Auctions for hydrogen-based electricity generation

Several countries have taken steps to support the use of hydrogen and ammonia in the power sector, including through auctions.

Korea held tenders in 2023 for electricity generated from hydrogen with a combined volume of 1 430 GWh, without any constraints on the emissions intensities of the hydrogen. A tender for up to 6 500 GWh electricity produced from clean hydrogen and ammonia was launched in May 2024, for generation starting in 2028 with contracts running for 15 years. For this tender, hydrogen and ammonia have to meet Korea's "clean" hydrogen definition, which has four emissions intensities tiers in the range of 0.1-4 kg CO_2-eq/kg H_2. For hydrogen and ammonia produced from fossil fuels with CCS to be eligible, the capture rate has to be higher than 90%.

In January 2024, Japan held its first auction for long-term zero-emissions power capacity for various clean electricity sources, including hydrogen and ammonia. The winners comprise five coal-fired power plants planning to co-fire ammonia, with a combined ammonia-fired capacity of 770 MW (corresponding to an average ammonia co-firing share of 20% for the combined coal capacity of 3 850 MW [net capacity, 4 100 MW gross capacity]), plus 55 MW for a gas-fired power plant with hydrogen co-firing. The submitted bids stayed below the targeted capacity of

[34] The estimate of the H_2-ready capacity is based on individual plant announcements and does not include planned auctions for H_2-ready capacity, which are discussed in the following section.
[35] Other factors, such as the capability of the gas supply pipes and valves to handle certain hydrogen blending shares are not considered here, but are, of course, critical to assessing specific plants.
[36] Derived by taking the maximum co-firing share multiplied by the total capacity for individual plants.

1 000 MW, such that all bids were awarded funding at a fixed cost for 20 years, if the project starts by FY2030-2031.

In 2023, Germany announced plans for three tenders for hydrogen-ready or directly hydrogen-fired power plants with a combined capacity of 24 GW. As part of the country's power plant strategy, these plans were scaled back to 12.5 GW in July 2024. In a first phase, 5 GW of new hydrogen-ready gas-fired capacity and 2 GW of hydrogen-ready retrofits for existing plants will be tendered. Plants must switch to hydrogen after the eighth year of operation (for new plants) or after the modernisation to hydrogen firing (for existing plants). Winners of the tenders will benefit from support with capital cost and operational subsidies for the cost difference between natural gas and hydrogen for 800 hours per year. In addition, support for 500 MW of capacity running immediately on hydrogen is being planned. The first tenders are being planned for early 2025. In a second phase, a further 5 GW of new gas-fired capacity will be tendered.

In 2023, Singapore's Maritime and Port Authority and the Energy Market Authority issued a tender for the development of an ammonia-fired 55-65 MW gas turbine or combined-cycle gas turbine, using imported low-emissions ammonia. Two consortia out of six shortlisted proposals were selected in July 2024, one led by Keppel and another by Sembcorp. After engineering studies have been conducted, a lead project developer will be selected in 2025.

Chapter 3. Hydrogen production

Highlights

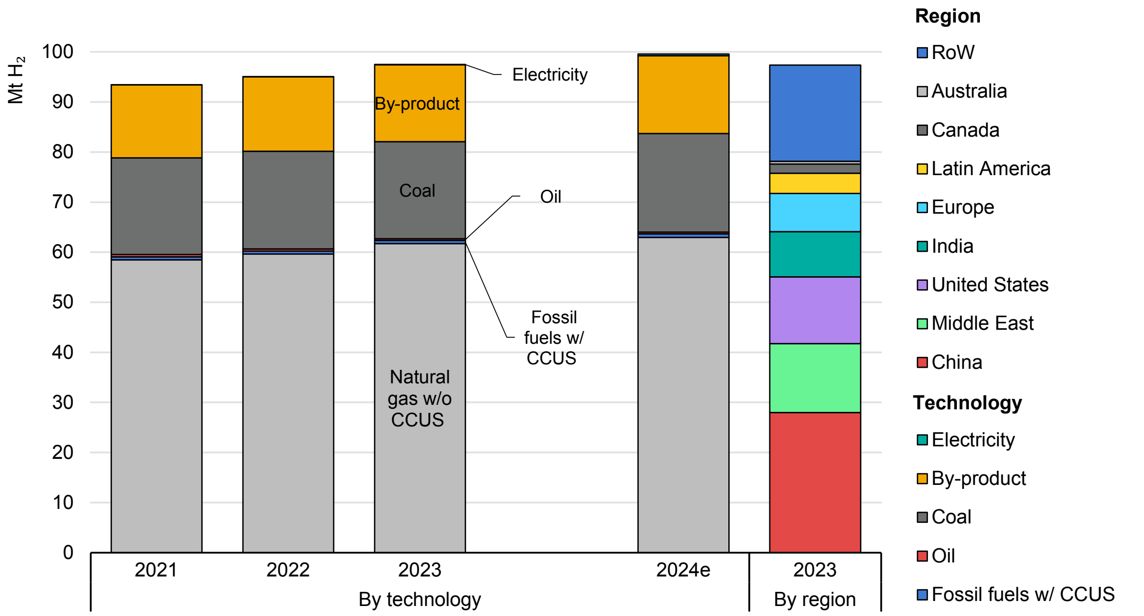
- Hydrogen production reached 97 Mt in 2023, of which less than 1% was low-emissions. Based on announced projects, low-emissions hydrogen could reach 49 Mtpa by 2030 (up from 38 Mtpa in the Global Hydrogen Review 2023).
- Installed water electrolyser capacity reached 1.4 GW by the end of 2023 and could reach 5 GW by the end of 2024. China leads in terms of committed projects and could account for almost 70% of 2024 capacity. Announced projects suggests that capacity could grow to close to 520 GW by 2030, although only 4% has reached a final investment decision (FID) or is under construction. For fossil-based production with carbon capture, utilisation and storage (CCUS), 14% of the announced potential production has reached FID, boosted by an acceleration of FIDs in the last 12 months. Progress is being made, albeit far more slowly than was expected a few years ago.
- Around 6.5 GW of electrolyser capacity reached FID in the past 12 months, nearly 12% less than in the 12 months prior to GHR 2023. More than 40% of this capacity is in China and 32% in Europe, where there was a four-fold increase compared to the previous 12 months. Committed projects are mainly in industry, or to produce hydrogen-based fuels for transport. On the other hand, several projects have been cancelled due to uncertainty about demand or regulations, financial hurdles, licencing and permitting issues.
- Electrolyser manufacturing capacity doubled in 2023 to reach 25 GW/yr, with China accounting for 60%. This capacity is heavily underutilised, with only 2.5 GW of output in 2023. Considering projects with FID or under construction, capacity could reach more than 40 GW/yr in 2024. The project pipeline to 2030 adds up to more than 165 GW/yr, of which 30% has reached FID.
- Producing renewable hydrogen today is generally one-and-a-half to six times more costly than unabated fossil-based production. This cost premium is much lower further down the value chain; for consumers, it typically represents only a few percentage points on final products (for example, it is around 1% for electric vehicles with steel produced using renewable hydrogen), but acceptance of higher prices varies by product.
- Around 40% of planned low-emissions hydrogen production projects are in water-stressed regions, where using diverse sources of water and managing them sustainably will be crucial. Project developers are exploring large-scale desalination and treated wastewater to secure sufficient water supplies.

Overview and outlook

Hydrogen production today

Global hydrogen supply increased by 2.5% in 2023 compared to 2022, to reach 97 Mt H_2 (Figure 3.1). Demand was primarily met by domestic production in industrial hubs, with minimal international trade. China leads in terms of production, accounting for almost 30% of the global total, followed by the United States and Middle East with 14% each, and India with 9%. We estimate that global production will keep growing to meet increasing demand, and could approach 100 Mt H_2 by the end of 2024.

Figure 3.1 Hydrogen production by technology and by region, 2021-2024



Notes: By-product hydrogen from the chlor-alkali industry is not included. CCUS = carbon capture utilisation and storage; RoW = rest of world; 2024e= estimate for 2024. The estimated value for 2024 is a projection based on trends observed until June 2024.

Global hydrogen production reached 97 Mt in 2023, practically all derived from unabated fossil fuels. China is the largest producer of hydrogen worldwide.

Hydrogen production is today largely dependent on unabated fossil fuels, continuing the trend of recent years, and this is expected to remain mostly unchanged in 2024. The unabated natural gas route dominates, accounting for around two-thirds of total production. The Middle East is a key player – it produces 20% of all the hydrogen from unabated natural gas – with the United States and China together contributing around one-quarter. Hydrogen production from unabated coal gasification accounted for 20% of the global total in 2023, and is predominantly located in China. In addition, more than 15% of hydrogen globally is produced as a by-product in refineries and in the petrochemical industry, from processes such as naphtha reforming.

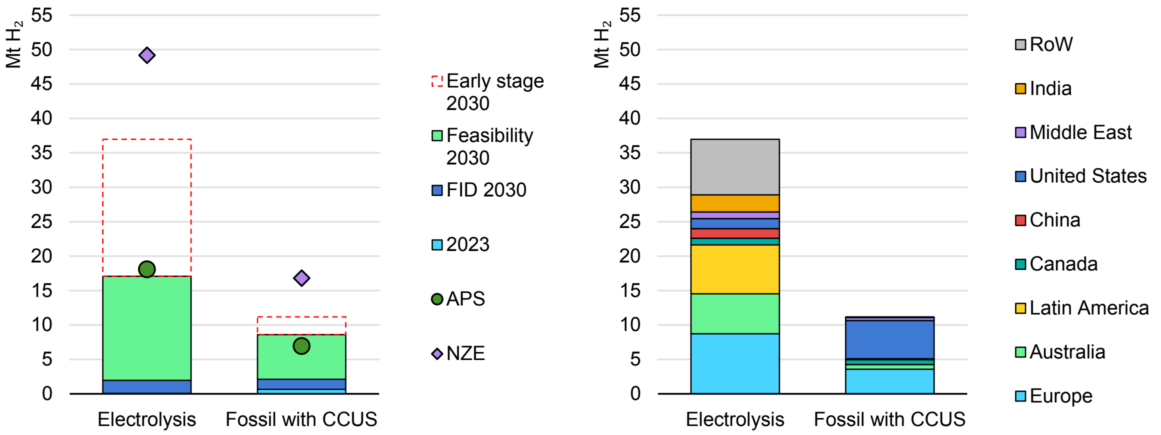
Low-emissions hydrogen production has grown marginally over the past 2 years and remains under 1 Mtpa H_2 – accounting for less than 1% of global production. This low-emissions hydrogen relies mostly on production from fossil fuels with CCUS. Electrolytic hydrogen production still makes up only a very small share of the total, remaining below 100 kt H_2 in 2023, and is primarily located in China, Europe and the United States, which together account for around 75% of global electrolytic hydrogen production.[37]

Outlook to 2030

More and more projects for the production of low-emissions hydrogen have been announced since the previous edition of the Global Hydrogen Review (GHR 2023), resulting in a more promising outlook to 2030. Annual production of low-emissions hydrogen could reach 49 Mtpa H_2 by 2030, an increase of more than a quarter on the 38 Mtpa H_2 by 2030 reported in last year's publication (Figure 3.2). If projects at very early stages of development (such as those where only a co-operation agreement among stakeholders has been announced) are excluded, annual production of low-emissions hydrogen could exceed 26 Mtpa H_2 by 2030. More than 45% of the projects in terms of potential production volume are undergoing feasibility studies,[38] and a similar share are at early stages. Committed projects – i.e. those that have taken FID or are under construction – account for only 7% (3.4 Mtpa) of the new low-emissions hydrogen production announced by 2030, of which 55% is from electrolysis and almost 45% from fossil fuels with CCUS projects. Nevertheless, this is a notable increase from the 4% (1.7 Mtpa) reported in the GHR 2023, driven up in particular by projects using fossil fuels with CCUS, which have seen an acceleration in terms of FIDs in the past year (in the GHR 2023 they accounted for only 35% of the committed capacity). Excluding the projects at very early stages of development, which are less likely to be fully realised by the end of the decade, the share of capacity that has at least reached FID changes to 13%. Approximately two-thirds of low-emissions hydrogen production in 2030 could come from electrolysis, and this could rise to almost 75% if projects at early stage of development are also included.

[37] Hydrogen from chlor-alkali electrolysis is not included in this analysis.
[38] See Explanatory notes annex for a description of the project statuses used in this report.

Figure 3.2 Low-emissions hydrogen production by technology, status and region based on announced projects and in the Announced Pledges and Net Zero Emissions by 2050 Scenarios, 2030



Notes: APS = Announced Pledges Scenario: NZE = Net Zero Emissions by 2050 Scenario; FID = final investment decision; RoW = rest of world. The '2023' label refers to operational projects, and the label FID 2030 includes projects that are under construction and projects that have reached FID. "Feasibility" includes projects undergoing a feasibility study; "Early stage" includes projects at early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced. The right-hand side figure includes operational projects and projects that have taken FID, at advanced planning and at early stages.

Source: IEA Hydrogen Production Projects Database (October 2024).

Low-emissions hydrogen production could reach 49 Mtpa by 2030, although only 7% of new projects has at least reached FID – a notable increase from the 4% reported in the GHR 2023.

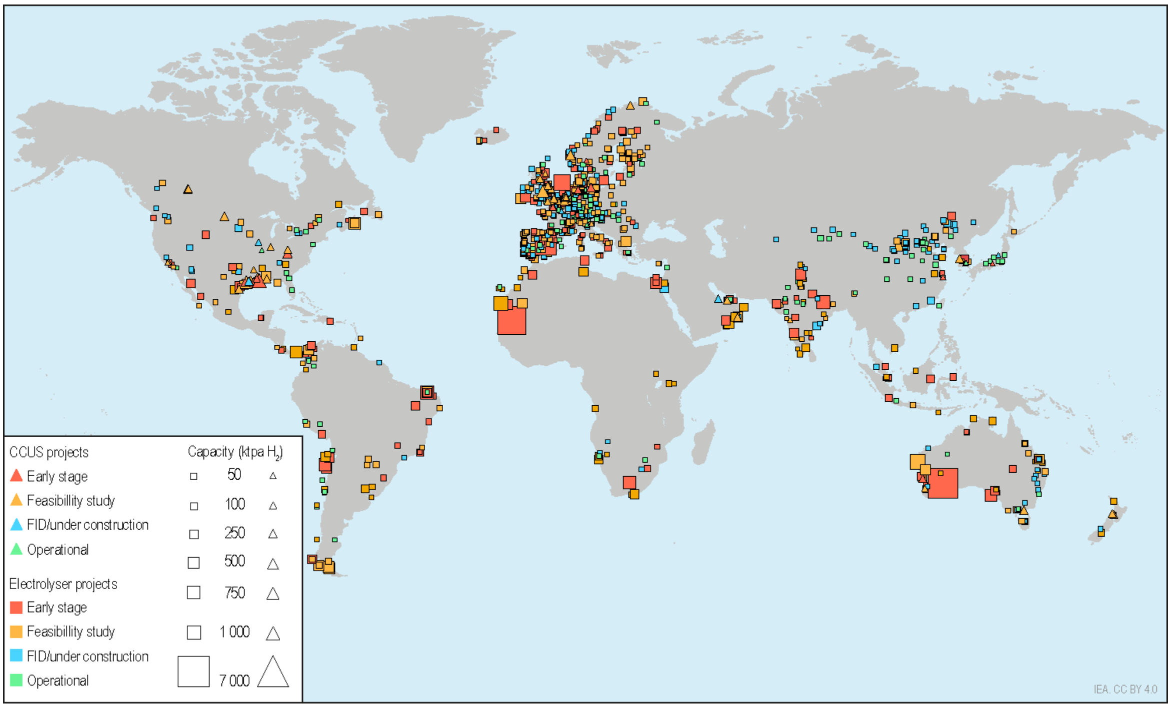
Europe (with 25%), Latin America (15%) and the United States (15%) together account for more than half of the potential low-emissions hydrogen production by 2030. In Europe, nearly 8 Mtpa of low-emissions hydrogen could be generated via electrolysis by 2030 (more than 5 Mtpa if projects at very early stages of development are excluded). Spain (20%), Denmark (12%) and Germany (10%) are leading in terms of announced water electrolysis projects, and could represent more than 40% of Europe's low-emissions hydrogen production by 2030.

In Australia, hydrogen production from electrolysis could reach almost 6 Mtpa by 2030 (almost 1.5 Mtpa if projects at very early stages of development are excluded). The availability of low-cost solar and wind resources, as well as its proximity to the Asian market, could make Australia one of the main exporters of hydrogen and hydrogen-based fuels (see Chapter 4. Trade and infrastructure). A similar trend is noticeable in Chile: according to our tracking, 16 electrolytic hydrogen projects, each with capacity greater than 1 GW, have been announced in Chile, although almost half of the potential capacity is in projects at very early stages of development. Potential production of low-emissions hydrogen from announced projects in Chile reaches almost 4 Mtpa (2 Mtpa if projects at very early stages of development are excluded), representing more than half of the low-emissions electrolytic hydrogen that could be produced in Latin America by 2030 (see Chapter 8. Latin America in focus).

Africa has seen a significant number of announcements for electrolytic hydrogen projects in the past year, potentially increasing production to more than 7 Mtpa by 2030. However, the majority of these projects – close to 6 Mtpa in terms of production – are still at very early stages of development, meaning that their full deployment by 2030 remains somewhat uncertain. This is not the case for China and the Middle East, where most of the announced projects are far more advanced, with half of the announced hydrogen production from water electrolysis in China, and 20% in the Middle East, coming from projects that are currently under construction or have already reached FID.

Based on announcements, the United States will remain the frontrunner in hydrogen production from fossil fuels with CCUS, with 5.6 Mtpa H_2 by 2030 (more than 3.5 Mtpa if projects at very early stages of development are excluded), followed by Europe with more than 3.5 Mtpa H_2 by 2030 (more than 3 Mtpa if projects at very early stages of development are excluded). This is an increase of almost 30% for the United States since the GHR 2023. In Europe, these projects are primarily located in the United Kingdom, the Netherlands and Norway – all countries with significant potential for CO_2 underground storage (Figure 3.3).

Figure 3.3 Map of announced low-emissions hydrogen production projects, 2024



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision.
Source: IEA Hydrogen Production Projects Database (October 2024).

A larger number of projects have been announced in Africa, Latin America and India in the past year, while the majority of operational capacity is in China, Europe and the United States.

Despite the growing number of announced projects for low-emissions hydrogen production, several projects delayed their FID or were even cancelled in the past year in the face of multiple challenges (see Box 3.1).

The 49 Mtpa of low-emissions hydrogen production that could get the go-ahead by 2030 represents close to three-quarters (40% if projects at very early stages of development are excluded) of the total low-emissions hydrogen production in the Net Zero Emissions by 2050 Scenario (NZE Scenario). An important gap remains to be closed in order to get on track, for which the largest part is accounted for by low-emissions hydrogen from electrolysis, while production from fossil fuels with CCUS is already closer to the value in the NZE Scenario. In contrast, under the Announced Pledges Scenario (APS), the low-emissions hydrogen production from announced projects (excluding projects at very early stage of development) could meet the scenario requirements both for electrolysis and for hydrogen from fossil fuels with CCUS.

Box 3.1 Challenges facing project developers are hindering faster progress

Several project developers aiming to produce low-emissions hydrogen have announced project delays, postponements to FIDs and even cancellations. Some of these announcements have come from highly ambitious projects that aimed for rapid market and technology developments (such as the adoption of hydrogen in new applications that are not yet commercial or international trade of low-emissions hydrogen and hydrogen-based fuels) or were looking at hydrogen use in applications with weaker business cases, or where more competitive alternatives are already commercially available (e.g. light-duty road transport, domestic heating and grid blending). The cancellation of these projects suggests that the sector is now maturing and moving beyond the hype observed in recent years, and that understanding among stakeholders about where the real opportunities for hydrogen lie – and where efforts must be focused – is now much stronger.

However, a large number of projects, even those built on solid use cases for hydrogen, are now facing diverse challenges that are hindering progress in the sector. These are the most common barriers facing project developers:

- **Regulatory uncertainty**: Project developers require clear and stable regulatory frameworks to secure investments. Although a large number of governments are making progress (see Chapter 6. Policies), on many occasions regulations are not yet clear, which can lead to companies halting their hydrogen programmes or postponing projects while awaiting clarity.
- **Demand uncertainty**: The slow development of the market for low-emissions hydrogen and insufficient demand mean that project developers cannot secure offtakers to underpin investments. Several delayed and cancelled projects

have reported barriers to securing sufficient offtake, in a variety of projects including methanol production, ammonia production, synthetic fuels and hydrogen production for multiple end-uses. The challenges in signing offtake agreements have recently led to the cancellation of Orsted's Flagship project (Sweden) for the production of methanol using renewable-based hydrogen, even after having taken FID in late 2022 and starting unit assembly earlier this year.

- **Financial hurdles and incentive delays:** Low-emissions hydrogen production and use cases remain more expensive than the fossil fuel incumbents they could replace. Timely government action to close this cost gap by favouring low-emissions solutions over fossil fuel alternatives (e.g. through carbon pricing, incentives, funding schemes and phasing out fossil fuel subsidies) is critical to help first movers to advance. Governments have started to implement support schemes for the first large-scale projects, but delays in making funding available have led companies to put off or scale back their production targets, or to delay investments in numerous projects. Even projects that had already received public funding have been delayed and cancelled due to increases in financing and material costs that completely changed the business case between the time when companies applied for the funding and the funding being approved.
- **Licencing and permitting issues**: Like the developers of renewable energy projects in the past, several low-emissions hydrogen project developers are now struggling to get necessary approvals from authorities, including for access to water supplies and grid connections. Local opposition has also complicated the obtention of licences to proceed with the development of projects and, therefore, their future operation. Although the complexity of some permitting procedures is often cited as the reason for the delays, bad industry practices (e.g. submission of incomplete files, poor project management) can also delay decisions from authorities and impact project plans. In the past year, eleven projects in Inner Mongolia (China), accounting for more than 3 GW electrolysis, had their development rights revoked as a result of delays from developers after land acquisition.*
- **Operational challenges**: Although several technologies for the production of low-emissions hydrogen are commercially mature, they are now facing the scale-up stage. The change in scale this implies requires new project configurations that need to be tested and perfected, through a process that presents technical and operational hurdles for developers. For example, Sinopec's Kuqa project, the world's largest operational electrolysis plant (260 MW), inaugurated in 2023, has faced operational issues with its electrolysers, limiting production, and is not expected to operate at full capacity until 2025. Other projects operating at a smaller scale have been delayed (20 MW project in Denmark) or put out of action (2.5 MW in Spain) for long periods after commissioning due to equipment faults.

These challenges do not occur in isolation, and in multiple cases project developers have reported that a combination of issues was behind their failed plans. For example, Uniper delayed the start-up of the first phase (100 MW) of the H2Maasvlakte project in the Netherlands (which had received support from the EU Innovation Fund), after failing to secure a power purchase agreement for the facility, and reporting challenges with high grid fees, uncertainty over sufficient offtake, and barriers with regulatory requirements, as well as complex administrative procedures needed to secure funding from public support schemes.

*Energy Iceberg (2024), Hydrogen Policy Navigator; Six mega green hydrogen projects were cancelled by Inner Mongolia energy regulator.

Electrolysis

Current status

Installed water electrolyser capacity reached 1.4 GW at the end of 2023, almost double the installed capacity at the end of 2022. This looks set to grow further: based on announced projects that have at least reached FID or are under construction, global installed capacity could reach 5 GW by the end of 2024. Nevertheless, as of September 2024, only 205 MW of new capacity has started operations. In addition, the installed capacity in 2023 represents only one-sixth of the capacity that was expected based on the announcements for projects at the time that the Global Hydrogen Review 2021 was published, signalling that progress is being made, though far more slowly than was expected just a few years ago.

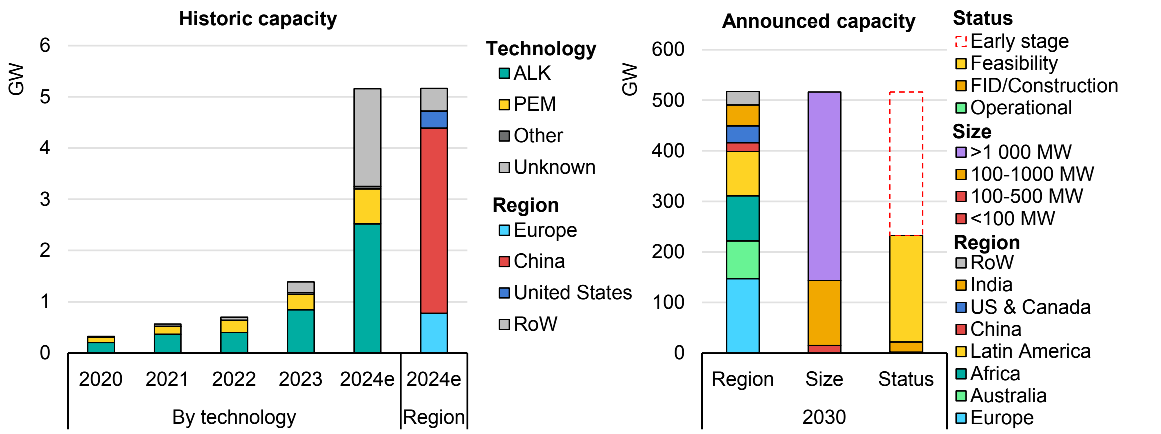
China accounted for 80% of the capacity that entered into operation in 2023, including the largest electrolyser project in the world, the 260 MW Kuqa plant by Sinopec. About 12% of the close to 700 MW that came online in 2023 was in Europe. China accounts for three-quarters of the new capacity additions that could become operational in 2024, increasing its share of global capacity from 55% in 2023 to almost 70%. Europe and the United States could reach shares of 15% and 6%, respectively, of global installed capacity by the end of the year, if all projects are realised on time. In the European Union, if all projects meet their planned timelines, total installed capacity could reach 0.7 GW at the end of 2024, falling very short of the interim target of 6 GW established in the EU Hydrogen Strategy back in 2020.

Alkaline technology continues to make up the largest share, accounting for more than 60% of the installed electrolyser capacity in 2023, followed by proton exchange membrane (PEM) with 22%. Despite their lower share to date, several projects using mid-size PEM electrolysers have started operations in the past few months. At the beginning of 2024, Plug commissioned plants for about 50 MW in total: the Camden County plant in the United States, for hydrogen use in mobility; and the 10 MW electrolyser in the Szazhalombatta refinery in Hungary. Another

PEM electrolyser came online in the United States at the end of 2023, the 25 MW Cavendish NextGen Hydrogen Hub at the FPL Okeechobee Clean Energy Center, powered by solar PV for application in the power sector. In Norway, the first phase of Yara's Porsgrunn (Herøya) project started operating a 24 MW PEM electrolyser in the beginning of 2024, manufactured by ITM Power, for ammonia production.

When we published the GHR 2023 in September 2023, projects in the pipeline worldwide accounted for 175 GW by 2030, and as much as 420 GW if projects at very early stages of development were also included. Taking into account the new announcements made in the past 12 months since then, 230 GW of water electrolyser capacity could be reached by 2030, and close to 520 GW if projects at early stages of development are also considered (Figure 3.4). The regional distribution could look quite different to today: regions with good renewable resources, such as Latin America and Africa, could each represent 17% of the installed capacity, up from just 65 MW in total today. Europe could reach more than a quarter of the global share by 2030, and Australia 15%. The decrease in China's share by 2030 should not be seen as a slow-down in project deployment, nor as evidence of declining interest, but rather as a reflection of short-term visibility of the projects under development in China, and project announcements that typically occur only when the projects are at a relatively advanced stage.

Figure 3.4 Installed electrolyser capacity by technology and region, 2020-2024e, and capacity by region, plant size and status based on announced projects, 2030



Notes: ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers; FID/Construction = final investment decision and under construction; RoW = rest of the world; US = United States; 2024e = estimate for 2024 capacity, based on projects planned to start operations in 2024 and that have at least reached FID. "Other" technology refers to solid oxide electrolysis, anion exchange membrane electrolysis or a combination of different technologies. The unit is GW of electrical input. Only projects with a disclosed start year are included.
Source: IEA Hydrogen Production Projects Database (October 2024).

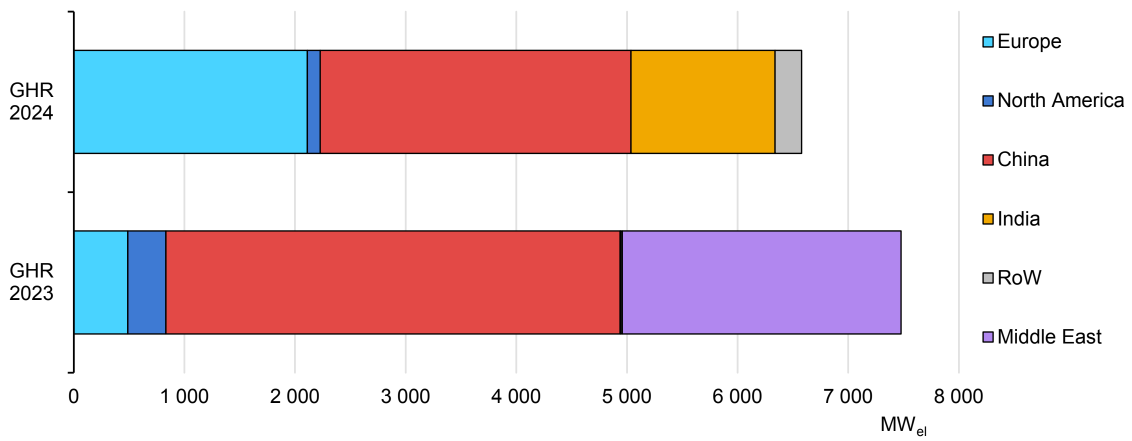
Based on announcements, electrolyser capacity could reach 230 GW by 2030, or up to 520 GW with projects still at early stages of development, from an installed capacity of 1.4 GW in 2023.

By 2030, three-quarters of the projects could be gigawatt-scale plants, consolidating a trend towards large-scale projects already observed last year. However, there is continuing uncertainty about the full development of the announced projects, as more than half of the electrolyser capacity is at early stages of development and only 4%, or 20 GW, of electrolyser capacity due to be online by 2030 has either reached FID or is under construction. By excluding the projects at early stages of development, which could be considered to be least likely to be fully realised by the end of the decade, the share of capacity that has at least reached FID rises to 8%. Between 2020 and 2023, the compound annual growth rate (CAGR) for water electrolyser installation has been around 60%, and if all projects for 2024 are realised on time, the year-on-year increase could be almost 400%. The realisation of all the projects by 2030 would entail a CAGR of more than 100% from 2024 onwards (80% by excluding projects at early stage of development): almost twice as high as any growth experienced by solar PV in any six-year period during the last two decades.

Advances

While looking at the entire project pipeline gives a clear indication of the potential growth in electrolyser plants globally, focusing on the projects that are committed provides a better overview of where projects are moving forward, in which sectors, and at what pace. In the 12 months since the GHR 2023 (September 2023), around 6.5 GW of electrolyser projects have reached FID, compared to about 7.5 GW in the 12 months prior to GHR 2023 (Figure 3.5).

Figure 3.5 Electrolyser capacity to reach final investment decision by the Global Hydrogen Review 2023 and 2024, by region



Notes: GHR = Global Hydrogen Review; RoW = Rest of the world. GHR 2023 includes projects that reached final investment decision (FID) between September 2022 and the end of August 2023. GHR 2024 includes projects that reached FID between September 2023 and the end of August 2024.
Source: IEA Hydrogen Production Projects Database (October 2024).

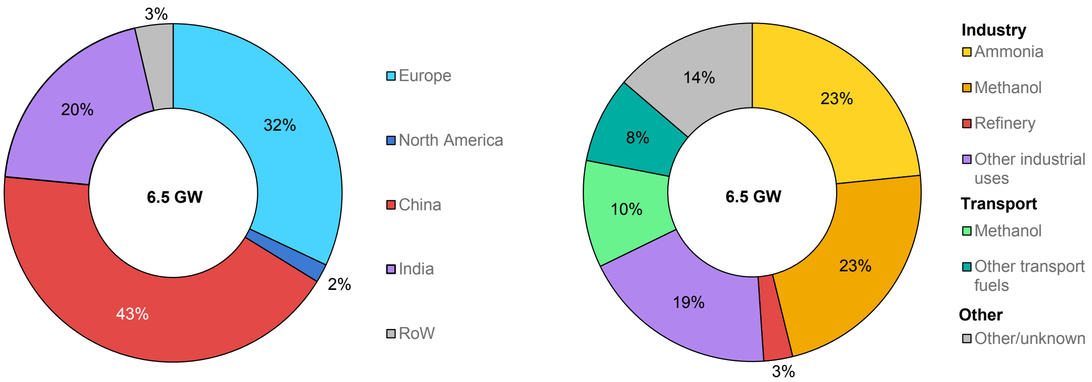
China continues to lead on committed investments in electrolyser projects, followed by Europe, with more than 2 GW of projects reaching FID since September 2023.

Advances in the first half of 2023 were, in part, driven up by the FID of the NEOM Hydrogen Project in Saudi Arabia, which is by far the largest project to have reached FID, with 2.2 GW of alkaline electrolyser capacity, of which 400 MW have already been installed.[39] This was equal to one-third of all advances in the following period, between September 2023 and August 2024. In that period, more than 2 GW reached FID in Europe, four times more than the previous 12 month period. The first phase of the Grey2Green project developed by GALP (100 MW, Portugal), the Green CCU Hub Aalborg (120 MW, Denmark), the Clean Hydrogen Coastline by EWE (320 MW, Germany) and the Refhyne II by Shell (100 MW, Germany) together represent one-quarter of the capacity that reached FID in Europe, while 40% of it is represented by the Stegra (formerly H2 Green Steel) project in Sweden. In addition, in September 2024 RWE took FID on the 300 MW GET H2 Nukleus project in Lingen, Germany (not included in Figure 3.5): state aid for this project was approved by the European Union under the Important Projects for Common European Interest scheme. China accounted for 2.8 GW of capacity that secured investment in the same period, retaining its position as the country with the largest share of committed investments. At the same time, India has taken its first big step into the regions with large production capacities committed, with the announcement in August 2024 by AM Green Ammonia of the FID for a 1.3 GW project in Kakinada for the production of ammonia in an existing fertiliser plant.

The majority of the announced capacity that took FID in the past 12 months is for the use of electrolytic hydrogen in industrial applications and for transport fuels (Figure 3.6). Half of this capacity, or 3.2 GW, targets sectors that already use hydrogen today, namely ammonia production, methanol production and the refining sector. These applications are all well placed to adopt low-emissions hydrogen in the near term, as the partial or full switch from fossil-based hydrogen generally requires only minor technical adjustments; they are also the sectors that can already secure offtakes for substantial volumes (see Chapter 2. Hydrogen demand). Of the projects that took FID in the past 12 months, about 0.7 GW are to produce synthetic methanol to be used as a transport fuel in shipping. The biggest projects under development are the Goldwind e-methanol project in China and the Green CCU Hub Aalborg in Denmark, together accounting for a capacity of 0.5 Mtpa of methanol.

[39] S&P Global (2024), Hydrogen Daily newsletter, 13 August.

Figure 3.6 Electrolysis capacity that reached final investment decision between September 2023 and August 2024, by region and sector



Notes: RoW= Rest of the world. "Other transport fuels" includes synthetic hydrocarbons and all other hydrogen-based products used as fuels in transport, except synthetic methanol. "Other industrial uses" include iron and steelmaking, high-temperature heating, and other industrial uses not disclosed. "Other/unknown" refers to all other uses not mentioned above, and undisclosed final uses.
Source: IEA Hydrogen Production Projects Database (October 2024).

Traditional uses of hydrogen in industry and the production of hydrogen-based fuels for transport are the sectors dominating FIDs for electrolyser projects.

In the United Kingdom, although revenue support is provided through the Hydrogen Allocation Round, no new projects have reached FID since publication of the GHR 2023. The first round selected 11 projects in December 2023, for a combined capacity of 125 MW, and could provide up to USD 2.5 billion through a combination of revenue support and capital cost support. However, project developers are currently negotiating contracts with the Low Carbon Contracts Company (the counterparty designated by the government) and none of them has taken FID so far. A second allocation round is ongoing, with a target to support projects with a total capacity of 875 MW.

The biggest electrolyser project currently under construction, the 2.2 GW NEOM Green Hydrogen project in Saudi Arabia, took financial closure in May 2023 and plans to start operations in 2026. If this project is used as a proxy indicator, it would suggest that the construction time required for a GW-scale plant is around 3 years (i.e. time between FID and beginning operation, although in the specific case of the NEOM project, construction began a few months before the FID was reached). Of all the projects in the pipeline expected to start operation by 2030 and with size equal to or above 1 GW, only four plants (6 GW cumulatively) have already reached FID or are under construction. However, more than 50 projects, for a combined capacity of 125 GW, are currently undergoing feasibility study. If they do not reach FID and start construction by 2027, it is unlikely that they will begin operation by the end of the decade. This means that 25% of the total announced capacity by 2030 is at significant risk of not beginning operation on time (55% if projects at very early stages of development are excluded).

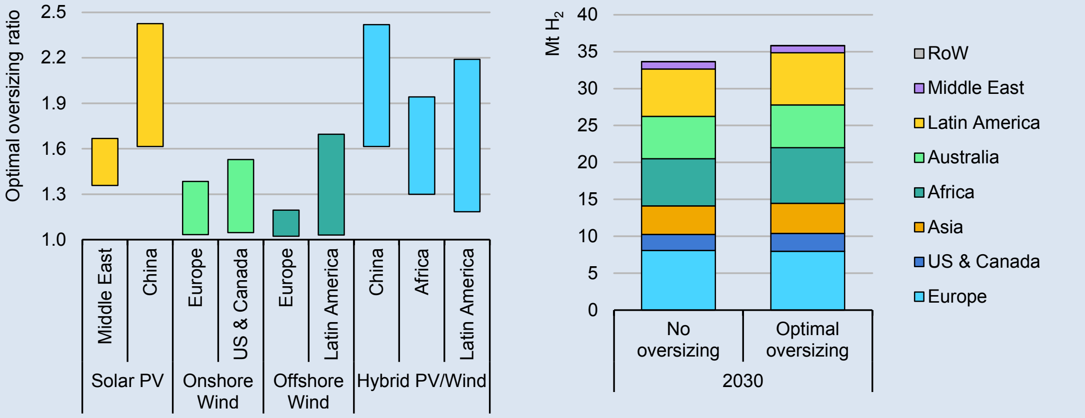
Many electrolyser projects plan to use dedicated renewable electricity generation as the electricity source. The design of the overall system, in particular the sizing of the renewable electricity capacity relative to the electrolyser, will be critical for the hydrogen production costs (Box 3.2).

Box 3.2 Impact of optimal sizing of renewable to electrolyser capacity

For renewables-based electrolysis projects, achieving high utilisation rates for the electrolyser reduces the impact of the electrolyser CAPEX in the overall cost of hydrogen production. For directly connected projects, oversizing the renewable generation capacity relative to the capacity of the electrolyser can be a way to achieve this. This increases the CAPEX spending for renewable electricity generation, but it can help to minimise the overall hydrogen production costs by increasing the utilisation rate of the electrolyser. Optimising the capacity ratio of the renewable plant in combination with other design options such as combining solar PV and wind in a hybrid configuration, and including electricity and/or hydrogen storage, can also lead to a more stable supply of hydrogen or industrial process, which also helps to improve the operation and economics of any subsequent synthesis process.

Through the Energy Transformation PatHway Optimization Suite (ETHOS) model suite, the optimal renewable-to-electrolyser ratio has been computed for several announced project locations around the world, minimising the levelised cost of hydrogen (LCOH) production in each of those locations. For onshore wind, the optimal sizing factor is between 1 (such as in the case for locations that already have relatively high capacity factors for wind) and 1.4 in Europe, slightly higher in the United States and Canada, and in the range of 1.6-2.8 for Brazil. In the case of solar PV, this factor is between 1.3 and 1.7 in regions with excellent solar irradiation, such as Chile, Africa and the Middle East, while it reaches a value of 2 in Europe and up to 2.4 in certain locations in China. The optimisation does not take into account other uses of the renewable electricity from the same plant; a higher renewable-to-electrolyser capacity ratio could be expected from projects that plan to use the same renewable electricity plant for multiple purposes besides hydrogen production. For example, the Puertollano Green Hydrogen project by Iberdrola, which has a solar PV capacity of 100 MW to power a 20 MW electrolyser, aims to send excess electricity to the local grid.

Optimal sizing factor for selected regions and renewable hydrogen production based on announced projects by 2030



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

Sources: IEA analysis based on IEA Hydrogen Production Projects Database (October 2024) and data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Change in the method used to determine the electrolyser capacity factor compared to the Global Hydrogen Review 2023

In previous editions of the GHR, low-emissions hydrogen production from electrolysers using renewable electricity has been computed assuming a 1:1 capacity ratio of the renewable electricity generation and the electrolyser. This year, the ETHOS modelling suite of the Forschungszentrum Jülich in Germany has been used to determine for each project location the optimal sizing of the renewable electricity capacity relative to the electrolyser capacity, taking into account local hourly solar PV and wind profiles and region-specific technology costs. The optimal capacity factors have been applied to projects using solar PV, onshore wind, offshore wind or planning to combine multiple renewables types, for which a hybrid configuration of solar PV and onshore wind has been selected; they account for more than half of the 36 Mtpa that could be produced from electrolysis by 2030. This approach is particularly useful for those projects where no information on the planned renewable capacity has been released. In order to provide values that are comparable with the previous editions of this report, the non-optimised production, i.e. using a 1:1 capacity ratio between the renewable electricity and the electrolyser capacities, is also provided. The difference between the two methodologies is only around 2.2 Mtpa H_2.

Renewable to electrolyser capacity ratio from selected announced renewable hydrogen projects

Source: IEA Hydrogen Production Projects Database (October 2024).

Among the announced projects for the production of hydrogen from electrolysis, several have announced the renewable capacity that will be used to power the facility. The solar PV-to-electrolyser capacity ratio is, in many cases, between one and three, with some larger values in the case of projects in Europe. Similar values can be derived for onshore wind in Europe, while the smaller sample for Australia and Latin America shows capacity ratios of one-and-a-half to two and three, respectively.

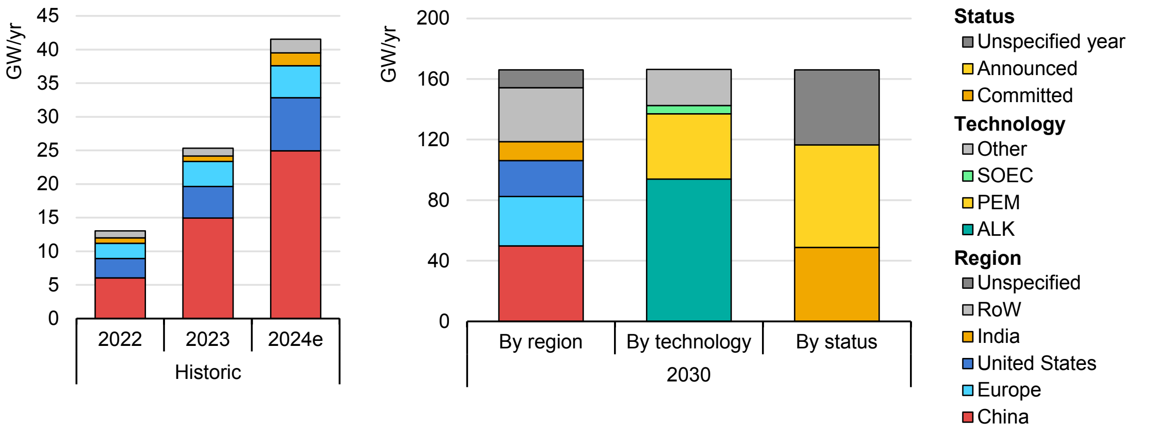
Electrolyser manufacturing

Manufacturing capacity for assembling electrolyser systems had reached 25 GW/yr by the end of 2023, based on the nominal facility size from company announcements. This has almost doubled compared to 2022, with nearly three-quarters of the new additions in China, which accounted for 60% of capacity in 2023, and is expected to maintain this share in the short term (Figure 3.7). Based on announcements that reached FID or are under construction, another 16 GW/yr of capacity could be added in 2024, to reach more than 40 GW/yr of global capacity. The largest share of new additions would be in China, followed by Europe, which could potentially add more than 3 GW/yr. However, based on an estimated output of 2.5 GW in 2023, this manufacturing capacity is currently underutilised; in addition, reaching the assembly capacity expansion envisaged by announced projects will depend on the scale-up of manufacturing capacity of all the components in parallel, for which there is limited visibility.

By 2030, more than 165 GW/yr of capacity could be reached based on all announcements – almost 30% of this announced capacity has reached FID, and another 30% has been announced without a target year for starting operations. Considering only the facilities that are expected to enter operation by 2030, the resulting capacity of 116 GW could meet almost two-thirds of the needs in the NZE

Scenario. China would continue to account for the largest share – 30% – of manufacturing capacity in 2030, followed by Europe (with 20%) and the United States (15%). Around 7% of announcements, for a total 12 GW, were made without a defined location, meaning that the regional distribution of global manufacturing capacity could still change by 2030.

Figure 3.7 Electrolyser manufacturing capacity by region, 2022-2024e, and announced capacity additions by region, technology and status, 2030



Notes: ALK = alkaline electrolyser; PEM = proton exchange membrane; SOEC = solid oxide electrolyser; RoW = rest of world; 2024e = estimate for 2024. “Committed” refers to capacity that is operational, under construction or has reached FID.
Source: IEA analysis based on announcements by manufacturers and personal communications.

Electrolyser manufacturing capacity could grow 60% in 2024, with China maintaining its lead. By 2030, more than 165 GW/yr could be operational, but only 30% of announced additions have been committed.

Alkaline technology continues to dominate, with 55% of the announced capacity by 2030, down from more than 70% of the facilities today, the majority of which is in China. As the Chinese market for electrolysers grows, it is attracting manufacturers from different business areas, such as Trina and Sungrow, who are both active in the solar PV industry, and are now among the largest companies in terms of electrolyser manufacturing capacity. The Chinese electric vehicle manufacturer BYD has obtained a patent for electrolyser equipment, signalling that it also sees potential to enter the market. PEM announced capacity is concentrated mainly in Europe, with almost half of the 43 GW/yr by 2030, followed by North America and India, which together have a fifth. The US-based manufacturer Accelera by Cummins has started production of its HyLIZER1000 in China, which with a 5-MW modular unit is the largest PEM electrolyser in China in terms of single unit capacity. The Chinese company Tianjin Mainland, traditionally a manufacturer of alkaline electrolysers, is beginning to explore PEM.[40] HydrogenPro has completed manufacturing of the alkaline units for the Advanced Clean Energy Storage hub in the United States and has also started

[40] Energy Iceberg (2024), Chinese Hydrogen Market Report H1.

delivering the units for the Salcos project in Germany, all together accounting for 320 MW planned to be commissioned by the end of 2024.

Although solid oxide electrolysers (SOEC) represent only about 6% of capacity today and are expected to maintain this share through to 2030 based on announcements, there have been notable recent developments. For example, thyssenkrupp nucera has expanded its product range by signing a strategic partnership with the German research centre Fraunhofer IKTS for commercialisation of the SOEC technology, and plans to open a pilot production line as soon as 2025. American energy service company Baker Hughes has invested in Elcogen, an Estonian SOEC and fuel cell maker. In Denmark, Topsoe will supply the ammonia producer First Ammonia with a 500 MW electrolyser, which should take up a big portion of the company's 500 MW/yr facility in Herning for the next couple of years before further scale-up. For the US market, a further 1 GW/yr manufacturing facility in Virginia has been announced by Topsoe. Another electrolyser technology that represents a very small share of current manufacturing capacity, but that could reach more than 10% by 2030 if all the announcements are realised, is anion exchange membrane (AEM). US-based EvolOH announced plans for a new facility in Lowell, Massachusetts. In addition, Enapter, which is one of the largest manufacturers of AEM electrolysers today, saw sales increase around fourfold between the last quarter of 2022 and the last quarter of 2023, confirming the interest of small-scale project developers in this technology.

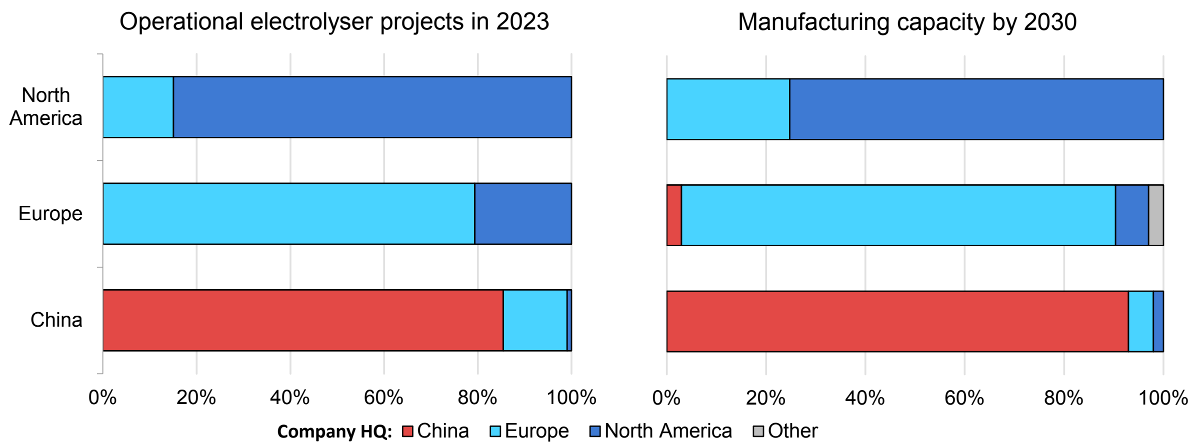
The geography of electrolyser manufacturing

Based on current manufacturing capacity, electrolyser orders and announcements for future expansions of facilities, Chinese companies are predominantly expanding manufacturing capacity in China in order to meet domestic demand. Certain European companies are also operating in the Chinese market, mainly through joint ventures or agreements with Chinese companies, such as in the case of the Jigli plant in Suzhou being developed with Belgian company John Cockerill, or the partnership between Norwegian HydrogenPro and Tianjin Mainland in Tianjin. AEM electrolyser manufacturer Enapter announced in 2024 a joint venture with the Chinese company Wolong to move part of their production and assembly to China, though not the manufacturing of the electrolyser stack itself.

Similarly, the largest European and North American electrolyser manufacturers typically locate the majority of their capacity in their home regions (Figure 3.8) in order to serve domestic demand. In the European Union, the Net Zero Industry Act, with a goal for manufacturing capacity to reach at least 40% of the European Union's annual deployment needs by 2030, could provide a long-term signal to manufacturers and investors. However, the expansion of some European companies to the United States has been observed recently, thanks to attractive policies – such as the Inflation Reduction Act (IRA), although the finalisation of the technical rules is still pending – for the development of hydrogen projects that can create demand for electrolysers. International trade of electrolysers has been limited so far: of 1.4 GW of total installed water electrolysers capacity as of 2023, less than 20% have been shipped internationally.

There are some signs of change in the geographical distribution of manufacturing, although whether this will add up to a longer-term trend remains to be seen. Chinese electrolyser manufacturer Guofu Hydrogen Energy Equipment (GuofuHee) announced in 2023 the intention to open a factory in Germany by 2026. Trina Hydrogen, which is headquartered in China, expects to take FID next year for a new facility to be built in Spain, and the Chinese Hygreen Energy has announced in August this year the plan for a facility in Spain together with local firm Coxabengoa. In 2024, Swedish company Metacon was granted rights to manufacture electrolysis systems based on China-based PERIC's technology. On the electrolyser supply side, the recent results of the European Hydrogen Bank pilot auction show that up to 25% of the projects might procure electrolysers from China based on the submitted letters of intent, while more than half intend to buy from domestic manufacturers in the European Union. With a growing pipeline of electrolysis projects, and the ongoing expansion in manufacturing capacity, trade in electrolysers could represent an opportunity for companies with capacity to enter new markets, especially in those regions where there is no manufacturing capacity today.[41]

Figure 3.8 Electrolyser manufacturing capacity by company headquarters, 2023, and by 2030



Note: HQ= head quarter.
Sources: IEA analysis based on IEA Hydrogen Production Projects Database (October 2024), announcements by manufacturers and personal communications.

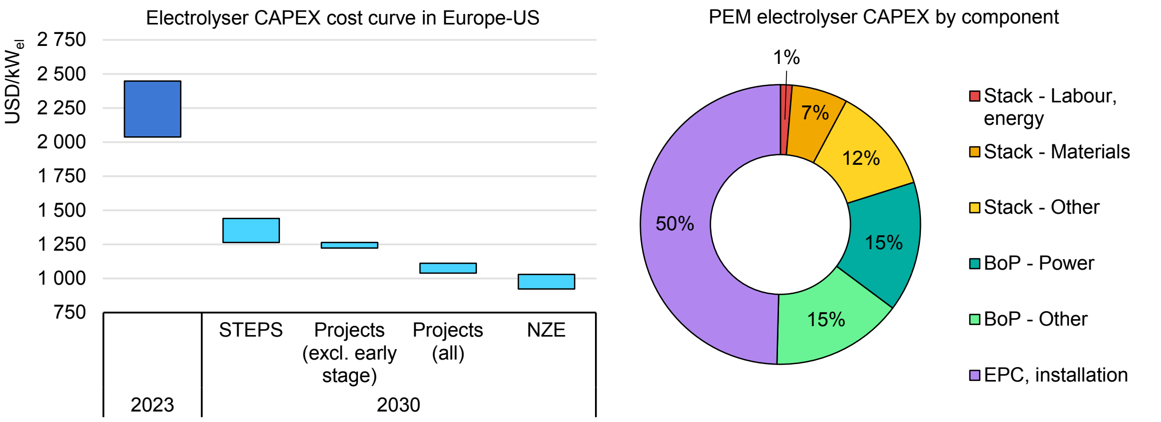
Electrolyser manufacturers are predominantly operating in their countries of origin today, but expansion plans could involve entry into other markets.

[41] This topic will be examined in detail in the forthcoming IEA publication *Energy Technology Perspectives 2024*.

The cost of electrolysers

The cost of an installed water electrolyser has increased in past years due to inflation affecting materials and labour costs, and higher interest rates. In 2023, the capital cost for an installed electrolyser (including the equipment, gas treatment, plant balancing, and engineering, procurement and construction cost, and contingencies) ranged between USD 2 000/kW for alkaline and USD 2 450/kW for PEM electrolysers (Figure 3.9). Alkaline electrolysers manufactured in China are cheaper than those produced in Europe or North America in terms of CAPEX, and can reach around USD 750/kW-1 300/kW for an installed system. Compared to the GHR 2023, the capital cost for 2023 has been revised based on newly available data from more advanced projects and to include contingency costs, resulting in an increase of about 20% (BNEF 2024, TNO 2024).

Figure 3.9 Electrolyser cost based on current and announced projects and in the Stated Policies and Net Zero Emissions by 2050 Scenarios, 2023-2030, and cost disaggregation by component, 2023



Notes: US = United States; STEPS = Stated Policies Scenario; NZE = Net Zero Emissions by 2050 Scenario; CAPEX = capital expenditure; PEM = proton exchange membrane; BoP = balance of plant; EPC = engineering, procurement, and construction cost. “Projects” refers to the capacity deployed according to announced projects, which is 520 GW by 2030, and 230 GW if excluding projects at early stage of development; in the case of the STEPS and NZE Scenarios, this is 50 GW and 560 GW by 2030 respectively. The learning rate for the electrolyser stack is assumed at 18% based on STORE&GO (2019) Deliverable 7.5, while for the other components of the balance of plant it is 2-10%. For the EPC and installation cost, a learning rate of 8% has been assumed. Electrolyser installed CAPEX is a global average value, with the range representing alkaline and PEM technologies (lower and upper end of the range respectively). The cost disaggregation refers to a PEM electrolyser manufactured in the United States. Installation costs include installation, project and commissioning management, temporary site construction facilities, commissioning labour assistance, etc. Other techno-economic assumptions are included in the Annex.
Sources: IEA analysis based on data from McKinsey & Company and the Hydrogen Council, STORE&GO (2019), communications with companies, BNEF 2024, TNO 2024, the IEA Hydrogen Production Projects Database (October 2024) and IEA (2024), Advancing Clean Technology Manufacturing Roadmap.

If all announced projects are realised, electrolyser installed capital cost could be reduced by 50-55% by 2030 due to economies of scale and mass manufacturing.

The cost of an installed electrolyser system can be divided into three main components: the stack, the balance of plant and the installation cost. The stack cost represents about 50-60% of the uninstalled electrolyser system, with the rest being the power supply unit (including the rectifier), oxygen separator tank, circulation pumps, piping, cooling system, valves, piping and various instrumentation (which is usually referred to as the balance of plant (BoP)). On top of that, installation could account for up to half of the final installed cost. Based on bottom-up calculations and assuming a high utilisation rate of factories, the direct cost of manufacturing an alkaline electrolyser stack could range between USD 45-65/kW (with China at the lower end, and Europe and the United States at the higher end). However, we estimate a low utilisation rate of electrolyser factories today, as demand has not yet scaled up and output was estimated at 2.5 GW in 2023: with a low utilisation rate such as 10%, the manufacturing cost could increase three- to fourfold, to USD 130-260/kW.

Based on capacity increases envisaged by announced projects, mass manufacturing and economies of scale – in particular to the stack – could lead to a decrease in the capital cost of an installed electrolyser system, with costs declining by 40-50% by the end of the decade, and up to 55% if projects at an early stage of development are also taken into account. This potential cost reduction is quite close to what is achieved in the NZE Scenario, with capital cost down by 55-60% compared to 2023, and an installed capacity of 560 GW by the end of the decade. In the STEPS, by predominantly taking into account projects that have at least reached FID, the cost reduction is much lower, at around 40% by 2030.

Fossil fuels with CCUS

About 15 hydrogen facilities[42] around the world are equipped with CCUS, with a cumulative capture capacity of around 12 Mtpa CO_2. Most facilities are retrofitted hydrogen production units in refining and fertiliser production in North America, with first operation dating from the early 1980s. Only around 1 Mtpa of the captured CO_2 is injected in dedicated storage (at the Quest facility in Canada), and the remainder is injected for enhanced oil recovery (EOR) or used in applications such as the food and drink industry, or for boosting yields in greenhouses. Moreover, most facilities have been retrofitted with partial capture, meaning only process emissions – which have a high concentration of CO_2 – are captured. This results in only around 0.6 Mtpa H_2 production qualifying as low-

[42] Only projects with a capture capacity above 100 000 t CO_2 per year are considered here.

emissions out of the 0.9-1.2 Mtpa produced[43], with 0.35 Mtpa from natural gas reforming (4 Mtpa CO_2 captured), and 0.3 Mtpa from coal and oil gasification (8 Mtpa CO_2 per year captured).

Hydrogen is one of the leading applications in CCUS deployment plans. More than one-quarter of CO_2 capture capacity under construction or in planning involves hydrogen or ammonia production across a range of applications, including dedicated production, refineries, fertiliser and iron and steel. In the United States, while CO_2 demand for EOR was the primary driver for the first plants to capture emissions, the 45Q tax scheme first introduced in 2008 and increased through the IRA in 2022 up to USD 85 per tonne of CO_2 stored (around USD 0.8/kg H_2[44]), and up to USD 60 per tonne of CO_2 used (around USD 0.55/kg H_2), along with USD 7 billion in funding for the establishment of clean hydrogen hubs, continues to support development. The United States now accounts for almost half of low-emissions hydrogen production from fossil fuels with CCUS announced for 2030. Air Products recently announced its intention to apply for the 45Q tax credit for the Eastern Louisiana Clean Hydrogen Complex to produce 0.7 Mtpa of hydrogen capturing 5 Mtpa CO_2. Projects producing low-emissions hydrogen from fossil fuels can also apply for the 45V tax credit (but not combine both tax credits), which provides an incentive of up to USD 3/kg H_2, depending on the CO_2 emissions associated with hydrogen production. However, it would be challenging for these projects to reach the maximum reduction of CO_2 intensity (0.45 kg CO_2/kg H_2) stipulated by the scheme, given that upstream emissions for the fossil fuel supply are included in the calculation of the carbon footprint. This would lead to a reduction in support. Moreover, there is still substantial uncertainty around the application of the 45V tax credit, which is delaying multiple investment decisions, affecting not only single projects but also entire hubs.

In Europe, CCUS-based hydrogen production announcements are concentrated around the North Sea area, which boasts access to both natural gas and CO_2 storage resources. The Netherlands is home to the most advanced CCUS-based hydrogen projects, with three projects that reached FID in 2023, planning to connect to large CO_2 transport and storage hubs under construction offshore of Norway and the Netherlands. The European Council approved in May 2024 a gas and hydrogen markets package, which set a deadline of 1 year from the package being signed into law for the European Commission to publish a Delegated Act specifying the methodology for assessing GHG emissions savings from low-carbon fuels (including hydrogen). This is expected to provide further regulatory clarity to project developers in the European Union. The United Kingdom currently

[43] Low-emissions hydrogen production is estimated from the plant CO_2 capture capacity, and therefore only includes hydrogen production for which CO_2 is captured and stored. The range of total hydrogen production is estimated assuming a 40-60% overall unit capture rate for gas-based production and 90-95% for coal and oil-based production, including projects capturing CO_2 for utilisation.

[44] Assuming gas-based production, 0.9105 kg CO_2 emitted per normal cubic metre (Nm^3) H_2 and 90% capture rate.

leads on planned CCUS-based hydrogen production announcements by 2030, supported by government-funded industrial decarbonisation programmes, with an FID on the country's first large-scale project expected this year as part of the Hynet cluster. In total, Europe could account for around 40% of low-emissions hydrogen production from fossil fuels with CCUS by 2030.[45]

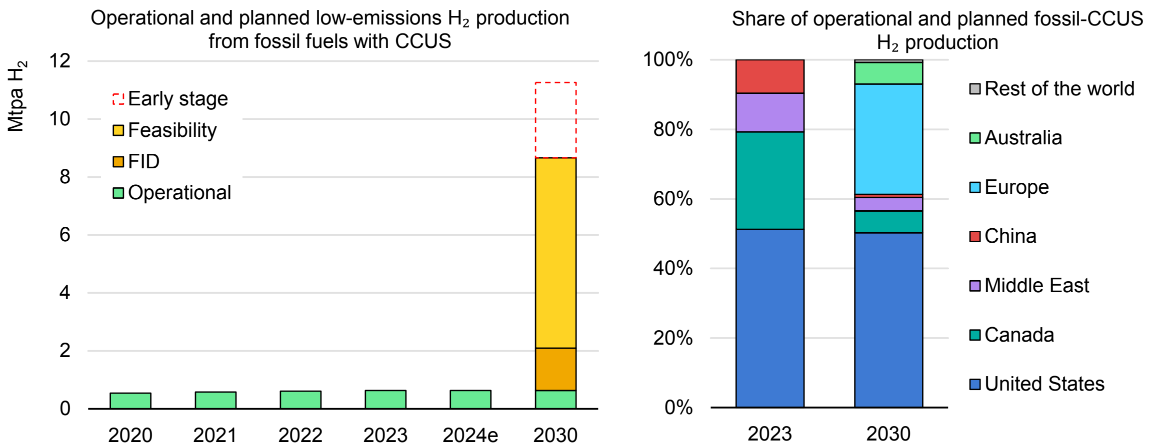
In Canada, the sector is benefiting from CCUS investment tax credits and is also likely to benefit from the Clean Hydrogen Investment Tax Credits. The development of carbon storage hubs is advancing in the province of Alberta, with one project that reached FID in June 2024. Projects in the Middle East are also progressing. In May 2024, Fertiglobe announced an FID for a 1 Mtpa new ammonia production facility in the United Arab Emirates, with plans to capture and store CO_2 from the facility in a second deployment phase that has not yet taken FID.

If all announced projects are realised, low-emissions hydrogen production from fossil fuels with CCUS could increase eighteen-fold, from around 0.6 Mt H_2 per year in 2023 to 11 Mtpa H_2 per year by 2030, or about 8 Mtpa H_2 if projects at an early stage of development are excluded (Figure 3.10). The vast majority comes from gas reforming, and less than 1 Mtpa H_2 from coal or oil gasification. This is still around 6 Mt H_2 short of the circa 17 Mt of low-emissions hydrogen production from fossil fuels with CCUS needed in 2030 in the NZE Scenario.

Projects under development are likely to need further policy and financial support to come to fruition. To date, just over 10% of planned production for 2030 is currently at FID or under construction. However, the number of FIDs in hydrogen or ammonia production almost doubled between 2022 and 2023, indicating higher investor confidence in the sector. Hydrogen and ammonia production projects now make up a third of all FIDs taken for CCUS-based projects in 2023.

[45] This could decrease to one-quarter if projects at a very early stage of development (e.g. only a co-operation agreement among stakeholders has been announced) are included.

Figure 3.10 Production of low-emissions hydrogen from fossil fuels with carbon capture utilisation and storage, historical and from announced projects, 2020-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; 2024e= estimate for 2024. FID refers to projects under construction or which have at least taken FID. Only includes projects with an announced operating date before 2030, assuming they will start on time.
Source: IEA Hydrogen Production Projects Database (October 2024).

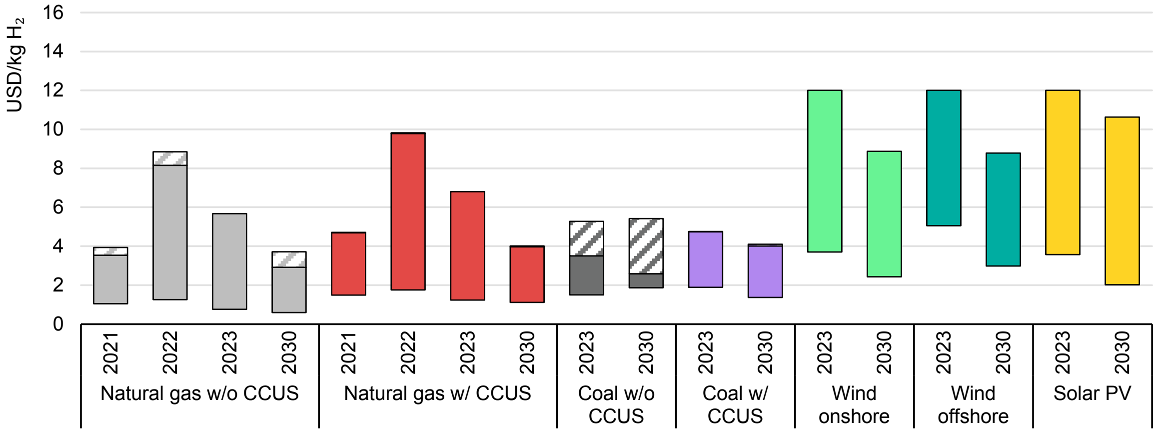
Low-emissions hydrogen production from fossil fuels with CCUS could reach close to 11 Mtpa by 2030, 2 Mt of which is in projects which are already operational or have at least taken FID.

Comparison of different production routes

Hydrogen production cost

The steep increase in natural gas prices over 2022 had a big impact on industrial activity, especially in Europe; the cost of producing hydrogen via unabated steam reformers increased by up to two-and-a-half times compared to the previous year. This increase was exceptional, and in 2023 natural gas prices fell again – including in Europe, with values around USD 25-70/MWh (based on the Dutch Title Transfer Facility [TTF] exchange). The hydrogen production cost from unabated natural gas was estimated at USD 0.8-5.7/kg H_2, similar to the cost prior to the energy crisis. Hydrogen produced from unabated natural gas is generally cheaper than electrolytic hydrogen today, but price volatility could remain a challenge. In Europe, the ratio between the maximum and minimum gas price (based on the TTF exchange) has been 13 in the last 2 years, and even the United States, which has lower gas prices on average, had a price ratio (based on Henry Hub) of more than 10 over the same period.

Figure 3.11 Hydrogen production cost by pathway, 2023, and in the Net Zero Emissions by 2050 Scenario, 2030



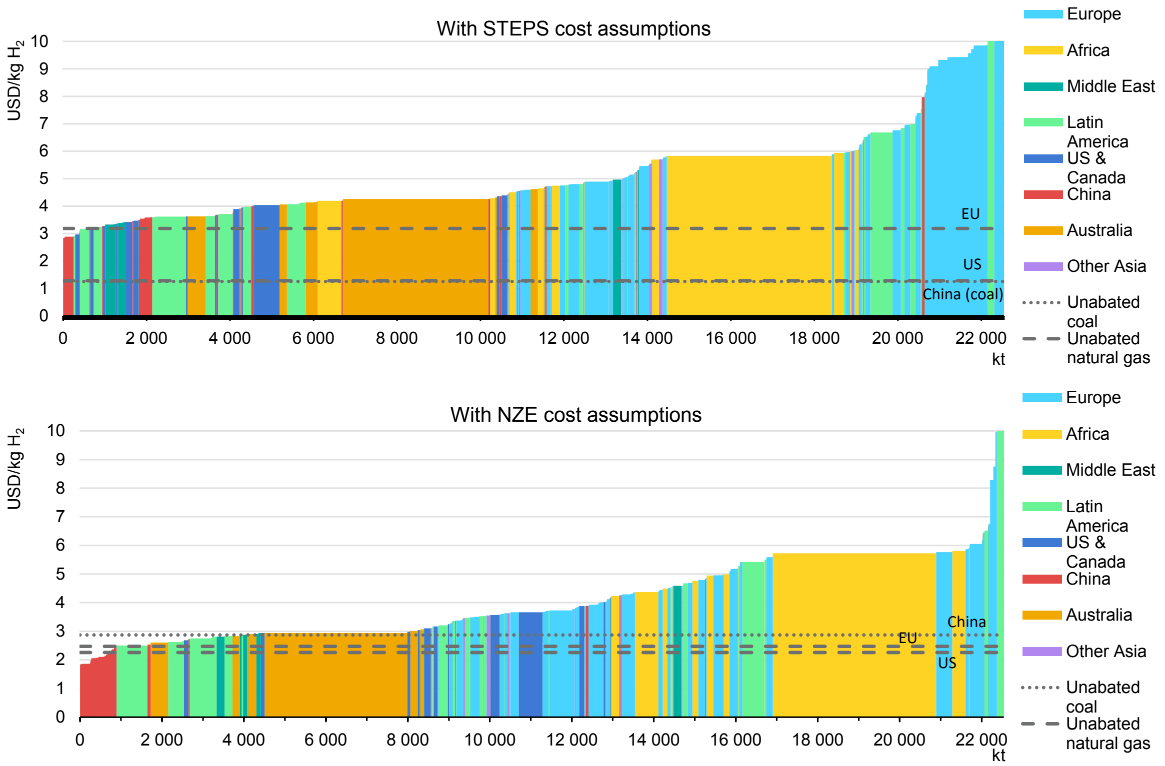
Notes: CCUS = carbon capture, utilisation and storage; w/ = with; w/o = without. Cost ranges reflect regional differences in fossil fuel prices, renewable costs, CO_2 prices, technology CAPEX and OPEX as well as cost of capital. Natural gas price is USD 5-21/MBtu for 2021, USD 6-51/MBtu for 2022, USD 3-35/Mbtu for 2023 and USD 1-15/MBtu for 2030 NZE. Coal price is USD 9-270/t for 2023 and USD 1-120/t for the NZE Scenario in 2030. The levelised production cost of solar PV electricity is USD 20-120/MWh for 2023, USD 14-90/MWh for the NZE Scenario in 2030, with capacity factor of 12-35%. Onshore wind electricity levelised production cost is USD 23-110/MWh for 2023, USD 22-100/MWh for the NZE Scenario in 2030, with a capacity factor of 15-53%. The offshore wind electricity levelised production cost is USD 55-230/MWh for 2023, USD 36-145/MWh for the NZE in 2030, with a capacity factor of 32-67%. Electrolyser CAPEX is USD 950/kW for the NZE Scenario in 2030 and includes the electrolyser system, its balance of plant and EPC, installation cost and contingencies; electrolyser capacity factor assumed to be the same as the renewable power plant. The cost of capital is 6-20%. The dashed area represents the CO_2 price impact, based on USD 15-140/t CO_2 for the NZE Scenario. Renewable-based hydrogen production costs are capped at USD 12/kg H_2. Water cost is not included. Other techno-economic assumptions are included in the Annex.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; NETL (2022); IEA GHG (2017).

Producing hydrogen from unabated natural gas is currently one of the cheapest options, but cost reductions for renewable hydrogen minimise the cost gap by 2030 in the NZE Scenario.

By 2030, large-scale deployment as in the NZE Scenario could bring down the costs of hydrogen production from electrolysis powered by dedicated renewable plants to around USD 2/kg H_2 for the main three sources considered in Figure 3.11, i.e. within the range of production costs from fossil fuels equipped with CCUS. In China, thanks to very good solar resources in certain locations and a lower electrolyser CAPEX, this could go down to below USD 2/kg H_2. In the NZE Scenario, CO_2 pricing implemented in several countries contributes to increasing the cost of unabated pathways.

Figure 3.12 Production cost curve of solar PV- and wind-based hydrogen production from announced projects and production cost from unabated fossil fuels, 2030



Notes: STEPS = Stated Policies Scenario; NZE = Net Zero Emissions by 2050 Scenario; US = United States. Based on announced projects planning to use solar PV, onshore wind, offshore wind or a hybrid configuration of these as electricity source for the electrolyser, with a specified location, planning to be operational by 2030. Assuming optimal oversizing of the renewable plant in each location, to minimise the levelised cost of hydrogen production. Solar PV CAPEX is USD 430-1 460/kW in STEPS and USD 380-1 300/kW in the NZE Scenario; Onshore Wind CAPEX is USD 1 000-3 350/kW in STEPS and USD 980-3 260/kW in the NZE Scenario, Offshore Wind CAPEX is USD 1 960-4 920/kW in STEPS and USD 1 770-4 300/kW in the NZE Scenario. CO_2 price assumed at USD 0-140/t in STEPS and USD 15-140/t in the NZE Scenario. The cost of capital is 6-20%. Water cost is not included. Other techno-economic assumptions are included in the Annex.

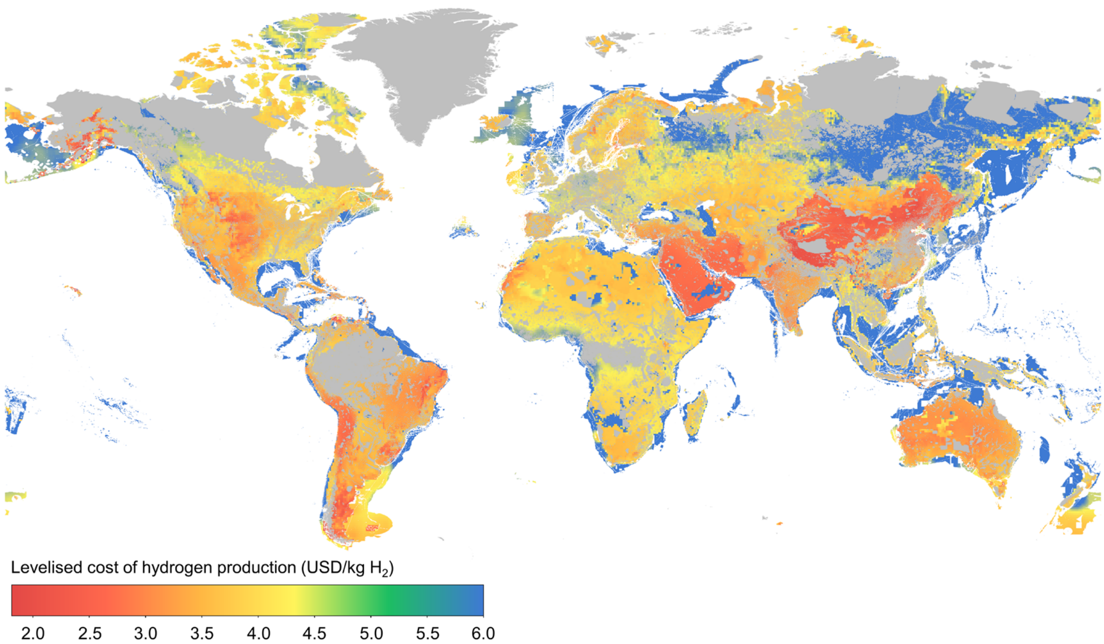
Source: IEA analysis based on IEA Hydrogen Production Projects Database (October 2024) and data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Renewable hydrogen production at under USD 2/kg H_2 could be realised in certain locations, with a large part of the potential volume by 2030 between USD 2-4/kg H_2 in the NZE Scenario.

By 2030, almost 49 Mtpa of low-emissions hydrogen could be produced globally based on announced projects. Of this, more than 22 Mt are projects aiming to use solar PV, onshore wind, offshore wind, or a hybrid configuration of these renewables to power the electrolyser. For projects for which a location has been specified, the optimal renewable-to-electrolyser capacity ratio has been computed to identify the potential minimal levelised cost of production. The combination of these results provides insight into the amount of renewable hydrogen that could be produced at low cost by the end of the decade.

The Asia Pacific region could be the cheapest in terms of production cost, with most of the volume coming from hydrogen from solar PV in China: here about 1 Mtpa H_2 could be produced at a cost around or below USD 3/kg H_2 in the NZE Scenario. In Europe, electrolytic hydrogen production volume could reach nearly 9 Mtpa (see Figure 3.12), but the majority of production from dedicated renewable electricity would be realised at a cost above USD 4/kg H_2 in both the STEPS and the NZE Scenario. Based on the announced projects, only around 1 Mtpa could be produced at a cost below the unabated natural gas route by 2030 in the NZE Scenario, while more than half of the volume (12 Mtpa) would be at costs up to USD 1.5/kg H_2 more expensive than hydrogen from unabated natural gas: without adequate support closing the cost gap, these projects are likely not competitive with the unabated fossil route (Figure 3.12). By considering only projects that are operational or have at least reached FID, only half a Mtpa could actually be competitive against the unabated fossil fuels route by 2030 in the NZE Scenario, and as little as 0.1 Mtpa in the STEPS.

Figure 3.13 Hydrogen production cost from hybrid solar PV and onshore wind, and from offshore wind in the Net Zero Emissions by 2050 Scenario, 2030



Notes: Assuming optimal oversizing of the renewable plant in each location to minimise the levelised cost of hydrogen production. Solar PV CAPEX is USD 380-1 300/kW, Onshore Wind CAPEX is USD 980-3 260/kW, Offshore Wind CAPEX is USD 1 770-4 300/kW. The cost of capital is assumed at 9% for all locations in this map. Water cost is not included. Other techno-economic assumptions are included in the Annex.

Source: Analysis by Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Various regions around the world have excellent renewable resources for low-cost hydrogen production. Production costs could fall below USD 2/kg H_2 by 2030 in certain locations.

Based on the supply cost curve in Figure 3.12, more than half of the production could be between USD 2/kg H_2 and USD 4/kg H_2 in the NZE Scenario, with Australia and Latin America occupying the largest part of this range. However, the LCOH from renewable sources could fall even further and reach values below USD 2/kg H_2 in locations with excellent resources, and by considering a hybrid renewable configuration.

In the NZE Scenario, hydrogen production could reach a levelised cost of around or below USD 2/kg H_2 by 2030 in Argentinian and Chilean Patagonia, and in certain parts of central China (Figure 3.13). In South America and India, a combination of onshore wind and solar PV is the optimal configuration to reach a high capacity factor and keep production costs low (in the south of Argentina, though, the share of solar PV is minimal as wind resources are excellent). Production cost from offshore wind at around or below USD 3/kg H_2 by 2030 could be achieved in Northern Europe and the southern part of Patagonia, where high capacity factors could be reached.

The impact of low-emissions hydrogen on the cost of final products

The cost of producing renewable hydrogen today is generally between one and a half and six times higher than unabated fossil-based hydrogen production, depending on the location. While this is expected to come down in the medium term, the "green premium" associated with renewable hydrogen is substantial today, and can have an impact on the economic competitivity of certain sectors. This cost premium is always a key consideration for the industrial sector in the production of materials and feedstocks, such as steel or ammonia, but a closer look downstream at different steps of the supply chain in which these materials are used gives a perspective on how this green premium could be passed to the end user (or final consumer) of different products. Three examples are provided below.

In the food supply chain, low-emissions hydrogen can be used to produce low-emissions ammonia as a feedstock to produce nitrogen-based fertilisers, such as urea. Fertilisers are commonly used in agriculture to increase crop yields, with their cost having an impact on the final cost of agricultural products – and therefore on the cost of food. Starting from a premium of 110-330% for renewable hydrogen today in China and Europe, respectively, the production cost of renewable ammonia could be 40-200% more than for unabated fossil-based production. For this step in the supply chain, it should be noted that in Europe, given high natural gas prices, domestic production of ammonia has reached very high values in recent years, therefore reducing the gap with renewable-based ammonia production. In several cases, this led to a reduction in activity in the European fertiliser industry and a shift towards imports. By taking into account average fertiliser application and yields for wheat production by region, the impact on the production costs for wheat goes down to 2% in China and to 5-10% in Europe and the United States (Figure 3.14). While this may seem very low, the impact on farmers' finances is not negligible. Moving another step downstream in the supply chain to a commonly used product based on wheat, such as pasta, the premium falls to under 1%. Numerous consumers in advanced economies can (and are willing to) absorb this cost increase, but the situation in emerging markets and developing economies (EMDEs) is completely different. Household budgets are very low in EMDEs and sensitivity to food prices is much higher. Even small increases in prices could put at risk food security.

Another commonly purchased product that could be affected by the "green premium" of renewable hydrogen is a flight ticket. Sustainable aviation fuels (SAF), which include synthetic kerosene, are needed to decarbonise the aviation sector, but their cost today is 4-10 times higher than fossil kerosene. Producing synthetic kerosene in Europe, with a mix of renewables, has a premium compared to fossil kerosene that ranges from 840% in 2023 to 370% in 2030 and 320% in 2035 on the basis of current policy settings (assuming a moderate cost reduction, in line with the STEPS). By considering the SAF blending shares mandated in REFuelEU Aviation, this translates into an increase in fuel cost of 13% in 2023, 8% in 2030 and 32% in 2035, which considering that fuel price usually represents 25-30% of total flight costs, translates into a ticket price increase in the range of 2% to 8%. The increase between years 2030 and 2035 is due mainly to the increase in SAF share to reach 20% SAF in 2035, of which 5% is synthetic kerosene.[46]

With regards to industrial materials, low-emissions hydrogen is set to play a critical role for decarbonisation in steelmaking. Steel, which is today responsible for about 7% of energy sector CO_2 emissions, is used in many different applications, including car manufacturing. Direct reduction of iron ore (DRI) with hydrogen, if powered by clean electricity, could reduce the direct emissions intensity of iron-based steelmaking from more than 2 000 kg CO_2 per tonne of crude steel to below 400 kg CO_2/kg steel if using 100% iron-based inputs, which would be compatible with the IEA's definition for near zero emission steel. Producing low-emissions steel today in China, Europe or the United States is 27-43% more expensive than producing traditional steel. This premium goes down to only around 1% when passed to the final price of an electric vehicle (EV), by considering an average EV price of USD 27 000 in China and USD 40 000 in Europe and the United States.

In general, at every additional step downstream in each supply chain, the premium is reduced due to additional cost components and margins of the different processes (which have been assumed to be constant, for simplicity). The impact of the premium cost of low-emissions hydrogen on commonly used final products

[46] The ReFuelEU aviation regulation does not mandate synthetic kerosene use before 2030. For the year 2023, the 2030 mandate has been used for illustrative purposes.

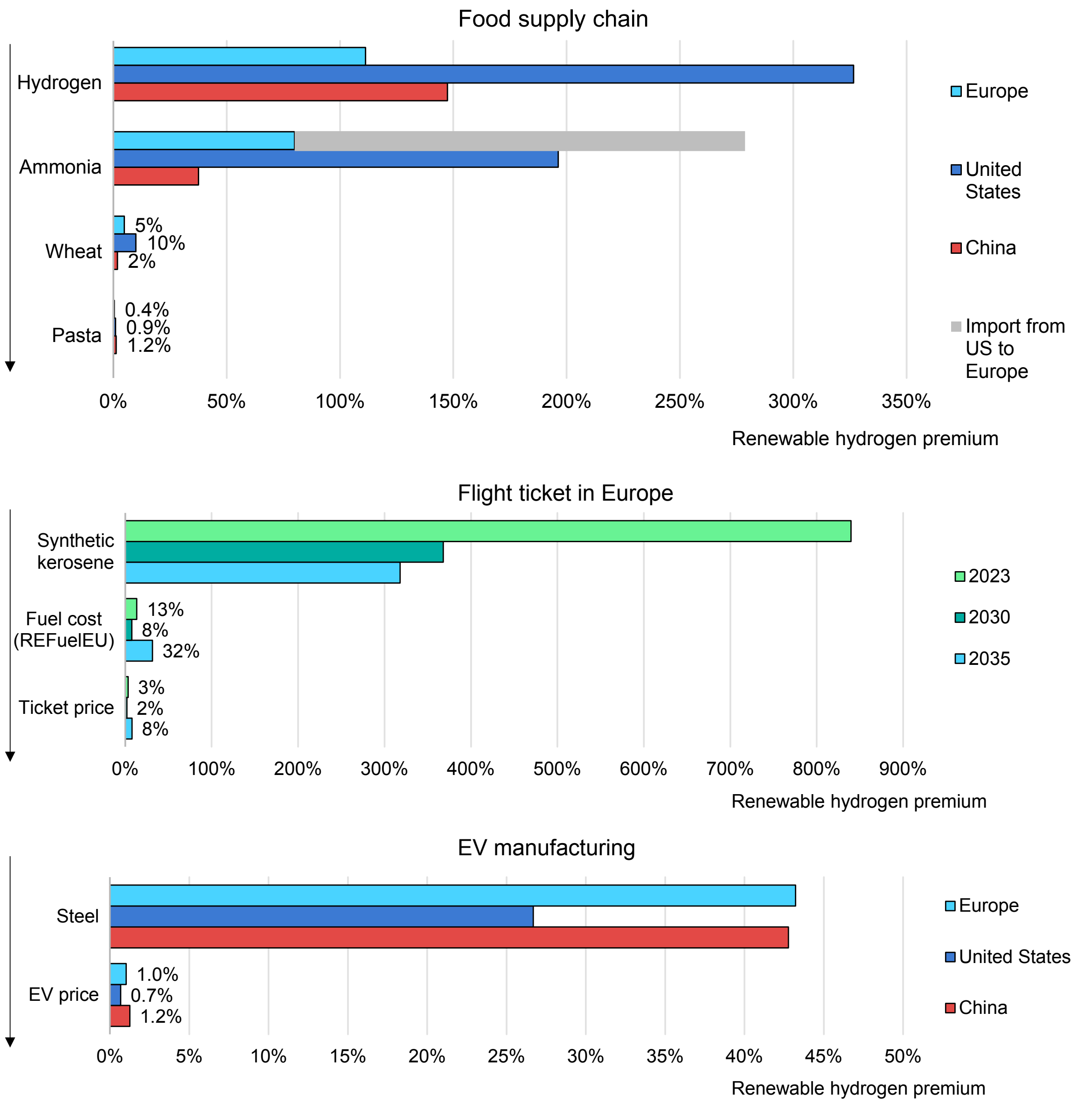
therefore falls to just a few percentage points in all the examples analysed, even when starting from today's high production costs.

There are some premium markets where consumers could be willing to accept this small green premium, and even more if they have sustainability goals. Governments have an opportunity to implement policies that stimulate markets for these end products through public procurement, to reduce emissions in these sectors, which can, in turn, generate demand for low-emissions hydrogen. However, the consequences of these policies on stakeholders right across the value chains would need to be carefully assessed, with significant implications for policy design.

Different end users can be expected to respond to these small price increases in different ways. In the case of flights, a small premium can be relatively easily absorbed by clients, in particular those flying in business class, or by large corporations that have already taken action by buying SAF certificates (see Chapter 2. Hydrogen demand). In the case of cars, the willingness to pay the green premium has already been proven in the EV market and is slowly being reflected in the growing number of offtake agreements for steel produced with low-emissions hydrogen from carmakers. However, the case of food products is very different: Price increases can be easily absorbed by the wealthiest individuals, but can have a significant impact on the personal budgets of a large share of the population, as has been seen in the recent inflationary period. This impact can be particularly serious in certain countries, particularly Africa, where it could even put at risk food security, due to the limited availability of the majority of the population to absorb price increases. Care should be taken in designing these measures to protect the most price-sensitive products and consumers while still making progress on decarbonising these industries. In addition, there are more factors to weigh in when considering public procurement in this sector. Previous experience shows that policies to incentivise fertiliser adoption have led to imbalanced and inefficient use. In the case of the food value chain, focusing public procurement policies on the end product (e.g. food purchases for schools, food banks or military bases) could help to avoid past policy failures. Procurement practices could also be adopted by the private sector, in the same way as for flight tickets. However, this would require the development of reliable systems of certificates and labels to provide certainty to consumers about the low-emission attributes of the end products they are acquiring, which can lead to additional bureaucratic burden.

Finally, farmers and manufacturers further up in the value chain are strongly impacted by cost increases, as their products are globally traded in highly competitive markets, where they operate with slim margins. They may be too far removed from the end consumers to be able to benefit from their willingness to pay a premium. Governments designing policies to stimulate these premium markets will need to take a holistic view of the value chain in order to mitigate any risks to stakeholders.

Figure 3.14 Renewable hydrogen cost premium on selected product prices



Notes: The arrow indicates moving downstream in the supply chain. For the "Food supply chain", average fertiliser use and yield for each region are assumed; wheat price at USD 270-440/t for 2024; a value of 0.7 kg of wheat per kg of pasta is assumed; "Import from US to Europe" refers to the case that renewable ammonia produced in Europe is compared against imported ammonia produced in the United States, due to lower natural gas prices in the United States compared to Europe. For "Flight ticket in Europe" assumptions are as follows: synthetic kerosene production from a mix of solar PV and onshore wind in Europe, assuming 70% of the CO_2 is sourced from direct air capture and the rest from biogenic sources; fuel cost computed with REFuelEU shares of sustainable aviation fuels (SAF) and e-fuels, assuming the 2030 shares for 2023 for illustrative purposes; fossil kerosene price at USD 25/GJ in 2023, USD 31/GJ in 2030 and in 2035; bio-jet kerosene price at USD 58/GJ; a margin of 10% is added on top of synthetic kerosene production cost; fuel cost assumed to be 25% of the final ticket price in all years. For "EV manufacturing": steel intensity of 820 kg/vehicle; EV price is USD 27 000/vehicle in China, USD 40 000/vehicle in Europe and United States.
Sources: IEA analysis based on IEA (2023), The Role of E-fuels in Decarbonising Transport, REFuelEU, and data from FAO, IFA, Bloomberg.

The hydrogen green premium, while substantial today, represents only a few percentage points of increase on the price of final products and is expected to fall further.

The role of water for hydrogen production

Hydrogen production today uses about 1.5 billion cubic metres (m^3) of freshwater, representing less than 5% of the energy sector's total water consumption. However, for future development of the hydrogen sector, it will be fundamental to take local water dynamics into account. Hydrogen production pathways differ with regards to water use for feedstock and cooling. The electrolysis process requires about 10 litres of water per kilogramme of hydrogen (l/kg H_2) for feedstock and a total 30-70 l/kg H_2 for feedstock and cooling, depending on the electrolyser technology and the local climate conditions. Producing hydrogen via steam methane reforming requires a total of 16-40 l/kg H_2, with cooling being responsible for the majority of this: water use for feedstock in the steam methane reforming process accounts for about 5 l/kg H_2. The water requirement scales notably when the facilities integrate CCUS technologies, and can become even higher than for electrolysis.

Various water sources could be used, such as groundwater, surface water, wastewater and seawater. Water stress in numerous regions worldwide necessitates increased investments in desalination plants for the use of seawater. The global installed capacity of desalination plants stands at approximately 145 million m^3 per day, nearly twice what it was in 2010. Desalination plants currently operate in approximately 45 countries worldwide, including China, Saudi Arabia, Spain, the United Arab Emirates and the United States, which together cover more than half of the global installed capacity.

Box 3.3 Defining water metrics

It is essential to distinguish between water “withdrawal” and “consumption” when defining water metrics, as they represent two different aspects of water use. Understanding the difference between these two metrics is crucial for accurate reporting and sustainable water management.

- **Water withdrawal**: refers to the total amount of water extracted from a source for use, i.e. surface water (lake, river), groundwater (including rainwater), seawater. After use, some or all of this water might be returned to the source (water discharge).
- **Water discharge**: refers to the return of water to natural sources after it has been used in various processes. This can include treated wastewater, cooling water from industrial processes, or run-off from agricultural fields.
- **Water consumption**: represents the portion of the withdrawn water that is not returned back to the initial water source. It is the water that is absorbed,

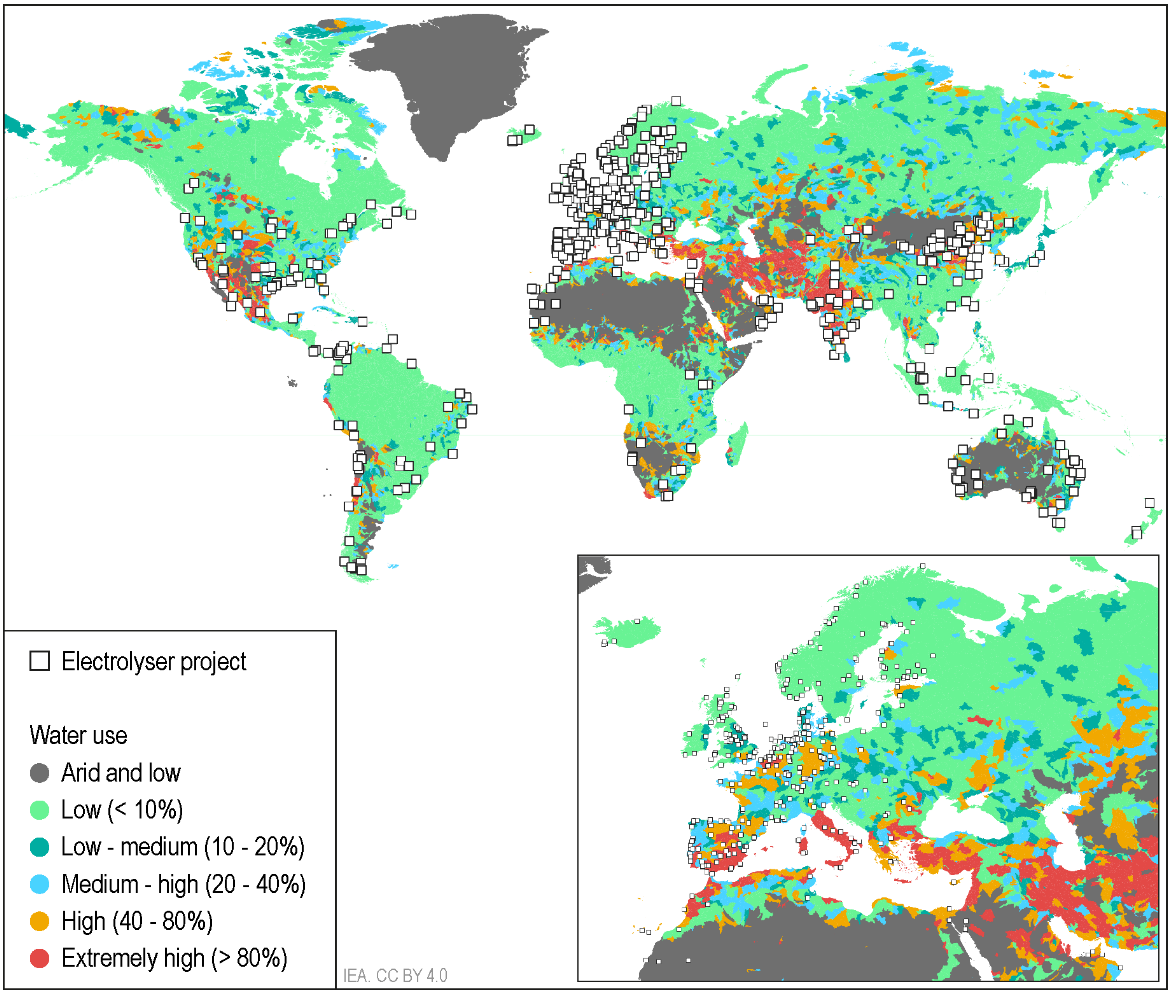
evaporated, or incorporated into products or processes, meaning it is no longer available for reuse in its original form. Put simply: Water consumption = Water withdrawal – Water discharge.

Advances and solutions for water supply in hydrogen projects

Water scarcity could pose a challenge to hydrogen projects, especially in renewable-rich but water-stressed areas. Regions that currently do not face water stress might also be at risk in future due to increases in droughts caused by climate change. For this reason, it will be important for hydrogen projects to use different water sources and take care of their sustainable management. Based on the announced projects, around 40% of the global low-emissions electrolytic hydrogen production by 2030 is located in water-stressed regions (Figure 3.15).

Water shortages could mean that hydrogen projects face disruptions or cancellations. Developers in various regions are therefore exploring large-scale desalination of seawater, or use of treated wastewater, to ensure an adequate water supply for their projects. For instance, the NEOM project plans to address its water needs through a desalination plant powered entirely by renewable energy, boasting a production capacity of 500 000 m^3 of desalinated water per day. This plant will meet 30% of NEOM's forecasted total water demand, including all the water needs for hydrogen production. Similarly, in South Australia, development agreements have been signed with five companies for hydrogen development, including plans for a large desalination plant with a capacity of 260 000 m^3 per day on the Eyre Peninsula, known as the Northern Water project. Additionally, desalination plants are also in the pipeline for several other hydrogen projects, indicating a trend towards integrating desalination into various development schemes to ensure water sustainability. Examples include a new hydrogen plant in Peru, aiming to produce 80 kt H_2 per year; the project of ACWA Power located in Tunisia; the Nour and Aman projects in Mauritania; a project located in the Port of Pecém (Brazil) and many others in Morocco, Namibia, Oman and the United Arab Emirates.

Figure 3.15 Announced low-emissions hydrogen production from electrolyser projects and water stress levels, 2030



Notes: The water stress level is a measure of the ratio of total water demand to available renewable surface and groundwater supplies. Regions with a water stress level above 40% or in arid zones with low water use are considered to be water-stressed.

Sources: Analysis by Jülich Systems Analysis at Forschungszentrum Jülich based on IEA Hydrogen Production Projects Database (October 2024) and Aqueduct Water Risk Atlas.

Around half of the low-emissions hydrogen production from announced electrolyser projects in 2030 is located in regions facing water stress.

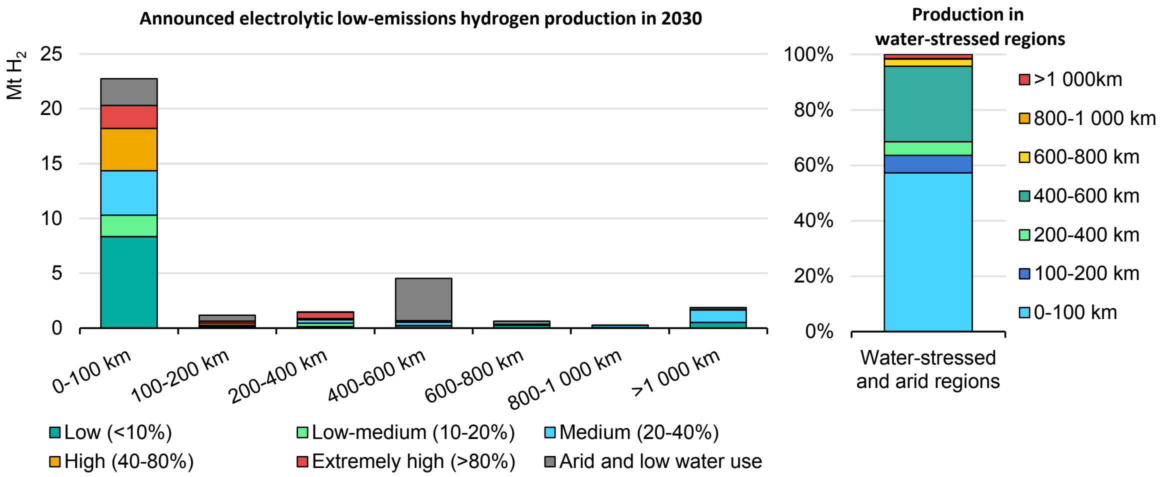
Desalination equipment will also play a crucial role in offshore electrolytic hydrogen production projects. The world's first offshore hydrogen production project, SeaLHyfe, with a 1 MW electrolyser developed by LHyfe, started operation in the second half of 2023 after extensive testing. Elsewhere, the pilot project PosHYdon, a 1.25 MW electrolyser situated 13 kilometres (km) off the coast of the Netherlands, is scheduled to start production in the fourth quarter of 2024. Moreover, additional interest in offshore hydrogen developments incorporating desalination plants has been expressed by various companies, such as the consortium of ITM Power, Ørsted, Siemens Gamesa Renewable Energy, and Element Energy in the Ørsted project; RWE in the H2OpZee floating project in the North Sea and in the AquaVentus project; LHyfe in the HOPE project; and many others.

Desalination plant costs represent only a minor portion (less than 2%) of overall hydrogen project expenses. The process of reverse osmosis seawater desalination requires around 3-6 kWh of electricity per m^3 of water, resulting in a cost for hydrogen production of around USD 0.05/kg H_2. In certain cases, developers could oversize desalination capacity to ensure ample freshwater supply for the project and surrounding areas, benefiting agriculture, industry and domestic users. This approach provides community benefits with limited impact on the economics of the hydrogen production project itself.

Seawater can be useful in coastal areas facing water scarcity, but seawater cooling and brine discharge from desalination can cause thermal pollution and environmental impacts. Thorough assessment and management are needed to minimise these impacts on the ecosystem and ensure that desalination in coastal areas is sustainable. The NEOM project will use brine as feedstock for minerals and metals production, aiming for 100% Zero Liquid Discharge in downstream brine industries.

Around 70% of the low-emissions hydrogen production in 2030 from announced projects using water electrolysis is within 100 km from the coast, so that seawater desalination is a viable option. Also, for projects more distant from the coast seawater desalination can be an option, but they require long-distance pipelines to transport the desalinated water. In water-stressed regions, more than 40% of the low-emissions electrolytic hydrogen production in 2030 is at locations more than 100 km off the coast (Figure 3.16). Experience in long-distance pipeline transport of water exists today, though not in combination with desalination plants. The longest freshwater pipeline in operation today transports in Australia water over 560 km from Perth to Kalgoorlie. The costs for long-distance water transport by pipeline depend not only on distance, but also on any elevation that needs to be overcome. Costs can vary from USD 0.15 per m^3 and 100 km in flat terrain to USD 1 per m^3 and 100 km in terrain with high mountains. Assuming transport costs of USD 0.5 per m^3 for a distance of 100 km, this would correspond to USD 0.025/kg H_2 (assuming water needs of 50 l/kg H_2)

Figure 3.16 Announced electrolytic low-emissions hydrogen production projects by distance from the coast, 2030



Notes: The distance from the coast includes a detour factor of 1.25, i.e. the length of a transport pipeline would be 25% compared to the as-the-crow-flies distance.
Sources: Analysis by Jülich Systems Analysis at Forschungszentrum Jülich based on IEA Hydrogen Production Projects Database (October 2024) and Aqueduct Water Risk Atlas.

Around 70% of the low-emissions hydrogen production from announced electrolyser projects in 2030 is within 100 km from the coast. In water stressed regions, more than 40% are at locations more than 100 km off the coast.

Effective thermal management in hydrogen production can reduce water needs and minimise environmental impacts. Efficient hydrogen production technologies generate less waste heat, reducing cooling demands and water use – research shows a 1% increase in electrolysis efficiency cuts water intensity by 2%. Alternative cooling technologies, such as dry cooling, fogging systems, adiabatic pads systems for Air Fin Coolers, and Tundracel closed-loop cooling tower systems, also offer the potential to reduce water requirements compared to traditional wet cooling methods. Researchers at the University of Adelaide and Stanford University have made progress on generating clean hydrogen through the electrolysis of untreated seawater, and the sHYp company has already patented a membrane-less electrolyser to produce hydrogen from seawater. In addition, Chinese state-owned Dongfang Electric produced hydrogen directly from seawater on a floating offshore pilot plant. This technology is still at a very early stage, but could have significant implications, allowing hydrogen producers to bypass potential disruptions to local freshwater supplies by utilising abundant seawater without the need for extensive desalination facilities.

Several projects for the production of low-emissions hydrogen for steelmaking have been announced, some of them in areas with water stress, such as North Africa or Namibia. DRI with hydrogen releases water: for every tonne of iron produced, 0.48 tonnes of by-product water is released. This can be recycled within the system and used for the hydrogen production process, thereby helping to reduce the demand for large-scale desalination facilities in these regions. The potential for water conservation adds another aspect of sustainability to the hydrogen-based DRI process, beyond reducing carbon emissions.

Countries with water-stressed regions have also introduced legislation that sets conditions for water usage for hydrogen production. For example, Egypt has unveiled a bill offering incentives for electrolytic hydrogen production sourced from desalinated water generated using renewable energy. These incentives will be extended to desalination plants and renewable power facilities that allocate at least 95% of their output to hydrogen plants. Brazil has introduced a bill prioritising the use of desalinated water for hydrogen production, as well as rainwater and the non-potable reuse of wastewaters.

Emerging production routes

Natural hydrogen

Natural hydrogen can be generated through multiple routes, such as biological reactions, geothermal activity, serpentinisation and radiolysis, among others, and the characteristics of the gas generated, such as its purity, will often depend on the route of generation. Exploration and development of natural hydrogen has been gathering steam during the past years, and in the following section we briefly summarise the progress made. Nevertheless, as of August 2024, there are no natural hydrogen wells that have demonstrated commercial feasibility.

Table 3.1 Selected surveys, databases and research activities on natural hydrogen

Institution	Country	Description
Geological Survey of Canada	Canada	Building a database of potential deposits (started in 2022).
Institut National de la Recherche Scientifique (INRS)	Canada	First province-scale survey (1.5 million km^2) of potential source rocks for hydrogen. Additional discoveries in collaboration with Quebec Innovative Materials Corp. at Ville Marie.
U.S. Geological Survey	United States	A national geological map for natural hydrogen.
H2NA project	France	Geological mapping for the Nouvelle Aquitaine region, with an industrial consortium and French Geological Survey BRGM (since 2021).

Institution	Country	Description
Colorado School of Mines and USGS	United States	Joint industry programme with international energy companies to study geologically formed natural hydrogen.
Advanced Research Projects Agency-Energy (ARPA-E)	United States	Two calls (USD 20 million in grant funding) to develop technologies for natural hydrogen exploration and stimulation launched in September 2023.
Hydrogen Laboratory at Coppe-Federal University of Rio de Janeiro Brazilian Hydrogen Association	Brazil	Hydrogen exploration surveys in the municipality of Maricá (Rio de Janeiro State, Brazil).
Geoscience Australia	Australia	Building database and maps of potential resources (since 2021).
HyAfrica	Multiple	Natural hydrogen research in Morocco, Mozambique, South Africa and Togo.
African Hydrogen Partnership (AHP) University Grouping	Multiple	A scientific review on natural hydrogen by AHP, comprising Afe Babalola University (Nigeria), University of Nairobi (Kenya), Manchester Metropolitan University (United Kingdom), University of Genoa (Italy).
Université Grenoble Alpes, University of Bordeaux, Université Toulouse III (France), National Agency of Natural Resources (AKBN), Polytechnic University of Tirana (Albania)	Albania	Discovery of 84% (by volume) pure hydrogen in a deep chromite mine at Bulqizë, Albania with an estimated output of 200 tonnes per year.

Note: km^2 = square kilometre.
Source: IEA Hydrogen Technology Collaboration Programme (TCP) Task 49.

Geological exploration for natural hydrogen follows similar principles as for hydrocarbons, starting with a technical assessment, which is often the step with the biggest uncertainty. Identification of source rocks, migration pathways, reservoirs and traps are followed by commercial feasibility checks, such as flow-tests, economic viability assessments and obtention of a licence to operate. Given the growing interest in this potential route for producing low-emissions hydrogen, several organisations and research institutions have launched geological surveys to identify the potential hydrogen resources available underground in numerous countries (Table 3.1).

The world's only documented hydrogen producer well is in Bourakébougou, Mali, with a production rate of about 1 500 m^3 per day, or 0.1 tonnes of hydrogen per day. To put this in context, the US Department of Energy (DoE) Advanced Research Projects Agency-Energy (ARPA-E) targets deposit production (from formation) rates of at least 30 000 tonnes of hydrogen per year. This is roughly equivalent to an electrolyser with 170 MW capacity operating for about 5000h/yr, or about 15-30% production of a typical steam methane reformer (SMR) plant.

Table 3.2 Selected industrial projects for natural hydrogen worldwide

Country	Location	Developers	Status
Mali	Bourakébougou	Hydroma (100%)	25 positive exploration wells, continued production on Bougou-1 (since 1987, 98% H_2 at approximately 4 bars). Economic assessment in progress.
France	Pyrenees	45-8 Energy (56.4%), Storengy (40%), Lavoisier H2 Geoconsult (1.8%) M&U SASU (1.8%)	"Grand Rieu" Application for exclusive exploration licence submitted in March 2023 (266 km²). Award expected September 2024.
France	Pyrenees	Terrensis	"Sauve TerreH²" Application for exclusive exploration licence (226 km²). First licence for natural hydrogen granted in France in November 2023.
France	Landes	Storengy (60%), 45-8 Energy (40%)	"Marensin" Application for exclusive exploration licence submitted in March 2023 (691 km²). Award expected September 2024.
France	Jura massif	45-8 Energy	"Avant-Monts franc-comtois" Exclusive Exploration licence for 5 years (306km²). Shallow well-drilling campaign planned for October 2024.
France	Puy de Dôme	Sudmine	"Vinzelle" Application for exclusive exploration licence submitted in September 2023 (6 km²), award expected in 2024.
France	Lorraine basin	Française de L'Energie	"Trois Evéchés" Application for exclusive exploration licence submitted in September 2023 (2 254 km²), award expected in 2024.
Finland	Outokumpu belt	Bluejay mining plc	Launching an exploration and sampling programme, building on the geological survey of Finland.
South Africa		H2AU Ltd	Application for three onshore exploration licences submitted in February 2024.
Australia	York Peninsula	Gold Hydrogen	First positive results from Ramsay 1 & 2 boreholes with up to 95.8% pure hydrogen content.
Australia	Eyre Peninsula	H2EX	H2EX received USD 570 000 grant from federal government to develop natural hydrogen licence.
Australia	Amadeus Bassin	Mosman Oil & Gas (25%), Greenvale Energy ltd (75%)	A Farm-In Agreement was established with Greenvale by funding seismic and drilling activities (Oct 2023). 2D seismic in progress. Drilling planned for August 2025.
United States	Kansas	HyTerra	Exploration leases in Kansas (12 720 acres), USD 4 million fundraised. Plans to continue leasing high-priority acreage and drill two exploration wells.

Country	Location	Developers	Status
United States		Koloma	Koloma has raised USD 336 million through two fundraisers. Drilling expected by the end of 2024.
Brazil		Petrobras	USD 3.8 million R&D investment on the generation and viability of extracting natural hydrogen within Brazil. The operation began in October 2023.
Kosovo	Dinarides	45-8 Energy	"Banja Vuca" Application for exclusive exploration licence submitted in January 2023 (57 km²). Award expected in mid-2024.
Canada	Northern Ontario	Chapman Hydrogen and Petroleum Engineering	Drilling planned for mid-2024 near Timmins and Sudbury in Northern Ontario.
Canada	Saskatchewan	Max Power Mining Corp.	Exploring Rider Natural Hydrogen Project (3 356 km²), with historical grades up to 96.4% reported.
Oman		Eden Geopower, Omani Earth Sciences Consultancy Centre	Ministry of Energy & Minerals signed a Memorandum of Understanding (MoU) in September 2023 to assess the potential of geologic hydrogen exploration in Oman.

Source: IEA Hydrogen Technology Collaboration Programme (TCP) Task 49.

40 companies were searching for natural hydrogen deposits commercially by the end of 2023, a fourfold increase since 2020. Exploration is underway in Albania, Australia, Canada, Colombia, France, Finland, Korea, Spain and the United States (Table 3.2). Canada-based producer Hydroma claims to be extracting natural hydrogen at an estimated cost of USD 0.5/kg H_2 in a commercially favourable site in Mali (i.e. very shallow wells [~100 m], nearly pure hydrogen). In Spain and Australia, developers report aiming for a cost of about USD 1/kg H_2, depending on the deposit's depth and purity. Production tax subsidies provided by the US IRA also have the potential to make this production route more economically viable in the United States. Nevertheless, the technical maturity of natural hydrogen is currently estimated to be at Technology Readiness Level (TRL) 5.

Several countries have altered their laws and regulations to encourage exploration for natural hydrogen, but it features explicitly in only 3 of the 60 hydrogen strategies published so far. In Europe, an amendment to Poland's Geological and Mining Law, made in September 2023, provides the legal framework for the exploration and recognition of natural hydrogen fields. In France, natural hydrogen is considered to be an important pillar of the National Hydrogen Strategy, and the country aims to be a pioneer for the production of natural hydrogen. In February 2024, the Philippines opened an auction for the rights to explore for natural hydrogen across two zones around 200 km from the capital city, Manila. Australia passed a bill to enable exploration for naturally occurring hydrogen in

May 2024. Furthermore, additional legislative support has been offered in South Australia, where one-third of the state is already covered by natural hydrogen exploration permits that have either been requested or granted. Elsewhere in the world, though, the legal framework is less clear, and the landscape is evolving fast.

Other emerging routes

Hydrogen can be produced from solid biomass through biological, thermochemical or electrochemical conversion. The hydrogen yield is the highest for thermochemical processes like gasification, pyrolysis, and reforming, which can produce 40-190 kg H_2 per tonne of feedstock,[47] while biological processes like fermentation and anaerobic digestion only achieve around one-quarter of those yields (5-50 kg H_2 per tonne of feedstock). The energy efficiency of most of these processes is 40-67% (lower heating value). Thermal and thermochemical conversion, which have the highest TRL, can achieve costs as low as USD 1.2-2.4/kg H_2, but on average are closer to USD 4.5-7/kg H_2. Biological and electrochemical processes have the dual challenge of a low TRL and higher production costs, in the range of USD 1.7-4.5/kg H_2. Production from biomass can lead to CO_2 removal on a lifecycle basis when the CO_2 captured during hydrogen production is coupled with underground storage. The choice to produce from biomass will be influenced by the hydrogen application; for example, in the transport sector it might be cheaper to use the biomass (products) directly.

In China, there were fewer than ten operating gasification plants for hydrogen production in 2023, though several additional plants are under preparation. A 2.2 ktpa plant in Guangdong province (China) started operating in 2023. This uses steam reforming of biogas from food waste. The estimated investment was CHN 92 million (Yuan renminbi) (~USD 13 million). The targeted application is road transport, with Foshan city having almost 1 000 hydrogen buses and over 500 fuel cell electric vehicles in operation. Another 200 Nm^3/hr bioethanol reforming plant in China also started operating in 2023.

In Europe, the Fuel Cell Tractor Fuelled with Biogenic Hydrogen (FCTRAC) project in Austria aims to demonstrate hydrogen separation from syngas that comes from decentralised wood combined heat and power, biogas and sewage treatment plants for application in fuel cell tractors, and started its demonstration phase in Q3 2023. In the Netherlands, the Fuse Reuse Recycle project is targeting FID in 2024 for a project to convert non-recyclable municipal waste (half of it consisting of biogenic material) to hydrogen. The hydrogen will be used in the nearby Chemelot industrial park. The project had previously received about

[47] This can vary widely depending on the feedstock and the technology.

USD 120 million from the Innovation Fund, out of a total investment of around USD 745 million, and has a capacity of 54 ktpa.

Public support is also being allocated to emerging production routes. Under the second phase of Mission Innovation, Italy approved around USD 39 million for biohydrogen (among other technologies), to be spent across 2024-2026. The European Investment Bank will provide free financial advisory to Plagazi (a waste-to-hydrogen company) for project development in Köping Hydrogen Park (Sweden). This project is sized for 51 MW of hydrogen production, with a total investment of about USD 140 million, and aims to start operation in 2025. In the United States, the DoE awarded USD 8.7 million to seven research projects covering biomass gasifiers, modular designs, techno-economic analysis, and air separation. The DoE also issued a request for information on industry capability for gasification technologies, industry experience and modelling methods.

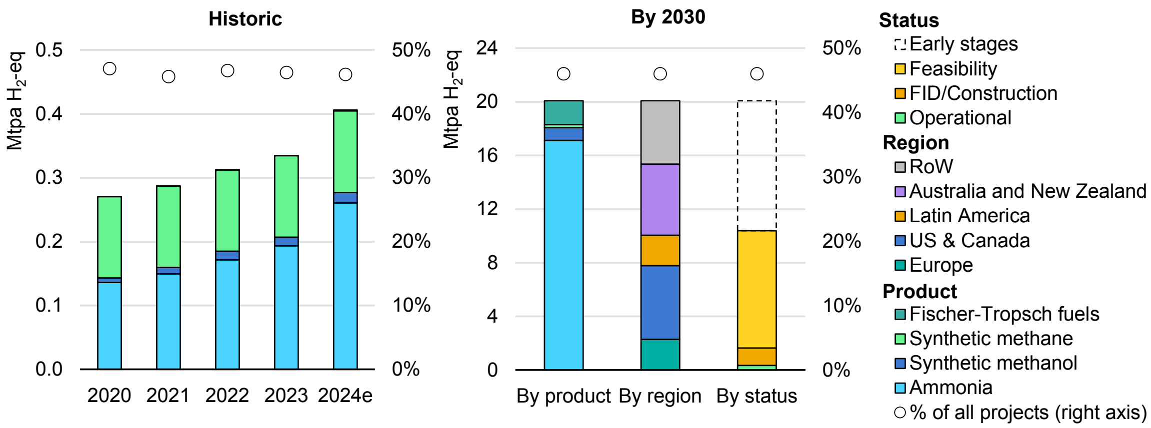
Hydrogen-based fuels and feedstock

Project developments and outlook to 2030

Total production of hydrogen-based fuels and feedstocks is expected to grow by almost 15% in 2024, to reach a total of almost 0.5 million tonnes of hydrogen equivalent per year (Mtpa H_2-eq) (Figure 3.17), on the basis of announced projects that have at least reached FID. This volume represents 70% of the total low-emissions hydrogen production by 2023, but only a small fraction of global annual hydrogen production today of 97 Mt H_2. Almost all of the year-on-year growth comes from ammonia production projects. Almost three-quarters of the new ammonia capacity that is expected to be commissioned during 2024 is located in China, 20% in the Middle East, and most of the remainder in Europe. Over half of the capacity located in China comes from just two projects in Inner Mongolia. Methanation capacity has remained nearly stable, with the biggest project to have advanced beyond demonstration stage being the Great Plain Synfuels plant with a capacity of 125 ktpa H_2 – representing 99% of methanation capacity operating today.

The outlook for hydrogen-based fuels or feedstock based on announced projects adds up to nearly 10 Mtpa of low-emissions hydrogen production by 2030 (20 Mtpa if projects at very early stages of development are included). However, only 7% has taken FID, is under construction, or is operational (13% if excluding projects at very early stages of development). Nearly 85% of the project pipeline has ammonia as a targeted product. If all the announced capacity comes to fruition, it would be equivalent to 50% of current global ammonia production. The number of projects targeting the production of synthetic methanol, as a feedstock or fuel, is much lower, equivalent to 5 Mtpa of methanol by 2030, or almost 4% of global methanol production today. All the announced projects for Fischer-Tropsch (FT) fuel production could produce 1.8 Mtpa H_2-eq. by the end of the decade, equal to 1.6% of the aviation sector jet fuel demand in 2023. Smaller still, the full project pipeline for synthetic methane to 2030 would be equivalent to less than 0.02% of global natural gas production in 2023. Projects for hydrogen-based fuels and feedstocks are widely distributed across the world, with North America and Australia having 25% each, and Europe and Latin America each with around 11% of 2030 announced output. The project pipeline could meet a significant share of regional hydrogen demand, should all the projects materialise (Figure 3.18).

Figure 3.17 Projects for hydrogen-based fuels and feedstocks by product, 2020-2024, and announced projects by product, region and status, 2030



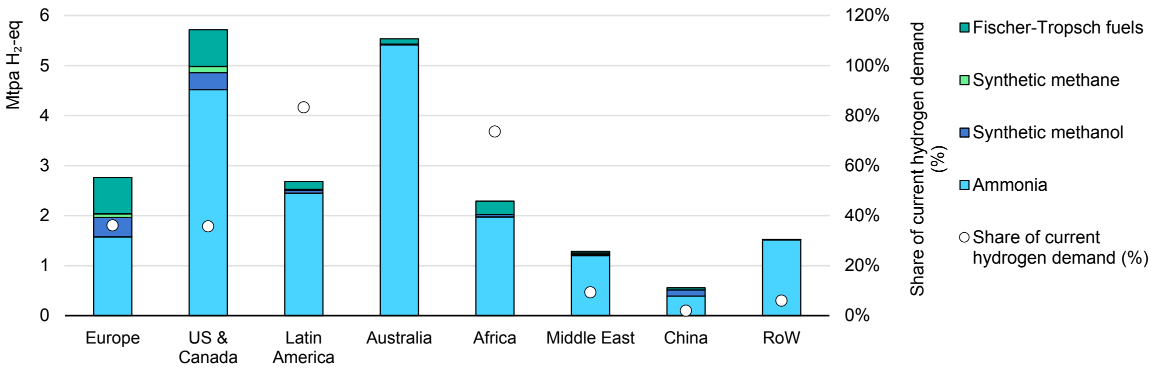
Notes: FID = final investment decision; US = United States; RoW = rest of world; 2024e= estimate for 2024.The percentage share represents the share of hydrogen inputs for the production of hydrogen-based fuels and feedstocks in the total low-emissions hydrogen production from all announced projects for low-emissions hydrogen and hydrogen-based fuels production.
Source: IEA Hydrogen Production Projects Database (October 2024).

The project pipeline for hydrogen-based fuels and feedstocks continues to be dominated by ammonia, although over 40% of the volume expected by 2030 is at an early stage of development.

The country with the largest surplus is Australia, where the project pipeline adds up to nearly ten times the current domestic hydrogen demand. Africa and Latin America have a project pipeline that is comparable to their current hydrogen demand. China, which represents nearly 30% of global hydrogen demand, has the smallest project pipeline for hydrogen-based fuels of all regions, with potential to cover just 2% of their current domestic hydrogen demand. However, projects are not announced far in advance in China, and also have shorter lead times than in other regions, so the current snapshot of the pipeline might not be representative of the actual production that could be expected by 2030. In addition, 70% of the output from announced projects in China is for ammonia, while it only represents 1% of current demand.

If projects at early stages of development are not considered, low-emissions production by 2030 drops by 50%. More than 85% of the projects for the production of synthetic methanol and FT fuels, in terms of output, are at least undergoing a feasibility study. Australia, India, Indonesia and Mexico are the regions with most projects still at early stages of development. A large share of the low-emissions ammonia is expected to be for export, with ammonia being the most favoured hydrogen carrier for international trade (Chapter 4. Trade and infrastructure).

Figure 3.18 Announced production of hydrogen-based fuels by region, 2030



Notes: US = United States; RoW = rest of world. Bars represent the equivalent hydrogen-based fuels demand in hydrogen terms based on the project pipeline, which is compared against the current hydrogen demand (right axis) as a reference. The project pipeline for Australia adds up to nearly ten times its current demand, so it is not shown in the figure to avoid distorting the secondary vertical axis.
Source: IEA Hydrogen Production Projects Database (October 2024)

Apart from in China, the project pipeline could cover a significant share of current hydrogen demand for hydrogen derivatives, if all projects come to fruition.

The cost of producing hydrogen-based fuels and feedstocks

Production cost is one of the key barriers to hydrogen-based fuels deployment. To date, development outside of China has been limited, due to multiple challenges including production cost, lack of CO_2 regulation and infrastructure, methodological gaps for measuring and accounting for the GHG mitigation benefit[48] of the carbon feedstock (see Chapter 7. GHG emissions of hydrogen and its derivatives), and lack of demand incentives. Other than the FuelEU and ReFuelEU targets for shipping and aviation in the European Union, there are no

[48] Including the GHG savings allocation among product for multi-product processes such as Fischer-Tropsch.

other binding policies that would create a significant demand for hydrogen-based fuels. Even these would only equate to 1.1-1.5 Mtpa H_2[49] of demand by 2035.[50]

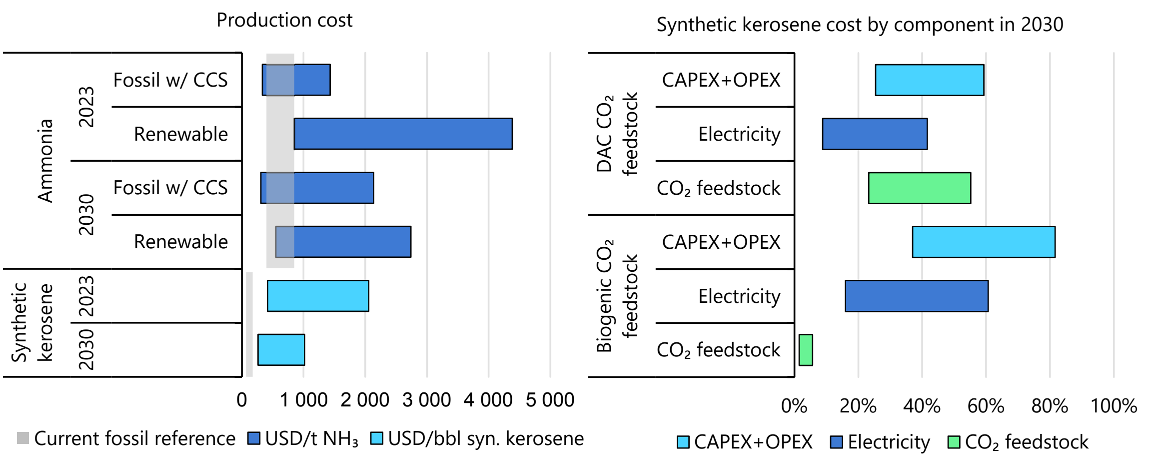
In 2023, the cost of electrolytic ammonia (NH_3) production was nearly triple the average production cost from fossil fuels (Figure 3.19). This is driven by the high investment cost of the assets. This also means that the cost of electrolytic pathways is largely fixed over the asset lifetime, in contrast to the incumbent fossil-based routes where the dominant cost is the fuel subject to price volatility. The electrolyser represents 90% of the total plant CAPEX and it can alone be more than the average fossil-based ammonia price of USD 560/t NH_3, with additional operating costs, electricity consumption for compression and synthesis, and profit margins, translating into a price premium. CAPEX is the main cost driver today, with electricity becoming the dominant factor as the technology is deployed. Production costs are dependent on deployment rather than a fixed timeline. In the most optimistic scenario, production costs could decrease by 30-50% by 2030 in the NZE Scenario, largely driven by a 60% drop in the CAPEX of the electrolyser, which is, in turn, driven by a cumulative electrolyser capacity of 560 GW and continuous innovation. Other cost reductions come from the massive deployment of solar PV and wind, and from a potential improvement of 3-4 percentage points in electrolyser efficiency.[51] All these factors combined are sufficient to close the cost gap with unabated fossil-based ammonia. At the other extreme, in the STEPS, electrolyser deployment could be an order of magnitude lower, at 50 GW, leading to a cost reduction of about 25-40% by 2030. For ammonia produced from natural gas with CCUS, a gas price of USD 50/MWh (which was close to the average price for Europe in 2023) would lead to a cost contribution of nearly USD 500/t NH_3 just from the fuel cost[52].

For synthetic kerosene, similar drivers are behind the cost breakdown and expected cost reduction to 2030, but substantial differences result from the CO_2 feedstock cost: there is a wide range of costs from point-source capture, depending on the CO_2 concentration in the stream. For concentrated streams, like those from ethanol production, ethylene oxide and natural gas processing, the costs are USD 15-35/t CO_2, while for more diluted streams, like the flue gas from power generation, the costs can be USD 50-100/t CO_2. The upper bound for the CO_2 cost is defined by direct air capture (DAC) which can be as wide as USD 100-1 000/t CO_2 based on literature and providers' cost estimates. Using fossil-based CO_2 can only lead to certain degree of CO_2 reduction, but not to a carbon neutral

[49] 1% target for shipping with a 2x multiplier (so half of the energy actually needs to be delivered, and the target is not yet mandatory) until the end of 2033. Range mainly depends on the uptake of energy efficiency rather than fuel mix. Value includes the hydrogen demand for other synthetic products besides kerosene.
[50] FuelEU Maritime establishes a conditional 2% RFNBO target by 2034 if a 1% RFNBO target is not reached by 2031, which is assumed to be the same by 2035, to be able to combine it with the 2035 ReFuelEU target of 5% of synthetic kerosene.
[51] This does not consider the emergence of disruptive electrolysis technologies which could offer larger improvements.
[52] The correlation between natural gas and hydrogen prices could be partially broken by using electricity to achieve the high temperatures in steam reforming and using the natural gas only for the feedstock.

product, thus only DAC and biogenic CO_2 sources are compatible with a net zero emissions scenario (see Chapter 7. GHG emissions of hydrogen and its derivatives). By 2030, DAC costs could decrease by 40%, driven by a reduction in CAPEX and lower costs for the energy input. This cost decrease is not certain, and will depend on the learning from deployment and material costs. Moreover, it differs significantly depending on the scenario, since DAC deployment is driven by deep decarbonisation. The CO_2 feedstock is a key cost driver for synthetic kerosene (Figure 3.19). These two parameters are directly proportional to each other, and for every USD 100/t change in CO_2 feedstock costs, the production of synthetic kerosene changes by nearly USD 55/bbl – a value that is equivalent to 70% of the average WTI oil price from the first half of 2024.

Figure 3.19 Levelised costs of ammonia and synthetic kerosene for electricity-based pathways in 2023 and in the Net Zero Emissions by 2050 Scenario in 2030



Notes: CAPEX = capital expenditure; OPEX= operational expenditure; NH3 = ammonia; CCS = Carbon Capture and Storage. Values for 2030 are based on the Net Zero Emissions by 2050 Scenario. Hydrogen storage cost to reach a minimum of 80% capacity factor of the synthesis processes is included. Fossil reference based on ammonia production from steam methane reforming without CCS and oil price in 2023. Other techno-economic assumptions are included in the Annex.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; NETL (2022); IEA GHG (2017).

The cost of low-emissions ammonia production could be reduced by 40% by 2030. The cost of synthetic kerosene is highly dependent on the source of CO_2 feedstock.

Chapter 4. Trade and infrastructure

Highlights

- Hydrogen trade remains minimal and mainly limited to small-scale, localised transport between neighbouring countries, and trade in hydrogen-based products such as ammonia or methanol. In the Net Zero Emissions by 2050 Scenario (NZE Scenario), interregional trade in hydrogen and hydrogen-based fuels reaches more than 70 Mt in hydrogen-equivalent terms (Mt H_2-eq) by 2050, representing almost 20% of global low-emissions hydrogen demand in that year.
- If all announced projects come to fruition, export-oriented projects could account for 16 Mtpa H_2-eq, or about one-third of low-emissions hydrogen production by 2030. The amount has increased only marginally since the Global Hydrogen Review 2023, indicating that production projects announced in the past year mainly focus on domestic markets. The announced volume still highlights the potential for an international market, though uncertainties persist. As much as 11 Mtpa H_2-eq of this is still at very early stages of development, and a further 5 Mtpa H_2-eq is undergoing feasibility study.
- Ammonia accounts for 85% of the trade from announced projects, reflecting the chemical industry's existing experience in shipping ammonia. Australia and the United States combined could account for 10 Mtpa H_2-eq of exports in 2030, while most projects (75%) target Europe as an import market.
- Announced new pipeline projects could reach nearly 40 000 km by 2035 – which is almost in line with needs in the NZE Scenario, though only 2% have reached final investment decision (FID). Infrastructure development is a capital-intensive, lengthy process, meaning planning must start early. Several pipeline projects got underway in the past year, but progress on others is slow.
- Pipelines are the most cost-effective transport option, particularly for large volumes, but shipping can be cheaper over longer distances. This would require new port infrastructure and suitable tankers. On the basis of announced projects, more than 100 new hydrogen and ammonia terminals and port infrastructure projects could be realised by the end of the decade, on multiple continents. More than half of these projects are new ammonia export terminals.
- Despite recent project announcements, planned underground hydrogen storage capacities – 10 TWh by 2035 and 40 TWh by 2050 – fall far short of the requirements of the NZE Scenario, in which more than 230 TWh is required by 2035. By 2050, the need for hydrogen storage in the NZE Scenario may reach 410 bcm, a volume comparable to natural gas storage infrastructure today.

Overview

Today, hydrogen is mostly produced where it is needed, with limited quantities transported over a few hundred kilometres by truck or pipeline. While some pure hydrogen is transported between neighbouring countries via interconnecting pipelines, and there is trade in hydrogen-based products such as ammonia or methanol, hydrogen trade remains minimal overall. However, hydrogen trade has the potential to play an important role in the transition to a sustainable, secure and affordable energy system. Countries with ample resources for low-emissions hydrogen production that is more than sufficient to meet domestic needs could benefit economically from exporting hydrogen and products produced from hydrogen, once domestic demand has been met. Countries with limited domestic resources for low-emissions hydrogen production at low costs could import the hydrogen needed to decarbonise their energy systems and reduce their reliance on fossil fuels, and could also improve their energy security by diversifying the mix of supply countries for hydrogen imports.

The development of hydrogen markets, underpinned by trade, will require infrastructure for transporting and storing hydrogen. For pure hydrogen, this is more complex – and therefore more costly – than transporting and storing fossil fuels, given that hydrogen in gaseous form has a lower energy density per volume unit, and a lower liquefaction temperature than natural gas. Compression and liquefaction of hydrogen reduce its volumetric energy density for transport and storage, as does converting hydrogen into carriers such as ammonia or liquid organic hydrogen carriers (LOHC) that are subsequently dehydrogenated to supply pure hydrogen. Choosing which option to pursue largely depends on cost considerations, but is also influenced by the extent to which existing infrastructure for handling fossil fuels could be repurposed for hydrogen.

In addition, or as an alternative to trading hydrogen or hydrogen carriers, countries can economically benefit by producing and exporting higher-value products made with low-emissions hydrogen. These products include ammonia, other nitrogen-based fertilisers, methanol or synthetic fuels for which handling infrastructure and demand already exist.

Status and outlook of hydrogen trade

In the IEA Net Zero Emissions by 2050 Scenario (NZE Scenario), interregional trade[53] in hydrogen and hydrogen-based fuels reaches more than 70 Mtpa in

[53] Interregional trade refers to the transport of hydrogen and hydrogen-derived fuels among regions covered by the Global Energy and Climate Model, but not among countries within the same region.

hydrogen-equivalent terms (Mtpa H_2-eq) by 2050, representing almost 20% of global low-emissions hydrogen demand in that year.

Hydrogen trade flows are today minimal, and little changed since the publication of the Global Hydrogen Review 2023 (GHR 2023) in September 2023. There are some cross-country hydrogen pipelines connecting industrial areas in Belgium, France and the Netherlands, but these are all relatively small in size and connect users located close to one another. However, there are a few pilot projects aiming to demonstrate the potential for shipping hydrogen, and ammonia and methanol are already traded internationally as feedstocks for the chemical industry. Around 10% of global ammonia demand and 20% of global methanol demand is met through international trade, almost entirely transported by ship. Between 1981 and February 2022, a 2 500 km international ammonia pipeline was in operation between Togliatti in Russia and the port of Odesa in Ukraine, but operations were suspended after Russia's invasion of Ukraine, and the pipeline was damaged in June 2023.

Recent trade projects

International shipping of hydrogen using an LOHC was first demonstrated in 2020 from Brunei Darussalam to Japan using tank containers, and again in 2022 along the same route, but this time in a chemical tanker. A first cargo of liquefied hydrogen (LH_2) was shipped in 2022 from Australia to Japan, and two further shipments took place in 2022 and 2024.

More recently, notable projects include several cargoes of low-emissions ammonia shipped in 2023 and 2024, mainly from the Middle East to Asia and Europe (Table 4.1). However, traded volumes are still at a small scale and the definition of low-emissions ammonia varies. The ammonia shipments of the Saudi Arabian fertiliser producers Ma'aden and SABIC Agri-Nutrients were certified by TÜV Rheinland as using "blue" hydrogen[54] (138 kt NH_3 for Ma'aden and 37.8 kt NH_3 for SABIC Agri-Nutrients). An ammonia shipment from the United Arab Emirates to Japan in 2024 was certified as low-carbon by TÜV SÜD. Ammonia produced from renewable electricity in Egypt and certified under International Sustainability and Carbon Certification (ISCC) Plus was shipped to India in 2023. A further shipment of ISCC Plus-certified ammonia produced from biomethane and municipal waste took place in 2023 from the Netherlands to Germany.

In early 2024, DNV certified 614 kt NH_3 of Ma'aden's production as ultra low-carbon ammonia, which requires an 80% reduction of GHG emissions compared to unabated fossil production. No details have been announced on potential offtakers for this certified ammonia to date.

[54] See Explanatory notes annex for the use of the term "blue" hydrogen in this report.

Table 4.1 Planned and completed trade pilot projects for low-emissions hydrogen and hydrogen-based fuels, 2023-2024

Trade pilot project	Hydrogen carrier	Exporter	Importer	Year	Quantity traded	Certification
Chile to United Kingdom	Synthetic gasoline	HIF Global	Porsche	2023	2 600 L	
Saudi Arabia to Japan	Ammonia	SABIC Agri-Nutrients	Fuji Oil Company	2023	TBC	TÜV Rheinland
Saudi Arabia to India	Ammonia	SABIC Agri-Nutrients	Indian Farmers Fertilizer Cooperative	2023	5 000 t NH_3	TÜV Rheinland
Saudi Arabia to China	Ammonia	Ma'aden	Shenghong Petrochemicals	2023	25 000 t NH_3	TÜV Rheinland
Saudi Arabia to Bulgaria	Ammonia	Ma'aden	Agropolychim	2023	25 000 t NH_3	TÜV Rheinland
Saudi Arabia to European Union	Ammonia	Ma'aden	Trammo	TBC	50 000 t NH_3	TÜV Rheinland
Saudi Arabia to Chinese Taipei	Ammonia	SABIC Agri-Nutrients	Taiwan Fertilizer Co.	2023	5 000 t NH_3	TÜV Rheinland
Saudi Arabia to Chinese Taipei	Ammonia	Ma'aden	Taiwan Fertilizer Co.	2023	TBC	TÜV Rheinland
Saudi Arabia to India	Ammonia	Ma'aden	Coromandel International	2023	TBC	TÜV Rheinland
Netherlands to Germany	Ammonia	OCI Global	Rohm	2023	800 t NH_3	ISCC PLUS
Egypt to India	Ammonia	Fertiglobe	Tuticorin Alkali Chemicals & Fertilisers	2023	TBC	ISCC PLUS
Egypt to India	Ammonia	Fertiglobe	Tuticorin Alkali Chemicals & Fertilisers	2023	37.4 t NH_3	
United Arab Emirates to Japan	Ammonia	ADNOC	Mitsui	2024	> 1 000 t NH_3	TÜV SÜD
Norway to Sweden	Ammonia	Yara	Lantmannen	2024	TBC	
Australia to Indonesia	Hydrogen	Marubeni		2024	TBC	
Australia to Fiji	Hydrogen	Halcyon Power	Fiji Gas	2024	TBC	

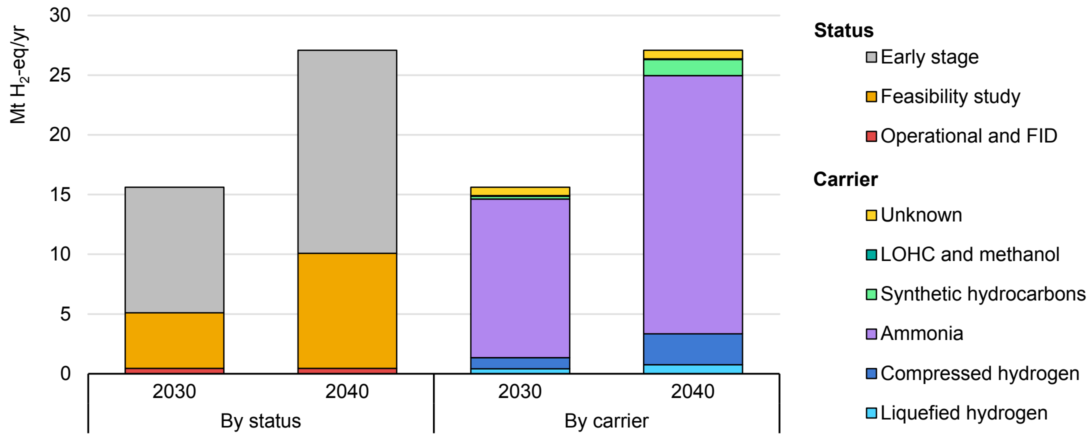
Notes: L = litre, NH_3 = ammonia; TBC = to be confirmed. This table does not include pre-existing ammonia trade in the fertiliser industry. Around 10% of global ammonia production for the fertiliser industry is traded today, but this is almost entirely based on ammonia production from unabated fossil fuels. Projects characterised as "low-carbon" or "blue" ammonia or hydrogen are included, although information on the emission reduction compared to the unabated production from fossil fuels is not always available. TÜV Rheinland certification requires a CO_2 emissions reduction by at least 30% by capturing CO_2 and storing it, or chemically or minerally fixing it for at least 25 years. TÜV SÜD certification requires at least a 70% GHG emissions reduction compared to a benchmark intensity of 94 kg CO_2 equivalent (CO_2-eq) per GJ of ammonia. The ISCC PLUS certifications for OCI Global and Fertiglobe required GHG emissions being at least 70% and 73%, respectively, lower compared to production with fossil fuels.

Announced trade projects

Export-oriented projects account for 16 Mtpa H_2-eq, or about one-third of the low-emissions hydrogen production that could be achieved by 2030, if all announced projects are realised (Figure 4.1). This highlights the potential for an international market, although uncertainties persist.

As many as 11 Mtpa H_2-eq of the announced export projects by 2030 are still at very early stages of development, and a further 5 Mtpa H_2-eq are undergoing feasibility study. Of this, less than a third has a potential offtaker among the project partners – an area where lack of progress was already observed in the GHR 2023. The share of committed volume, i.e. projects that have at least reached FID or are under construction, is still very low, at less than 3% of the total volume that could be traded by 2030 (or less than 9% if projects at an early stage of development are excluded). As much as 70% of the potential volume to be exported by 2030 not only has not yet reached FID, but also has no potential offtaker among the project partners.

Figure 4.1 Low-emissions hydrogen trade by status and by carrier based on announced projects, 2030-2040

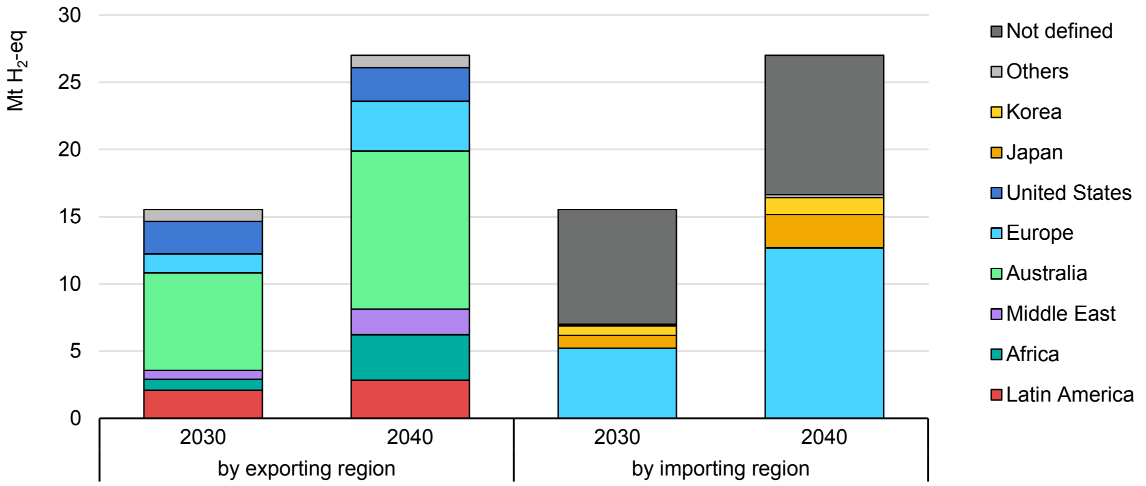


Notes: FID = final investment decision; LOHC = liquid organic hydrogen carrier. "Gaseous hydrogen" includes both projects aiming to transport gaseous hydrogen via pipelines and projects planning to ship it using a compressed hydrogen carrier. "Synthetic hydrocarbons" includes projects aiming to trade synthetic methane or synthetic oil products.
Source: IEA analysis based on multiple sources, including company announcements.

Almost all announced projects for low-emissions hydrogen exports are still at an early stage or undergoing feasibility studies, and ammonia is by far the preferred carrier.

Potential output from announced export-oriented production in 2030 (if all projects are realised on time) has only marginally increased since GHR 2023, by 0.1 Mtpa H_2-eq (and by 2.3 Mtpa H_2-eq for production in 2040). This compares to an increase of 11 Mt H_2-eq in low-emissions hydrogen production in 2030 from all announced projects, indicating that domestic use of hydrogen, rather than export, has been the focus of low-emissions production projects announced since September 2023.

Figure 4.2 Low-emissions hydrogen imports and exports by region based on announced projects, 2030-2040



Note: "Not defined" refers to projects for which the import destination has not been disclosed.
Source: IEA analysis based on multiple sources, including company announcements.

Australia and the United States could become the largest exporters by 2030, and Europe the largest importer, although over half of all production has no defined import destination.

Ammonia is the most frequently chosen carrier, accounting for 85% of the trade from announced projects. This is due to the already developed international trade market and existing shipping infrastructure for ammonia as feedstock for the chemical industry. In addition, at the import side, ammonia could be directly used in applications such as fertiliser production or potentially as a shipping fuel (see Chapter 5. Investment, finance and innovation), avoiding the need for reconversion into hydrogen. A preference for ammonia as a near-term trade option is also reflected in the 58 national hydrogen strategies published so far, many of which mention ammonia trade as well as potential demand volumes (see Chapter 6. Policies). Less than 10% of the volume that could be traded by 2030 based on announced projects is using hydrogen in its pure form, whether liquefied or compressed, while around 2% is in the form of synthetic hydrocarbon fuels. Synthetic methane, which is produced from hydrogen and CO_2 and is compatible with existing natural gas infrastructure and end uses, accounts for around 0.7% of the announced trade projects in 2030. Announced projects to produce synthetic methane in Australia, the United States and Peru for exports to Japan are at early development stages.

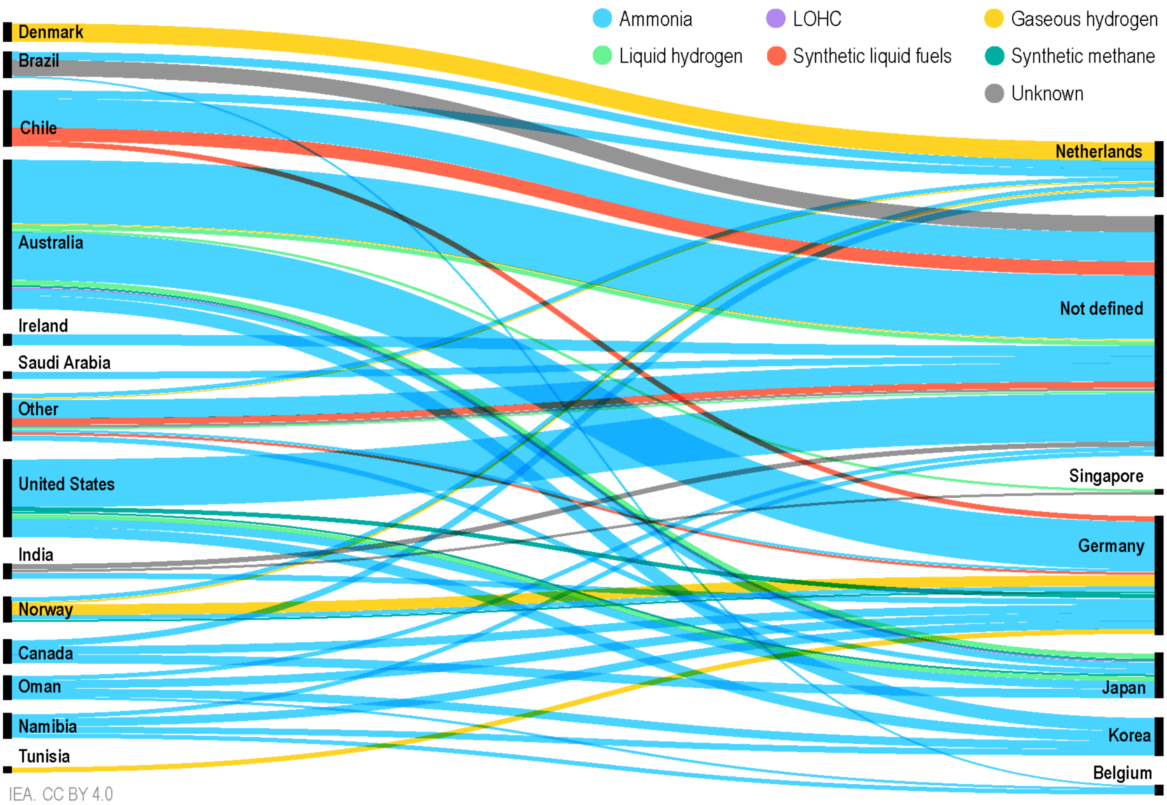
Australia and the United States could become the largest exporters by 2030, together accounting for 10 Mtpa H_2-eq by 2030 – more than a third of this volume, however, is from a single project in Kalgoorlie (Australia) for which the exact export location has not yet been defined (Figure 4.2). Latin America could become the third-largest exporter, with more than 2 Mtpa H_2-eq by 2030, although a large part of this has not yet found a delivery destination. Among the projects that have a defined import destination, Europe accounts for 75% of the announced import volume and is expected to become a key market for hydrogen and hydrogen-based fuels and feedstocks. Countries in the Asia Pacific region represent another important demand centre: based on announced projects, Japan and Korea together could import 3.7 Mtpa H_2-eq by 2040.

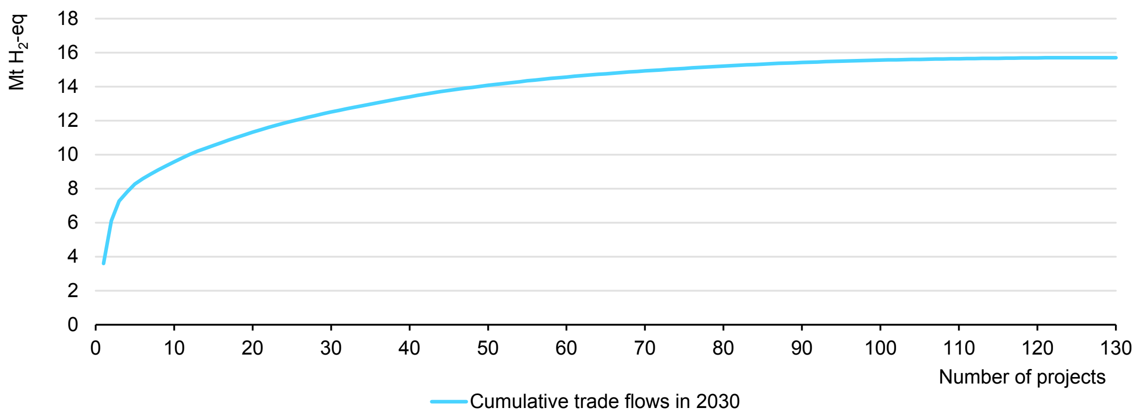
Looking ahead to potential exports by 2030, only around 0.5 Mtpa H_2-eq is from projects that already have an offtake agreement in place with a buyer. All of these projects are for the delivery of ammonia. It is perhaps little surprise that the two largest traders of this commodity today – Trammo and Yara International – have both signed offtake agreements for low-emissions ammonia from projects under development. Each had a purchased volume of about 4 Mtpa of ammonia in 2022 (including ammonia from unabated fossil fuels), accounting for just under half of all global trade of ammonia, which mainly serves the fertilisers sector. In the case of the NEOM project in Saudi Arabia, Air Products is part of the joint venture behind the project, and is also the sole offtaker. In this case, the target market is different, as the company aims to export ammonia for its subsequent reconversion into hydrogen for use as fuel in the transport sector. Another use of ammonia can be seen in the case of the Donaldsonville (United States) project by CF Industries: Japan's largest power generation company, JERA, plans to import the purchased ammonia to meet demand for low-carbon fuels in Japan (Table 4.2).

Table 4.2 Selected export projects with identified offtaker

Project name	Developer	Offtaker	Offtake agreement
Teal ammonia plant, (Quebec, Canada)	Teal	Trammo	Agreement for 800 ktpa of ammonia supply that Trammo will distribute to global customers from 2027, for 15 years.
NEOM Green Hydrogen Project (Saudi Arabia)	NEOM, ACWA Power, Air Products	Air Products	Air Products is the sole offtaker of the 1.2 Mtpa ammonia from the project, from 2027, for 30 years.
CF Industries blue ammonia (Donaldsonville, United States)	CF Industries	JERA	Joint development agreement including the supply of 500 ktpa of ammonia from 2028.
Green Hydrogen and Chemicals SPC (Oman)	ACME, Green Hydrogen and Chemicals Company	Yara International	Agreement to buy 100 ktpa of ammonia.
Egypt Green Hydrogen Project	Fertiglobe	Hintco	Agreement for up to 397 kt NH_3 over the period 2027-2033 (with a guaranteed minimum offtake of 240 kt NH_3).
Phase-1 of green ammonia project in Odisha (India)	ACME	IHI	Agreement for over 400 ktpa NH_3 from 2028

Figure 4.3 Potential low-emissions hydrogen bilateral trade flows by carrier based on announcements and cumulative hydrogen trade volume over number of projects, 2030





Notes: LOHC = liquid organic hydrogen carrier. “Gaseous hydrogen” includes both projects aiming to transport gaseous hydrogen via pipelines and projects planning to ship it using a compressed hydrogen carrier. “Synthetic hydrocarbons” includes projects aiming to trade synthetic methane or synthetic oil products. In million tonnes of hydrogen equivalent.

Source: IEA analysis based on multiple sources, including company announcements.

Five large projects in Australia, Brazil, Denmark and the United States account for half of all production from 130 announced export-oriented low-emissions hydrogen production projects.

Overall, around 130 export-oriented projects for low-emissions hydrogen production have been identified, with the project size varying from a few kilotonnes of traded hydrogen to 3.6 Mtpa for the largest project (Figure 4.3). Five large-scale projects alone account for 8.3 Mtpa, or half of all announced export-oriented production in 2030 (16 Mtpa). None of these projects has reached FID and one is undergoing feasibility studies, while four are at very early development stages. Depending on the progress of these large-scale projects, the actual amount of low-emissions hydrogen traded by 2030 could vary significantly.

Trade contracts and tenders

The majority of announced trade projects to date are based on bilateral trade contracts, which can provide investment security to project developers for capital-intensive hydrogen production plants and transport infrastructure by offering clear pricing mechanisms and a sufficient contract duration. Auctions or tenders are often used as competitive instruments to award these contracts. In most cases, auctions are designed so that suppliers bid for the lowest price for which they are willing to sell a certain amount of hydrogen or hydrogen-based fuel (which may be also specified as part of the bid).

Over the past year, several international auctions or tenders for low-emissions hydrogen have been launched, in many cases initiated by companies planning to use low-emissions hydrogen. In Germany, several steel makers (including Salzgitter AG, Stahl-Holding Saar and thyssenkrupp Steel Europe AG) announced tenders for low-emissions hydrogen. Outside the steel sector, Total Energies announced in September 2023 a tender for 500 000 tpa H_2 of renewable hydrogen for its refineries in Europe (more details on the tenders are available in Chapter 2. Hydrogen demand).

Auctions initiated by companies suggest that there is a demand for low-emissions hydrogen, which often has been fostered by policy instruments such as incentives or grants. One instrument that combines support for low-emissions hydrogen supply with demand creation is a double auction, in which an intermediary "market-maker" buys low-emissions hydrogen through long-term offtake agreements from suppliers and sells the hydrogen to end users, helping to create a market. As such, the auction covers both buying and selling hydrogen, with the intermediary market-maker covering any losses incurred from the difference between purchase cost and sale price. The H2Global initiative is based on such a double-auction mechanism. The German government was the first supporter of the H2Global approach, committing EUR 900 million to H2Global's pilot auction, implemented by Hintco, a 100% owned subsidiary of the H2Global Foundation. Hintco enters contracts with sellers and buyers, who often struggle to connect independently at an early stage of market development. This intermediary then buys products – which are typically more expensive than their carbon-intensive counterparts – to sell them through an auction at a lower price to end consumers, thereby supporting growth in demand. First tenders for supply contracts for the imports of renewable ammonia, synthetic methanol and synthetic kerosene were launched at the end of 2022. Tender results for ammonia and synthetic kerosene were announced in July 2024. Fertiglobe, a joint venture of OCI and ADNOC, was awarded the lot for ammonia at a delivered price to Europe of EUR 1 000/t NH_3 (EUR 811/t NH_3 net price excluding delivery). Fertiglobe plans to produce the ammonia in Egypt using hydrogen from the Egypt Green Hydrogen project, with deliveries to Europe starting in 2027 with a potential 19.5 kt NH_3 and rising to a total of 397 kt NH_3 cumulatively by 2033. The sales auction for renewable ammonia is set to start in 2025-2026. No winners were awarded for the H2Global tender for synthetic kerosene, and the funds will instead be allocated to the tender for synthetic methanol, for which winners have not yet been announced. Moving forward, Germany has allocated an additional EUR 3.83 billion to new tenders of the H2Global programme, including a joint tender by the Netherlands and Germany for hydrogen imports to Europe, with each country contributing EUR 300 million. While the first round of H2Global tenders was not dedicated to specific supply regions or countries, future auctions could be geographically targeted. Canada and Germany announced a joint H2Global auction for hydrogen trade from Canada to Germany, with each country committing CAD 300 million (USD 221 million) and the auction to be launched by the end of 2024. Australia and Germany announced a similar H2Global tender, with funds of up to EUR 400 million (USD 443 million).

Status and outlook of hydrogen infrastructure

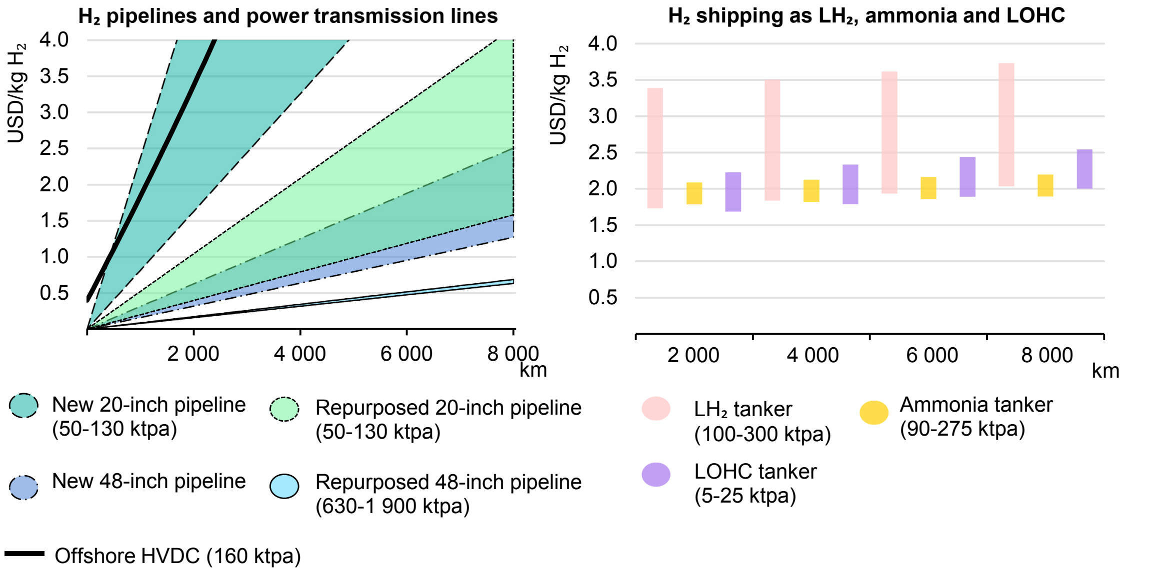
Hydrogen transport infrastructure is essential to connect supply and demand regions, while storage enables efficient management of fluctuations and enhances system resilience in the event of supply disruptions. However, the development of infrastructure for hydrogen and hydrogen-based fuels faces several challenges:

- Gas infrastructure projects are large civil engineering projects, often spanning several jurisdictions. As a result, they tend to have long lead times, due in part to lengthy permitting processes and, often, a lack of socio-political support. On average, these projects, including natural gas pipelines, port terminals and underground gas storage facilities, take between 6 and 12 years to complete.
- The capital costs associated with gas transport and storage infrastructure benefit significantly from economies of scale, particularly in the case of pipelines, which can facilitate the competitively priced transport of large quantities of energy over long distances. For example, a new 20-inch diameter pipeline can transport up to 1.2 GW of hydrogen at a levelised cost of USD 0.6/kg H_2/1 000 km. By comparison, a new 48-inch diameter pipeline can transport up to 17 GW of hydrogen at a levelised cost of less than USD 0.2/kg H_2/1 000 km. For reference, a high-voltage direct current (HVDC) transmission line of 500 kV, which is often

used for power transmission over long distances, can transport approximately the same energy as a 20-inch pipeline, though at 2.5 times more cost per GWh for a 1 000 km distance (Figure 4.4).

The long lead times associated with gas and power infrastructure mean that it must be planned ahead of the supply and demand projects it will connect, which usually have shorter lead times. Failure to do so may prevent these projects from reaching FID. Planning must also incorporate long-term foresight to accurately anticipate infrastructure needs and avoid oversizing facilities that may remain under-utilised, even as projects reach economies of scale.

Figure 4.4 Indicative levelised cost of delivering hydrogen, by transport option and distance in the Net Zero Emissions by 2050 Scenario, 2030



Notes: HVDC = high-voltage direct current; H_2 = hydrogen; ktpa = kilotonnes per year; LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier (methylcyclohexane considered); USD/kg H_2 = USD per kilogramme of hydrogen. Hydrogen pipelines refer to onshore transmission pipelines operating at 25-75% of their design capacity for 5 000 full-load hours. Electricity transmission by offshore HVDC indicates electricity transmission required to obtain 1 kg H_2 in an electrolyser with 69% efficiency. Transport costs by ship include investment and operational costs to convert hydrogen to a higher-density carrier, store it, ship it and reconvert it to deliver gaseous hydrogen. Shipping capacity range corresponds to the annual capacity of a port terminal with 10 (upper cost range) to 30 (lower cost range) shipments per year.

Pipelines are the most cost-effective transport option, particularly for large volumes, while shipping becomes more economical over longer distances.

Transport by pipeline

The total length of natural gas transmission pipelines in operation is currently approximately 1 million km. In addition, about 70 000 km are under construction and about 160 000 km are under consideration. As natural gas consumption falls in the transition to net zero emissions, repurposing this infrastructure for hydrogen represents an opportunity to minimise the risk of stranded assets, reduce investment costs and potentially shorten lead times, while reducing the environmental impact associated with manufacturing and laying of pipelines.

Approximately 5 000 km of hydrogen pipelines are already in operation worldwide, primarily in the United States and Europe. These pipelines are privately owned, relatively small, and connect refineries and chemical complexes, operating under constant loads, all onshore. However, future hydrogen pipelines could be significantly larger, connecting different countries and even continents, including offshore routes. These new pipelines should offer system flexibility, with the capacity to withstand pressure swings from cyclic loading, and provide linepack.[55] A hydrogen transmission system of this kind would be quite distinct from current local networks, and would more closely resemble the natural gas transmission in use today, but would be more centralised, and largely rely on trunklines. Even under the NZE Scenario, hydrogen consumption would be lower than current natural gas consumption and concentrated around fewer large users, such as industrial facilities.

Legal and regulatory frameworks for hydrogen pipelines

Policy makers are already working on legal and regulatory adjustments needed to enable the deployment of dedicated hydrogen infrastructure. In May 2024, the European Council adopted the "Hydrogen and Decarbonised Gas Markets Decarbonisation Package" to reform the existing EU regulatory framework for low-emissions gases (see Chapter 6. Policies). The package covers transmission, storage and distribution, introducing unbundling[56] and a regulated third-party access regime by January 2033. Hydrogen pipelines will be regulated according to the European Union's standard Regulated Asset Base model, allowing operators to obtain a guaranteed return on investment, in exchange for allowing third-party access to their infrastructure.

The new regulation also initiated the European Network of Network Operators for Hydrogen (ENNOH), which consists of certified hydrogen transmission network operators in EU member states. In June 2024, future EU hydrogen transmission network operators agreed on draft rules for the establishment of ENNOH, including statutes, rules of procedure and a list of members. These draft rules will be reviewed by the European Commission and the Agency for the Cooperation of Energy Regulators, with ENNOH expected to be established in the second quarter of 2025. The European Network of Transmission System Operators for Gas and

[55] Linepack refers to the volume of gas stored in a pipeline. The gas can be compressed, increasing the pressure of the pipeline. Since the pipeline can operate within a safe pressure range, the amount of gas injected into a pipeline may differ from the amount of gas withdrawn at a specific time, providing short-term operational flexibility to match supply and demand.
[56] Unbundling refers to the separation of activities potentially subject to competition, such as hydrogen production, from those where competition is not possible or allowed, e.g. transmission and distribution, which is a regulated monopoly in the European Union. This would allow the independent transmission system operator model under certain conditions.

ENNOH will jointly develop a 10-year hydrogen network development plan, to be published in 2026. This will serve as the basis for selecting “Projects of Common Interest”, and from 2028 onwards, ENNOH will be solely responsible for the network’s development.

Member states have started to designate their hydrogen network operators to be part of ENNOH and participate in planning the European hydrogen network. In December 2023, Spain appointed Enagás as the provisional operator of the hydrogen transmission network. In April 2024, Belgium appointed Fluxys as Hydrogen Network Operator for the future transmission grid, in accordance with the Belgian Law on the Transmission of Hydrogen by Pipelines of July 2023. In June 2024, the Netherlands appointed Gasunie as the intended network operator for the future North Sea hydrogen network. Outside the European Union, other countries are also taking steps to develop the required regulatory frameworks. In April 2024, Israel granted Natgaz permission to build and operate hydrogen and CO_2 pipelines.

In June 2024, the EU Commission approved a EUR 3 billion German state aid scheme to support the development of a hydrogen core network. The aid, in the form of a state guarantee from the state-owned development bank KfW, will enable transmission system operators (TSOs) to secure favourable loans. Germany's hydrogen network is expected to be completed by 2032, with the possible extension of some projects until 2037, and will cover 9 700 km, 60% of which would be repurposed natural gas pipelines, at a cost of around EUR 20 billion. The network will be funded by user charges and private sector investment, with interim government funding to cover initial shortfalls, through top-up funding dubbed “WANDA”. Initially, the network fee will be set at a rate lower than would be needed to cover costs, to prevent very high fees from low utilisation rates. The Federal Network Agency (BNetzA) will review the fees every 3 years, with the aim of recovering the investment made by 2055. In April 2024, BNetzA launched a consultation on determination of the WANDA, and this was confirmed in June 2024, with the aim of setting uniform tariffs from January 2025 and keeping them as stable as possible until 2055. Furthermore, the government will implement an amortisation system, which will guarantee a 6.7% pre-tax return on equity, with operators covering 24% of the costs if the ramp-up of the network fails. In May 2024, Germany passed the Hydrogen Acceleration Act, which, among other things, gives hydrogen infrastructure the status of “overriding public interest” and simplifies approval procedures.

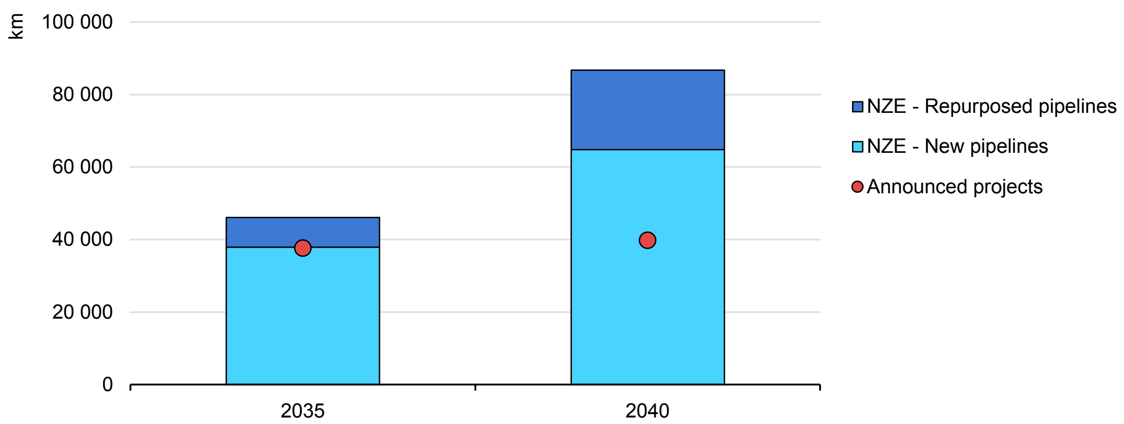
In April 2024, the Danish government agreed to provide financial backing for the construction of a hydrogen pipeline network, subject to the fulfilment of certain conditions. These include securing a committed booking capacity of 1.4 GW (approximately 44% of the pipeline’s total capacity), with the possibility of lower tariffs being charged by the Danish gas TSO, Energinet, during the start-up period, with the provision to recover the shortfall once more users are connected.

The Hydrogen and Fuel Cell Technologies Office of the US Department of Energy (DoE) aims to develop more efficient guidelines for permitting hydrogen pipelines and large-scale projects by 2025, with stakeholder engagement, as outlined in its Multi-Year Program Plan. This goal is also a near-term milestone in the US National Clean Hydrogen Strategy and Roadmap.

Project announcements for dedicated pipelines

A number of project announcements and updates on hydrogen transmission pipelines across and between countries have been made during the past year.[57]

Figure 4.5 Global hydrogen transmission pipeline length in the Net Zero Emissions by 2050 Scenario and announced projects, 2035-2040



Note: NZE = Net Zero Emissions by 2050 Scenario.

The length of hydrogen pipelines announced for the next decade is almost in line with the needs of the NZE Scenario, but only 2% of projects have reached FID.

Although the total length of announced new pipeline projects could reach almost 40 000 km by 2035 – which is almost in line with the needs of the NZE Scenario (Figure 4.5) – the total length of projects that have reached FID remains minimal at only 2%. Since the publication of GHR 2023, construction of the first 30 km of the Dutch hydrogen backbone started in October 2023 (Table 4.3), and the cross-border MosaHYc project between France and

[57] A detailed list of announced projects for the construction of new hydrogen pipelines or the repurposing of natural gas pipelines for hydrogen can be found in the IEA Hydrogen Infrastructure Database (October 2024).

Germany reached FID in April 2024. In addition, construction of a 700 km hydrogen pipeline in China is due to start in mid-2024.

In spite of these announcements, uncertainties in production and demand, coupled with a still-limited regulatory framework, could mean that there is not yet sufficient financial and legal certainty for potential investors in low-emissions hydrogen infrastructure. This is already impacting plans for the development of infrastructure projects. The target year for the completion of Germany's planned hydrogen pipeline network is 2032, but in April 2024 an extension of 5 years was announced, pushing the completion date to 2037, so as to facilitate financing and allow more time for certain projects to become operational. Similarly, in June 2024, the completion of the Delta Rhine Corridor between the Netherlands and Germany was delayed by 4 years, from 2028 to 2032. Simultaneous construction of pipelines for hydrogen, CO_2 and ammonia has proved challenging due to different requirements, and separate timelines for each pipeline will now be considered.

Delays in the deployment of hydrogen infrastructure have a knock-on effect on the speed at which low-emissions hydrogen production and demand can scale up. Without the necessary infrastructure, the link between production and demand cannot be made. For the developers of projects to produce low-emissions hydrogen, this increases the risk of being unable to secure offtakers, since they have no visibility on when they could be able to deliver their product to consumers. Similarly, a lack of certainty on infrastructure also puts at risk the plans of potential consumers of low-emissions hydrogen (which are often developed as a response to new regulatory requirements), since they cannot be sure of securing supply.

Although the deployment of hydrogen pipelines has been sluggish, gas TSOs have issued several calls to confirm interest in hydrogen transmission infrastructure since mid-2023 (Table 4.3). Calls typically start with a non-binding phase to assess market needs and conduct feasibility studies. If this initial phase is successful, it is followed by a binding phase, in which transmission capacity is contracted and investment decisions are made. In December 2023, the first capacity contract was signed for the transport of low-emissions hydrogen through a repurposed ONTRAS pipeline. This contract secures transport capacity for producers to deliver hydrogen to the TotalEnergies refinery in Leuna, Germany, by 2025. In addition, since the GHR 2023, several non-binding calls of interest have been launched in Denmark, France, Germany, Italy and Spain. For cross-border hydrogen transmission networks, high-level announcements and commitments from gas TSOs and/or governments in the jurisdictions concerned are crucial to enabling the development of networks and related infrastructure.

Table 4.3 Progress on selected hydrogen transmission projects in new and repurposed pipelines, Q3 2023 - Q2 2024

Countries	Length (km)	Date	Description
Netherlands	30	October 2023	Construction began on the first section of the 1 200 km hydrogen backbone, for operation by 2025.
France	90	April 2024	GRTgaz and Creos Deutschland announced the FID for the MosaHYc project connecting Germany and France; operation planned for 2027.
Germany	20	December 2023	Uniper and VNG Handel & Vertrieb signed the first capacity contract for hydrogen transport in the ONTRAS pipeline network, for supply to the TotalEnergies refinery in Leuna by 2025, using a repurposed pipeline and a newly constructed short connection pipeline to the refinery.
Germany	280	December 2023	GASCADE published an invitation to tender for hydrogen filling as part of the Flow – making hydrogen happen project. A repurposed pipeline is expected to be operational from Q3 2025, with the tender for capacity allocation planned for late 2024 or early 2025.
Spain	3 000	January 2024	Enagás presented the results of the Call for Interest for the Spanish hydrogen network conducted in Q4 2023. 206 companies participated, submitting 650 projects. Based on the most mature projects, Enagás estimates domestic production of 2.5 Mtpa and 1 Mtpa of domestic consumption in 2030.
France	100	September - November 2023	GRTgaz launched an open season to assess interest in transport infrastructure as part of the RHYn project.
France Germany	200	September - November 2023	GRTgaz and terranets bw and badenovaNETZE launched an open season to assess interest in transport infrastructure between France and Germany, as part of the RHYn Interco project.
France	150	September 2024	GRTgaz presented the results of the call for interest for the HYnframed project: ~20 stakeholders responded. Next steps include carrying out engineering studies; an investment decision is expected in 2025 and commissioning by 2028.
Germany	105	March 2024	GASCADE and REPCO signed a letter of intent to connect the ports of Rostock and Lubmin to the hydrogen network. A new hydrogen pipeline, expected to be commissioned by 2028, will connect Rostock and Wrangelsburg.
China	737	December 2023	Hebei provincial government approved a hydrogen pipeline project connecting Zhangjiakou Kangbao to the port of Caofeidian. Construction is expected to begin in 2024 and operation by 2027, at a cost of CHN 6.1 billion (Yuan renminbi) (USD 861 million).
Denmark	360	January 2024	Energinet launched a non-binding call for interest in the hydrogen pipeline network, receiving 30 responses from 15 participants. A conditional FID is expected by 2025, subject to meeting the government's targets for binding capacity agreements.
Italy	2 300	February – May 2024	Snam and Confindustria conducted a market test to assess hydrogen production and demand in Italy, with results expected to be published in Q3 2024.

Note: More information on project announcements for the construction of new hydrogen pipelines or the repurposing of natural gas pipelines for hydrogen can be found in the IEA Hydrogen Infrastructure Database (October 2024)

The European Hydrogen Backbone initiative involves 33 gas infrastructure operators from 25 EU member states, as well as Norway, Switzerland and the United Kingdom. The latest roadmap for this initiative envisions a 31 000 km pan-European hydrogen pipeline network by 2030, based on repurposed natural gas pipelines wherever possible. There are additional co-ordination activities between European gas TSOs to co-operate on the development of joint cross-infrastructure hydrogen pipelines. In June 2024, nine European gas TSOs signed a Memorandum of Understanding (MoU) to co-ordinate and facilitate hydrogen infrastructure in the Baltic Sea region. This is intended to contribute to the Marienborg Declaration of August 2022, which commits to strengthen energy security in the region by exploring joint cross-border renewable energy projects and identifying infrastructure needs.

Some of the projects resulting from these co-operation initiatives are already moving forward. In April 2024, the European Commission published the first list of Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI). Of the 166 selected projects, 31 relate to the development of onshore and offshore hydrogen pipelines, including between member countries (in the framework of PCIs), as well as PMIs with non-member countries. These projects will benefit from streamlined permitting, regulatory support and possible EU financing from the Connecting Europe Facility. The process for establishing the second EU list of PCIs and PMIs will start in the third quarter of 2024.

In February 2024, the European Commission approved the third round of Important Projects of Common European Interest (IPCEI) for hydrogen infrastructure under EU state aid rules. A total 33 projects in seven member states – France, Germany, Italy, the Netherlands, Poland, Portugal and Slovakia – were approved, committing up to EUR 6.9 billion in public funding, with the expectation of unlocking a further EUR 5.4 billion in private investment. IPCEI Hy2Infra aims to deploy approximately 2 700 km of new and repurposed hydrogen transmission and distribution pipelines for operation by 2027-2029.

While there are still no offshore hydrogen pipelines, offshore projects are also advancing. In April 2024, Gassco (Norway) and GASCADE (Germany) signed an MoU to transport hydrogen by pipeline from Norway to Germany by 2030, a project with PMI status. Gassco would develop the Norwegian export infrastructure, while GASCADE would develop "AquaDuctus", an offshore hydrogen pipeline in the North Sea to connect to Germany. In June 2024, Enagás (Spain), GRTgaz and Teréga (France), in co-operation with OGE (Germany), signed a joint development agreement for the BarMar hydrogen infrastructure, which holds PCI status. This agreement outlines conditions for feasibility studies, and preliminary conditions for an FID, with Enagás contributing 50%, GRTgaz 33.3%, and Teréga 16.7%. In April 2024, Germany and the United Kingdom announced a joint feasibility study on hydrogen trade (including via offshore pipeline), with results expected by the end of the year.

Announcements have also been made outside Europe for both onshore and offshore hydrogen pipelines. In September 2023, Morocco announced plans to build a 5 600 km hydrogen pipeline from Nigeria through 11 West African states, mostly offshore, in parallel with a planned natural gas pipeline for which feasibility studies are underway. In the same month, Oman announced plans for a 2 000 km hydrogen pipeline network, which may extend to other countries such as the United Arab Emirates. A few months later, it was reported that Hydrogen Oman (Hydrom) was establishing an infrastructure company for the hydrogen sector, with OQGN, the owner and operator of Oman's natural gas transmission network, as one of the stakeholders. In October 2023, Singapore's Sembcorp Utilities and Indonesian state-owned utility company PLN signed a joint development study agreement to explore the feasibility of an offshore hydrogen pipeline from Indonesia to Singapore. In the same month, Singapore's City Energy announced that they would conduct a feasibility study for the transport of hydrogen by pipeline from Johor, Malaysia, to the Senoko gas plants in Singapore. However, in April 2024, the Singaporean government highlighted that despite the ongoing studies, there were no immediate plans to construct hydrogen transmission pipelines in the country. In February 2024, Germany and Algeria set up a hydrogen taskforce to assess the potential for production, storage and transport of hydrogen and hydrogen-based fuels, including by offshore pipeline as part of the Southern Hydrogen Corridor, connecting North Africa and Europe. In June 2024, Korea announced a USD 577 million plan for a hydrogen belt along its east coast, with the President emphasising the necessity of constructing a hydrogen pipeline network. Namibia and South Africa are also exploring the possibility of a hydrogen pipeline to connect the two countries.

Technical advances in hydrogen pipelines

Hydrogen pipelines already exist today, but there are several technical issues that will need to be addressed for the hydrogen pipelines of the future, which could connect regions, countries and even continents.

Onshore hydrogen pipeline standards. The American standard ASME B31.12, launched in 2008, is currently the only standard providing specific requirements for onshore hydrogen pipelines. However, it is now due to be retired, as it was originally designed for smaller pipelines over relatively short distances, and is considered impractical and overly conservative for hydrogen transmission pipelines. Instead, relevant requirements will be integrated into the 2026 edition of the widely used ASME B31.3 (process piping) and ASME B31.8 (gas transmission and distribution) standards. This will streamline regulatory compliance for hydrogen pipelines, enhancing consistency across hydrogen and gas pipeline standards.

Offshore hydrogen pipelines. There is currently no practical experience with offshore hydrogen pipelines. Nevertheless, ongoing initiatives, such as the DNV H2Pipe joint industry project, are working to develop standards for new and repurposed offshore pipelines for hydrogen transmission, focusing on structural integrity, material challenges and safety. In August 2024, a protocol to assess the performance of metals and welds used in subsea pipelines exposed to hydrogen developed by Saipem (an Italian energy and engineering construction company) received two certifications (Approval in Principle and Technology Qualification) from RINA (a multinational consultancy specialised in inspection, certification and engineering). In addition to these standards, several announced projects have commenced feasibility studies involving offshore hydrogen pipelines. In February 2024, Wood and Tecnoambiente were contracted to undertake preliminary assessments and environmental evaluations of the BarMar pipeline between Barcelona and Marseille in the Mediterranean Sea. In April 2024, Mott MacDonald was awarded a contract by Gasunie to assess the feasibility of offshore hydrogen transport infrastructure, with Gasunie also assessing the potential of repurposing offshore gas pipelines for hydrogen transport.

Detecting hydrogen leaks. Regulations must encompass detection, monitoring and mitigation strategies for hydrogen leakage, especially in transport and storage. However, due to regulatory gaps, hydrogen leakage detection technologies are currently limited, and primarily focus on identifying large, potentially explosive leaks, lacking the speed and sensitivity needed for smaller leaks. Although there is no commercially available high-sensitivity technology today, several projects have demonstrated the use of advanced sensors with parts-per-billion (ppb) sensitivity. In April 2024, the US DoE announced up to USD 20 million in funding for the H2SENSE exploratory topic, an initiative managed by ARPA-E that aims to develop low-cost, high-accuracy hydrogen detection and quantification technologies. In addition, the NHyRA (pre-Normative research on Hydrogen Releases Assessment) project, funded by the European Commission and the Clean Hydrogen Partnership, was launched in April 2024. The aim is to develop methodologies to measure and quantify hydrogen releases throughout the value chain, and propose solutions to mitigate them.

Non-metallic composite pipelines. Non-metallic composite pipelines are being explored for their lightweight, ductile, spoolable, and corrosion-resistant properties, which make them easier to transport and lay. Given that they have higher investment costs than steel pipelines, these composite pipes may be most suitable for shorter distances. In February 2024, Strohm completed a hydrogen permeation assessment using a thermoplastic composite pipe, demonstrating an almost tenfold reduction in hydrogen permeation compared to a steel pipeline. In May 2024, China's first non-metallic hydrogen composite pipeline began operating, and can transport both natural gas and pure hydrogen at 42 bar. For offshore applications, the HOPE project is aiming to use a thermoplastic pipeline to transport hydrogen ashore over a kilometre distance to the port of Ostend, Belgium, by 2026.

Hydrogen blending

Hydrogen blending is seen as an interim solution for the period until more efficient uses of hydrogen are available, or as a derisking option for large production projects while demand becomes available and the required infrastructure to deliver hydrogen to end users is deployed. However, blending projects face concerns about their efficiency and how the associated cost can impact final individual consumers, as well as local opposition due to safety fears. In spite of these setbacks, a meaningful number of projects are now under development, backed by supportive policy decisions. For example, in December 2023, the UK government announced the decision to support blending of up to 20% hydrogen by volume into gas distribution networks in Britain.

Blends of natural gas and hydrogen are already being used in several town gas networks in Singapore, Hong Kong and Hawaii, with plans to eventually replace fossil-based hydrogen with low-emissions hydrogen. For example, in May 2024, Hawai'i Gas announced a partnership with Euros Energy America to increase the hydrogen content of its gas mix from 15% today to 20% (in volumetric terms), using renewable hydrogen.[58] Moreover, in recent years, gas operators have been assessing the feasibility of blending hydrogen into their natural gas networks and any adaptations required. In March 2024, DNV announced that it is developing feasibility studies for Enbridge (transmission) and Fortis (distribution) to determine the percentage of hydrogen that can be safely transported through their existing natural gas infrastructure in British Columbia (Canada). In April 2024, Stuttgart-based gas distributor Netze announced that its distribution network would be able to operate with blends of up to 30% hydrogen, with minor adjustments, following the completion of the Hydrogen Island Öhringen project. In November 2023, the Spanish gas association Sedigas and BIP Consulting released the CavendisH2 study, a theoretical research assessment of the retrofitting requirements for different hydrogen blends in the existing gas distribution infrastructure.

Since the GHR 2023just a few hydrogen blending projects have entered operation. Dominion Energy Ohio launched a 5% hydrogen blending pilot in a closed loop system at its training centre.[59] In September 2024, the Green Hysland project injected hydrogen from the 2.5 MW plant into Mallorca's 1,400 km natural gas grid. There are some new announcements that may involve larger-scale hydrogen blending at the distribution and/or transmission level in the coming years. In

[58] If not stated otherwise, hydrogen shares are on a volumetric basis.
[59] A list of hydrogen blending projects and their status can be accessed through the IEA Hydrogen Infrastructure Database (October 2024).

January 2024, German gas TSO GASCADE confirmed the grid connection of HH2E's hydrogen production site in Lubmin to the EUGAL gas transmission pipelines. This connection will enable hydrogen blending once the plant becomes operational, by the end of 2025, until the dedicated hydrogen pipeline from the "Flow - making hydrogen happen" project enters service. In May 2024, the Portuguese government launched its first tender for renewable hydrogen and biomethane to be blended into the national gas network. The tender sets a price cap of EUR 127/MWh H_2, with a procurement target of 3.0 ktpa H_2, divided equally, with half designated for injection into the transmission grid and the other half into the distribution grid.

Deblending technology, which enables the separation of hydrogen from natural gas being transported in hydrogen networks, is still not widely available at a large-scale. In January 2022, Linde inaugurated the world's first full-scale demonstration plant in Dormagen, Germany, which uses membrane separation followed by pressure swing adsorption to produce high-purity hydrogen. In May 2023, Towngas in Hong Kong announced the successful extraction of hydrogen from their town gas stream using pressure swing adsorption technology, achieving a purity of 99.99%. Elsewhere, in December 2023, DNV announced its support for UK National Gas Transmission (NGT) in the FutureGrid Phase 2 project. This project aims to develop a hydrogen deblending, purification and refuelling facility at the Spadeadam test site.

Underground hydrogen storage

The global underground storage capacity for natural gas is approximately 490 billion cubic metres (bcm), which represents around 12% of annual gas demand. In Europe, capacity can account for as much as one-third of demand to accommodate seasonal spikes in demand for heating. Approximately 80% of this storage is in porous reservoirs, primarily depleted gas fields. In a global shift towards low-emissions hydrogen, storage requirements would need to follow accordingly. While demand for hydrogen is expected to be less seasonal than demand for natural gas, it will be essential for countries to determine appropriate storage levels to ensure energy security, particularly for those dependent on imports.

Hydrogen storage can also be used to provide seasonal flexibility to electricity systems with high shares of variable renewables or strong seasonal variations in electricity demand. Hydrogen storage facilities can handle multiple cycles per year to accommodate such intra-seasonal variations. Where geologically available, salt caverns are a suitable storage option. Despite their higher cost per unit of capacity, salt caverns offer a favourable option for managing variability, and lined hard rock caverns (which can be found in more places), may do the same, although this is still at demonstration phase. Despite being more widely available, porous reservoirs such as depleted gas fields and saline aquifers have yet to be fully tested for their flexibility to ramp up quickly, and to assess any issues related to hydrogen losses during storage. As such, while the technology for pure hydrogen storage in porous reservoirs has yet to be fully demonstrated, they could potentially play an important future role in improving energy security due to their larger size and lower investment cost per storage capacity.

New salt cavern facilities for hydrogen storage have been announced, and several have progressed towards more advanced planning stages. In November 2023, Vortex started drilling at the site of two salt structures potentially suitable for hydrogen storage in Canada. In December 2023, the H2CAST Etzel project completed the conversion of two large existing salt caverns previously used for natural gas storage into hydrogen storage, with leak tests (using nitrogen) successfully completed during the first half of 2024. During the second half of 2024 the facility will run leak tests with hydrogen. In August 2024, Uniper inaugurated a hydrogen storage pilot at a salt cavern site in northern Germany. The pilot project can store 3 000 m^3 and – if tests are successful – Uniper announced plans to invest up to EUR 500 million to expand the facility to commercial scale (with a storage capacity of 250 GWh of H_2), subject to the availability of public support. In January 2024, it was announced that China had started the construction of its first project for underground hydrogen storage of hydrogen in caverns, in the abandoned mines of the city of Daye, which will be dedicated to research activities. In the European Union, seven underground hydrogen storage projects were included in the first list of PCI and PMI published in April 2024. In addition, the EU IPCEI Hy2Infra covers the development of large-scale hydrogen storage facilities with capacity of at least 370 GWh.

Nevertheless, despite this progress, as of today there are only three projects for underground hydrogen storage worldwide that have at least reached FID – two of them since the launch of the GHR 2023.[60] In addition, some storage system operators in the European Union have already launched calls for interest (Table 4.4). All EU operators will have to carry out these market assessments every 2 years, according to the EU Regulation on the internal market for renewable gas, natural gas and hydrogen adopted by the European Parliament in April 2024.

[60] A comprehensive list of project announcements related to the construction of new underground hydrogen storage facilities or the repurposing of existing natural gas storage facilities for hydrogen can be found in the IEA Hydrogen Infrastructure Database (October 2024)

Table 4.4 Calls for interest in underground hydrogen storage projects, Q3 2023 - Q2 2024

Countries	Date	Description
Spain	January 2024	The results of the call for interest for the Spanish hydrogen network (Q4 2023) included two salt caverns in the Basque-Cantabrian Basin in northern Spain.
Germany	February - March 2024	VNG Gasspeicher launched a non-binding call for interest for hydrogen storage in salt caverns, as part of the project Green Octopus Mitteldeutschland - GO! Storage (150 GWh).
Germany	February - March 2024	Storengy launched a non-binding call for interest for hydrogen storage in salt caverns in and around Lower Saxony.
Germany	April 2024	In early 2024, Uniper conducted a non-binding call for interest to assess demand for 250-600 GWh of hydrogen storage capacity in salt caverns, starting with the Krummhörn site. The results confirmed a strong interest in capacity by 2029, with notable demand for greater flexibility, i.e. significantly higher injection and withdrawal rates compared to natural gas.
Germany	April – May 2024	INES, the association of German operators of gas and hydrogen storage systems, has launched a market survey on the future demand for hydrogen storage.

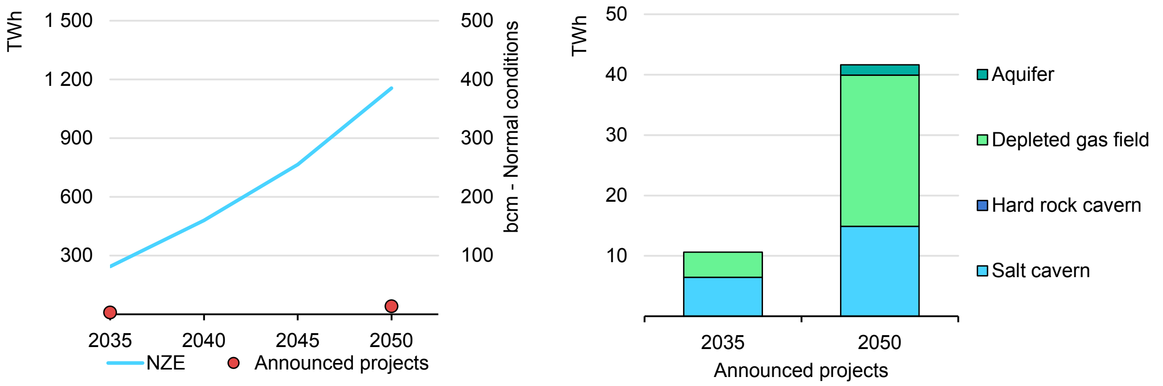
Salt caverns. Salt caverns have been used for hydrogen storage since 1972 in Teesside (United Kingdom) and since 1983 on the Gulf Coast of Texas (United States), mainly for chemical and petrochemical processes, with a total capacity of 500 GWh. Although the technology is already available, further research is being carried out to test cyclic loading and unloading and the possibility of repurposing salt caverns previously used to store natural gas for hydrogen. In March 2024, the FrHyGe project, supported by the European Union, was launched to demonstrate the feasibility of repurposing natural gas salt caverns for hydrogen storage in France and Germany, with high cycle injection and withdrawals. In June 2024, 350 kg H_2 were injected into the Géométhane salt caverns in Manosque, France, to study the behaviour of hydrogen and to prepare for full-scale deployment in the GeoH2 (France, 6 000 t H_2) and SaltHy (Germany, 5 200 t H_2) projects by 2030.

Lined hard rock caverns. In 2022, the HYBRIT project in Luleå, Sweden, launched the first 100 m^3 pilot plant for hydrogen storage in lined hard rock caverns, with testing continuing through 2024. The results show that the integration of storage can reduce the costs of a constant supply of hydrogen by 25-40%. In March 2024, the UK NGT secured public funding to assess the potential of Gravitricity's lined hard rock cavern technology, known as H2FlexiStore, which has a capacity of 100 t H_2. This evaluation could pave the way for a demonstration project in 2025.

Porous reservoirs. Depleted gas fields and saline aquifers have not been proven for storage of pure hydrogen. Storage of town gas,[61] containing up to 50-60% of hydrogen, was commercially deployed at several porous reservoirs from the 1950s until the 1980s, but there were instances of hydrogen loss due to microbial activities, such as methanation and sulphate reduction, which react with hydrogen and reduce its content. The extent to which these issues could arise with pure hydrogen storage remains unclear. While research has been carried out to understand the behaviour of hydrogen stored in porous reservoirs, these studies have been small-scale and often involved hydrogen mixtures rather than pure hydrogen. In November 2023, the Underground Sun Storage 2030 project in Austria, led by RAG Austria, announced that it had started injecting hydrogen in a porous reservoir, and in June 2024 announced that it had started its first withdrawal phase. In March 2024, Uniper's HyStorage project in Germany presented preliminary results after injecting a 5% hydrogen blend into a depleted gas porous reservoir. Almost 90% of the hydrogen was successfully recovered and microbial activities were observed on a small scale. Large-scale projects are planned for the end of the decade. In January 2024, the EUH2STARTS project, also led by RAG Austria and supported by the European Union, was launched to demonstrate large-scale underground hydrogen storage in depleted porous natural gas reservoirs. In June 2024, Centrica Energy Storage awarded a front-end engineering design (FEED) contract to Wood to prepare the Rough natural gas storage facility in the United Kingdom, a depleted gas field, for future repurposing for hydrogen storage. The FEED is expected to be completed by early 2025. With regards to hydrogen storage in saline aquifers, Fluxys launched the BE-HyStore project in October 2023 to explore the possibilities of hydrogen storage in Loenhout, Belgium, which has a potential storage capacity of 2.4 TWh H_2.

[61] Depending on the processes used to obtain town gas, it is a mixture of hydrogen, carbon monoxide, methane and other volatile hydrocarbons.

Figure 4.6 Global underground geological storage capacity for hydrogen in the Net Zero Emissions by 2050 Scenario and announced projects, 2035-2050



Note: NZE = Net Zero Emissions by 2050 Scenario.

The long lead times associated with underground hydrogen storage projects mean that accelerated action is urgently required to get on track with the NZE Scenario.

Despite recent project announcements, the expected underground hydrogen storage capacities – 10 TWh by 2035 and 40 TWh by 2050 – are well below the requirements of the NZE Scenario (Figure 4.6). Due to its low density, hydrogen requires three to five times the volume needed for natural gas to store an equivalent amount of energy at the same pressure. In the NZE Scenario, more than 230 TWh (85 bcm under normal conditions, 0.5 bcm at 200 bar) of underground hydrogen storage would be required by 2035, compared to the current 4 800 TWh (490 bcm under normal conditions, 2.2 bcm at 200 bar) of natural gas storage. By 2050, the need for hydrogen storage in the NZE Scenario may reach a volume comparable to the extensive natural gas storage infrastructure developed over the last 50 years. The current gap between announced underground storage projects and NZE Scenario needs is significantly larger than for production projects, demand creation or pipelines. For hydrogen to play its role in the transition to a net zero energy system, the scale-up of production and use will need to be accompanied by the development of the required infrastructure, including large-scale storage capacities that can help to deal with seasonality and potential supply disruptions. Failure to have this critical infrastructure available at the time when large production projects are expected to start operating, or when large industries are aiming to switch to low-emissions hydrogen, can jeopardise these projects and, therefore, the required scale-up of hydrogen uptake (and its subsequent contribution to climate goals). There is an urgent need for government, TSOs and industry to work together to find ways to speed the development of storage projects, which have longer lead times than production and demand projects.

Infrastructure for transport by ship

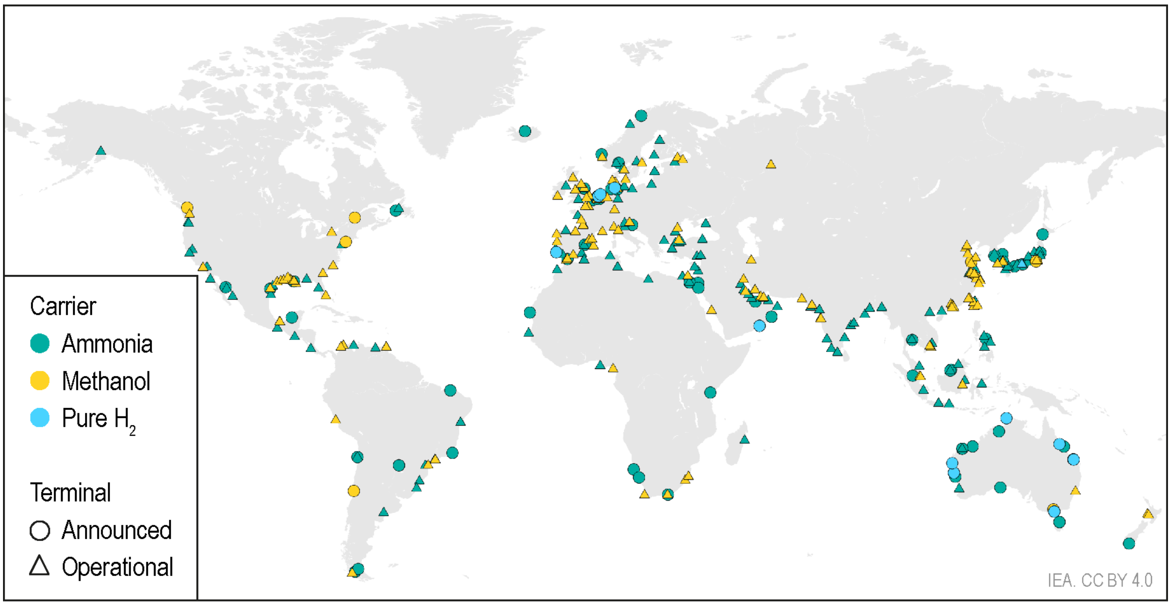
For transporting hydrogen over very long distances there are options that can be less expensive than pipelines (Figure 4.4). Given the complexities involved in achieving significant economies of scale, particularly at the initial stages, and in crossing multiple jurisdictions, shipping hydrogen can be an attractive alternative. If pure hydrogen is required at the destination, it can be shipped as liquefied hydrogen or as ammonia – which needs to be cracked back into hydrogen and nitrogen – or using a LOHC (which should then be dehydrogenated to supply pure hydrogen). If pure hydrogen is not required, hydrogen can be transported more easily as ammonia, methanol, synthetic fuels, or even in bulk as products manufactured with low-emissions hydrogen, such as hot briquetted iron (see Chapter 8. Latin America in focus).

Transporting hydrogen and hydrogen-based fuels requires the use of specialised port infrastructure. This includes deep-water facilities for the handling of liquefied gases such as hydrogen and ammonia, as well as conversion plants for the transformation of hydrogen into hydrogen carriers at the exporting port. Additionally, reconversion facilities may be necessary at the importing port for the processing of these carriers back into pure hydrogen.

Infrastructure at ports

Current energy trade by ship relies on infrastructure designed to store coal, oil and liquefied natural gas (LNG) in ports. For natural gas, this infrastructure also includes liquefaction facilities at export terminals and regasification facilities at import terminals. In addition, ammonia and methanol are traded globally, albeit as chemical feedstocks. The export infrastructure for natural gas, ammonia and methanol (which are mainly produced by steam reforming of natural gas) is located in regions with abundant natural gas resources. In contrast, the import infrastructure for these energy and chemical commodities is more widespread, reflecting the larger number of importing countries compared to exporting countries.

Figure 4.7 Existing and announced port infrastructure projects for hydrogen and hydrogen-based fuels trade and bunkering



Port facilities for the trade and bunkering of ammonia and methanol are planned around the world, which will significantly expand current capacity at terminals.

The current global anhydrous ammonia[62] trade is approximately 20 Mtpa, which is equivalent to around 3.5 Mtpa of hydrogen and represents approximately 10% of global ammonia production. However, as well as anhydrous ammonia trade,[63]the majority of ammonia-derived trade is currently in the form of urea (16% of global ammonia production) and other nitrogen-based fertilisers, which are solids that can be transported in bulk. In contrast, ammonia is a gas at ambient conditions and must be liquefied, in addition to requiring specific safety considerations.

There are currently 150 terminals and ports capable of handling ammonia (Figure 4.7), but this infrastructure is relatively limited in comparison to the announced projects for trading 13 Mt of hydrogen as ammonia by 2030, which is equivalent to around 70 Mt of ammonia (Figure 4.1). To meet this demand, there is a need for a significant expansion of ammonia trade infrastructure, effectively tripling the current capacity within this decade. This could lead to a significant increase in demand for port infrastructure to support ammonia storage in liquefied tanks. While some of this increased capacity can be integrated into existing plants, either by replacing fossil-based ammonia trading or by improving annual plant utilisation with minor adjustments, the majority will require major expansion. This expansion may become even more critical in the post-2030 period in light of additional

[62] Anhydrous ammonia is a pure form of ammonia containing over 99% ammonia and no water.
[63] Hereafter, the term “ammonia” refers to “anhydrous ammonia”.

demand for ammonia bunkering at ports to support shipping decarbonisation. In addition, countries with good renewable energy resources that have not traditionally been involved in energy or ammonia trade may play an increasingly significant role. This transition will require not only new ammonia storage tanks, but also the construction of new deep-water ports and berthing facilities to support these emerging routes.

Methanol is already stored in more than 120 ports worldwide. Storage of methanol and LOHC at ports requires simpler infrastructure than storage of ammonia, as they use liquid bulk storage, and existing oil storage facilities at ports can be adapted to store methanol and LOHC.

There are over 100 natural gas liquefaction plants worldwide, situated across more than 40 ports. Additionally, there are over 160 LNG regasification plants in nearly 150 ports. However, the distinct chemical properties of hydrogen and natural gas present a significant challenge in repurposing existing infrastructure. The liquefaction of natural gas occurs at -162°C, while the liquefaction of hydrogen requires a much colder temperature of -253°C, at which point even air liquefies. This difference in temperature presents a challenge to adapting current facilities for handling pure hydrogen. With the aim of addressing these challenges, many announced regasification projects, especially in Europe, are considering flexible designs to facilitate the transition into multi-molecule hubs in the future. Such hubs could handle synthetic methane without any technical adaptation, and potentially also ammonia or pure hydrogen with a degree of refurbishment and equipment replacement. For instance, in June 2024, Enagás announced plans to assess the feasibility of converting its Musel LNG regasification terminal into a "multi-molecule" facility. In the same month, construction began on Germany's first land-based LNG terminal, the Hanseatic Energy Hub. This terminal, due to start importing LNG in 2027, is also designed to be "ammonia-ready", according to the project developers. However, just as in the case of converting already existing terminals, the technical feasibility of converting these newly designed terminals also needs to be demonstrated. Certain elements of the infrastructure available in the terminals (e.g. jetties, berthing facilities) are likely to be easily reusable, but there is other specific equipment (e.g. compressors, heat exchangers) that will require a certain amount of modification or replacement, and there is no real experience of converting them for handling hydrogen-based fuels.[64]

On the basis of announced projects, more than 100 new hydrogen and ammonia terminals and port infrastructure projects could be realised by the end of the decade.[65] More than half of all terminals are ammonia export terminals, with more

[64] More details on the feasibility of LNG conversion to hydrogen and hydrogen-based fuels can be found in the Global Hydrogen Review 2022 and the Energy Technology Perspectives 2023.
[65] A comprehensive list of hydrogen and hydrogen-based fuels infrastructure projects in ports can be accessed via the IEA Hydrogen Infrastructure Database (October 2024).

than ten potentially located in Australia. Further terminals are planned in Brazil, Egypt, Namibia, Mauritania and the United Arab Emirates, among other locations. Ammonia import terminals account for more than a quarter of all planned terminals. In Europe, a number of ammonia import terminals have been announced in countries including Belgium, Germany and, the Netherlands, and outside Europe, in Japan and Korea. It is worth noting that the capacity of the OCI Rotterdam ammonia terminal is being tripled to 1.2 Mt NH_3, with completion expected by the end of 2024, after a 1-year delay. In April 2024, Samsung C&T signed a contract to build an ammonia import terminal for co-firing power generation at Gangwon-do, Korea, expected to be operational by 2027. Nevertheless, there has been limited progress beyond announcements since the GHR 2023. However, Fluxys has initiated several non-binding calls for interest to assess the demand for handling hydrogen and hydrogen-based fuels at Belgian ports (Table 4.5).

Table 4.5 Calls for interest for hydrogen-based fuels import terminals at ports between Q3 2023 and Q2 2024

Port	Date	Description
Zeebrugge, Belgium	November 2023 - February 2024	Fluxys launched a non-binding call for interest for its expansion plans for the Zeebrugge terminal. The call included infrastructure for conventional and synthetic LNG as well as hydrogen and ammonia.
Antwerp, Belgium	June 2024	Fluxys launched a non-binding call for interest for a new ammonia terminal in the port of Antwerp, including plans for an ammonia pipeline.
Eemshaven, Netherlands	June 2024	Gasunie and Vopak launched a non-binding call for interest on LNG, hydrogen and CO_2 infrastructure at the EemsEnergyTerminal at the port of Eemshaven (Groningen).

Several large-scale ammonia cracking projects have also been announced in addition to related port infrastructure, although the technology is not yet proven on a commercial scale. Facilities are being considered in Wilhelmshaven, Rostock and Brunsbüttel (Germany), in the port of Antwerp (Belgium), in the ports of Liverpool, Newcastle and Immingham (United Kingdom), in the Port of Dunkirk (France) and in the port of Krk (Croatia), as well as three facilities in the port of Rotterdam (the Netherlands). Based on the capacity of the announced projects, ammonia cracking in Europe could supply approximately 2 Mt H_2 by 2030. Elsewhere, ammonia cracking plants have been announced for the ports of Daesan and Ulsan (Korea), as well as plans for a unit in Singapore. There are even plans for the construction of an offshore ammonia cracking terminal in Germany. In July 2024, Deutsche ReGas and Höegh LNG entered into a preliminary agreement to develop the H2 Import Terminal Lubmin in Germany. The terminal would have an output capacity of 30 ktpa H_2 and the cracker is set to become operational in 2026. Construction of the pilot project for the Höegh ammonia cracker is underway in Stord, Norway.

Tankers for shipping hydrogen and hydrogen-based fuels

Existing tankers can carry hydrogen-based fuels (e.g. ammonia, methanol) and LOHCs. Ammonia, a gas at ambient temperature, requires liquefied gas tankers, while methanol, synthetic fuels and LOHCs, being liquids, can be shipped in chemical (including dedicated methanol tankers) or oil product tankers.

Currently, around 40 tankers are exclusively dedicated to the transport of ammonia, with up to 200 liquefied gas tankers capable of carrying ammonia, such as liquefied petroleum gas (LPG) tankers, as they have similar liquefaction points (-44°C for LPG and -33°C for ammonia). According to shipping analytics firm Vortexa, between mid-2021 and mid-2023, 114 unique tankers had loaded ammonia, with a combined capacity of around 3.1 million m^3, equivalent to around 2 Mt of ammonia loading capacity. While the fleet includes several very large gas tankers, with a capacity of over 70 000 m^3, ammonia is usually shipped by midsize tankers (25 000-50 000 m^3) due to the typical parcel sizes and the availability of port infrastructure. New orders for ammonia tankers have already increased, reflecting shipowners' anticipation of rising demand for ammonia cargoes in the coming years. However, an increase in the number of tankers may be constrained by the relative technical complexity of liquefied gas tankers, with only a few shipbuilding yards in Korea, Japan and China capable of constructing them. This limited shipbuilding capacity could potentially create bottlenecks in the short term, and there have already been reports of a lack of capacity in Korean shipyards.

New orders for midsize gas tankers have also been on the rise since 2023, boosted by the demand for dual-fuel vessels, the anticipated growth in low-emissions ammonia trade, and drought-induced restrictions at the Panama Canal, which favour the transit of midsize gas tankers. In the first half of 2024, 20 midsize gas tankers were ordered, approaching the 2023 total of 26 orders. There has also been a surge in orders for very large gas tankers, with 21 in 2023, and 26 during the first half of 2024, with most set to be delivered from 2027. These tankers will initially serve the LPG market until the ammonia market matures. However, there are some concerns of potential overcapacity in the very large gas tanker segment, including for LPG/ammonia tankers.

Decarbonising the shipping of hydrogen and hydrogen-based fuels remains a significant challenge, which also affects the carbon intensity of low-emissions hydrogen when considering both production and transport-related emissions. Existing gas carrier fleets can potentially be adapted for low-emissions marine fuels, depending on the space required for new tanks and additional equipment. The decarbonisation of ammonia, chemical and product tankers needs to progress in parallel to the growth of low-emissions hydrogen trade. In 2016, the first dual-fuel methanol tankers that can run on their methanol cargo were introduced, and by early 2023, there were 23 dual-fuel methanol tankers, with more orders on the way. In the same year, the first orders for ammonia-fuelled ships were placed at the Hyundai Mipo Dockyard in Korea, starting with a pair of midsize LPG/ammonia gas tankers ordered by EXMAR in October 2023, that will be propelled by dual-fuel engines and are expected to be delivered by 2026. In May 2024, Trafigura placed an order with the same dockyard in Korea for four ammonia-fuelled midsize LPG/ammonia tankers, with the first expected to be delivered in 2027. In August 2019, the ammonia-fuelled medium gas carrier being developed by a consortium of NYK and Nihon Shipyard received the world's first "Machinery Room Safety for Ammonia" accreditation granted by ClassNK.

There are currently no commercially available tankers for shipping liquefied hydrogen. The Suiso Frontier, with a capacity of 1 250 m^3 (~75 t H_2), is to date the only demonstration project and completed a shipment of liquefied hydrogen from Australia to Japan in 2022. Several companies are working on the development of liquefied hydrogen tankers, expected to be operational by 2030, with hydrogen cargo capacities of up to 160 000 m^3 (~9 600 t H_2) (Table 4.6). In addition, the use of hydrogen to fuel ships could have positive spill-over effects, as these technologies could be incorporated into liquefied hydrogen tankers, allowing part of the cargo to be used as fuel.

Table 4.6 Announced designs for liquefied hydrogen tankers expected to be commercial before 2030

Company	H_2 cargo containment	Country	Approval in Principle*	Volume (m^3)
Korea Shipbuilding & Offshore Engineering, Hyundai Mipo Dockyard	Spherical	Korea	Korean Register of Shipping (KRS) DNV	20 000
Samsung Heavy Industries	Type C	Korea	ABS	20 000
Houlder, Shell, CB&I	Spherical	United Kingdom	DNV (H_2 containment)	20 000
C-Job Naval Architects, LH_2 Europe	Spherical	Netherlands	-	37 500
TotalEnergies, GTT, LMG Marin, Bureau Veritas	Membrane	France	Bureau Veritas	150 000
Kawasaki Heavy Industries (KHI)	Spherical (technological development completed)	Japan	Nippon Kaiji Kyokai (ClassNK)	160 000
Samsung Heavy Industries	Membrane	Korea	Lloyd's Register	160 000
GasLog	NA	United States	NA	NA

* An Approval in Principle is an independent assessment of conceptual and innovative shipbuilding within an agreed framework, confirming that the ship design is feasible and that no significant obstacles exist to prevent the concept from being realised.
Note: m^3 = cubic metre.

Chapter 5. Investment, finance and innovation

Highlights

- In 2023, USD 3.5 billion was spent globally by project developers on hydrogen supply projects that are under construction. Around 80% of this was for projects building electrolysis facilities and the rest on projects coupling hydrogen production with carbon capture, utilisation and storage (CCUS). For electrolysers, this was an increase of over 350% compared with 2022, mostly for the industrial and refining sectors. Spending on infrastructure projects – pipelines, storage and refuelling – remains at a much lower level.
- Half of the spending on electrolysis projects was in China in 2023 and one-third in Europe. China leads on annual investment due to the large numbers and sizes of projects, which offset lower unit costs than in other countries. If all Chinese projects that have achieved a final investment decision (FID) are delivered to plan, spending there would rise 140% in 2024. Spending on CCUS-equipped hydrogen projects was highest in North America.
- Investment spending on electrolysis projects could rise by as much as 150% in 2024, based on recent FIDs. Spending on CCUS-equipped plants will also increase in the coming years. Four projects representing around 1 Mtpa in total for hydrogen production with CO_2 capture and storage took FID since last year's report, including new facilities and retrofits of existing plants. For both production routes, the largest projects are reaching industrial scales and this trend, coupled with recent cost inflation, is driving up investment, despite some project delays. However, annual investment of USD 50 billion is needed this decade to get on track with the Net Zero Emissions by 2050 Scenario (NZE Scenario).
- While hydrogen company valuations have struggled recently on public markets, hydrogen start-ups successfully increased the total equity funding they raised to USD 3.7 billion in 2023. Project developers for industrial hydrogen uses and technology developers for hydrogen production dominated this total, but deals so far in 2024 show more technology variety.
- Several innovation milestones have been achieved in the past year, and anion exchange membrane (AEM) electrolysis and catalytic decomposition of methane to make hydrogen both moved up to Technology Readiness Level (TRL) 7. Promising tests of ammonia combustion in boat engines and power plants have also been reported.

Investment in the hydrogen sector

This report covers four different types of investment that, when considered together, provide an overview of the capital being committed to the scale-up of a commercial-scale hydrogen industry and an indication of private sector confidence in hydrogen projects and firms.

The largest category of investment is spending by project developers on projects that have already taken FID and are under construction. For low-emissions hydrogen production, we estimate this to have reached USD 3.5 billion globally in 2023, around 80% of which was for projects building electrolysis facilities for hydrogen production, and the rest for projects coupling hydrogen production with CCUS. However, given the different unit costs of these types of investments (partly because some CCUS projects are retrofits of existing hydrogen plants), these relative shares change when considering the expected annual output of projects in construction around the world in 2023, to 55% for hydrogen produced through electrolysis and 45% for facilities with CCUS (see Chapter 3). Recent FIDs for large CCUS-equipped projects look set to support this balance over coming years. However, spending on infrastructure projects – pipelines, storage and refuelling – remains at a much lower level.

Spending on hydrogen supply projects under construction was over 350% higher in 2023 than 2022, and is expected to grow further in 2024 as work ramps up on projects that took FID in 2023 and since the start of 2024. Many of these projects have electrolysis capacities of over 100 MW and up to 2 GW in one case. However, as described in Chapter 3. Hydrogen production, concerns about costs and regulation continue to delay the time taken for some projects to reach FID. In addition, for projects achieving financial close, inflation means that costs are often higher today than when the projects were first proposed, a trend that is inflating future investment projections without increasing the associated expected hydrogen production. The Bad Lauchstädt Energy Park 30 MW project in Germany, which took FID in June 2023, has experienced cost increases of 50% since the initial engineering design. Another source of high costs is insurance against performance risks for this new type of industrial activity without an established track record. New, dedicated products are emerging to make it easier to insure projects in the early stages of market development, but so far they have limited scope and unknown prices.

Since the Global Hydrogen Review 2023 (GHR 2023), several policy developments have raised the prospects of higher investment in hydrogen projects in coming years. Japan passed its Hydrogen Society Promotion Act, which includes a budget of JPY 3 trillion (USD 20 billion) and provisions for 15-year contract-for-difference production subsidies for domestic and imported hydrogen and ammonia. In the European Union, the third (infrastructure projects) and fourth rounds (mobility projects) of Important Projects of Common European Interest saw EUR 8.3 billion (USD 9 billion) in total of national public support approved for 46 projects, with total costs of twice this amount. In the United States, USD 7 billion in grants was awarded to seven consortia planning hydrogen "hubs" that have total estimated capital costs of USD 50 billion. The 2024 Australian Budget included a hydrogen production tax incentive worth AUD 6.7 billion (USD 4.5 billion) which individual projects may claim for up to 10 years, and a further AUD 2 billion (USD 1.3 billion) for large-scale hydrogen projects via the Headstart programme was also announced. The USD 2.6 billion of OPEX support awarded to 11 projects under the United Kingdom's first Hydrogen Allocation Round is intended to facilitate GBP 413 million (USD 525 million) in UK projects by 2026. The first auction of the European Hydrogen Bank awarded operational support worth EUR 720 million (USD 780 million) to seven projects for 10 years. The second round, to be launched in late 2024, is expected to almost triple the total pot. Germany announced a new tranche of EUR 3.5 billion (USD 3.8 billion) for its H2Global double-auction scheme, and the Dutch government joined the H2Global process. France agreed grants of more than EUR 140 million (USD 150 million) to two individual projects. These and other policy developments are described in more detail in Chapter 6. Policies.

The other types of investment covered in this section include commitments of multilateral development banks (MDBs) to provide finance for hydrogen efforts, especially in emerging market and developing economies (EMDEs). After a flurry of announcements in 2023, this type of investment has seen less activity in 2024. The section also includes equity investment in hydrogen-focused companies and funds, including those listed on public exchanges and start-ups raising venture capital. While the value of investments in the former has declined since GHR 2023 amid uncertainty about major contracts for equipment supplies, the latter rose to nearly USD 3.7 billion, signalling that investors continue to see significant long-term market value in high-performing hydrogen technologies.

Spending on hydrogen supply projects in construction

The amount of money flowing to hydrogen projects continues to grow rapidly, demonstrating that new assets – especially for the production of hydrogen – are getting financed on commercial terms. This is despite the various headwinds facing developers, which are described throughout this report.

Electrolysis

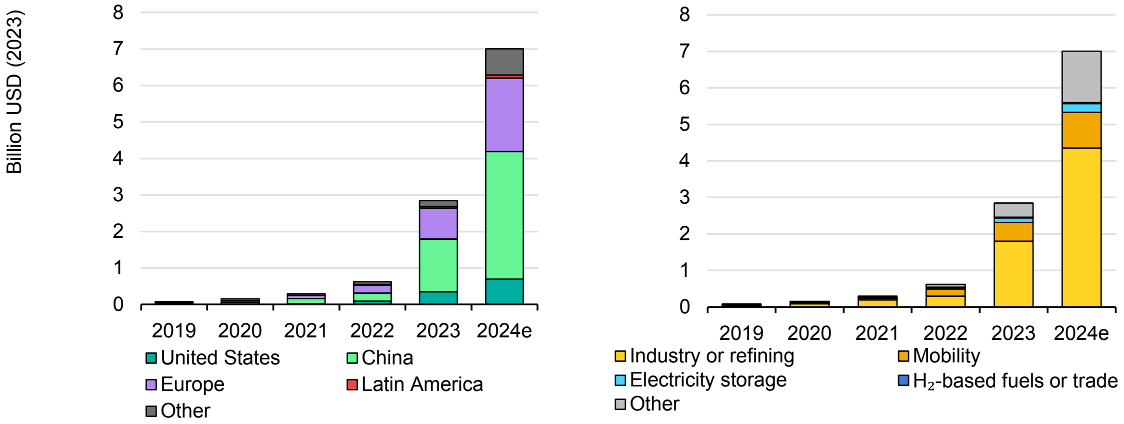
The majority of investment in 2023 was in the deployment of hydrogen electrolysers and associated equipment. Investment in electrolysers continued its growing trend to reach a record high of USD 2.9 billion in 2023, almost five times the level reached in 2022. This trend is expected to continue in 2024, with investment increasing 150% compared to 2023. Even though the rate of deployment is impressive, it still represents only 6% of the USD 50 billion that needs to be invested on average annually until 2030 in order to get on track with the NZE Scenario.

Spending is rising in all regions and our 2024 estimate includes spending on close to 50 projects, across five continents, that have taken FID since GHR 2023. This spending is in addition to the continued investment in 2024 in projects that had already started construction before GHR 2023. Among the projects that have taken FID since GHR 2023, the largest is Greenko ZeroC, an ammonia production project in eastern India that is sited at an existing urea plant and is designed to have 1.3 GW of electrolysers. Following FID in August 2024, its developers aim to export ammonia to Europe from 2026.

More spending is occurring in China than any other region, despite the revocation of development rights by authorities in Inner Mongolia for several projects in the region (accounting for more than 3 GW of electrolysis capacity).[66] Given the lower costs in China, this will result in an even higher share of capacity additions when these projects under construction enter operation. Among the largest projects that have taken FID since GHR 2023 are the Taonan Green Methanol project (with around 700 MW of electrolysis), the Tianying Green Methanol project (around 670 MW of electrolysis) and the Fengzhen, project in China will have over 650 MW of proton exchange membrane (PEM) capacity, making it the largest PEM project in the world. Also in China, Goldwind, a Chinese wind energy manufacturer, and Mærsk, a Danish shipping giant, are collaborating on a 550 MW project to make hydrogen for methanol production by 2026. China is continuing to build more large projects than any other country, driven by the strategies of state-owned enterprises, concessional finance from local government and rules to limit renewable electricity curtailment. If all Chinese projects that have reached FID are delivered according to their development plans, spending there would rise 140% in 2024 compared with 2023.

[66] Energy Iceberg (2024), Hydrogen Policy Navigator; Six mega green hydrogen projects were cancelled by Inner Mongolia energy regulator.

Figure 5.1 Investment in electrolyser installations by region (left) and intended use (right), 2019-2024



Notes: 2024 values are estimated annualised spending on projects that had begun construction by mid-2024. Estimates are based on capital cost assumptions and announced capacities of electricity input or hydrogen output volumes per project and include electrolysers for hydrogen supply used for energy purposes or as an alternative to fossil fuel use in industry (such as chemical production and oil refining). "Other" includes buildings heating, combined heat and power, grid injection, biofuels upgrading and unspecified uses.

Source: IEA analysis based on data from McKinsey & Company and the Hydrogen Council, STORE&GO (2019), communications with companies, BNEF 2024, TNO 2024, the IEA Hydrogen Production Projects Database (October 2024).

Investment in electrolysers is on a steep growth trajectory: the record investment of 2022 almost quintupled in 2023, and a further 150% growth is anticipated through 2024.

In Europe, investment is expected to rise 140% in 2024 compared to 2023 and to continue to account for around one-third of global investment in electrolysers. Among the FIDs taken in Europe since GHR 2023, the Boden steel plant being built by Stegra – formerly H2 Green Steel – for 2030 in Sweden is the largest in terms of electrolysis capacity, at 700 MW of electrolysis capacity. The FID, in April 2024, was for a total plant cost of over USD 7 billion, making it the world's largest hydrogen-related project in terms of financial scale. In Germany, EWE has taken FID on a 320 MW electrolysis plant in Emden and RWE is constructing 300 MW of electrolysis at its GET H2 Nukleus project in Lingen, both of which will serve industrial hydrogen consumers. Four projects installing around 100 MW each took FIDs to supply hydrogen to the refining, mobility and biofuel upgrading sectors: CCU-HUB Aalborg methanol project in Denmark; CRI's Circlenergy methanol project in Norway; Galp's Grey2Green project on the site of a decommissioned coal-fired power plant in Portugal[67];and a project of Shell in Germany to expand the 10 MW "REFHYNE" electrolyser already operating at its Rheinland refinery. Two other projects larger than 50 MW took FID in Germany (with USD 130 million of public grants) and Romania (with USD 50 million of public grants) for industrial

[67] The project has received USD 30 million in public grants and has applied for IPCEI support from the Portuguese government to cover a share of the private costs.

uses, vehicle refuelling and biofuel upgrading. Each of these projects likely suffered cost inflation since the first estimates were made.

In the United States, which accounts for about 12% of global investment in electrolysers today, a 100% increase in electrolyser investment in 2024 is foreseen. Two projects have taken FID since GHR 2023, the larger of which involves building an 80 MW electrolyser facility by 2026 for refuelling trucks. The USD 550 million capital cost is expected to be borne by the promoter, Fortescue, and recovered via the 45V tax credit, pending final guidance for 45V. The other project is for 40 MW of electrolysis to produce liquefied hydrogen to be delivered by road to customers in the material handling, vehicle refuelling and stationary power sectors from the end of 2024. While the direct policy support for the investment is unclear, the supplier, Plug, benefits from concessional finance and grants for manufacturing from the US government. Overall, US investments since GHR 2023 may have been higher if clarification of the rules for implementation of 45V – including the time-matching requirements for renewable electricity inputs – had not been delayed further, with market players still awaiting the decision on the final rules, expected later this year. Uncertainty relating to the outcome of the US election in 2024 and its impact on hydrogen support policies is also impeding investment.

Outside these major regions, there was notable FID activity in Australia and Malaysia. In Parak, Malaysia, a local renewable energy developer is working with a Chinese power company to construct 60 MW of electrolysis capacity, powered by floating solar PV, at a capital cost of around USD 400 million. The intended use of the hydrogen from this project remains unclear. In Australia, the 55 MW electrolyser being built by Origin Energy, to be powered by grid electricity, will supply Orica's ammonia fertiliser production. It is supported by USD 75 million in central and state-level government grants, and is part of a shortlist for receipt of production subsidies. Fortescue took FID on both phases of its 50 MW electrolyser installation project linked to a new electrolyser factory that has received USD 30 million from the state government towards USD 76 million capital costs.

Fossil fuels with carbon capture, utilisation and storage

In contrast, investment in projects under construction for producing low-emissions hydrogen with CCUS stood at only USD 0.7 billion in 2023, though this was more than double the amount in the previous year. However, deployment of such projects appears set to ramp up, with six FIDs since GHR 2023, including for what is currently the world's largest potential project to produce low-emissions hydrogen. To date, much of the investment in hydrogen production equipped with CCUS has been in North America, including several entirely new hydrogen production facilities. However, of the six FIDs since GHR 2023, three were in the Netherlands and were for retrofitting existing hydrogen production plants.

Among the CCUS projects in construction in the Netherlands, the two largest are both for hydrogen supply to the Botlek/Pernis refinery and other onsite industrial customers from 2026. Both involve capturing CO_2 from the production of roughly 0.1 Mtpa H_2 each from existing hydrogen production plants.[68] These two projects will receive a 15-year contract from the Sustainable Energy Production and Climate Transition Incentive Scheme (SDE++) under which the government will top up any difference between the cost of hydrogen production with CCUS and without. The projects will pay a pipeline operator to take away the CO_2 for offshore geological storage via new infrastructure that is also under construction, having received around USD 120 million in Dutch and EU government grants. The third project in the Netherlands to have recently reached FID is slightly smaller, but still very large by the standards of the emerging low-emissions hydrogen sector. It is for CO_2 capture from the production of hydrogen for ammonia and will capture and store around 45% of the CO_2 that is not used elsewhere, either onsite in the production of fertiliser or by third parties. This captured CO_2 – and associated payments – will be passed to the operator of a service for shipping CO_2 to Norway for offshore geological storage. Due to the CO_2 being stored outside of the country, the plant is considered ineligible for an SDE++ contract, but part of its USD 200 million costs will be covered with a USD 30 million grant from the Netherlands.

The largest FID – in terms of budget and potential to produce low-emissions hydrogen – since GHR 2023 was in the United States. To put the scale of the Eastern Louisiana Hydrogen Complex in context, its projected hydrogen output would be three times larger than the roughly 0.2 Mtpa H_2 from the world's largest electrolyser project currently under construction, the NEOM project in Saudi Arabia, despite having a similar capital cost, at USD 7 billion.[69] Its projected output is equivalent to roughly all the low-emissions hydrogen produced globally in 2023. However, despite its high CO_2 capture rate of 95%, whether all the hydrogen from the Louisiana project will be low-emissions hydrogen will depend on the associated emissions from the fossil fuel lifecycle, notably any upstream methane emissions.[70] Another large FID was taken in February 2024 for a natural gas-based ammonia facility in the United Arab Emirates that will enter operation in 2027 without CCUS, before adding CO_2 capture by 2030. The project, which has Japanese contractors, has received concessional finance as an export credit loan of USD 27 million.

[68] One of the two project promoters, Air Liquide, issued a EUR 500 million (USD 540 million) green bond in May 2024 to help finance these types of projects.

[69] While the capital costs per unit of hydrogen production are lower than for NEOM, the costs of hydrogen production will depend on operational and fuel costs and these are likely to be higher than those of the NEOM project, which does not need to procure external energy supplies.

[70] Air Products' indication that its plan for the plant's finances include the 45Q CO_2 storage tax credit suggest that the upstream methane conditions of the more lucrative 45V hydrogen tax credits might be difficult to meet. Other public support for this project is expected to come from a performance-based grant of up to USD 5 million from the state of Louisiana (including workforce development support) and the state's Industrial Tax Exemption and Quality Jobs programmes.

Investment decisions for hydrogen production with CCUS have continued in 2024. In June 2024, Shell announced an FID for the Polaris project in Canada, which will capture CO_2 from a steam methane reformer, among other sources, for geological storage in the Atlas Carbon Storage Hub from 2028. In addition to the Polaris FID, Shell and partner ATCO EnPower announced FID to proceed with the Atlas Carbon Storage Hub.

Infrastructure

There was some activity in the area of infrastructure development, which nevertheless still has the largest gap to fill – current investment levels are less than 5% of what is needed to get on track with the NZE Scenario projections in 2030.

One notable development is the expected start in mid-2024 of the construction of the world's longest hydrogen pipeline, in China, at a cost of USD 845 million, expected to be completed in 3 years. No other hydrogen pipelines have reached FID since GHR 2023, though in June 2024 German gas transmission operator Bayernets secured a USD 230 million credit facility for the construction of a 40 km hydrogen-ready gas pipeline by the end of 2025. In the same month, the European Commission approved the German government's request to make USD 3.2 billion in financial guarantees available for the construction of hydrogen pipelines in Germany this decade. Fluxys, a Belgian pipeline operator, declared in August 2024 its intention to spend USD 2.2 billion on hydrogen infrastructure over the next 10 years, three times more than previously foreseen. For cross-border pipelines, a first step is typically a co-operation agreement between the countries concerned, and, in 2024, such an agreement was signed between Austria, Germany and Italy for the proposed Southern Hydrogen corridor connecting Europe with North Africa, which is one of five components of the European Hydrogen Backbone initiative.

On the storage side, Chevron bought 78% of the USD 1 billion Advanced Clean Energy Storage hydrogen project in Utah, United States, in September 2023 after declining to do so in 2022, even though the project had already secured offtakers and a USD 0.5 billion loan guarantee from the US government. This reversal indicates that the project's economics meet the requirements of an oil major, and that Chevron is now more enthusiastic about gaining a foothold in hydrogen distribution in the region. Elsewhere, repurposed salt caverns are also planned to be used for large-scale hydrogen storage in Lower Saxony, Germany. The Etzel project in the region remains at a pilot stage, which the federal and state governments have funded with a low double-digit million Euro investment for over a third of the total project costs.

For hydrogen refuelling stations, Hydrogen Refuelling Solutions secured USD 3.4 million in bank finance to expand its test facility in France for research into heavy-duty vehicle operations. The financing is counter-guaranteed by French state-owned banks.

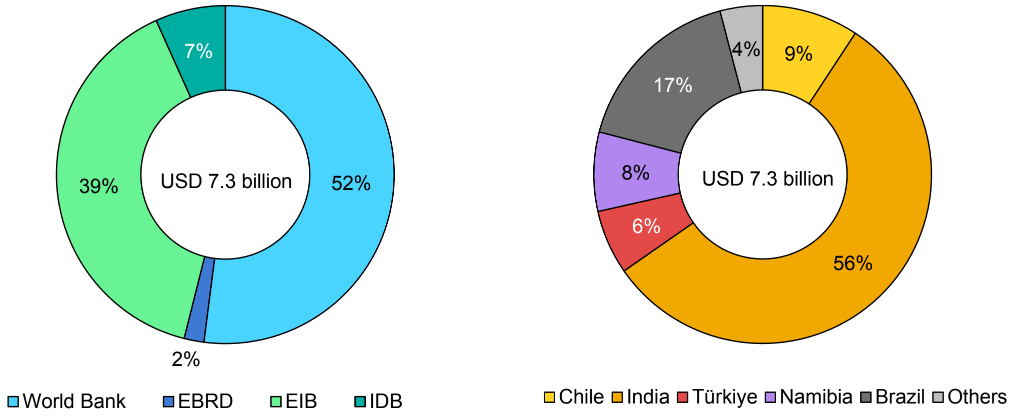
Multilateral financial commitments are moving into the implementation phase

After a slew of very large announcements in 2023 (USD 4.8 billion), less multilateral finance has been announced so far in 2024 (USD 1.8 billion). The largest announcement is the second tranche of USD 1.5 billion of debt from the World Bank to India, all for hydrogen. This new large allocation of concessional debt lifts the World Bank to representing over half of all multilateral finance for hydrogen since 2022 and India to be the recipient of nearly 60% of the total. Notable other examples since GHR 2023 include World Bank funding of USD 135 million to Brazil for hydrogen infrastructure development, which may be further boosted following a Memorandum of Understanding signed at COP 28 that foresees a further USD 1 billion for hydrogen-related projects in Brazil. The World Bank also granted a USD 150 million loan to Chile in 2023.

MDBs and development finance institutions have a strategic role to play in supporting EMDEs to become first movers in developing a market for low-emissions hydrogen. They can support governments to attract private sector investment by improving enabling conditions, and accepting or mitigating some of the early risks related to individual projects and the low-emissions hydrogen sector more generally, in addition to non-sector-specific risks impacting EMDEs, such as currency volatility. Moreover, they can support countries in defining policy frameworks that catalyse local socio-economic benefits and support the energy transition in line with national development agendas.

The lower levels of announcements in 2024 can be interpreted as a shift by the large MDBs from building partnerships and high-level finance agreements with recipient countries to working on the details for how to implement previously approved programmes, rather than scouting for new opportunities. Many of the renewable electricity-based hydrogen projects funded by MDBs have long lead times, significant social and regulatory aspects, and complex engineering challenges to resolve, requiring extensive planning and co-ordination for these projects to achieve their promised impact. The approved large-scale programmes cover many of the countries that could reasonably invest large sums in hydrogen deployment in the near-term without extensive capacity building. In contrast, much of the new funding that has been announced since GHR 2023 focuses on technical assistance to help build capacity in other developing economies that could become major project hosts in future. In the NZE Scenario, more than USD 365 billion is needed in EMDEs by 2030.

Figure 5.2 Funds committed to hydrogen by multilateral development banks, by source (left) and by recipient country (right), 2022-2024



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Notes: EBRD = European Bank for Reconstruction and Development; EIB = European Investment Bank; IDB = Inter-American Development Bank. IEA analysis based on the publicly available information until 9 September 2024.

India and Brazil have been the recipients of the largest MDB financing agreements since 2022, with the World Bank and EIB responsible for around 90% of the total.

In 2024, the World Bank approved a USD 1.5 billion loan to India for promoting hydrogen from renewable energy, scaling up renewable electricity and enhancing finance for low-carbon energy investments. This follows a similar loan to India for the same amount announced in 2023. A USD 100 million loan is also earmarked for Mauritania for institutional capacity building for low-emissions hydrogen projects and minerals mining, building on previous smaller grants for studies in the country. In June 2024, the European Bank for Reconstruction and Development (EBRD) approved a loan of USD 55 million to Uzbekistan for its first renewable hydrogen production project, which is expected to create an example for similar projects in Central Asia. The Inter-American Development Bank (IDB) announced USD 2 million of technical co-operation with Colombia for the development of renewable hydrogen, among other projects. The private sector financing arm of the IDB (IDB Invest) has proposed a USD 35 million loan to Renewstable Barbados Ltd to develop hydrogen storage facilities.

Bilateral funding agreements are also supporting hydrogen development in EMDEs. Recent examples include a EUR 20 million (USD 22 million) grant from Germany to Algeria, and cumulatively around USD 3 million of grant from the United States and United Kingdom, to Namibia, Uzbekistan and South Africa in separate agreements. France has indicated it may loan EUR 350 million (USD 380 million) to Morocco, in addition to a EUR 0.8 Million (USD 0.9 million) grant for hydrogen projects agreed in mid-2024. Increasingly, bilateral finance also includes examples of "south-south" co-operation, such as USD 5 million of loan from South Africa to a company developing hydrogen projects in Namibia.

Financial performance of hydrogen firms

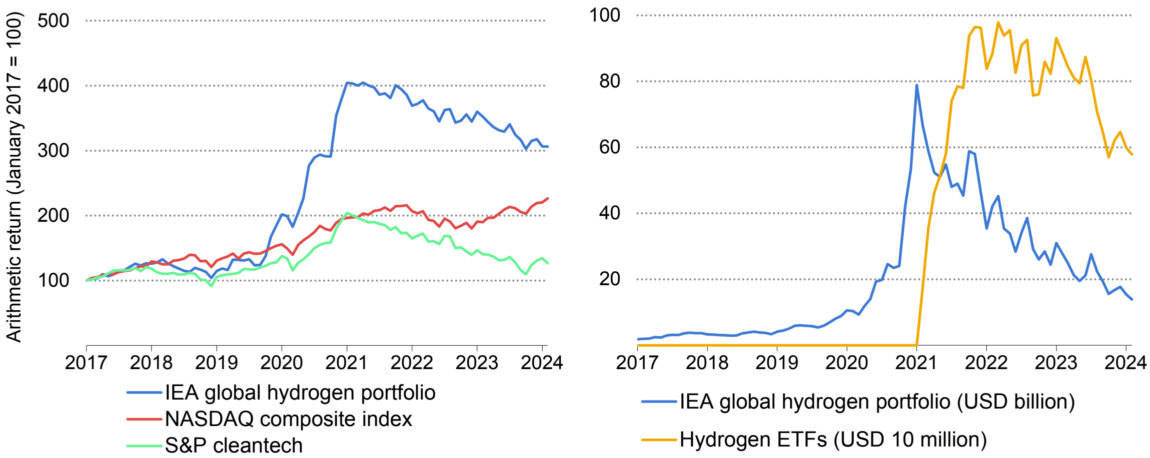
In aggregate, the commercial health of companies that have staked their future success on low-emissions hydrogen is not yet robust. Many of these companies are scaling up new businesses and therefore necessarily putting significant capital at risk (e.g. in factories or project equity) to be able to take orders for equipment sales. However, just as project orders have picked up, as projects begin to reach financial close, these young companies have been hit by higher costs of capital and expectations of further project delays.

In order to track investment trends in hydrogen-related businesses, we have assembled a portfolio of 45 publicly traded companies in the sector. While the monthly investor returns and revenues of this portfolio rose over the past 5 years, its recent performance is more reflective of the troubled S&P Cleantech index, rather than the NASDAQ index that is dominated by hardware-light digital technology firms. The combined capitalisation of the firms in the portfolio has been on a steady downward trajectory since 2021, reflecting the difficult balance between needing to spend on R&D, facilities and projects while revenue is not yet covering costs, and the cost of capital on private markets is rising in competition with other investment options. Continued increases in interest rates have led investors to withdraw equity from sectors struggling to meet shareholder requirements. By the end of February 2024, the market capitalisation of the portfolio had dropped back to its level in May 2020.

As a reflection of investor wariness about new, capital-intensive sectors such as low-emissions hydrogen, there have been no major new additions to the portfolio since the initial public offering of thyssenkrupp nucera in 2023. The one listing that occurred was via a merger of Apex Group, a project developer, with a listed company that had previously undergone a de-SPAC in 2011 – a relatively low risk transaction. Some existing portfolio members did raise additional capital, though the total amount was relatively small. Among these, McPhy raised USD 33 million to help finance its electrolyser factory.

Moreover, there are signs that companies are taking measures to try to shore up the most viable parts of their businesses. For example, ITM Power sold its refuelling business in late 2023. Nel is spinning off its refuelling business as Cavendish Hydrogen from its electrolyser business, in an effort to separate the risks of these two different segments, and McPhy has undertaken something similar. These trends reflect other corporate measures to scale back expectations for refuelling network expansion and profitability, and also reflect the reduced need for electrolyser manufacturers to play a role in creating the market for smaller-scale HRS projects as demand increasingly comes from large-scale industrial projects (see Chapter 2. Hydrogen demand).

Figure 5.3 Monthly returns (left) and market capitalisation (right) of hydrogen companies, hydrogen funds and relevant benchmarks, 2017-2024



Notes: ETFs = exchange-traded funds. Tickers of included firms are 288620 KS, 336260 KS, 702 HK, ACH NO, ADN US, AFC LN, ALHAF FP, ALHRS FP, AMMPF US, AQUNU US, BE US, BLDP CN, CASAL SW, CI SS, CPH2 LN, CWR LN, F3C GY, FCEL US, FHYD CN, GHY AU, GNCL IT, GREENH DC, H2O GY, HDF FP, HTOO US, HYON NO, HYPRO NO, HYSR US, HYZN US, HZR AU, IMPC SS, ITM LN, LHYFE FP, MCPHY FP, NCH2 GY, NEL NO, NHHH CV, NXH CN, PCELL SS, PHE LN, PLUG US, PPS LN, PV1 AU, SPN AU, TECO NO, VIHD US.

Source: IEA analysis based on Bloomberg (2024).

Despite more hydrogen projects attracting investment, financial markets continue to be cautious about the prospects of individual specialist companies in the supply chain.

Some project companies are exploring new business models that are “asset light” and can help spread risks and bring new sources of capital into project development. For example, Lhyfe, a company whose share price has fallen 40% in the past year, is proposing a new model of co-development of projects to be sold to co-owners once operational. Other companies are looking at new types of partnerships that help bring in capital, such as the tie-up between John Cockerill and SLB. In contrast, larger multinationals that are not solely focused on hydrogen have more options for raising capital at lower costs.

The values of specialist exchange-traded hydrogen funds have been badly hit since GHR 2023, reflecting investors’ scepticism that they will quickly find enough profitable companies and projects to beat market averages. No new funds have been launched. The Clean H2 Infra Fund, which is not publicly traded, has been cautiously spending its EUR 2 billion (USD 2.1 billion) war chest that was raised in 2022, and joined investment rounds for Stegra and HysetCo. Its manager is currently trying to raise a further USD 500 million for investment in hydrogen-related equipment manufacturing, and has used money raised so far to invest in Hexagon Purus, a maker of hydrogen storage systems. Similarly, the sixth investment made by Antin’s USD 1.3 billion NextGen Infrastructure Fund I was in GTL Leasing, a US-based hydrogen transport and storage equipment leasing firm.

In a young sector like hydrogen, where corporate viability is so dependent on government policy, the precarious financial position of these high-potential firms – which could supply the technologies needed to accelerate energy transitions – should be a priority for government attention. There may be a role for national banks, as exemplified by the partnership between the Canadian Infrastructure Bank and HTEC to accelerate infrastructure development. A fund may be launched in India, but at the moment it remains just a proposal.

Venture capital and private equity

Venture capital (VC) investment has continued to increase, reaching a new high of USD 3.7 billion in 2023, but the rate of growth slowed down due to macroeconomic conditions that impacted the amount of capital available for venture investments across the global economy. Hydrogen-related VC funding held up better than total energy-related VC funding, which outperformed total VC funding across all sectors in terms of equity raised. However, we estimate that persistently high interest rates are likely to depress the 2024 total and result in the first significant annual dip in hydrogen-related VC for a decade.

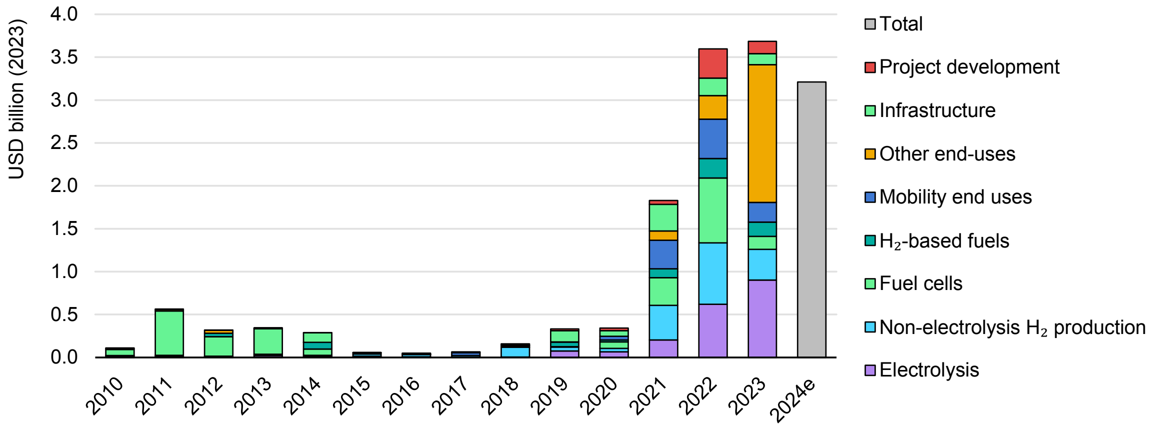
Some of the concerns of investors include the barriers to entry due to sky-high valuations of some of the hydrogen companies (which also make it difficult to see viable exit pathways for investors), and the difficulty of derisking an entirely new business for scalability, with inherent technological uncertainties and often lacking established supply chains – all while operating in a climate of limited demand. Greater momentum in the investment pipeline for hydrogen project deployment will help clarify expected future returns and valuations of hydrogen-related start-ups. On the other hand, it will also accelerate the necessary process of winnowing the cohort of competing start-ups as more is learned about the effectiveness and competitiveness of their technologies and processes.

Equity investment in start-ups with technologies for hydrogen production represented more than one-third of the 2023 total. Electric Hydrogen, a US electrolyser company, raised USD 380 million in October 2023 and Amogy, also in the United States, raised USD 150 million to develop a technology for converting ammonia to hydrogen fuel.[71] Some of the equity for these deals came from oil and gas companies, which together invested about USD 55 million in start-ups working on various hydrogen production technologies. Ohmium, another US-based electrolyser maker, raised USD 250 million in growth equity in 2023. Large bets on electrolysis technologies continued in early 2024 when Sunfire, a German electrolyser maker, raised USD 230 million of growth equity, complemented by a

[71] As an example of how VC funding can be combined with other finance sources, Electric Hydrogen received USD 50 million of equipment financing in March 2024, USD 65 million in US government grants and tax credits in April 2024, and USD 100 million in corporate credit in May 2024.

USD 110 million loan from the EIB. Another start-up developing an electrolyser, Australia's Hysata, raised around USD 75 million in May 2024. Natural hydrogen also attracted investors in 2023, with Koloma, a US-based technology developer, raising USD 91 million in 2023 and USD 245 million in early 2024. In the area of methane pyrolysis technology, Rotoboost, a Norwegian start-up, raised USD 10 million in June 2024, and Sakowin, a French start-up, raised USD 4 million in February 2024.

Figure 5.4 Venture capital investment in energy start-ups in hydrogen-related areas, per technology domain, 2010-2024



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Notes: Project development category includes start-ups that do not own intellectual property on technology and raise funds for supply-side project development costs. Other end-uses include steel production, chemicals, waste management and heating. 2024e is a full-year estimate for all hydrogen-related VC based on data up to Q1 2024, which does not provide a high enough confidence level for a breakdown by technology area.
Source: IEA analysis based on Cleantech Group (2024) and Crunchbase (2024).

Hydrogen-related start-ups continued to attract record levels of venture capital through 2023, but a slowdown is forecast in 2024 given the challenging macroeconomic climate.

While VC investment in start-ups developing electrolysis technology grew nearly 50% compared to 2022, investment in other areas related to hydrogen – notably mobility and supply project development – shrank. The funding raised by start-ups developing hydrogen fuel cells fell 80%. Nevertheless, there were notable investments, such as the USD 48 million investment by Hyundai into Estonia-based Elcogen, which designs solid oxide fuel cells, and USD 44 million secured by hydrogen fuel cell company Tangfeng energy. Deals so far in 2024 include around USD 70 million raised by INOCEL, a French start-up developing heavy-duty fuel cells. ZeroAvia raised USD 116 million in November 2023 for fuel cell applications targeted at the aviation sector, but this positive news has been tempered by the bankruptcy in mid-2024 of its competitor Universal Hydrogen after it had raised over USD 100 million since 2021 and successfully made an initial flight in 2023. Among earlier-stage start-ups in the aviation segment, HyLight, a

French company, raised USD 4 million in April 2024 to develop its hydrogen-powered airship drone.

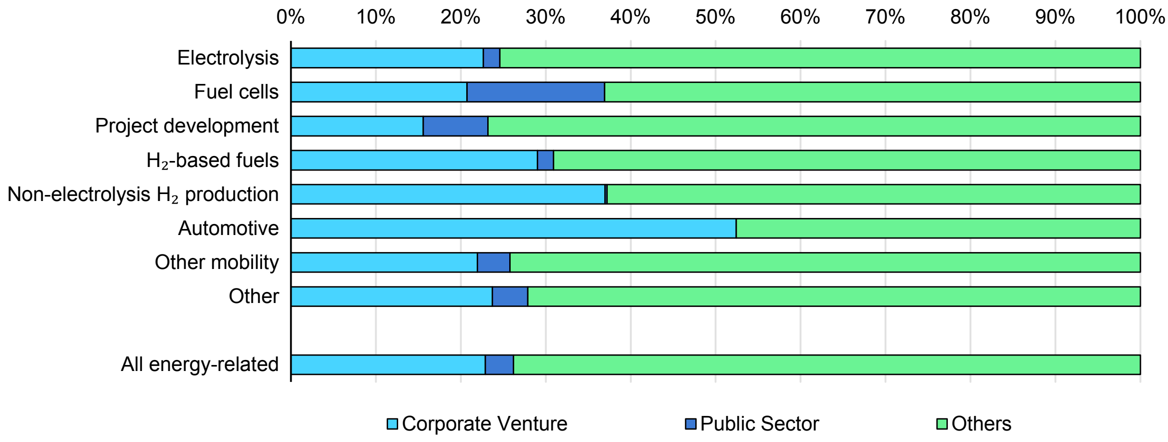
In 2023, the largest single area of hydrogen-related VC investment was for end-uses and industrial applications in particular. However, this was mostly related to more than USD 1.6 billion growth-stage equity raised by Stegra, which is building a commercial-scale steel production plant using hydrogen as the major reactant, and has raised nearly USD 7 billion in public and private finance so far.

Among the VC funding raised since GHR 2023 by start-ups working on hydrogen infrastructure technologies, Sinoscience Fullcryo raised USD 111 million, in part for gaseous hydrogen storage solutions. Yara invested USD 2.85 million in Azane, an ammonia storage technology developer, and Chevron invested in the ammonia production company Ammobia. Some more mature start-ups have recently raised debt financing, including HTEC's USD 250 million loan from the Canada Infrastructure Bank for building hydrogen refuelling stations.

In terms of the sources of VC finance for hydrogen-related start-ups, we estimate that 88% has come from investors in advanced economies and China since 2019. The role of investors from other EMDEs remains small, though efforts to boost this are ongoing in some places. In mid-2023, a new accelerator for Indian hydrogen start-ups was launched by a private consortium.

Most money has come from funds, such as VC funds, that are primarily seeking the largest financial return, as is the case for energy-related start-ups as a whole. However, in some technology areas, the share of capital from strategic corporate investors – that are also buying access to technology and knowledge – is higher than the energy-related average. These areas include hydrogen for automotive applications, non-electrolysis production of hydrogen (including from fossil fuels and biomass) and hydrogen-based synthetic fuels. Investments from automotive and oil and gas firms are all playing a major role in these areas. In other segments, such as fuel cell and project development, equity investments by the public sector are more important than for the energy-related cohort on average. Although direct public investment in equity tends to play a smaller role in hydrogen VC, it can act as a strategic investor and help attract private co-investment. Although not for a start-up, this role appears to have motivated the governments of Belgium and its province Wallonia to have taken a stake in an electrolyser company when it raised its capitalisation by almost USD 250 million in mid-2024, with most of the money coming from SLB, an energy technology and services company with extensive oil and gas experience.

Figure 5.5 Early- and growth-stage equity investment in energy start-ups in hydrogen-related areas by type of funder, 2019 to Q1 2024



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Notes: Others include VC funds and other financial investors primarily seeking a return and without a strategic interest in using or learning about the technology.
Source: IEA analysis based on Cleantech Group (2024) and Crunchbase (2024).

The sources of VC funding vary by technology area of the start-ups, with some areas showing higher corporate or public sector equity than the average for all energy-related start-ups.

Innovation in hydrogen technologies

The readiness of hydrogen technologies varies across the supply chain. Low-emissions hydrogen production technologies are already commercially available but not yet mature, and demand-side innovation is making slow progress, though several technologies may be on the cusp of significant advances in technological maturity.

Innovation in hydrogen production technologies

Electrolytic hydrogen production technologies are commercially available, but other production technologies for low-emissions hydrogen still need to be proven at scale. In addition, to ensure market uptake, further innovation is needed to reduce production costs by improving efficiency and reducing equipment costs, for example by reducing reliance on critical materials, increasing the stack lifetime, improving the manufacturing process, and designing for recycling.

Hydrogen from electrolysis

Stack innovation

Alkaline and PEM electrolysers are the most mature electrolysis designs and are commercially available, with ongoing innovation efforts aimed at reducing hydrogen production costs. Research on PEM electrolysers focuses on minimising the use of expensive platinum group metal components in catalysts to lower stack costs. In September 2023, H2U Technologies achieved a 25 000-hours durability test with an iridium-free catalyst, outperforming other iridium-free catalysts, which last up to 1 400 hours. In February 2024, Toshiba partnered with Bekaert to commercialise Toshiba's technology that reduces iridium use by 90%. Solid oxide electrolysers (SOECs) achieve the highest efficiencies among electrolyser designs, although they need to use an external heat source for steam generation, and also face durability challenges, with a typical lifetime of around 2 years. A few projects are currently operating at single-digit MW commercial scales, and innovation is underway, such as at Dynelectro, which is seeking to extend their lifetime to up to 10 years. Anion Exchange Membrane (AEM) electrolysers are still at an earlier stage of development, but between 2023 and 2024 Enapter supplied them to several projects around the world, including some projects with a capacity of over 1 MW, with one project already in operation in Germany and two more under construction in the UK and the Netherlands respectively.

High-pressure electrolysis

Innovation efforts to reduce the balance-of-plant costs include increasing hydrogen outlet pressure to minimise the need for compression and associated power requirements, which are costly, as hydrogen users often require high pressure. The European Union-funded HYPRAEL project, which began in 2023, aims to produce hydrogen from alkaline electrolysers at 80-100 bar, significantly higher than current pressurised alkaline electrolysers, with pressures up to 30 bar. In November 2023, Supercritical Solutions demonstrated its 50 kW high-pressure electrolyser at a whisky distillery, producing hydrogen at 220 bar, thereby avoiding downstream hydrogen compressors. Supercritical Solutions and HAMR Energy have since announced plans to further test this technology for methanol synthesis, which needs hydrogen at high pressure.

Offshore hydrogen production

Between May and November 2023, Lhyfe's Sealhyfe project successfully tested for the first time a 1 MW electrolyser on an offshore platform off the French coast, despite extreme weather conditions. The second stage is the European Union-backed HOPE project, in which a consortium of companies led by Lhyfe aims to operate a 10 MW offshore hydrogen production plant off the coast of Belgium by 2026. The PosHYdon project in the Dutch part of the North Sea plans to produce hydrogen on a gas platform, and while onshore testing began in May 2024, the 1 MW electrolyser is expected to be transferred offshore by year end, and for the first time, hydrogen will be transported alongside gas via an existing pipeline. In December 2023, the Dutch government launched an interest survey for two offshore hydrogen demonstration projects, and in June 2024, the Minister for

Climate and Energy Policy announced that a first 30-50 MW demonstration project with a budget of EUR 380 million (~USD 410 million) would be selected in the first half of 2025, to be operational by the end of the decade.

Hydrogen from fossil fuels with CCUS

Methane reforming

In steam methane reforming (SMR), 60% of the CO_2 emissions are emitted during hydrogen production in the reformer, and 40% from natural gas combustion in the furnace. Currently, CO_2 is captured from the concentrated reformer syngas, but capturing the remaining 40% from diluted furnace flue gas remains costly. However, hydrogen production from natural gas with CCUS requires capture rates well above the current 60% achieved in commercial operating plants for the hydrogen to be classed as low-emissions. To address this challenge, two plants currently under construction in Canada and United States to become operational in 2025 will use natural gas and CCUS with autothermal reformers (ATR) instead of SMR, which make it easier to achieve high CO_2 capture rates by producing a single stream of concentrated CO_2. Electrified SMR, where the reformer is heated by an electric current, eliminates the need for costly capture of flue gas emissions. In October 2023, Topsoe and Aramco announced a collaboration to build an electrified SMR demonstration plant in Saudi Arabia using Topsoe's technology. In June 2024, Nu:ionic and XRG Technologies announced the first commercial deployment of their electrified SMR, with a capacity of 20 t H_2/day.

Methane pyrolysis

Methane pyrolysis produces solid carbon and hydrogen without gaseous CO_2 emissions, thus avoiding the need for CO_2 capture. In January 2024, Hazer announced the first production of hydrogen and graphite at its commercial demonstration plant in Australia, using thermo-catalytic pyrolysis, and with a capacity of 100 tpa of hydrogen. In the same month, Hycamite began the construction of a thermo-catalytic methane pyrolysis demonstration plant in Finland, with a capacity of 2 000 tpa H_2, which opened in September 2024.

Emerging technologies for hydrogen production

Other technologies for low-emissions hydrogen production, such as photocatalytic water splitting, are still at low maturity levels, but some pilot projects are underway. For example, in June 2024, the HyPEC project, a collaboration between Qatar Shell Research and Technology Centre and academia, announced the production of hydrogen from wastewater and sunlight in a pilot facility in Qatar. In Spain, the Hylios project will develop new titanium-based metal-organic frameworks for photocatalytic wastewater splitting, while

Sparc Hydrogen (Australia) has started front-end engineering and design for what could be a first-of-a-kind pilot plant for this technology.

Production of synthetic hydrocarbons

Despite the lack of large-scale industrial plants for the production of synthetic hydrocarbon fuels, several demonstration plants are seeking to advance relevant technologies. In January 2024, LanzaJet inaugurated its Freedom Pines Fuels plant in Georgia, United States, the largest plant using alcohol-to-jet technology to date. It aims to produce 34 million litres of jet fuel and 4 million litres of diesel annually from ethanol and hydrogen, which will be produced using a PEM electrolyser. In March 2024, Infinium's Pathfinder plant in Texas began producing e-diesel from CO_2 and hydrogen. Similarly, in May 2024, Turn2X inaugurated a synthetic methane plant in Extremadura, Spain, using a 2 MW electrolyser, with the aim of scaling up the technology in other plants.

Innovation in hydrogen end-uses

On the demand side, certain technologies using hydrogen and hydrogen-based fuels in applications where there are few alternatives for decarbonisation have yet to be demonstrated at scale. However, ongoing innovation efforts may soon lead to advances in the technological maturity of key end-use technologies.

Industry

Iron and steel

In November 2023, Stegra started construction of the world's first large-scale 100% H_2-based direct reduced iron (DRI) plant in Boden (Sweden), to produce around 2.5 Mtpa of steel. At the same time, construction started on the Oshivela project site in Namibia, which aims to produce 15 kilotonnes per year (ktpa) of steel using 100% H_2-based DRI technology from HyIron, using an airtight rotary furnace instead of a shaft furnace, which can reduce iron ore powders and result in a more homogeneous product.

Hydrogen-based DRI typically requires high-grade iron ore pellets, which have limited availability. There are several ongoing projects with different technologies to use lower-grade iron ore. In August 2024, Fortescue started the construction of its USD 50 million Green Metal project in the Pilbara region of Australia, which will use an electric smelting furnace that directly melts and reduces iron ore. This technology can process a range of iron ore grades and impurities, increasing its versatility. The project is expected to start production in 2025 with a capacity of 1.5 ktpa of pig iron. In February 2024, Rio Tinto and BHP iron ore producers partnered with Australian steelmaker BlueScope for the development of an electric smelting furnace pilot plant in the country, which could be commissioned by 2027. In Korea, POSCO aims to have a demonstration plant for fluidised bed reactor technology by 2026, using hydrogen as a reducing agent for fine ore instead of iron ore pellets, as in DR shaft furnaces. This will be integrated with an electric smelting furnace that can use DRI from low-grade iron ore. In Japan, Nippon Steel's R&D programme aims to test hydrogen-based technology for directly reducing low-grade iron ore, jointly developed by Tenova and Danieli, with a demonstration project planned in Hasaki.

Nippon Steel conducted tests to blend hydrogen in a blast furnace in Q3-4 2023, and achieved a reduction in CO_2 emissions of up to 33%. Nippon Steel plans to continue demonstration work and implement its Super COURSE50 technology to achieve up to 50% reduction of CO_2 emissions in large-scale blast furnaces.

Chemicals

Commercially available designs for the production of ammonia via the Haber-Bosch process require high temperatures, pressure, and continuous operation with limited flexibility (variable load of 70-110% of nominal capacity). Skovgaard Energy is building a demonstration plant in Lemvig, Denmark that was inaugurated in August 2024 using Topsoe's flexible ammonia synthesis technology with a 5 ktpa ammonia capacity, able to operate from 5-100%. By 2025, Topsoe's technology will be scaled up at the Baotou plant in China, with a planned capacity of 390 ktpa.

In November 2023, the Leuna100 plant in Germany was inaugurated. This is the world's first pilot plant to produce methanol from CO_2 and hydrogen via co-electrolysis, using a novel catalytic process which allows load-flexible operation.

High-temperature heating

Projects that aim to demonstrate the feasibility of using hydrogen for process heating in different industries are also increasing. In September 2023, in Hofors (Sweden), Ovako inaugurated a plant for heating steel with hydrogen before rolling, equipped with a 20 MW electrolyser. In June 2023, Hydro announced that it had tested aluminium smelting fired by hydrogen at its recycling plant in Navarra (Spain), followed by confirmation in November 2023 that the aluminium meets the requirements to be used by Irizar for electric vehicles. In December 2023, Veidekke's asphalt plant in Kristiansund (Norway) produced 3 000 tonnes of asphalt using hydrogen as its sole energy source. In April 2024, Schott announced the successful production of optical glass using 100% hydrogen for the first time at its plant in Mainz (Germany), with ongoing quality assessment tests. In February 2024, Holcim announced that it had achieved a hydrogen injection rate of more than 50% in the La Malle cement kiln in France, becoming the first to achieve this level of blending. In July 2023, the Australian Renewable Energy Agency announced funding for the Rio Tinto and Sumitomo Corporation Yarwun Hydrogen Calcination Pilot Demonstration Program, which aims to be the first to use hydrogen calcination in alumina refining. Construction is expected to start in 2024, to include a 2.5 MW electrolyser and the retrofitting of a calciner with a hydrogen burner. R&D is also revealing future needs for innovation: In November 2023, Aurubis reported on its tests on ammonia co-firing with natural gas for processing copper into wire rod, revealing that while technically possible, it proved infeasible due to high nitrogen oxides (NOx) emissions and a reduction in the quality of the final product.

Transport

Methanol-fuelled shipping

The operation of ships with methanol as a fuel has already been demonstrated with commercial vessels and methanol-capable ships already in operation, although they mostly run on traditional shipping fossil fuels today. In January 2024, the world's largest methanol-powered vessel, the “Ane Mærsk” containership, capable of carrying 16 592 TEU (twenty-foot equivalent units), made its maiden call at Tanger Med Port, Morocco, and two similar vessels, the “Astrid Mærsk” and the “Antonia Mærsk”, have since set sail. The Ane Mærsk is nearly eight times larger than its predecessor, the feeder vessel “Laura Mærsk”, which was deployed in September 2023. In April 2024, Wärtsilä secured China's largest methanol new-build order for twelve 24 000 TEU containerships, which are expected to be delivered to two shipping lines by 2026.

Ammonia-fuelled shipping

Ammonia-fuelled vessels are not yet at the commercial stage, but progress has been made on tests of ammonia-fuelled engines for maritime applications, and there are plans for ammonia-fuelled ships to enter service in the next 2 years.

Wärtsilä announced the commercial availability of the first four-stroke ammonia-fuelled marine engine[72] for smaller vessels in November 2023, and has already signed a contract with Norwegian shipowner Eidesvik to retrofit an already operating vessel. The retrofit is expected to be completed in the first half of 2026, meaning the vessel could become the world’s first ammonia-fuelled in-service ship. Wärtsilä also has plans to install this type of engine in short-sea vessels[73]

[72] Four-stroke marine engines, which are more compact but heavier, are commonly used in smaller vessels, while the larger two-stroke engines are typically used in bigger vessels.
[73] Short-sea vessels are ships used for the maritime transport of goods over relatively short distances, typically within the same continent and not involving the crossing of an ocean.

for Viridis Bulk Carriers, as well as in two medium-sized gas carriers for EXMAR, to be delivered by Hyundai Mipo Dockyards (Korea) in early 2026.

In July 2023, MAN Energy Solutions began the first combustion tests on a large (50-bore) [74] two-stroke ammonia engine, including running at 100% engine load. In addition, in December 2023, MAN and BUTTING announced that its first selective catalytic reduction converter for an ammonia two-stroke engine had passed testing, reducing NOx emissions (which are a concern with ammonia combustion) by up to 90%. In April 2024, MAN announced a pilot project to install ammonia-fuelled engines in bulk carriers being built by Nihon Shipyard, in collaboration with several Japanese companies, with the aim of commercialisation by 2027. Furthermore, WinGD's 72-bore ammonia engines, the largest for ammonia and with combustion tests expected in 2024 in cooperation with Alfa Laval, have been ordered by CMB.TECH for bulk carriers, with first delivery by 2025, and for container ships (by 2026), and by AET for dual-fuel Aframax oil tankers.

Hydrogen-fuelled shipping

The use of hydrogen fuel cells for maritime applications has already been demonstrated and the orderbook is growing (see Chapter 2. Hydrogen demand), but the use of hydrogen engines in shipping is still at the earlier stages of research. In March 2024, Mitsui announced the world's first test of a two-stroke marine engine from MAN running on hydrogen at up to 100% load.

Hydrogen in aviation

The direct use of hydrogen in aviation is still in the early stages of development and requires significant innovation and demonstration efforts before it can reach commercial operation. ZeroAvia continues to test its 600 kW fuel cell propulsion system, which was first flight-tested in 2023, with the aim of carrying up to 19 passengers on commercial flights by 2025. It is also developing a 2-5 MW system for aircraft with up to 80 seats, expected by 2027. In September 2023, H2FLY completed the first piloted flight using liquefied hydrogen in a small demonstrator aircraft, doubling the range of gaseous hydrogen. At the end of 2023, Airbus ground-tested a 1.2 MW fuel cell system, with in-flight tests on an A380 aircraft (with a maximum certified capacity for 853 seats) planned for 2026, and in November 2023, Airbus tested a small hydrogen engine in a glider, flying for 30 minutes, to study hydrogen contrails. In April 2024, Japan's NEDO

[74] The bore of a marine engine refers to the diameter of the engine's cylinders. A 50-bore engine, often used in smaller vessels for regional routes, has smaller cylinders than a 72-bore engine, which powers larger vessels suitable for long-distance international routes.

announced a grant of JPY 13 billion (Japanese yen) (USD 87 million) to IHI to develop a 4 MW fuel cell using liquefied hydrogen for a three-hour flight on an aircraft with at least 40 seats by 2029.

Electricity generation

Hydrogen-fuelled technologies

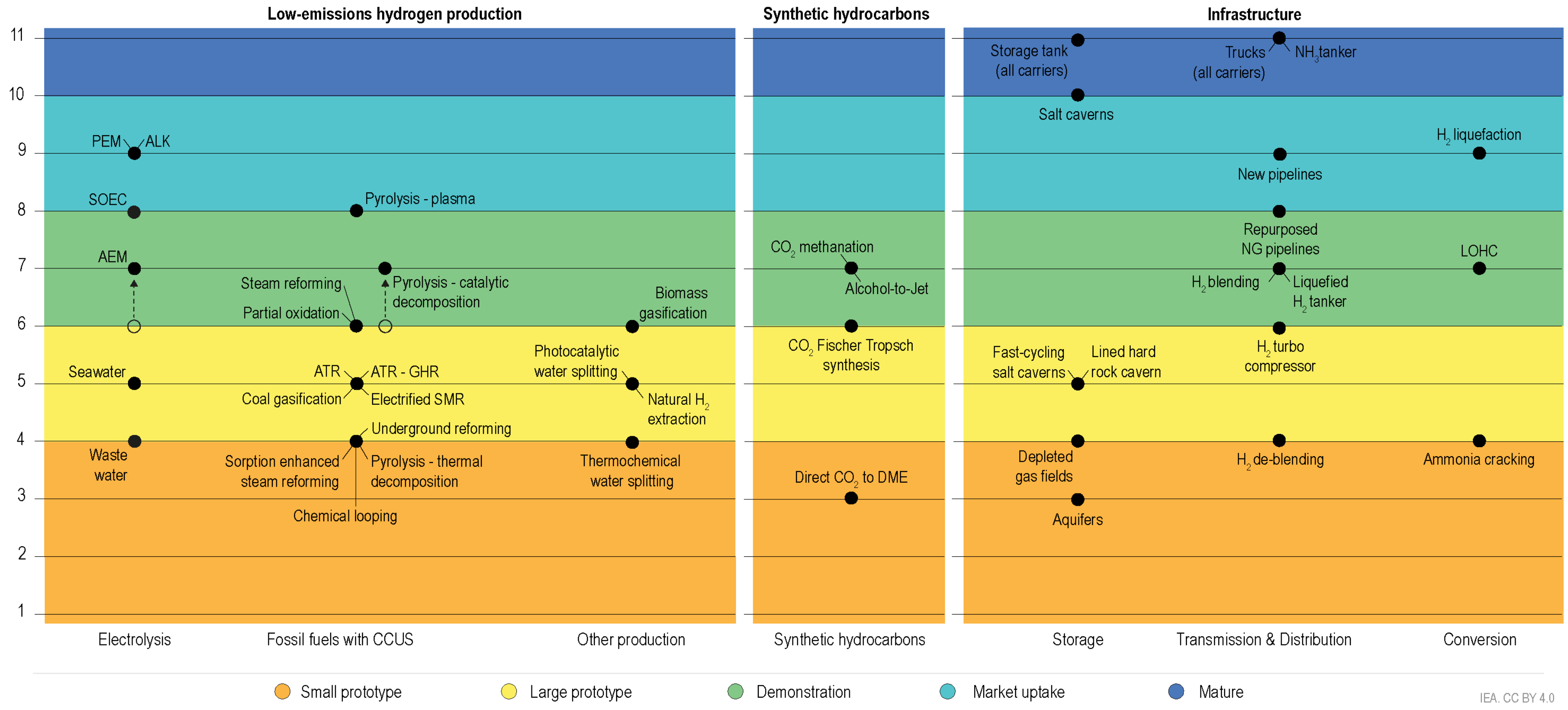
In October 2023, a consortium of European energy component manufacturers and universities demonstrated the use of 100% renewable hydrogen in a 12 MW gas turbine in the Hyflexpower project. This followed initial tests in 2022 with blends of 30% of hydrogen that were gradually increased up to 100%, in a first for the generation of electricity integrated with renewable generation of hydrogen. Previous work from NEDO, Kawasaki Heavy Industries and Obayashi in Japan had already demonstrated the use of 100% hydrogen at smaller scale, using a dry low NOx combustion method that improves electrical efficiency while lowering NOx emissions. In June 2024 Wärtsilä launched a hydrogen-ready engine (which can be converted to run on 100% hydrogen) and a fuel-flexible engine that can run on hydrogen or natural gas, both of which will be commercially available from 2025.

Ammonia-fuelled technologies

In April 2024 JERA started a 3-month pre-commercial large-scale demonstration trial to co-fire 20% of ammonia at its 1-GW Hekinan coal power plant. The results of the test were positive, indicating that NO_x levels were no higher than from the combustion of coal alone, levels of sulphur oxides were 20% lower, nitrous oxide emissions were below the detection threshold, and operability was comparable to coal-fired operation. Based on these results, and provided that the supply of ammonia can be secured, JERA plans to move to commercial operation from 2027. While efforts in developing this technology have mainly been spearheaded by Japanese and Korean companies, in November 2023 Adani Power announced its intention to test 20% ammonia co-firing in a 330 MW coal-fired power plant in India.

The IEA's Clean Energy Technology Guide and Project Demonstration Database provide further information on hydrogen-related innovation projects.

Figure 5.6 Technology readiness levels of production of low-emissions hydrogen and synthetic fuels, and infrastructure

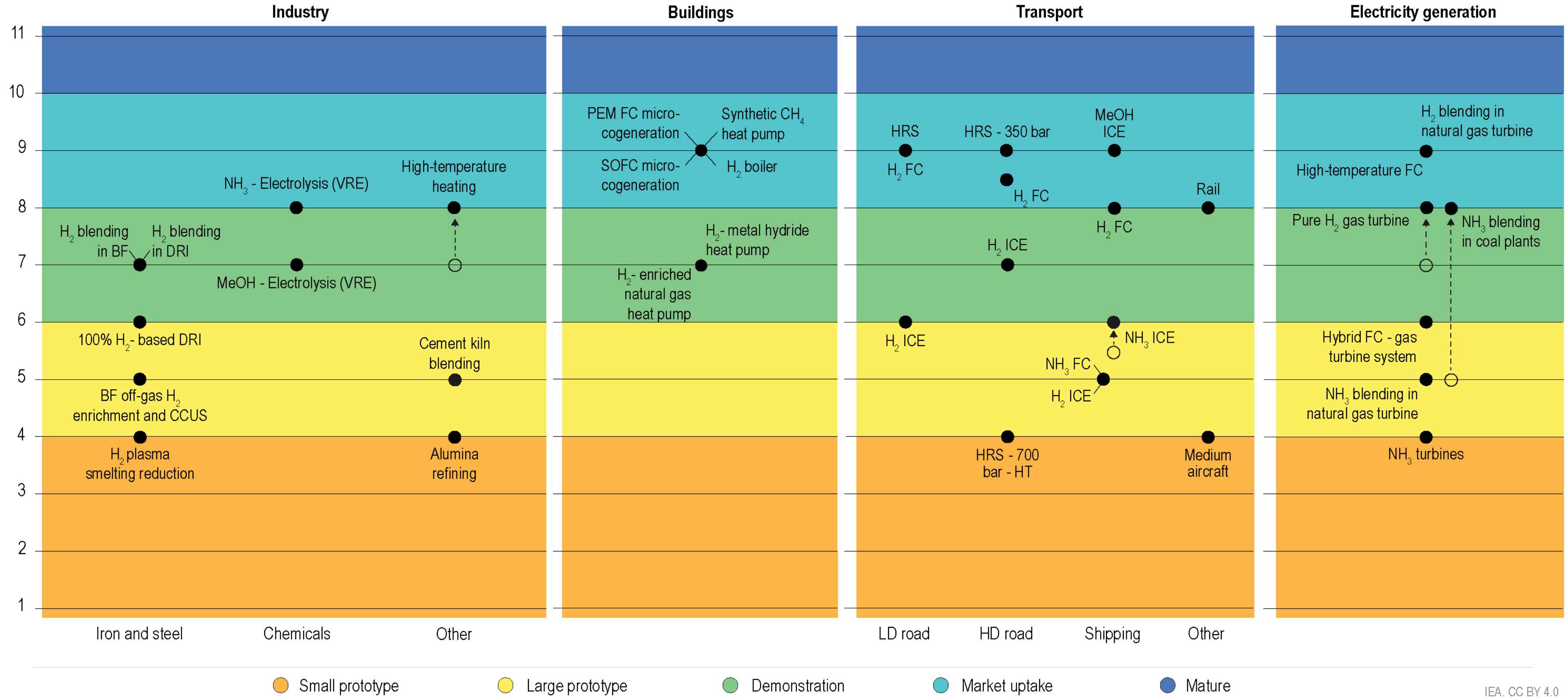


Notes: AEM = anion exchange membrane; ALK = alkaline; ATR = autothermal reformer; CCUS = carbon capture, utilisation and storage; CH_4 = methane; DME = dimethyl ether; GHR = gas-heated reformer; LOHC = liquid organic hydrogen carrier; NH_3 = ammonia; PEM = proton exchange membrane; SOEC = solid oxide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

Sources: IEA (2024), Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

Although some technologies for producing low-emissions hydrogen are already commercially available, innovation is critical to reduce production costs and ensure market uptake, as well as to demonstrate synthetic hydrocarbon production technologies at scale.

Figure 5.7 Technology readiness levels of technologies for hydrogen end-uses by sector



Notes: BF = blast furnace; CH_4 = methane; DRI = direct reduced iron; FC = fuel cell; HRS = hydrogen refuelling station; HD = heavy-duty; HT = high throughput; ICE = internal combustion engine; LD = light-duty; MeOH = methanol; NH_3 = ammonia; PEM FC = proton exchange membrane fuel cell; SOFC = solid oxide fuel cell; VRE = variable renewable electricity. "Other" in industry includes all industrial sectors except methanol, ammonia and iron and steel production. "Other" in transport includes rail and aviation. Arrows show changes in technology readiness level because of progress in the last year. Cogeneration refers to the combined production of heat and power. Technology readiness level classification based on Clean Energy Innovation (2020).

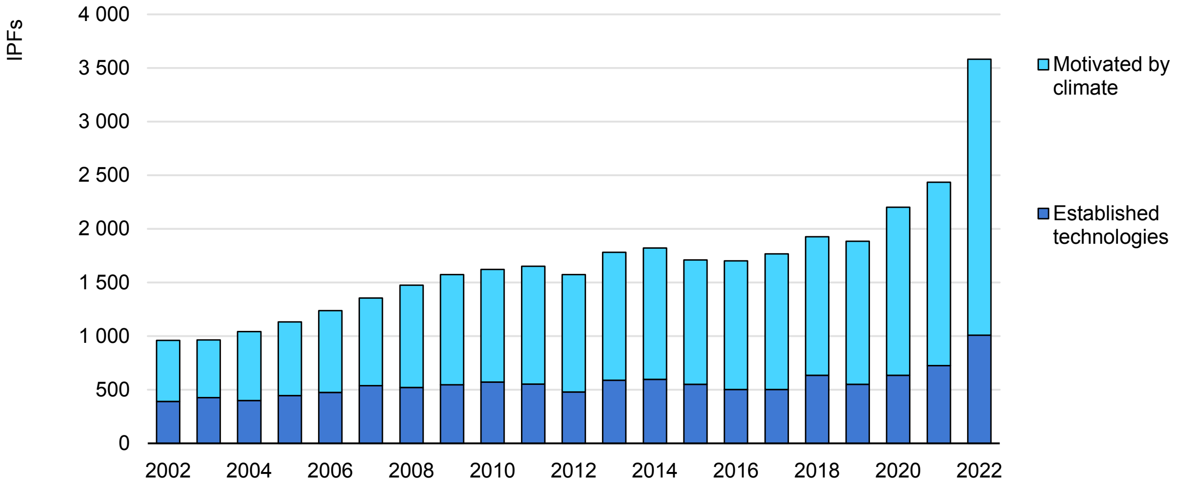
Source: IEA (2024), Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

Most of the end-use technologies for which low-emissions hydrogen and hydrogen-based fuels are among the few alternatives for decarbonisation are still at the demonstration stage, but several projects aim to bring them to market within this decade.

Tracking patent applications

The latest data on global hydrogen patenting, as measured by international patent families (IPFs), shows a jump in applications of 47% globally in 2022.[75] This represents a significant break with the steady growth of the previous years. Most of the growth came from the patenting of technologies in categories that are primarily motivated by climate change concerns, such as those that facilitate low-emissions hydrogen production, new approaches to hydrogen storage and avoidance of fossil fuels in end-use applications. The data suggest that confidence in future policy-led market opportunities for low-emissions hydrogen technologies, as well as additional public funding for R&D, are stimulating more new ideas and product designs with commercial potential. The year-on-year uptick is too short to extrapolate into the future and it is important to note that patenting is typically a lagging indicator of innovation direction and funding. Despite these caveats, the data nonetheless appear to offer positive news for clean energy innovation and could translate into lower costs and improved technology performance in the coming years.

Figure 5.8 Hydrogen technology patenting trends by main areas of focus, 2002-2022



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Notes IPFs = international patent families. The calculations are based on the country of the IPF applicants, using fractional counting in the case of co-applications. “Established” refers to well-established processes in the chemicals and refining sectors and “Motivated by climate” refers to emerging technologies that could help mitigate climate change by making hydrogen a clean energy product for a much wider range of sectors that would otherwise use fossil fuels. For more information, see IEA & EPO (2023), Hydrogen patents for a clean energy future.
Source: IEA analysis based on data from the European Patent Office.

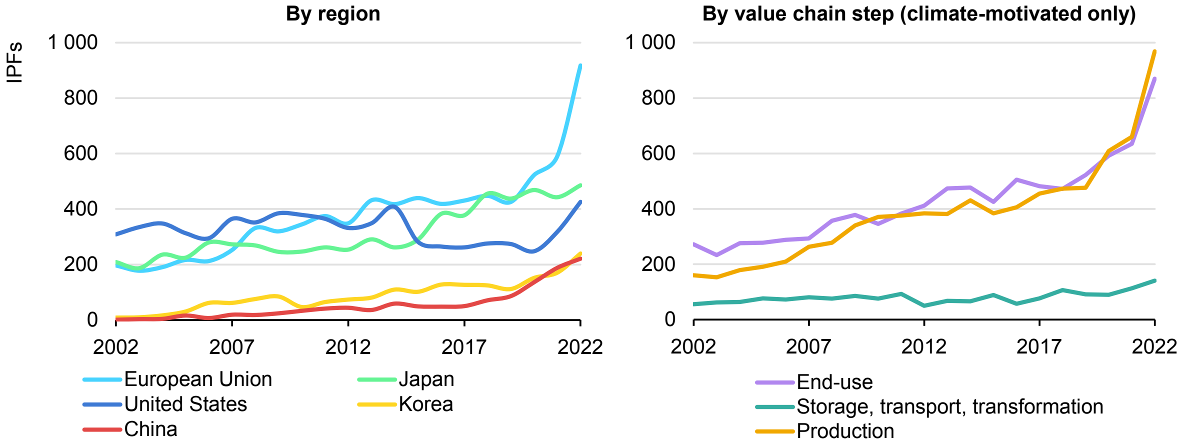
Global hydrogen patenting, as measured by international patent families, jumped by 47% in 2022, a significant and encouraging break with the trend over prior years.

Growth in 2022 came from all main regions, but was led by the European Union, where patents grew at a much faster rate than in Japan, which had a similar number

[75] An international patent family represents an invention for which patent applications have been filed at two or more patent offices worldwide. It is used as a means of identifying higher-value patents.

of hydrogen patent applications in 2021. EU hydrogen patent applications rose by 55% in 2022, taking the region to a level of activity equal to one-quarter of the global total. There were also notable increases in the United States (34% year-on-year growth), Korea (40% growth) and China (18% growth). The US trend represents a significant uptick compared with relative stagnation over the prior two decades. Across the different steps in the hydrogen value chain, patenting is not uniform. For those technologies categorised as being motivated by climate, activity is led by production and end-use technologies. Although the production of ammonia and methanol from hydrogen are categorised as established technology areas, they have low-emissions applications, and patenting in these areas grew significantly in 2022 – by 23% compared with the year before.

Figure 5.9 Hydrogen technology patenting trends by main regions, 2002-2022

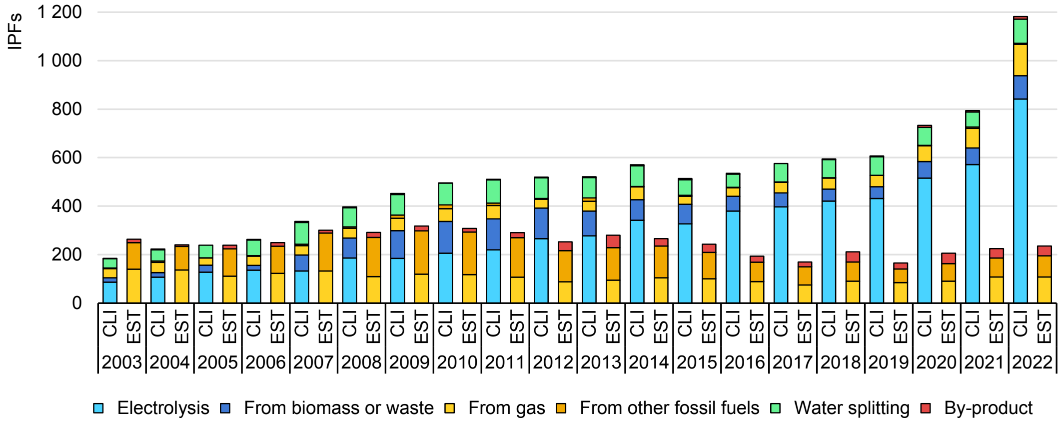


Notes IPFs = international patent families. For more information, see IEA & EPO (2023), Hydrogen patents for a clean energy future.
Source: IEA analysis based on data from the European Patent Office.

Growth in patenting in 2022 was seen in all main regions but led by the European Union, with most climate-motivated activity related to hydrogen production and end-use technologies.

Over the last decade, IPFs for electrolysis have trebled. IPFs for alkaline electrolysis have increased but remain lower than for PEM or SOEC, reflecting the greater maturity of the technology. IPFs for AEM electrolysis have shown steady growth and were responsible for 28% of all the growth in water electrolysis patents in 2022 across these four technology types. Patenting in hydrogen production from unabated fossil fuels peaked in 2009 but has continued to grow somewhat in recent years. This is also likely to be partly related to the growing interest in hydrogen for clean energy purposes, as some of the technologies that can improve traditional hydrogen production methods may also have crossover potential, for example for producing hydrogen from fossil fuels with CCUS or from biomass.

Figure 5.10 Hydrogen production technology patenting trends by type, 2003-2022

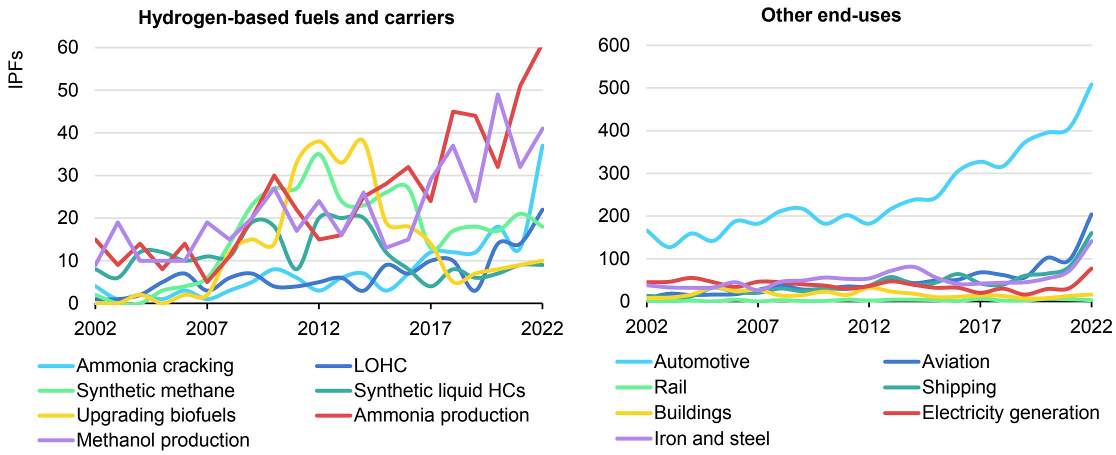


Notes: CLI = Climate technologies; EST = Established technologies; IPFs = international patent families.
Source: IEA analysis based on data from the European Patent Office.

Patenting of hydrogen production technologies is growing rapidly, boosted by the rise of electrolysis and, to a lesser extent, natural gas-based pathways with CCUS.

In hydrogen end-use technologies, patenting growth in 2022 was spread across almost all areas. Patents for hydrogen use in the automotive sector continue to grow, and represented almost two-fifths of the patenting activity related to end-uses, including conversion of hydrogen to hydrogen-based fuels and other energy carriers. This share has declined in recent years, from a high of 55% in 2019. Growth in patenting related to ammonia – both the production and cracking of ammonia – was especially strong in 2022. However, in general, patenting of inventions that relate to hydrogen conversion remains at a lower level than that for direct end-uses.

Figure 5.11 Hydrogen end-use technology patenting trends by type, 2002-2022



Notes: HCs = hydrocarbons. IPFs = international patent families. LOHC = liquid organic hydrogen carrier. Synthetic liquid hydrocarbons include synthetic diesel and synthetic kerosene production.
Source: IEA analysis based on data from the European Patent Office.

Patenting for hydrogen end-use technologies grew markedly in 2022, driven by the continued dominance of patenting for automative uses and broader growth across almost all other areas.

Chapter 6. Policies

Highlights

- Policy support is now taking strides towards implementation, with almost USD 100 billion of public funds being announced, entering into force, or being allocated to projects in the past year. Nearly two thirds of these funds are at the announcement stage and thus are still uncertain, and 95% come from advanced economies, which typically have longer-standing hydrogen strategies. Funding for the supply side is 1.5 times higher than for the demand side.
- Nineteen new hydrogen strategies were published in the past 12 months, bringing the total to 60, and now covering countries that account for over 84% of global energy-related CO_2 emissions. Most of the new strategies were from emerging markets and developing economies (EMDEs), and most new targets are for production. This represents just the beginning of the policy-making process – so far none of the new targets are binding or tied to specific policies.
- Funding related to demand-side policies from the past 12 months adds up to USD 40 billion. About 20% of these funds target existing applications, while more than half – 60% – is for new applications. Policies already in place could trigger demand for 6 Mtpa of hydrogen by 2030, which would be equivalent to only half of the amount envisaged by announced demand targets, as little as 15-20% of production targets, and less than 10% of what is needed in the Net Zero Emissions by 2050 Scenario. Around two thirds of the funding are from Germany alone, through support for industrial decarbonisation and power.
- Public subsidies were the most common policy instrument in developed markets, while tax incentives are common across EMDEs. Competitive bidding was used in a diverse range of countries, with auctions carried out in Egypt, Europe, India and Oman in order to facilitate market formation, price discovery, and competition. Nine countries introduced incentives for electrolyser and fuel cell manufacturing, but only six of them have policies already in force.
- At COP 28, 37 governments committed to pursue mutual recognition of national certification schemes based on common design principles. Towards the same aim, 14 Latin American countries launched “CertHiLAC”, backed by Multilateral Development Banks. In December 2023, the International Organization for Standardization (ISO) published a Technical Specification that provides the basis for a full ISO standard for the methodology for determining the GHG emissions associated with hydrogen production, conditioning and transport. This is expected to be published in 2025/2026.

Overview

The number of countries with a hydrogen strategy in place continues to increase: 19 governments have published a new strategy in the past 12 months, principally in emerging markets and developing economies (EMDEs). Coverage increased principally in European (7 new strategies), African (4 new strategies), and Association of Southeast Asian Nations (ASEAN) countries (3 new strategies). Common drivers were decarbonisation, energy security, domestic industrial development and export potential. All the new strategies depict a future characterised by strong exports that enable the creation of a burgeoning domestic industry, while there is no new strategy that envisages importing hydrogen. This also reflects the broader trend across strategies published to date. Countries accounting for 84% of global energy-related CO_2 emissions have now published a hydrogen strategy.

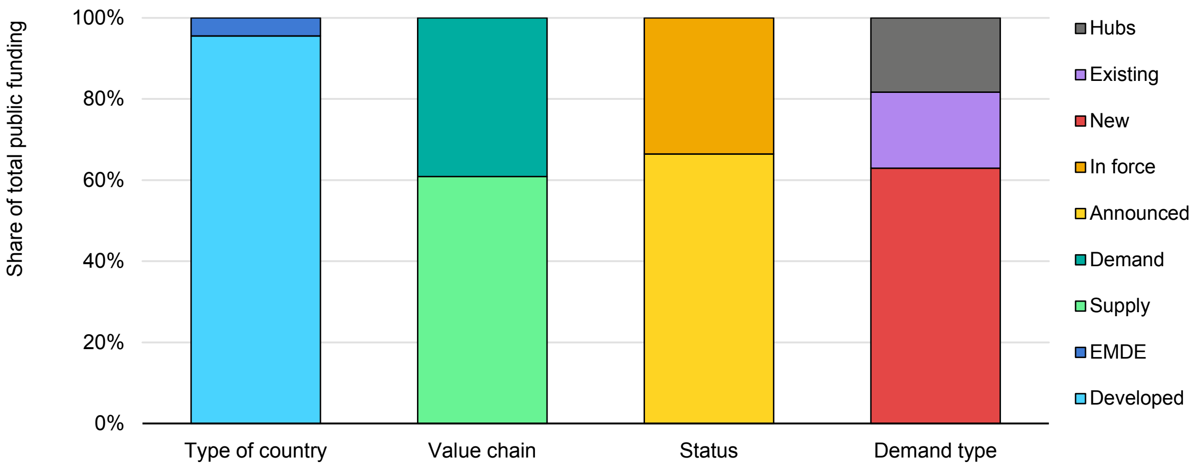
Policy support is now moving from visions and targets to implementation, with specific policies and funding programmes, using various instruments that aim to close the cost gap between low-emissions hydrogen and fossil counterparts. In the past year, the equivalent of almost USD 100 billion of public funds have been announced, entered into force, or been allocated to specific projects to improve the business case for low-emissions hydrogen. Although nearly two thirds of these funds are only at the announcement stage and are therefore uncertain, they nevertheless indicate commitment from governments and progress towards implementation. The vast majority – 95% – come from advanced economies, whereas EMDEs currently have limited economic incentives for domestic industry development (Figure 6.1). Overall, this funding amounts to only a small fraction of the trillions in investment needed to achieve net zero goals, but it is significant given the nascent state of the low-emissions hydrogen industry (see Chapter 5. Investment, finance and innovation) and the need to both demonstrate deployment under different settings and build experience across diverse geographies.

Public funding for the supply side is almost 1.5 times higher than for the demand side. This mirrors a similar disparity across strategies between aims to export and plans to import. Funding related to supply-side policies that have been introduced in the past 12 months adds up to almost USD 62 billion, while funding for demand-side policies totals USD 40 billion.

Public subsidies are currently the most common instrument used in developed markets, while tax incentives are common across EMDEs. Direct grants, which can be critical to reducing the CAPEX premium, de-risking investments and obtaining a lower cost of capital, are one of the most common instruments. Almost all (99%) of the direct grants were from advanced economies. Almost two thirds of the eleven countries using tax incentives were EMDE. Competitive bidding was used on a more geographically widespread basis, with auctions for hydrogen production carried out across Europe and in India. Incentives covered a wide range, from USD 0.16/kg H_2 (Denmark, through competitive bidding) to USD 10/kg H_2 (United Kingdom, through contracts for difference [CfD]). While direct comparison is complicated by differing auction and power market designs, and different electricity prices, among other factors, all bidding processes contribute to market formation, price discovery, and competition that will drive down costs. Competitive bidding was also common on the demand side, with auctions for the use of hydrogen and ammonia in the power sector launched or planned in Germany, Japan, Korea and Singapore.

Alongside the development of certification schemes, governments are working to clarify the underlying rules and requirements for hydrogen under their respective national frameworks. The United States is developing guidelines on qualifications for hydrogen under the Inflation Reduction Act (IRA), while the European Commission is developing a definition of "low-carbon" under the Hydrogen and Gas Decarbonisation Package. Meanwhile, the United Kingdom released an update to its Low-Carbon Hydrogen Standard, while Kenya put forward its sustainability criteria for "green" hydrogen produced in the country.[76] Brazil moved ahead with the Brazilian Hydrogen Certification Scheme (SBCH2), passing legislation that sets a GHG threshold of 7 kg CO_2-eq/kg H_2 for low-carbon hydrogen. Japan proposed GHG thresholds for hydrogen, ammonia, synthetic methane, and synthetic fuels under the Hydrogen Society Promotion Act, with the rules still to be finalised.

Figure 6.1 Share of public funding linked to hydrogen-related policies by location, status and use, 2023



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Notes: EMDE = emerging markets and developing economies. Not all the policies can be converted into a monetary value. Some of this funding is multi-year. Numbers include both specific calls and tenders that have been awarded and announcements of future funding programmes (which lack detail in many cases).

About 60% of the public funding announced in 2023 is directed towards the supply side, has not yet been passed into legislation, and targets new demand applications.

[76] See Explanatory notes annex regarding the use of the term "green" hydrogen in this report.

Strategies and targets

Since the release of the Global Hydrogen Review 2023 (GHR 2023), 3 governments have updated their hydrogen strategy and a further 19 – mostly from EMDEs – have adopted new national hydrogen strategies (Table 6.1). A total of 58 governments, the European Union and the Economic Community of West African States (Figure 6.2), accounting for more than 84% of global energy-related CO_2 emissions, have now adopted hydrogen strategies. Strategies are just the first concrete step towards development, and in most cases, they outline the status of and potential for hydrogen development, and announce short-term actions. Only later are they translated into specific legislation and incentives. As such, most of the legislation in place today results from strategies that were announced a couple of years ago, and more recent strategy announcements (Table 6.1) are yet to translate into specific legislations with legally binding targets or defined incentives.

Figure 6.2 Hydrogen strategies by country and year of first announcement

2017	2018	2019	2020	2021	2022	2023	2024
Japan	France	Australia	Canada	Belgium	Austria	Algeria	Iceland
		Korea	Chile	Colombia	China	Argentina	Egypt
			European Union	Czech Republic	Costa Rica	Bhutan	Kazakhstan
			Germany	Denmark	Croatia	Brazil	Lithuania
			Netherlands	Hungary	Namibia	Bulgaria	Tunisia
			Norway	Luxembourg	Oman	ECOWAS	Viet Nam
			Spain	Morocco	South Africa	Ecuador	
			Portugal	Poland		Estonia	
			Russia	Slovak Republic		India	
				United Kingdom		Indonesia	
						Ireland	
						Israel	
						Kenya	
						Malaysia	
						Mauritania	
						New Zealand	
						Panama	
						Romania	
						Singapore	
						Sri Lanka	
						Türkiye	
						United Arab Emirates	
						United States	
						Uruguay	

Note: ECOWAS = Economic Community of West African States.

In total, 30 advanced economies (including the European Union) and 30 emerging market and developing economies have already adopted hydrogen strategies.

Table 6.1 National hydrogen roadmaps and strategies launched or updated since September 2023

Country	Description
Argentina	Targets for 2050 include production of 5 Mtpa (0.3 Mtpa by 2030), 30 GW of electrolysis and 55 GW of renewables. Most production targets are for export, with domestic demand expected to reach 1 Mtpa by 2050 (0.02 Mtpa by 2030). Estimated investment needs are USD 90 billion. Actions focus on RD&D, regulatory support and certification.
Bhutan	Electrolyser target of 5 MW by 2030 and 485 MW by 2050 with investment needs (for production only) of USD 9 million by 2030 and USD 454 million by 2050. Estimated maximum hydrogen demand of 4.2 ktpa for steel, 12 ktpa for cement, and 52.5 ktpa for road transport.
Bulgaria	Roadmap identifying 18 actions across 4 areas to be implemented before 2026. Actions include enabling measures such as power market design and development guides for project construction, and deployment targets such as 10 pilot projects and 2 hydrogen valleys by 2026.
ECOWAS	Regional production target of 0.5 Mtpa by 2030 requiring 4-5 GW of electrolysis and a cumulative investment of USD 3-5 billion. Hydrogen production target of 10 Mtpa by 2050.
Egypt	Targets 1.5 Mtpa of renewable hydrogen by 2030. Focus on industry, transport and export. 40 Mtpa CO_2 emissions reduction resulting from hydrogen use by 2040, and GDP growth of USD 10-18 billion.
Estonia	Roadmap for hydrogen deployment across three phases until 2050. Targets for the pilot phase (until 2030) include 3-5 hydrogen refuelling stations (HRS) and 2-40 ktpa of renewable hydrogen.
Iceland	Targets domestic hydrogen demand in 2030 of 12 ktpa plus another 24 ktpa to satisfy 10% of demand from international aviation. Satisfying this with renewable hydrogen would require 237 MW of electrolysis. Investment needs for 2030 of USD 1.8-3.2 billion. 2040 demand is estimated to be ten times larger (with almost 80% from international aviation).
Indonesia	Strategy based on three drivers (decarbonisation, energy security, and exports), with nine action areas including hubs, hydrogen use in mini-grids and power generation, a carbon pricing scheme, and definition of a hydrogen certification scheme. Defines a methodology for establishing priority uses for hydrogen based on relevance (for the strategy), impact (expected output) and urgency.
Ireland	Potential demand for 2050 is estimated to be 0.6-2.2 Mtpa with the bulk (between 35% and 65%) coming from aviation (for electro-sustainable aviation fuel [e-SAF]).
Israel	Hydrogen demand in 2050 ranging from 580 ktpa to 5.3 Mtpa (equivalent to 10-100% of Israel's final energy demand in 2021) with the difference coming from the power sector. Introduction of a 5.5% combined target for synthetic fuels and biofuels by 2033 is under consideration.
Kazakhstan	Concept note defining broad areas of action for development, with 6 target indicators to measure results, including a 10 GW electrolyser target and up to KZT 5 trillion (Kazakhstani Tenge) (USD 11.3 billion) of investments in hydrogen by 2040 and a 20% share of domestic supply of technologies.
Lithuania	Targets for 2030 of 1.3 GW of electrolysis (129 ktpa), 30 buses and 10 HRS (with at least 1 for shipping), and exports of over 5% of domestic production by 2050. Electricity demand for the electrolysers in 2050 estimated to be over 35 TWh, compared to a current national electricity demand just over 13 TWh.
Malaysia	The hydrogen roadmap goes together with the national energy transition roadmap as one of the key levers to achieve carbon neutrality by 2050. Targets include the phase-out of fossil-based hydrogen, 3.3 Mtpa of renewable hydrogen, and 3 hubs by 2050. An accompanying technology roadmap adds more detail.

Mauritania	Target of 1.5% of the global hydrogen market and up to 1% of the global "green" steel market by 2050. Explicit production targets for hydrogen, ammonia, "green" steel, methanol and ammonium nitrate. Hydrogen production targets of 1.2 Mtpa by 2030 (almost exclusively for exports), increasing to 6.5 Mtpa by 2050 (of which 4.3 Mtpa are for export).
New Zealand	A public consultation on the hydrogen roadmap closed in November 2023 and resulting updates will inform the National Energy Strategy, due by end of 2024. Estimated 2050 demand of 0.6-1.4 Mtpa, requiring 4.5-9.8 GW of electrolysis. Hydrogen is expected to contribute to decarbonisation, economic growth and energy security.
Romania	Action plan for implementation of the roadmap with 33 actions across 4 objectives (decarbonisation; "clean" hydrogen production, skills and innovation; sectoral coupling and renewables integration). 2030 targets include 34.4 ktpa of renewable hydrogen by 2030, 21 500 heavy- and medium-duty trucks, and 1.6 GW of combined-cycle gas turbine (CCGT) capacity with 50% renewable hydrogen co-firing.
Tunisia	Targets 8.3 Mtpa of total hydrogen production and 87 GW of electrolysis by 2050, including 6 Mtpa for export. Intermediate milestones for 2030 include 320 ktpa of hydrogen production, 3.9 GW of electrolysis, and 5 GW of renewables. Short-term use is in chemicals and refining, with long-term use in aviation (e-SAF), shipping and power. Investment needs for 2050 total USD 130 billion.
Uruguay	Estimated hydrogen production of 1 Mtpa in 2040, requiring 9 GW of electrolysis capacity, with two-thirds of the output exported, and potential annual revenue of USD 1.9 billion in 2040.
Viet Nam	Production target of 0.1-0.5 Mtpa by 2030 and 10-20 Mtpa by 2050.
Australia (update)	0.5 Mtpa production target by 2030 requiring 3 GW of electrolysis with a stretched target of 1.5 Mtpa. Base 2030 export target of 0.2 Mtpa with a stretch potential of 1.2 Mtpa. About 30% of the 2030 demand is expected to come from aluminium production. Hydrogen could represent 30% of final energy use in road transport by 2050 and 45% in road freight.
Czech Republic (update)	Update based on the latest market conditions and EU legislation. Strategy is divided into three stages: The first, to 2030, targets 400 MW of electrolysis and 20 ktpa of renewable hydrogen. The second, to 2045, focuses on network development. The third focuses on new production pathways.
South Africa (update)	Strategy first published in 2022 approved by the cabinet. Targets include 1 Mtpa of renewable hydrogen (13 GW of electrolysis) by 2030, increasing to 4 Mtpa (41 GW of electrolysis) by 2050. Exports are expected to account for 50% by 2050. Focuses on use of domestic resources (platinum) for 1 GW/yr of proton exchange membrane (PEM) manufacturing capacity. Total investment needs of USD 300 billion by 2050.

Notes: See Explanatory notes annex for the use of the term "clean" hydrogen in this report.

Notably, ASEAN member countries have progressed with strategies and targets since the release of GHR 2023. While there are several ongoing projects in the region (see Chapters 2-4), only Singapore had a hydrogen strategy at the time of our last edition. Since then, Indonesia, Malaysia and Viet Nam have also published national hydrogen strategies. All three have decarbonisation as a key driver and an export-oriented nature, and use a phased approach with different time horizons, each with different areas of focus and objectives. Although the strategies differ in their level of detail, all have the overarching aim of identifying enablers for hydrogen development.

In addition, several more European countries joined the list of those with hydrogen strategies, including Bulgaria, Estonia, Ireland, Lithuania and Romania. Their strategies largely focus on renewable hydrogen, with Estonia, Lithuania and Romania having set explicit targets. Ireland's strategy does not set specific targets, but rather assesses potential demand, and highlights the country's offshore wind potential. Industry and transport are common end-uses across strategies, with Romania also including targets for the power sector. Lithuania's national strategy for energy independence defines hydrogen targets, including 1.3 GW of electrolysis by 2030 and 8.5 GW by 2050 (to produce more than 730 ktpa). Croatia published an implementation plan for its hydrogen strategy, identifying regulatory gaps and priority activities to 2030. In Italy, the National Energy and Climate Plan foresees domestic consumption of renewable hydrogen of 250 ktpa[77] by 2030, of which 70% is produced domestically, requiring 3 GW of electrolysis. Portugal has revised its electrolyser capacity target to 3 GW by 2030 (from 5.5 GW) in its public consultation of the national and energy climate plan and in August 2024 Greece revised its target from 1.7 GW by 2030 (set in 2023) to 187 MW. Germany published its hydrogen import strategy in July 2024. It expects the import share to be 50-70% in 2030. The strategy follows a diversification approach for supply (partners), infrastructure (carriers) and products (hydrogen derivatives). Germany is also expected to publish its hydrogen storage policy in 2024.

In China, several provinces announced plans and targets for hydrogen production and road transport, including incentive measures to be used (see Box 6.1). There are few incentives at the national level (other than technology promotion), and financial incentives are set by the provinces.

Elsewhere, countries with longer-standing hydrogen strategies turned their attention to updates. In December 2023, France issued a document for consultation on their strategy update. This confirms funding of EUR 9 billion (USD 10 billion), of which EUR 4 billion is envisioned for CfD. On the supply side, the focus is on electrolytic hydrogen, with electrolyser targets of 6.5 GW by 2030 and 10 GW by 2035. The main policy instrument considered for supply is CfD, with annual tenders expected to be launched in 2024 that will support a total electrolyser capacity of 1 GW by 2026.[78] The proposed update also includes undertaking a study to map and assess the economic potential of natural hydrogen by 2025, and a domestic manufacturing incentive that is also available for equipment exports. With regards to infrastructure, the proposal includes the development of major hubs (e.g. Dunkirk), 500 km of transmission pipes, HRS every 200 km (to comply with the EU Alternative Fuels Infrastructure Regulation), salt cavern storage, and assessment of imports. Similarly, Chile published a new document that provides more detailed actions for each of the action areas identified in its existing hydrogen strategy, with the aim of enabling more concrete progress towards accelerating hydrogen development in the country. Austria published a progress report on the implementation of its 2022 hydrogen strategy, in line with its biennial update cycle, and also published a SAF roadmap covering scenarios and 15 actions for the short term to promote SAF ramp-up.

[77] The 2020 draft had a target of 0.7 Mt/yr.
[78] With additions of 150 MW in 2024, 250 MW in 2025 and 600 MW in 2026.

Canada published a progress report covering the project pipeline, incentive schemes, deployment, hubs, priorities, and a comparison of scenarios for hydrogen demand to 2050. India published a document confirming its 2030 targets, and providing an overview of the progress so far and the financial incentives in each state, as well as the financing options available.

Box 6.1 Provincial hydrogen targets in China

China produced 28 Mt H_2 in 2023 – nearly 30% of the global total. Almost 60% of the hydrogen was produced from unabated coal and a quarter from unabated gas, together emitting about 400 Mt CO_2. At the same time, China has been leading global hydrogen deployment across electrolysis, synthetic fuels, industry and road transport (see Chapter 2. Hydrogen demand and Chapter 3. Hydrogen production). In March 2022, China published its national Hydrogen Industry Development Plan, with targets for 100-200 ktpa production and deployment of 50 000 fuel cell electric vehicles (FCEVs) by 2025. Since then, Chinese provinces have published more ambitious plans, with targets adding up to 1 200 kt H_2, nearly 120 000 FCEV and more than 1 500 HRS by 2025. In 2024, electrolytic hydrogen production from projects that are operational, have reached a final investment decision (FID) or are under construction could total 165 ktpa (see Chapter 3. Hydrogen production), surpassing the national target and reaching almost 15% of the total from provincial targets. At the end of 2023, the FCEV stock stood at 20 600 (see Chapter 2. Hydrogen demand), 50% up from 2022. A similar pace of growth would be needed to meet the national FCEV target by 2025, but 2024 data indicates that growth has slowed significantly. As a result, Anhui province has revised its 2025 FCEV target from 3 000 to 2 000. Similarly, HRS deployment remains far behind the provincial targets, standing at over 400 HRS at the end of 2023.

The incentive for provinces to achieve their targets is a financial reward from the central government (for example, USD 109 million was awarded for the first phase of FCEV pilot programmes). Incentives offered by provinces include CAPEX subsidies for HRS (e.g. up to USD 280 000 in Tangshan, Hebei), OPEX subsidies for HRS (USD 2.8/kg H_2 for HRS that sell hydrogen below USD 4.2/kg H_2), a price cap on the hydrogen for FCEV (e.g. USD 4.2kg H_2 in Hebei), as well as supply-side subsidies such as on OPEX for hydrogen production (e.g. USD 1.4/kg H_2 in Zhangye, Gansu) and lower electricity prices (e.g. a reduction of USD 21-28/MWh in Chengdu, Sichuan) as well as CAPEX support for electrolysis (e.g. 30% CAPEX in Shenyang, Liaoning).

Inner Mongolia is the region with the most ambitious low-emissions hydrogen production target: 2.5-5 times the national target and equal to more than one-third of the current hydrogen production in the province. Its plans, released in early 2022, target production of 1.6 Mt by 2025, with a 30% share of renewable hydrogen. In early 2023, regional authorities had approved 31 "green" hydrogen projects,* but the development rights for 12 of these, with a total electrolysis capacity of more than 3 GW, were later revoked. Some of the incentives in place allow for the establishment of hydrogen projects outside the designated chemical industrial zones, and have limited requirements for licences in addition to subsidies for production and HRS. Among the projects that are already operating or under construction are a 90 kt project close to Ulanqab that started construction in July 2024, and the first phase of the Chifeng city project from Envision, which started operations in 2023 with the next phase of more than 56 kt to start in 2024. Two 8-10 kt projects started operations in March 2024 and July 2024.

Province	2025 production target (ktpa)	2025 FCEV target (thousands)	HRS
Inner Mongolia	480-500	5	60
Gansu	200	1.2	28
Hainan	100	0.2	6
Henan	8	5	100
Shanghai		10	70
Guangdong	100	10	300
Hebei	100	10	100
Shandong		10	100
Shanxi	30	10	180
Shaanxi		10	100
Other provinces	181	46	468
Total	**1 200-1 220**	**117**	**1 512**

Sources: IEA analysis based on data from the Center on Global Energy Policy and Energy Iceberg.

Elsewhere, Jilin and Hainan have launched initiatives to promote renewable methanol, and Shanghai has set an objective to develop a low-emissions port, recognising methanol as a potential pathway. This is also aligned with the Action Plan for Green Development of Shipbuilding Industry (2024-2030), released in December 2023 by the central government, which focuses on research and pilot projects for hydrogen, ammonia and methanol ships. Shandong targets at least 2 vessels with fuel cells by 2025 and more than 30 by 2030.

Qinghai is leveraging its industrial base and has identified 43 renewable hydrogen and chemical projects integrating 50 kt of ammonia production, 90 kt of urea, 120 kt of nitrate molten salts, and 50 kt of methanol. Guangxi is pursuing a broad approach, including demonstration of hydrogen production from offshore wind, biomass and nuclear energy; hydrogen blending at the transmission level; fuel cell trucks and ships; and hydrogen for industrial boilers.

* See Explanatory notes annex for the use of the term “green” hydrogen in this report.

Demand creation

A total of 26 different policies targeting demand creation have been announced since the publication of GHR 2023 (Table 6.2). The most common policy instrument used is CAPEX support in the form of grants, although India's policy, which establishes quotas, and Germany's, which will use carbon contracts for difference (CCfD), are notable exceptions. Public procurement (e.g. for steel) has not been explicitly used to trigger hydrogen demand over the past year. Across all the demand-creation policies, applications are most commonly located within hydrogen valleys or hubs. Among the policies that list specific target sectors, industrial uses are most common, while four countries – Germany, Japan, Korea and Singapore – have announced support for the power sector. The aviation and shipping sectors are notably absent, despite hydrogen derivatives being essential to decarbonisation in these sectors in the Net Zero Emissions by 2050 Scenario (NZE Scenario) – representing 2% and 9% of final energy consumption, respectively, by 2030. Nearly all the funding envisaged by these policies comes from developed countries, though India is an exception, with USD 24 million for hydrogen hubs. However, half of the policies and almost 60% of the total public funding is only at the announcement stage and yet to be converted into a binding law.

The United States approved almost USD 1.7 billion for six hydrogen-related projects as part of the Industrial Demonstration programme. The projects include two hydrogen direct reduced iron (DRI) plants, a furnace in an ethylene plant that will use up to 95% hydrogen, a synthetic ethylene plant, a synthetic methanol plant, and a syngas production plant from liquid by-products. Construction should begin by October 2026, and up to 50% of the project costs can be covered by the grant. Overall, the entire programme (which also covers areas other than hydrogen) has announced public funding of USD 6 billion and is expected to mobilise over USD 20 billion of private capital investment. Of the USD 6 billion in public funding, USD 5.5 billion will come from the IRA, while the remaining USD 0.5 billion comes from the Bipartisan Infrastructure Law.

In a separate effort, the US Department of Energy (DoE) announced the winners of the H2Hubs call in October 2023. Seven hubs were selected for negotiation. Once negotiation has been completed, funding will be allocated progressively across four phases with 8-12.5 years to full capacity. Three hubs[79] have already received total funding of USD 87.5 million for the first phase (detailed planning). The public funds allocated amount to USD 7 billion, which is expected to trigger a total investment of almost USD 50 billion. The DoE also announced the H_2DI consortium that will design and implement demand-side support mechanisms in order to facilitate purchases of hydrogen produced by the H2Hubs, with the aim of helping to provide

[79] Pacific Northwest Hydrogen Association (PNWH2), the California Hydrogen Hub (ARCHES) and the Appalachian Regional Clean Hydrogen Hub (ARCH2).

offtake certainty and unlock FID. The measures and implementation plan should be ready by the end of 2024. Separately, the DoE also announced USD 98 million for HRS and research facilities.

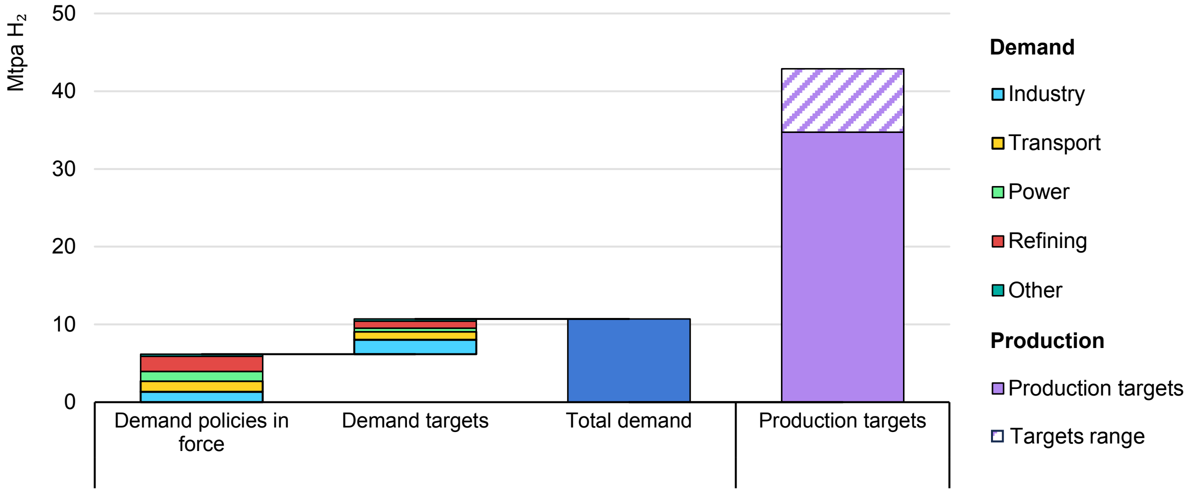
In Europe, Spain has included renewable fuels of non-biological origin (RFNBO) among the fuels eligible to be used towards meeting renewable targets in the transport sector from 2025 onwards. RFNBO will benefit from having a multiplier of two in comparison to biofuels, and fuels delivered to aircraft and ships will be worth 1.2 times as much as road transport fuels.

Elsewhere, Japan has released more information on its proposed hydrogen and ammonia clusters support scheme to support demand creation in the industry sector. The scope of this support includes infrastructure (storage and transport facilities), and covers different phases of project development, from feasibility studies to infrastructure development. Targets include three large-scale clusters around metropolitan areas, and five medium-scale clusters in regional locations. Assets need to have a planned operation of at least 10 years, and operation should start before 2030.

India launched a tender for hydrogen hubs in August 2024. Up to INR 1 billion (USD 12 million) of public support will be given to each hub. The target is to have at least two hydrogen hubs of 100 ktpa each. Projects must reach completion before April 2026. Australia launched a consultation paper in June 2024 on policies to promote the uptake of low-carbon liquid fuels. Policy instruments under consideration for the demand side include mandates, low-carbon fuel standards and targets, and for the supply side, CfD, grants and production tax incentives.

The demand envisaged by demand-side policies and targets remains behind production targets (Figure 6.3). Demand for low-emissions hydrogen from policies already in force adds up to more than 6 Mtpa by 2030. The European Union leads the way on the basis of mandates introduced by the ReFuelEU Aviation and FuelEU Maritime regulations. At the sectoral level, refining has the largest share of demand, led by China, Canada, and India, where – despite the absence of specific policies – the committed projects in the pipeline drive demand. Looking forward, on the basis of announced government targets, demand could almost double to reach nearly 10.5 Mtpa by 2030, with half of this growth coming from the transport sector. However, targets for demand are far lower than targets for production, where the United States and India alone represent 15 Mtpa by 2030 (10 Mtpa and 5 Mtpa, respectively).

Figure 6.3 Potential annual demand for low-emissions hydrogen created by implemented policies and government targets, and production targeted by governments, 2030



Notes: Values reflect all the policies announced at time of writing. "Demand policies in force" represents the maximum of the capacity from committed projects in the pipeline and the legislated policies. The dashed area in production targets represents policy targets' ranges. For countries that do not have a production target, the low-emissions hydrogen production target is estimated from the capacity targets, assuming a capacity factor of 57% and an energy efficiency of 69% for electrolysers.

Meeting government targets could create demand for up to 10.5 Mtpa low-emissions hydrogen in 2030, far less than the 35-43 Mtpa foreseen by government production targets.

Table 6.2 Policy measures to promote demand creation implemented or announced since September 2023

Country	Status	Sector	Description
Australia	In force	Hubs	AUD 490 million (Australian dollars) (USD 324 million) allocated to seven hydrogen hubs as part of the Regional Hydrogen Hubs Programme announced in 2022. All target renewable hydrogen and could ultimately produce 2.8 Mtpa (with additional investment).
Chile	Announced	All	Up to USD 1 million for demand creation and demonstration of new uses. Up to 60% of costs can be covered.
China	In force	Industry	The National Development and Reform Commission issued actions plans for four industry sectors defining targets on efficiency improvement, energy saving and carbon reduction. Plans for refining and ammonia explicitly mention use of renewable hydrogen, without setting explicit targets. By 2025, any capacity below the efficiency thresholds (currently 15% of refining capacity and 11% of ammonia capacity) will need to be improved or closed. New-build ammonia plants should use renewable power and hydrogen.
India	Announced	Hubs	INR 2 billion (Indian rupees) (USD 24 million) during FY2025-2026 to set up at least two renewable hydrogen hubs with a minimum size of 0.1 Mtpa. Larger hubs will be given a higher priority (50% of the evaluation criteria).
India	Announced	Industry	5-15% renewable hydrogen quota for the refining sector starting from 2026-2027. Draft regulations are under consultation with stakeholders. State-owned Indian Oil Corporation has set its own target of 50% by 2030.
Italy	Announced	Industry	EUR 550 million (USD 596 million) and EUR 400 million (USD 434 million) to support investments for the use of hydrogen in industrial processes. Established under the Temporary Crisis and Transition Framework adopted in 2023; resources will come from the National Recovery and Resilience Plan. These funds should be granted by 2026 and the maximum grant per project is EUR 200 million (USD 217million).
Italy	Announced	Rail	EUR 300 million (USD 325 million) to replace diesel trains with hydrogen ones across six regions. EUR 24 million (USD 26 million) will be used for the trains and EUR 276 million (USD 299 million) for the production, storage and fuelling of renewable hydrogen. Projects should be completed by June 2026.
France	Announced	Industry	Extends the TIRUERT scheme* to include "low-carbon" hydrogen in road transport, which is equivalent to an incentive of EUR 4.7/kg (USD 5.1/kg).
Germany	In force	Industry	EUR 4 billion (USD 4.3 billion) available in the first round of CCfD, giving 15-year support for fuel switching of industrial assets (i.e. hydrogen is one of several eligible technologies). Winners are expected to be announced in Q3 2024. A second round, for EUR 19 billion (USD 20.6 billion), is expected before end of 2024.

Germany	Announced	Industry	Concept proposed for demand creation in steel, cement, ammonia and ethylene, which could indirectly trigger hydrogen demand. Proposes starting to set a definition for "green" products in these markets and suggests possible instruments like public procurement, product requirements and quotas.
Germany	Announced	Power	Tenders for 12.5 GW of hydrogen-ready gas power plants will be launched in 2024/2025. The funds for the tender will come from the Climate Transition Fund, which has a total budget of EUR 19.9 billion (USD 21.6 billion) for hydrogen and industrial decarbonisation, of which EUR 1.3 billion (USD 1.4 billion) is part of the 2024 budget. The first phase includes 5 GW of new plants and 2 GW of refurbishments. The subsidy will be as OPEX for up to 800 hours a year. Plants must switch to low-emissions hydrogen from the 8^{th} year of operation.
Japan	In force	Industry	CAPEX support for industrial demand covering transport to the end user. Commercial operation should commence before 2030 and at least 10 years of operation is needed.
Japan	In force	Power	JPY 234 billion/yr (Japanese yen) (USD 1.5 billion/yr) awarded to five coal plants (770 MW of capacity) to co-fire ammonia (at 20% volume) and one gas plant (55 MW) to co-fire hydrogen (at 10%). OPEX support granted for 20 years.
Korea	In force	Power	15-year contracts (starting by 2028) for 6.5 TWh/yr for power generation. Technology pathways include 100% hydrogen, hydrogen co-firing (in gas plants), and ammonia co-firing (in coal plants). Auction opened in May 2024 and criteria includes a maximum GHG threshold of 4 kg CO_2-equivalent (CO_2-eq)/kg H_2 with an increasing score as emissions decrease. In parallel, an auction for 1.3 TWh of hydrogen-fired power generation by 2026 was launched without GHG criteria. This will contribute towards the target of 2.1% of total electricity generation from hydrogen derivatives in 2030.
Lithuania	In force	Industry	EUR 122 million (USD 132 million) awarded as a direct grant to replace 30% of natural gas-based ammonia production with renewable ammonia. Project comprises a 171 MW electrolyser starting operations in 2026.
Netherlands	Announced	Road	The government issued a public consultation on a subsidy for HRS and transport by truck, that would cover up to 40% of the HRS CAPEX (up to EUR 2 million), up to 80% of the eligible costs of the trucks (up to EUR 3 million per application) and variable caps depending on the vehicle category. The total budget is EUR 150 million (USD 163 million) for 2024-2026 and it is expected to trigger the construction of at least 40 HRS.
Netherlands	Announced	Industry	Renewable hydrogen demand from refineries to count towards meeting the targets for fuel suppliers under the Renewable Energy Directive. Credit trading could be allowed to decrease the compliance costs.

Singapore	In force	Power	Tender for the development of 55-65 MW of ammonia-fired gas turbines. 26 proposals were received and 2 were selected for a restricted request for proposals with the lead developer expected to be announced in Q1 2025.
Spain	In force	Hubs	Public tender to promote at least two hydrogen valleys by 2030 with a minimum capacity of 200 MW of electrolysis and EUR 200 million (USD 217 million) in eligible funding for each valley.
Sweden	In force	Steel	EUR 265 million (USD 287 million) grant to support Stegra. Scope includes a 690 MW electrolyser, a direct reduction plant, two electric arc furnaces, and cold rolling and finishing facilities. Targeted capacity is 2.4 Mt of steel, starting operations in 2026.
United Arab Emirates	Announced	Hubs	Framework with principles for the “low-carbon” hydrogen industry, co-operation with other sectors (natural gas and power), and technical standards for the creation of hydrogen oases.
United Kingdom	In force	Industry	GBP 185 million (USD 235 million) allocated as part of Phase 3 of the Industrial Energy Transformation Fund. Outcomes of the competition will be published in Q4 2024, with operation starting no later than March 2028.
United Kingdom	Announced	Aviation	10% sustainable aviation fuels (SAF) quota mandated for all flights departing from the United Kingdom by 2030, increasing to 22% by 2040. There is a specific quota for synthetic fuels of 3.5% of jet fuel demand by 2040. Incentives are the equivalent of USD 6-6.4/L. Pending approval by Parliament. If approved, the mandate would be in place from 2025.
United States	In force	Industry	CAPEX grants totalling USD 1.7 billion across six projects as part of the Industrial Demonstration programme.
United States	In force	Hubs	USD 7 billion across seven hydrogen hubs (through the H2Hubs initiative), which should start operation within 8-12.5 years. The H_2DI consortium will design and implement demand-side support mechanisms to facilitate purchases of hydrogen produced by the H2Hubs.
United States	Announced	Road	USD 98 million for HRS and research facilities.

* TIRUERT is an incentive scheme to promote renewable energy in transport.
Note: See Explanatory notes annex for the use of the term “low-carbon” hydrogen in this report.

Mitigation of investment risks

A total of 16 new policies using direct grants have been announced since GHR 2023, adding up to almost USD 18 billion. All these funds come from advanced economies (mostly Europe), except for USD 109 million from China. Almost 70% of these funds are not allocated to a specific call or law.

In contrast, 7 of the 11 countries that have introduced tax benefits for hydrogen technologies are EMDEs. One advantage of this policy measure is that the effect on the fiscal budget is lower revenue rather than additional cost. This can be especially beneficial in EMDEs, which have a higher cost of capital and have to pay an additional premium for extraordinary disbursements.

In addition, as a reflection of the growing interest in industrial strategies, the past year has also seen a rise in policies targeting electrolyser manufacturing. Nine countries have now announced such policies, covering up to 60% of the total costs, and – in some cases – introducing local content requirements.

Grants

Most of the public funding for grants announced in the last year came from the European Union through the Important Projects of Common European Interest (IPCEI) and the national Recovery and Resilience Plans (RRP), which were part of the COVID-19 recovery programme (NextGenerationEU). At the EU level, two new rounds of IPCEI have been announced since the publication of GHR 2023, with a total public funding of USD 9 billion unlocking USD 9.4 billion of private capital. At the level of EU member states, Germany and Spain gave funding notices to specific projects from the IPCEI rounds, while Finland, Italy, Poland and Spain announced funding through RRP.

The Dutch Government has allocated EUR 1 billion (USD 1.1 billion) to electrolysis in 2024, to cover up to 80% of the investment cost and provide OPEX support (up to EUR 9/kg) for up to 10 years, supporting at least 200 MW of electrolysis. EUR 3.9 billion (USD 4.2 billion) are reserved for renewable hydrogen in subsequent years. This is part of the EUR 9 billion (USD 9.8 billion) that has been reserved for renewable hydrogen from the Climate Fund. The Dutch Government also awarded EUR 250 million (USD 271 million) of grants to seven renewable hydrogen projects that add up to a total electrolysis capacity of over 100 MW. The average subsidy for the winning projects was EUR 2 500/kW_{el} (USD 2 711/kW_{el}).[80] The total request for subsidies amounted to EUR 600 million (USD 651 million), and the projects will have to finish construction by 2028.

[80] Considering that the maximum size for the application was 50 MW_{el}.

Competitive bidding schemes

Several competitive bidding schemes have been announced and carried out in the past year. These span a more diverse range of countries than grants, and include auctions for ammonia and refining in India, approval of contracts to award land to projects worth USD 11 billion in Oman, and auctions opened globally under the H2Global scheme. They have helped build experience in the countries concerned and supported initial steps towards market creation through transparency and price discovery. Given the diversity of auction design, of market and power regulation, and of economic conditions, the bid price premiums have varied widely, from USD 0.16/kg H_2 to USD 1.2/kg H_2.

H2Global launched the first (pilot) auction for renewable ammonia, renewable methanol and synthetic kerosene in December 2022, with total funding of EUR 900 million (USD 976 million) provided by Germany. The results of the auction for renewable ammonia were announced in July 2024. The winner was a 100 MW project in Egypt powered by 273 MW of onshore wind and solar, and the ammonia produced will be delivered to the Port of Rotterdam. The guaranteed minimum offtake is for 2027-2033 (240 kt), and the total product price was over EUR 1 000/t (USD 1 084/t). The project relies on existing infrastructure, preventing the need for additional permitting and enabling lower costs. No winners were selected for the synthetic kerosene auction, and its funding will be allocated to the renewable methanol auction, though no winners have been announced at the time of writing. Preparations for launching new auctions are underway for Canada (with a funding commitment of CAD 300 million (Canadian dollars) [USD 220 million] from Canada to be matched by EUR 200 million [USD 217 million] from Germany), with the aim to launch the tender by the end of 2024. Auctions are also being planned for Australia (total funds of EUR 400 million [USD 434 million] are under discussion), Germany (with EUR 3.53 billion [USD 3.8 billion]), the Netherlands (with EUR 300 million [USD 325 million] for a joint window with Germany) and for the United Arab Emirates. The H2Global Foundation is also working on a report on auction design to inform policy makers on how to shape auctions to attain diverse goals.

The European Union announced the winners of the first auction of the Hydrogen Bank (Box 6.2) and approved the third round of IPCEI (Hy2Infra), which will support up to 3.2 GW of electrolyser capacity and 2 700 km of pipelines, at least 370 GWh of storage capacity, and port handling capacity for liquid organic hydrogen carrier (LOHC) to handle 6 kt of hydrogen-equivalent per year. The European Union also selected 42 projects for EUR 424 million (USD 460 million) of grant support under the fifth and final selection of the first Alternative Fuels Infrastructure Facility call. A total EUR 115 million (USD 125 million) of this funding went to 43 HRS across 7 countries. The first call granted a total of EUR 1.3 billion [USD 1.4 billion] (for both electricity and hydrogen) supporting the development of 202 HRS in 2022-2023. The second call opened in February 2024 with a total budget of EUR 1 billion [USD 1.1 billion] (for both electricity and hydrogen), and will be open until the end of 2025.

Denmark awarded DKK 1.25 billion (Danish kroner) (USD 182 million) to 6 projects for a total electrolyser capacity of 280 MW. Winning bids had price premiums between DKK 9.3/GJ (USD 0.16/kg H_2) to DKK 67.5/GJ (USD 1.2/kg H_2), which are relatively low. Some possible reasons for this are lower power purchase agreement (PPA) prices in Denmark in comparison to other European countries, strategic bidding with risk taking, and a low retention penalty. The auction was oversubscribed more than three times, with total funding requested of DKK 4 billion (USD 581 million) and a total capacity of 675 MW. After conclusion of the contracts, the projects will have 4 years to build the construction plants.

In its auction scheme for renewable hydrogen, India has two separate bidding processes, known as “modes”. Mode 1 is for a 3-year period, and is open to exports. Mode 2 has specific volumes of hydrogen and ammonia, to be used only for domestic consumption, with contracts to be signed for 10 years. The total budget available for hydrogen production (across all modes) is INR 130 billion (USD 1.6 billion). For Mode 1, the total bid capacity from the first round was 551.7 ktpa from 13 bids against an auction target of 450 ktpa, with a final capacity awarded of 410 ktpa. The incentive provided is equivalent to USD 0.23-0.42/kg H_2. Most of the winners plan to export the hydrogen produced rather than using it to meet domestic demand. The second round was launched in July 2024 for 450 ktpa, with the same subsidy caps as the first round (USD 0.6/kg H_2 the first year, decreasing to USD 0.36/kg H_2 in the third year). For Mode 2, the first round has been launched for 200 ktpa of hydrogen and 750 ktpa of ammonia, with the same 3-year subsidy and caps.

Contracts for difference

Japan passed the Hydrogen Society Promotion Act, which includes 15-year CfD subsidies for domestic and imported hydrogen production as a supply-side instrument that complements the clusters support scheme for demand. The total funds available are JPY 3 trillion (USD 19.7 billion), which will come from Climate Transition Bonds. The programme is open to different technology pathways, as long as the “low-carbon” hydrogen[81] threshold is satisfied (70% reduction compared to fossil-based production, which is equivalent to 3.4 kg CO_{2eq}/kg H_2). The scheme includes hydrogen and ammonia, with the respective reference commodities of liquefied natural gas and coal. Operation must start before 2030 and continue for at least 10 years once the 15-year period has expired. The strike

[81] See Explanatory notes annex for the use of the term “low-carbon” hydrogen in this report.

price is set based on levelised cost of production (including a profit margin), and the exact price is set at a project level. The scheme is also open to subsidy stacking, so export projects could benefit from subsidies in the country of origin and this CfD scheme. Public consultation on the scheme design was open until September 2024 and a first tender (using a share of the total funds) is expected by the end of 2024.

In the United Kingdom, the 11 winning projects of the first Hydrogen Allocation Round (HAR1) have now been announced. Projects will receive GBP 2 billion (USD 2.5 billion) of OPEX support through 15-year contracts, and GBP 90 million (USD 114 million) of CAPEX support, subject to the successful signing of the contracts with the Low Carbon Contracts Company (the counterparty for the hydrogen production support contracts). This is expected to trigger GBP 413 million (USD 525 million) of private capital investment between 2024 and 2026. The total electrolysis capacity is 125 MW, with a weighted average strike price of GBP 241/MWh (USD 10.2/kg H_2), and first production is expected 18-24 months after signing the contracts. The total capacity from bids was 262 MW in comparison to a government target of 250 MW. The government is planning to award contracts to the winning projects by the end of 2024. The second HAR round was also launched in 2023, aiming to support a capacity of 875 MW and achieve the ambition of having 1 GW of electrolysis capacity under construction or in operation by the end of 2025.

Tax incentives

Several tax incentives have been introduced since GHR 2023, predominantly in EMDEs. Incentives range from tax refunds to deductions and exemptions. Most of the policies (except for in Australia and Brazil) do not introduce caps on the total budget allocated to the specific measure, and in most there is no public quantification of the effects and cost competitiveness.

Australia has proposed an AUD 2/kg H_2 (USD 1.3/kg H_2) production tax incentive (similar to the Clean Hydrogen Production Tax Credit under the US IRA), available from 2027 for up to 10 years, for facilities starting operation by 2030. The total funds are uncapped, but the estimated budget is AUD 6.7 billion (USD 4.4 billion) for 2024 to 2034. The incentive can be used for domestic use and exports, and it also includes ammonia and methanol. Only hydrogen with less than 0.6 kg CO_2-eq/kg H_2 (well-to-gate) is eligible. The consultation paper explicitly mentions that additionality and hourly matching are not necessary to qualify for the tax incentive. In parallel, the budget of the Headstart programme, which aims to bridge the cost gap for first movers using a CfD, has been extended to AUD 4 billion (USD 2.6 billion) in total (over 2023-2039). The first round of funding for AUD 2 billion (USD 1.3 billion) for a 10-year period from 2027-28 was open for expressions of interest in October 2023, with six applicants, adding up to 3.5 GW of electrolysis, shortlisted in December 2023. These two hydrogen initiatives are part of a broader programme, Future Made in Australia, aimed at enabling investment in clean technologies and reaping the benefits of a transition to clean energy.

Other policy instruments

Other policy instruments included land allocation for renewable hydrogen (Egypt, Morocco, Oman), hydrogen coverage and rules for issuing certificates under carbon pricing schemes (China, European Commission), financing instruments (Chile, Japan) and relaxation of local content rules for equipment supply (India).

One risk to investment that has largely not yet been covered by any policy relates to infrastructure and the need for co-ordination between supply, intermediate infrastructure (pipelines, storage, ports and terminals), and end use (including local transport). Delays in one part of the supply chain – which may be related to the novel character of some of these steps – could affect other stakeholders across the supply chain. One example of a policy initiative targeting infrastructure for end use is The Canada Infrastructure Bank-approved CAD 337 million (USD 248 million) loan to construct 20 HRS in British Columbia and Alberta, of which 14 will enable the refuelling of 300 heavy-duty vehicles.

Box 6.2 First auction of the EU Hydrogen Bank

The European Union awarded EUR 721 million (USD 780 million) to seven renewable hydrogen projects (five of them in the Iberian Peninsula) in the first auction of the European Hydrogen Bank. There were a total of 132 bids, adding up to 8.5 GW of electrolysis capacity, and nearly 8.8 Mt of production volume over 10 years, and an oversubscription of 15 times the budget available. Two-thirds of the projects were planning to use domestically manufactured electrolysers (or a mix of domestic production and imports), and over 60% were targeting industry as the end-use sector. The winning projects add up to a total electrolyser capacity of 1.5 GW, producing nearly 1.6 Mt of hydrogen over 10 years. When annualised, this would be equivalent to almost 4% of the EU Hydrogen Strategy target of 40 GW by 2030. The winning bids will receive fixed incentives of EUR 0.37-0.48/kg H_2, in comparison to a levelised cost of hydrogen (LCOH) of EUR 5.3-13.5/kg H_2, and a ceiling price of the auction of EUR 4.5/kg H_2. Potential reasons for the low bids are lower LCOH in the countries with awards, strategic bidding due to competition across the European Union rather than in a single country, and higher offtake prices for frontrunners in the downstream uses. The individual grant agreements, in which the winners will commit to developing the projects, are expected to be signed by November 2024, with entry into operation within 5 years. The draft terms and conditions for the next round were also published in April 2024. The budget available for the second round is EUR 1.2 billion (USD 1.3 billion). The main changes include a ceiling price of EUR 3.5/kg, a maximum period of 3 years to enter operation, and a dedicated budgetary basket for the maritime sector. The “auction-as-a-service” scheme* was also used by Germany, which allocated an additional EUR 350 million (USD 380 million) for projects that met the eligibility criteria but did not benefit from EU-level support. Austria has also announced the allocation of EUR 820 million (USD 890 million) of funds for auctions for renewable hydrogen. EUR 400 million (USD 434 million) will be open for bids before the end of 2024, and could use the auction-as-a-service scheme in the second funding round.

*This model simplifies the auction process by using a standardised design for all member states and the same tender process to enable the funding of additional projects

Table 6.3 Policy measures to mitigate investment risks in hydrogen projects implemented or announced since September 2023

Policy	Country	Status	Description
Grants	China	In force	Central government has issued CHN 770 million (Yuan renminbi) (USD 109 million) of reward funds to the local governments of Hebei, Inner Mongolia, Shanghai, Zhejiang and Guangdong for the first year of FCEV demonstration.
	European Commission	Announced	EUR 6.9 billion (USD 7.5 billion) of public funding, which is expected to unlock EUR 5.4 billion (USD 5.9 billion) of private capital. Funding is approved for 33 projects across 7 member states as part of the Hy2Infra IPCEI.
	European Commission	Announced	EUR 1.4 billion (USD 1.5 billion) of public funding, which is expected to unlock EUR 3.3 billion (USD 3.6 billion) of private capital. Funding is for 13 projects across 7 member states as part of the Hy2Move IPCEI. Applications include all modes of transport, fuel cells, and on-board storage.
	European Commission	In force	EUR 1 billion (USD 1.1 billion) for both electricity and hydrogen supply and refuelling infrastructure in heavy-duty transport, railways, aviation and shipping. Financial support is 30-50% of the eligible costs and there are three cut-off dates for submission of proposals until the end of 2025.
	Finland	In force	EUR 200 million (USD 219 million) to support the production of RFNBOs and energy storage. Direct grants can cover up to 45% of the investment costs and funds should be allocated to projects before the end of 2025.
	France	In force	EUR 900 million (USD 976 million) to support companies investing in the use of renewable hydrogen in industry. These funds should be granted by 2026 and companies have 36 months to complete the projects.
	Germany	In force	EUR 4.6 billion (USD 5 billion), which is expected to trigger EUR 3.3 billion (USD 3.6 billion) of private investment for 23 projects under the Hy2Infra IPCEI, adding up to 1.4 GW of electrolysis, 370 GWh of storage, 2 000 km of pipelines and 1 800 t/yr of LOHC.
	Italy	Announced	EUR 2 billion (USD 2.2 billion) to develop an industrial prototype for renewable hydrogen use in industrial heat and steel production. Operation should start by 2026.
	Italy	Announced	EUR 100 million (USD 108 million) for electrolysis, to be granted before 2026.
	Netherlands	In force	EUR 1 billion (USD 1.1 billion) allocated to electrolysis in the 2024 budget and approved by the European Commission in July 2024. The scheme will support at least 200 MW of electrolysis. Up to 80% of the CAPEX can be subsidised, plus a variable premium for 5-10 years.
	Netherlands	In force	EUR 250 million (USD 271 million) for seven electrolysis projects adding up to 101 MW. The end-use sectors are road transport and chemicals.
	Poland	In force	EUR 640 million (USD 694 million) to support 315 MW of renewable and low-carbon capacity.
	Spain	In force	EUR 794 million (USD 861 million) allocated to seven projects in July 2024 under the IPCEI Hy2Use, which was approved by the European Commission in September 2022. Projects add up to over 650 MW of electrolysis and will directly mobilise EUR 1.14 billion (USD 1.24 billion) in total investment.

	Spain	In force	EUR 150 million (USD 163 million) awarded to 12 projects for a combined electrolysis capacity of 309 MW, 3 HRS and 9 heavy-duty vehicles. The grant is expected to mobilise total investments of more than EUR 578 million (USD 627 million) in private capital.
	Spain	Announced	EUR 1.2 billion (USD 1.3 billion) for renewable hydrogen. EUR 300 million (USD 325 million) of these funds are for 30 demonstration projects and EUR 230 million (USD 249 million) for 40 projects in multiple parts of the value chain. For production, applicants should have secured at least 60% of the volume with offtake agreements.
	Sweden	In force	Grant equal to 30% of the investment differential between a fuel cell truck and a diesel one, up to SEK 50 000 (Swedish kronor) (USD 4 747) decreasing to USD 2 848 by July 2025. The scheme is in effect from February 2024 until the end of September 2025.
Competitive bidding schemes	Austria	In force	EUR 820 million (USD 889 million) for a funding period of maximum 10 years with the resulting payments to be completed by 2041. EUR 400 million for an auction starting in 2024 (with the option to use the "auction as a service" model) and the rest to be open for bids before 2026.
	Denmark	In force	DKK 1.25 billion (USD 182 million) awarded to 6 projects for a total electrolyser capacity of 280 MW. Winning bids had price premiums of DKK 9.3-67.5/GJ (USD 0.16-1.2/kg). Projects have 4 years to build the construction plants.
	Germany	In force	EUR 350 million (USD 380 million) allocated to use the "auction-as-a-service model" of the European Hydrogen Bank for projects that satisfy the Commission's criteria.
	European Commission	In force	EUR 720 million (USD 781 million) for seven projects (1.5 GW of electrolysis) in the first auction of the European Hydrogen Bank. The winning bid price premiums were EUR 0.37-0.48/kg (USD 0.4-0.52/kg) in comparison to an LCOH of EUR 5.3-13.5/kg (USD 5.7-14.6/kg) and a ceiling price of EUR 4.5/kg (USD 4.9/kg). The individual grant agreements are expected to be signed by November 2024 with entry into operation within 5 years.
	India	In force	INR 11.65 billion (USD 140 million) to subsidise 550 ktpa of renewable ammonia production over a 3-year period decreasing from USD 106/t ammonia (NH_3) (~USD 0.6/kg H_2) in the first year to USD 64/t NH_3 (~USD 0.36/ kg H_2) in the third year. Projects need to comply with the 2 kg CO_2-eq/kg H_2 of the National Green Hydrogen Standard.
	India	In force	Auction for 200 ktpa in refining. 3-year incentive decreasing from USD 0.6/kg to USD 0.36/kg.
	Spain	In force	Tenders to provide CAPEX subsidies to promote an electrolysis capacity of 700 MW. Individual projects should have at least 50 MW.
	Various	In force	Results from the pilot auction of H2Global for renewable ammonia were published in July 2024. Review of the pilot auction for renewable methanol is ongoing and the budget for synthetic kerosene will be reallocated to renewable methanol. See Chapter 4. Trade and infrastructure for details.

Tax incentives	Australia	Announced	AUD 2/kg (USD 1.3/kg) incentive for up to 10 years between 2027 and 2040 for projects that reach FID by 2030. Total funds are uncapped, but estimates are AUD 6.7 billion (USD 4.4 billion) in total over 10 years from 2024 and AUD 1.2 billion (USD 0.8 billion) per year from 2034 to 2041.
	Brazil	In force	Cap of BRL 18.3 billion (Brazilian reals) (USD 3.5 billion) for 2028-2032. Tax credits for 5 years to be assigned at a rate inversely proportional to GHG emissions starting in January 2025 for hydrogen produced from renewable energy or biofuels.
	Egypt	In force	Several tax incentives. For eligible projects, up to 30% of the workforce can be foreign, 70% of the investment cost should be financed with foreign investments, and a minimum of 20% of the project components should be domestically manufactured.
	Japan	In force	Tax incentives for capital investment over a 10-year period based on volume produced. Tax credits (draft) are JPY 20 000/t (USD 131/t) for "green" steel, JPY 50 000/t (USD 329/t) for chemicals, and JPY 30/L (USD 0.2/L) for SAF.
	Kenya	In force	10-year (withholding) tax holiday with 25% corporate tax rate afterwards; perpetual exemption on value added tax (VAT) for machinery and raw materials; perpetual exemption from stamp duty; 100% investment deduction allowance over 20 years.
	Korea	Announced	Tax credits of 15-25% of the investment costs. A production tax credit of up to 50% tax deduction for "clean" hydrogen production based on water electrolysis is also under consideration.
	Mauritania	Announced	Several tax benefits. Operating licences will also be granted for 35 years. Council of ministers passed the draft law in July 2024 and parliamentary approval is pending.
	Morocco	Announced	Several tax benefits, including exemption from import duties, VAT on goods and equipment, tax and customs advantages.
	Philippines	Announced	Tax benefits including tax breaks, duty exemption from equipment and materials, tax exemption of carbon credits, tax credit on domestic capital equipment and services.
	South Africa	Announced	Several tax benefits including accelerated depreciation, industrial policy allowance, exemption of proceeds, and import duties have been identified as potentially applicable to renewable hydrogen. These are yet to be proposed in a specific law.
	Canada (update)	Announced	Production and manufacturing tax credits of CAD 5.7 billion (USD 4.2 billion) for the 2023-2028 period with the total incentive to 2035 expected to be CAD 17.7 billion (USD 13 billion). A manufacturing tax credit of 30% has been available from 2024, which also includes upstream (renewables) and downstream equipment (FCEV). The legislation was passed in June 2024.
Contracts for Difference (CfD)	Australia	In force	AUD 4 billion (USD 2.6 billion) for the Headstart programme over 10 years. Shortlisted applicants for the first round (for USD 1.3 billion) were announced in December 2023, with a cumulative electrolyser capacity of 3.5 GW.
	France	Announced	EUR 4 billion (USD 4.3 billion) from 2024 to 2026. Contracts for up to 20 years. Price has 70% weight in the selection criteria. The launch of the first tender is pending.
	Italy	Announced	Two-way CfD with annual competitive auctions from 2024 to 2027, targeting a total capacity of 250 ktpa of renewable hydrogen by 2027 and 50 ktpa of hydrogen from bioenergy. Contract duration of 10 years with price ceilings of EUR 4/kg for electrolysers (inflation-adjusted).

Other	Japan	Announced	15-year CfD for technology-agnostic hydrogen production and a strike determined on a project basis. Total funds of JPY 3 trillion (USD 19.7 billion). Public consultation was open until September 2024 with applications expected before the end of 2024.
	Portugal	In force	EUR 140 million (USD 152 million) for a two-way CfD with a variable premium to support the production of renewable hydrogen (and biomethane). Contract is for 10 years, with a cap of EUR 127/MWh (~USD 4.6/kg), for injection of 120 GWh/yr in the natural gas grid.
	United Kingdom	In force	Over GBP 2 billion (USD 2.5 billion) of OPEX support was allocated to 11 projects (125 MW of electrolysis) in the first HAR1, with operations to start in 2025. The average strike price was GBP 241/MWh (USD 10.2/kg). Private capital investment of GBP 413 million (USD 525 million) is expected between 2024-2026.
	Chile	In force	USD 1 billion fund from the Green Hydrogen Facility targeting the mobilisation of USD 12.5 billion of private capital and operating from the second half of 2024. Financial instruments will be concessional loans, partial credit guarantees and credit lines.
	China	Announced	Hydrogen is expected to be covered under the China Certified Emissions Reduction (CCER) mechanism (for the voluntary carbon market) that was restarted in 2024 after a 6-year pause. Methodologies for CCER issuance have been published for other clean technologies and it is anticipated that a methodology for hydrogen will be released in 2024.
	Egypt	Announced	41 700 km^2 designated by the government for renewable hydrogen production.
	European Union	In force	Producers of renewable hydrogen (and derivatives covered under the EU Emissions Trading System (ETS)) will be eligible for free allowances from 2025. This translates into an additional benefit equivalent to EUR 0.7/kg. Free allowances will be phased out from 2026 until 2034.
	India	In force	Exemption from using solar and wind equipment from government-approved manufacturers (which are largely domestic) for renewable hydrogen plants located inside a Special Economic Zone or Export Oriented Unit. Plants should be commissioned before 2031 to benefit from incentive.
	Japan	In force	Public CAPEX funding for hydrogen production and storage through two instruments: debt guarantee for business and asset acquisition and equity acquisition for additional liquidity. Funds can be used for domestic or overseas assets and up to 75% of the costs can be covered.
	Morocco	Announced	1 million hectares (ha) allocated to hydrogen production. The first phase has 0.3 million ha in lots of 10 000 to 30 000 ha and received 40 proposals. These lands are listed as favourable for renewable development, which may accelerate the administrative steps. 1 million ha would be enough to produce over 10 Mtpa H_2.[82]
	Oman	In force	Contracts signed to award land to two projects worth USD 11 billion in investment. Both projects are in Dhofar and exceed Oman's 1 Mtpa H_2 2030 target (reaching 1.4 Mtpa H_2). This closes Phase A of the auction, with eight projects awarded.

* Grant-based schemes with a budget under USD 100 million excluded. Note: See Explanatory notes annex for the use of the term "clean" hydrogen in this report.

[82] Assuming a 50/50 split in onshore wind and solar PV, 5 MW/km^2 of power density for onshore wind and 45 MW/km^2 for solar PV

Industrial policies to support domestic manufacturing of hydrogen technologies

The United States announced USD 750 million for 52 hydrogen projects across 24 states. Over 40% of the funding was for electrolyser manufacturing and 20% for fuel cell manufacturing. This budget is part of the USD 1.5 billion available under the Bipartisan Infrastructure Law for R&D and manufacturing. The DoE also allocated USD 1.9 billion to 35 clean technology manufacturing projects under the Qualifying Advanced Energy Project Credit (48C) of the IRA. This included USD 337 million for demonstration of advanced manufacturing processes that can decrease costs and increase capacity. Almost one-third of the funding was awarded for solid oxide electrolysers (SOEC) to Topsoe and direct CO_2 electrolysis in PEM was also included. The Internal Revenue Service issued a second round of the 48C programme with the concept paper submission expected in mid-2024.

In Europe, Italy, the Netherlands, Spain, and the United Kingdom have announced or put in place specific policies for clean technology manufacturing – including for hydrogen production. In the European Union, the Net Zero Industry Act sets a target of domestic manufacturing capacity of at least 40% of the annual deployment needs in 2030. Electrolyser manufacturers can tap into the general broader funding opportunities such as the Temporary Crisis and Transition Framework, which can fund 15-35% of investment costs, the Innovation Fund, IPCEI (as already funded through Hy2Tech), and Horizon Europe for novel manufacturing processes.

India has allocated a total of INR 44 billion[83] (USD 0.5 billion) for the FY2025-2030 period for electrolyser manufacturing. In 2023, the government published the results of its first auction for electrolyser manufacturing, with a total auctioned capacity of 1.5 GW/yr, with 20% of domestically developed stack technology. It received 21 bids for a total capacity of 3.3 GW/yr. There were eight winning companies, with three of them awarded funding for 0.3 GW/yr each. In early 2024, India launched a call for the second tranche, for another 1.5 GW/yr, with the winners announced in August. In this second tranche, 23 companies bid for a total capacity of over 2.5 GW/yr, with 13 of those companies receiving support. The incentive is for 5 years, decreasing from INR 4 440/kW (USD 53/kW) in the first year to INR 1 480/kW (USD 18/kW) in

[83] This represents about 20% of the INR 197 billion (USD 2.4 billion) budget (until 2030) of the National Green Hydrogen Mission.

the last year. There is also a local value addition criterion, increasing from 40% in the first year of production to 80% by the fifth year.[84]

Table 6.4 Policy measures targeting electrolyser manufacturing implemented or announced since September 2023

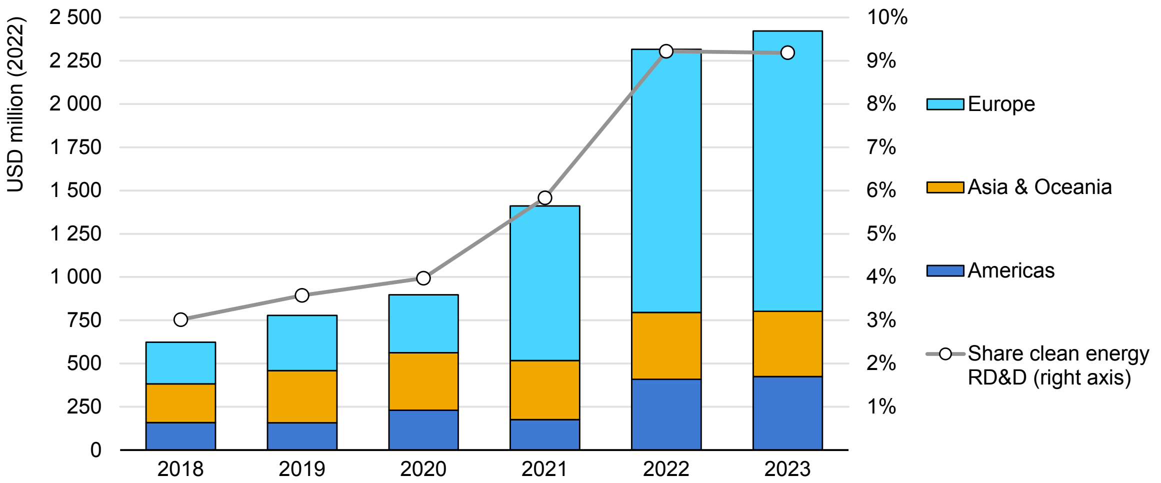
Country	Status	Description
Australia	In force	AUD 3 billion (USD 2 billion) from the National Reconstruction Fund to provide finance in the form of debt, equity and guarantees for manufacturing of electrolysers and other clean technologies.
Chile	In force	Up to USD 10 million per project (and up to 60% of total costs) for domestic manufacturing capacity for electrolysers. Facilities are expected to be in operation within 5 years of receiving the subsidy. Winners will be announced in November 2024.
India	In force	INR 44 billion (USD 0.5 billion) for FY2025-2030 for electrolysis. Incentives for 3 years decreasing from USD 53/kW to USD 18/kW. A first tranche, for 1.5 GW/yr, has already been awarded to eight companies; the second tranche, for another 1.5 GW/yr, was launched in March 2024.
Italy	Announced	EUR 1.1 billion (USD 1.2 billion) for manufacturing (including electrolysers as one of six technologies). Funds should be granted by 2026 and the maximum funding per project is EUR 150 million.
Korea	Announced	Tax deduction of up to 12% for fuel cell manufacturing.
Netherlands	Announced	EUR 100 million (USD 108 million) for electrolyser manufacturing for 2024 and 2025. 15-20% of the eligible costs are covered. Recipients will need to reach full capacity within 5 years of receiving the subsidy.
Spain	In force	EUR 750 million (USD 813 million) for manufacturing of five clean technologies (including electrolysers).
United Kingdom	In force	GBP 390 million (USD 496 million) over 2024-2028 for advanced manufacturing of hydrogen and carbon capture, utilisation and storage (CCUS).
United States	In force	USD 750 million for 52 hydrogen projects covering manufacturing and the electrolyser and fuel cell supply chains. Up to 50% of the costs can be funded.
United States	In force	USD 326 million for eight projects awarded in March 2024 as part of the Qualifying Advanced Energy Project Credit (48C) of the IRA.

[84] Defined as the fraction of the sale value that comes from domestic production. This is 10 percentage points lower for PEM and SOEC across all years.

Promotion of RD&D, innovation and knowledge-sharing

Government investment in RD&D in hydrogen technologies remained robust in 2023, exceeding the historical record of 2022 by almost 5% (Figure 6.4).[85] In the past 5 years alone, RD&D spending on hydrogen technologies has nearly quadrupled – increasing faster than spending on other clean technologies – to reach a share of more than 9% of total clean energy RD&D spending. To put this growth into perspective, the first phase of Mission Innovation targeted a doubling of clean energy RD&D spending over a period of 5 years (across all clean technologies, which is more difficult to achieve given the larger baseline). For its second phase, Mission Innovation did not set a specific target, but rather recognises the need to increase clean energy RD&D spending to USD 90 billion by 2026, which represents far less ambitious growth than the earlier target of doubling spending.

Figure 6.4 Government RD&D spending on hydrogen technologies by region, 2018-2023



Note: Data includes IEA member countries and Brazil.

Public budgets for RD&D on hydrogen technologies remained robust in 2023, even exceeding the record spending of 2022 by almost 5%.

Two-thirds of the RD&D funding come from Europe. At the EU level, the Clean Hydrogen Partnership has an average funding of EUR 170 million/yr (USD 181 million/yr) for 2021-2027, complemented by national funding, which is led by Germany and France. In the United States, the budget has also increased

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

rapidly from just USD 150 million in 2020-2021 to USD 430 million in FY2023. While advanced economies contribute the most to global RD&D funding, there are also examples from EMDEs, which can help these economies to develop domestic capabilities and leverage their rich renewable resources. Notably, India launched several calls to demonstrate hydrogen use in steel, trucks, buses and shipping.

Governments are also committing funding to ensuring that communication and knowledge-sharing from low-emissions hydrogen RD&D projects is effective and transparent. For instance, the Australian Government funds both the Commonwealth Scientific and Industrial Research Organisation HyResearch web portal, reporting on 420 RD&D hydrogen-related projects, and the Australian Renewable Energy Agency RD&D projects public knowledge-sharing web platform, that reports on results of over 660 projects, of which 10% are hydrogen-related.

Table 6.5 Selected government programmes which include support for hydrogen technology demonstration projects launched since September 2023

Government	Description
Australia	AUD 1.7 billion (USD 1.2 billion) for the Future Made in Australia Innovation Fund, which includes "green" metals and low-carbon liquid fuels, which can include hydrogen derivatives.
China	The Action Plan for Green Development of Shipbuilding Industry (2024-2030), released in December 2023, includes research and pilot projects for hydrogen, ammonia and methanol in ships and the development of hydrogen engines.
China	The National Energy Administration approved 10 hydrogen projects in 2023, including PEM electrolysis, HRS and use for power generation.
European Union	EUR 173.5 million (USD 123.5 million) across 20 topics covering the entire value chain (including hydrogen valleys). 151 proposals were submitted, with results announced in August 2024, and 19 proposals were retained for funding.
India	INR 4 billion (USD 48 million) to promote domestic technology development, funding up to 80% of the total project cost.
India	INR 4.6 billion (USD 55 million) until FY2029-2030 to demonstrate use in existing blast furnaces and 100% hydrogen in DRI furnaces. A request for proposals was published in June 2024.
India	INR 5 billion (USD 60 million) until FY2025-2026 to support the deployment of renewable hydrogen as a fuel for trucks and buses and assess its role for vehicles.
India	INR 1.2 billion (USD 14 million) until FY2025-2026 to support the use of hydrogen (and derivatives) for ship propulsion, bunkering and refuelling, and validate technical performance and economic viability.
Japan	JPY 450 billion (USD 2.8 billion) to develop H_2-DRI that achieves at least 50% CO_2 reduction compared to blast furnaces. Funding covers hydrogen as one of the pathways (including energy efficiency of blast furnaces and electric furnaces).

Netherlands	EUR 380 million (USD 411 million) to demonstrate offshore hydrogen production from wind. Funds will be used for one project of less than 100 MW of electrolysis planned to start after 2027.
Norway	NOK 300 million (Norwegian kroner) (USD 28 million) to fund up to 80% of the investment cost of hydrogen and ammonia infrastructure, and up to 80% of the additional investment in a hydrogen and ammonia vessel when compared to a fossil one. The auction is expected in 2024.
Philippines	Government has defined two areas for exploration, development, and production of domestic natural hydrogen. Foreign entities are allowed to own 100% of operations.
Poland	USD 300 million in the form of loans (60% of the funds) and grants to be spent before July 2026. Maximum grant of USD 38 million per project covering up to 85% of the eligible costs.
United Kingdom	GBP 85 million (USD 108 million) for two consortia aiming to demonstrate the use of hydrogen trucks.
United Kingdom	Almost GBP 19 million (USD 25 million) across five projects for innovation in hydrogen production technologies.
United States	USD 59 million for R&D projects for medium- and heavy-duty fuelling, refuelling stations, hydrogen fuel cell powered equipment, permitting and safety, and community engagement.
United States	USD 20 million for two projects related to natural hydrogen, hydrogen production from mineral deposits and improvements in subsurface transport methods, modelling and monitoring.
United States	USD 10.5 million for hydrogen combustion engines.
United States	USD 10 million for a demo plant integrating a solid oxide electrolyser with an H_2-DRI plant.

International co-operation

Over the past few years, international co-operation on hydrogen has had a strong focus on bilateral efforts, but more recently there has been an increase in multilateral co-operation. In particular, COP 28 resulted in numerous hydrogen-related outcomes:

- The International Hydrogen Trade Forum (an initiative that was launched at a G20 meeting in India in 2023 under the umbrella of the Clean Energy Ministerial Hydrogen Initiative [H2I]), signed a partnership agreement with the Hydrogen Council. The agreement includes prioritisation of actions, progress monitoring, analysis of emerging cross-border trade corridors, knowledge-sharing of best practices, and an annual Ministerial-CEO roundtable as a platform for continued dialogue to accelerate cross-border trade and maximise socio-economic benefits.
- A set of international organisations (IPHE, IEA H2 TCP, UNIDO, IRENA, and UNECE),[86] brought together under the Breakthrough Agenda, agreed to work on

[86] IPHE = International Partnership for Hydrogen and Fuel Cells in the Economy; TCP = Technology Collaboration Programme; UNIDO = United Nations Industrial Development Organization; IRENA = International Renewable Energy Agency; UNECE = United Nations Economic Commission for Europe.

implementing a multi-year programme to develop and secure agreement on international standards, certification and related processes.

- The H2I and the Rocky Mountain Institute agreed to jointly co-ordinate a working group of international initiatives under the Breakthrough Agenda umbrella to increase uptake of renewable and/or low-emissions hydrogen in priority applications, mitigate financial risks, develop international standards and certification, and connect supply and demand including cross-border trade.
- A total of 30 shipping sector leaders signed a Call to Action to increase maritime fuels derived from renewable hydrogen to nearly 11 million tonnes by 2030.

Further COP 28 outcomes relating to hydrogen certification and standards are explored in more detail below.

Hydrogen has also gained attention in the G7 and G20 fora. Brazil's G20 Presidency has defined one of its priorities for the Energy Transitions Working Group as innovative perspectives on sustainable fuels – including hydrogen and biofuels. One of the expected outcomes for this year is a roadmap with policy guidelines for accelerating market development for new sustainable fuels, including hydrogen and its derivatives. In the case of the G7, in their 2024 Communiqué, the Climate, Energy and Environment Ministers committed to promote and facilitate the scale-up of investments in the industrial sector for innovative technologies, including low-emissions hydrogen and its derivatives, and to strengthen co-operation on low-emissions hydrogen as a key factor of the energy transition for EMDEs, prioritising local energy access and development needs.

UNIDO is implementing two funding schemes, the Green Climate Fund Readiness Programme and Global Environment Facility - Global Clean Hydrogen Programme. These are expected to support the development of clean hydrogen clusters and to help countries with the process of developing enabling policies, improving technical readiness, knowledge management, building capabilities for standards and developing financial mechanisms for the successful uptake of clean hydrogen. Most of the activities under these schemes will start in 2025.

The IEA H2 TCP and the Clean Hydrogen Mission of Mission Innovation have announced the development of a global research and innovation agenda which will aim to inform governments about priority areas for promoting research and innovation in hydrogen technologies. This initiative could significantly advance the alignment of R&D agendas, particularly for end-use hydrogen technologies. Furthermore, these two initiatives started a joint study on the future demand of hydrogen in industry (Task 48).

Certification, standards, regulations

Standards, certification and regulation on the environmental attributes of hydrogen

Certification (see Box 6.3) is essential to providing evidence on the contribution of low-emissions hydrogen deployment to GHG emissions reduction. Moreover, it is crucial to the development of hydrogen trade, given that traded hydrogen and its derivatives cross borders, potentially moving across regions with different accounting systems. The last few years have seen rapid progress, with several countries moving from proposing certification schemes, to specifying the rules, criteria and labels. Some have already incorporated these rules into law. However, with the plethora of schemes in place (see Chapter 7. GHG emissions of hydrogen and its derivatives), there is a risk of incompatibility and additional administrative burden as hydrogen is globally traded. The IEA has emphasised the importance of mutual recognition between national certification schemes as one of the key action areas for policy makers, as have other organisations (e.g. IPHE, UNIDO, IRENA), underlining the importance of harmonising schemes and GHG accounting methodologies. Several of these efforts are brought together under the umbrella of the Breakthrough Agenda,[87] which has made developing and implementing common standards for the GHG emissions of hydrogen production one of its priority areas, as well as safety, standards and certification.

Box 6.3 Key terminology related to certification

There are several terms related to certification that refer to different concepts, but which are often used interchangeably. In this section, these terms are used as follows:

Certification refers to the process of assessing whether a product complies with a given set of criteria. These may be **mandatory requirements**, in order to demonstrate **compliance** with legislation (e.g. the Low Carbon Fuel Standard in the United States), or eligibility for incentives (e.g. the Green Hydrogen Standard in India). Alternatively, they can be **voluntary**, such as **reporting** progress towards defined targets (e.g. the Climate Bonds Initiative) following **disclosure** guidelines.

Certificates can carry information about the origin of the energy used for production, as well as the time and location. This is usually intended to create transparency for customers. Information disclosed may be limited to the origin of the energy (in which case the certificate is called a “**guarantee of origin**”), or

[87] The Breakthrough Agenda was launched at COP 26, and currently with 59 government signatories and 39 specifically for the hydrogen sector.

broader environmental attributes such as land or water use (in which case it is called a "**sustainability certificate**"). An example is the EU Renewable Energy Directive (RED), which requires disclosure of the origin of the energy (Article 19) and aspects relating to broader environmental impact (Articles 29 and 30) leading to the emergence of schemes to verify compliance with each of these requirements.

Chain of custody is the name given to the process associated with the change of ownership of the certificates and correspondence between the certificate and the certified product. In a **book and claim** model, the certificate is completely separated from the product and can be traded independently. In a **mass balancing** model, both are directly linked.

A **certification scheme** encompasses the governance, application, evaluation, enforcement and verification of certificates. This includes the stakeholders (e.g. the issuing body) and their roles, registry and processes. In some cases, legislation comes first, followed by the establishment of certification schemes that in turn enable project developers to access incentives associated with legislation. For example, the production tax credit in the United States has set GHG thresholds that projects must comply with in order to access tax incentives, but there is currently no certification scheme to verify compliance, and final guidelines are still being defined. In contrast, the International Sustainability and Carbon Certification scheme for synthetic fuels was in place before the EU RED legislation was finalised, and the issuing body is now seeking recognition for the scheme from the European Commission as a way for projects to demonstrate compliance towards RED targets (as are the bodies behind other schemes).

A **labelling scheme** can be used to document that a product or production route has satisfied a defined set of criteria established by the certification process, such as labels that communicate the emissions intensity of hydrogen production. For example, the "green" hydrogen standard* in India is a label that can be applied to hydrogen meeting a threshold of 2 kg CO_2-eq/kg H_2.

A technical **standard** defines a formalised and shared methodology to be used to assess certain criteria defined by the certification scheme. This can include boundaries, product specifications, GHG accounting rules, and other aspects. The ISO Technical Specification is one example.

Elsewhere in this report, the term "certification" may be used to encompass several of the above aspects in order to facilitate understanding.

* See Explanatory notes annex for the use of the term "green" hydrogen in this report.

Important progress towards harmonisation and alignment was achieved at COP 28, with the launch of the Technical Specification for the methodology for determining the GHG emissions associated with the production and transport of hydrogen (ISO/TS 19870:2023). This was based on the methodology proposed by the IPHE and will be used as the basis for a multi-part series covering the hydrogen supply chain from production to consumption gate. The international standard for hydrogen production should be finalised in 2025, and the standards for GHG emissions from ammonia, LOHC, and liquid hydrogen in 2026. In addition, at COP 28, a Declaration of Intent for the mutual recognition of certification schemes for renewable and low-carbon hydrogen and hydrogen derivatives was signed by 37 governments. This effort is intended to drive convergence towards a minimum set of fundamental design principles for certification schemes, and to prevent a potential fragmentation that could delay the emergence of a global market, as well as increasing investor confidence. Signatories commit to seek accelerated technical solutions to enable mutual recognition of the schemes, including co-operation through the IPHE and the IEA H2 TCP, and the adoption of globally recognised standards such as the forthcoming ISO methodology.

In the United States, the Internal Revenue Service released the proposed rules to accompany the Clean Hydrogen Production Tax Credit (45V) in December 2023. The rules specify how to determine the lifecycle GHG emissions from hydrogen production and the conditions the electricity input needs to satisfy to produce what can be categorised as "clean" hydrogen.[88] GHG emissions should be estimated using the 45VH2-GREET tool, using a well-to-gate approach (i.e. including upstream emissions and without emissions from construction). Energy attribute certificates can be used to document the use of renewable electricity for electrolysis, and requirements for incrementality, temporal matching and deliverability must be fulfilled. These requirements are well aligned with those set in the European Union, with a maximum 36-month period between the operation of the renewable electricity input and the electrolyser beginning operations (incrementality), annual correlation between the renewable electricity and the hydrogen production until 2028 (when hourly correlation will become necessary [temporal matching]), and the same bidding zone for the renewable facilities and the electrolyser (deliverability). Furthermore, in June 2024, the Internal Revenue Service finalised rules for wage and apprenticeship requirements that can further increase the credit from USD 0.6/kg H_2 to USD 3/kg H_2. Guidelines for the tax credit itself are still to be finalised.

In the European Union, the RED Amendment entered into force on November 2023, and member states have until May 2025 to transpose it into national legislation. In addition, in May 2024, the European Council adopted the Hydrogen and Decarbonised Gas Package, which defines low-carbon hydrogen as needing to meet a 70% GHG reduction in comparison to the fossil fuel benchmark

[88] See Explanatory notes annex regarding the use of the term "clean" hydrogen in this report.

(94 g CO_2-eq/MJ). Details on the specific conditions, methodology to quantify GHG emissions and criteria are deferred to a Delegated Act that should be published within 12 months of the package entering into force (i.e. by June 2025). The European Union and Japan also announced intentions to co-operate to promote renewable and low-carbon hydrogen globally and ensure that standards and regulation converge.

Meanwhile, Denmark recognised the scheme from International Sustainability and Carbon Certification for the certification of renewable hydrogen. This was done as a temporary measure to avoid delays in project development while waiting for the list of recognised schemes by the European Commission.

Germany and France transposed the EU Delegated Acts for RFNBO into national legislation. In Germany, the updated regulation introduces a system for providing evidence of compliance with the requirements for the production and delivery of liquid and gaseous RFNBO. The certification of suppliers follows a similar process to the existing Biofuel Sustainability Ordinance.

In Spain, from 2025, hydrogen and its derivatives will count towards reaching the target of 29% of renewable energy in transport set in the revised EU RED. The same Ministerial Order that introduced this policy also modifies the guarantees of origin scheme for renewable gases to include sustainability criteria and CO_2 emissions reduction data, as well as requirements to account for the renewable electricity used in hydrogen derivatives.

In Portugal, the electricity and gas grid operator (REN) started issuing guarantees of origin (GoO) for renewable hydrogen in July 2024. This will be harmonised with the schemes in other EU member states by the end of 2024, which will enable these GoO to be used with imports and exports within the European Union.

The United Kingdom published an updated version of the Low Carbon Hydrogen Standard in December 2023. Updates include a refinement of key requirements for electrolysers, including a definition of eligible PPA, renewable energy GoO requirements, calculation of transmission and distribution losses, requirements for electricity storage systems, the addition of methane pyrolysis, and updated methodologies. This standard defines the criteria for projects to be able to apply for the Hydrogen Production Business Model (OPEX) support while the government is working on a Low Carbon Hydrogen Certification Scheme, which should be published by 2025.

In China, guidelines released in October 2023 for GHG reporting for industrial assets could give an indication of future guidance for hydrogen. Off-grid non-fossil electricity is considered to have zero emissions, while emissions from non-fossil fuel electricity are calculated using the national grid emission factor from 2022 set at 570 g CO_2/kWh, and “green certificates” cannot be used for emission offsets.

Japan has proposed GHG thresholds under the Hydrogen Society Promotion Act. Thresholds include 3.4 kg CO_2-eq/kg H_2 for hydrogen (well-to-gate), 0.87 kg CO_2-eq/kg NH_3 for ammonia (well-to-gate), 49.3 g CO_2-eq/MJ for synthetic methane (well-to-point of consumption) and 39.9 g CO_2-eq/MJ synthetic fuels (well-to-point of consumption). The CO_2 source should be biogenic, from direct air capture, or should be covered by agreements to avoid double counting of emissions (e.g. allocating the emissions to the original emitter). These rules are yet to be finalised.

In Latin America, 14 governments reached an agreement to work on a common certification scheme known as "CertHiLAC" for clean and low-carbon hydrogen. This initiative is receiving support from the Inter-American Development Bank and the Latin American Energy Organization. A group comprising national representatives was formed to establish a governance structure for the agreement, define relevant stakeholders, and issue recommendations. In Peru, a law was published defining "green" hydrogen as hydrogen produced using technologies with low GHG emissions. The law also makes the Ministry of Mines and Energy responsible for defining the criteria for certifying the GoO of the green hydrogen. In Brazil, the government has finalised the rules of the Brazilian Hydrogen Certification Scheme (SBCH2), including definitions and a governance structure. The rules set a GHG threshold of 7 kg CO_2-eq/kg H_2 to define low-carbon hydrogen, but additionality criteria for the renewable electricity was not included following its rejection by the Senate. Further details, such as on chain of custody, scope, criteria and instruments, will be defined in subsequent legislation. The scheme will be voluntary for producers, and the need for international collaboration and harmonisation of standards is also emphasised. The operator of the electricity market (CCEE) has manuals on governance, methodology and criteria for the certification of hydrogen and derivatives, and used these to certify two projects in 2023. Only electrolysis is included in the CCEE scheme. With regards to scope and criteria, the scheme covers both on- and off-grid configurations, includes indirect emissions from electricity, and requires more than 90% renewables, emissions lower than 18 g CO_2/MJ, and a PPA with additionality, a monthly correlation and geographical correlation.

Elsewhere, Kenya issued guidelines for the sustainability criteria for "green" hydrogen and derivatives. Sustainability is defined in terms of electricity source[89], water, land and local communities. Guidelines on health and safety, project registration, local content, incentives, commencement date, transition and complaints handling are also provided. The renewable hydrogen production must have well-to-gate lifecycle emissions of less than 1 kg CO_2-eq/kg H_2 and

[89] Three sourcing options are considered: (1) captive renewable supply; (2) grid connection with at least 80% renewable supply in a calendar year and with an average grid emission intensity below 64.8 g CO_2/kWh during the previous calendar year; and (3) Supply from a remote renewable plant by using PPA and renewable energy certificates.

0.3 kg CO_2-eq/kg NH_3 in the case of ammonia, averaged over a 12-month period. Qualitative targets are defined for most criteria, except for the GHG thresholds and the criteria for the electricity input.

In Australia, consultation on the scheme design and the emissions accounting approach to be used was undertaken prior to October 2023, and final legislation introducing a GoO scheme should be in place by July 2025. Australia is also considering extending the GoO scheme to cover the production of low-carbon liquid fuels (including synthetic fuels) and it has allocated AUD 18.5 million (USD 12.2 million) from the federal budget 2024-2025 to this initiative over the next 4 years.

The United Arab Emirates is working on developing a low-carbon certification scheme through the Hydrogen Taskforce as a follow-up to its hydrogen strategy. The certificates are expected to be voluntarily tradeable and to carry energy, environmental, and social attributes.

Among the new strategies published in the last year, Indonesia's strategy notably defines a certification scheme as a critical component of a clear regulatory framework to promote hydrogen deployment.

Operational and safety standards

In 2024, the ISO Technical Committee 197 published two new standards: (ISO 19880-9:2024) on sampling for fuel quality analysis at HRS and (ISO 19885-1:2024) on fuelling protocols of gaseous hydrogen for passenger vehicles. There are 21 standards published so far and 26 under development, of which the majority are related to fuelling stations, fuelling protocols and vehicle fuelling system components. Ten standards have now reached the status of Draft International Standards and one has reached the Final Draft International Standard stage.

In addition, the International Electrotechnical Commission has published 34 standards so far (including 6 since the publication of GHR 2023[90]) relating to the safety of fuel cell modules, performance test methods, and micro fuel cell power systems.

The IPHE performed a gap assessment of regulations, codes and standards (RCS) for large-scale storage of hydrogen to identify the critical areas for research and regulation to enable the large-scale deployment of bulk hydrogen storage. The report mapped the RCS in nine countries for above-ground and underground tanks, and for subsurface storage. Common gaps across countries included maximum storage sizes that are insufficient for the large-scale storage needs

[90] IEC 62282-2-100:2020/COR1:2023; IEC 62282-4-202:2023; IEC 62282-6-101:2024; IEC 62282-6-106:2024; IEC 62282-6-107:2024; IEC 62282-8-201:2024.

foreseen for the future and setback distances that must be reviewed. Importantly, in some cases hydrogen was either absent from the regulations or fell under the scope of different legislations.

In November 2023, UNIDO organised the ISO Hydrogen Technologies Plenary Week, which convened over 150 global experts representing 62 countries, including 34 EMDEs, and is now supporting the development of a framework for quality infrastructure along the renewable hydrogen supply chain. This will include a practical guide for the use of the ISO methodology by industry and government stakeholders. The guide will be used for capacity-building activities expected to begin in the second half of 2024.

At a regional level, in 2024, the United States is focusing on identifying and addressing permitting challenges, understanding and addressing indirect impacts of hydrogen releases, materials compatibility, and the advancement of sensor technologies (through R&D). The United States already has a tool to help projects navigate relevant codes and standards. Canada will complete a Codes and Standards roadmap in 2024, identifying and prioritising any gaps to be resolved to support hydrogen development.

In the European Union, an RCS Strategy Coordination Task Force will be set up in 2024, composed of the European Commission, the Clean Hydrogen Alliance, and Hydrogen Europe. The Task Force aims to enhance European engagement with international RCS bodies, and to support the Commission in working on standardisation with IPHE and the Clean Energy Ministerial (CEM). A report on international RCS developments is planned for publication by the end of 2024.

At the national level, in July 2024 Germany launched a strategic roadmap for the expansion and adaptation of the technical regulations for hydrogen technologies. In the Netherlands, the safety standards for ammonia storage and loading are now being revised in phases, and the final version of the first phase, applicable to new facilities, was published in July 2024. In the United Kingdom, the government aims to work with industry in 2024 to ensure the regulatory framework is fit for purpose for hydrogen along the value chain.

In other regions, Australia is developing national hydrogen codes of best practice for hydrogen and ammonia production and appliances, which will cover hydrogen production, refuelling and storage safety. These codes aim to provide clarity on the regulatory obligations for projects, the regulators involved in the different steps of the process, and timing and cost of compliance. Co-design workshops between government and industry were held in late 2023, with public consultation expected to take place in 2024. The government maintains lists of the regulations and standards that each part of the value chain should comply with. In April 2024, New Zealand launched a public consultation to adopt 13 hydrogen-related ISO technical standards.

Regulations on infrastructure, permitting and other areas

In the European Union, the Hydrogen and Decarbonised Gas Package was adopted in May 2024, after the Commission first proposed it in December 2021. This defines the governance of the hydrogen transmission network in the European Union, noting that a 10-year development plan will be published every 2 years starting from 2026, and setting a maximum of 2% (by volume) hydrogen blend for cross-border gas infrastructure in case member states cannot come to an agreement. Member states have until mid-2026 to transpose the new rules into national law.

Germany passed regulatory frameworks for hydrogen network development and its financing. The network is to be financed by the private sector, with fees that are capped to avoid high initial costs that could prevent market development. The fees have a deferral scheme, in which fees in the early years will be lower than the actual costs to promote market ramp-up. To ensure liquidity, there are extra payments from the government to ensure a pre-tax nominal return on equity of 6.69%. The European Commission approved EUR 3 billion (USD 3.3 billion) of German state aid to be provided as a government guarantee and will allow transmission system operators to obtain more favourable loans. The German Government also presented the draft Hydrogen Acceleration Act, which aims to digitalise, simplify and prioritise planning, approval and procurement procedures. This includes setting maximum deadlines for approval procedures, shortening appeal processes, and reducing administration. It will cover hydrogen production, pipelines, port terminals, ammonia cracking, and power lines supplying electrolysers. Elsewhere, in Denmark, the government reached an agreement on the economic framework conditions for hydrogen infrastructure[91] and the principles and conditions for state risk hedging. Spain granted a provisional authorisation to Enagas (the gas transmission system operator) to develop hydrogen networks recognised under the European Projects of Common Interest.

The United Kingdom announced support in principle for a hydrogen core network following the recommendation of the National Infrastructure Commission. The government published a strategic planning document in December 2023, and plans to open a consultation in 2024 for specific activities, with the system operator formally becoming responsible for network planning from 2026. A Regulated Asset Base emerged as preferred financing model of the network in the public consultation, with a revenue floor for 15 years for storage assets. Given the current lack of overarching regulation for the network, the government has extended the existing offshore oil and gas pipeline and storage regulatory frameworks to cover offshore hydrogen pipelines and storage. In parallel, a market consultation for the

[91] Including regulated third-party access, no tariff exemption for individual (types of) users, and 10% of network capacity reserved for short-term contracts.

first allocation rounds of the transport and storage business models was launched in December 2023. The government also announced its support for blending up to 20% hydrogen (by volume) in the gas distribution network in certain scenarios and circumstances. A position on blending in the transmission network is expected in 2024, and before a decision is taken, the HyDeploy industry trials will provide further evidence. There will be a safety review, and a report assessing economic support will be prepared. The government also launched the Track-1 expansion process of HyNet in December 2023 for a CO_2 storage capacity of 1.3-1.5 Mtpa CO_2 from 2028 (in which hydrogen is one of several relevant sectors), contributing to the 20-30 Mtpa CO_2 target for 2030. Winners will be announced in Q3 2024, with FID expected by 2026, and latest operating date by the end of 2030.

Elsewhere, in March 2024, Australia finalised a process of extending the national gas law and regulations to include hydrogen with the amendment of the National Gas Rules and the National Energy Retail Law. Israel granted a permit to allow the natural gas transmission operator to engage in the transportation of hydrogen and CO_2.

Chapter 7. GHG emissions of hydrogen and its derivatives

Highlights

- In 2023, global hydrogen production emitted 920 Mt CO_2. Nearly two-thirds of production was from unabated natural gas, which emits 10-12 kg CO_2-equivalent (CO_2-eq)/kg H_2; about 20% was from unabated coal, which emits 22-26 kg CO_2-eq/kg H_2. Between 75% and 95% of these emissions occur directly at the point of production, and can be reduced by carbon capture, utilisation and storage (CCUS). For hydrogen from steam methane reforming (natural gas), abatement costs are estimated at around USD 60-85/t CO_2 for capture rates of 55-70%, and USD 85-110/t CO_2 for rates above 90%. However, carbon capture alone is not sufficient; upstream and midstream emissions must also be tackled.
- Hydrogen from electrolysers is emissions-free at the point of production, and so emissions depend on the electricity used. Emissions intensity from electricity generation should be below 200-240 g CO_2/kWh for emissions to be lower than steam methane reforming. Renewable electricity is emissions-free at the point of generation, but embedded emissions can occur in the construction and manufacturing of renewable assets. Such emissions are currently not included in most standards and schemes; they can range from 0.4-2.7 kg CO_2-eq/kg H_2.
- The process of converting hydrogen to a carrier for transport incurs energy losses of 45-70%. This means that any GHG emissions from the electricity input to the electrolysers increases by a factor of 2-3 in terms of the final hydrogen delivered. The lowest emissions are achieved when the electrolyser uses renewable electricity, and the hydrogen transported is used as shipping fuel and no fossil fuels are used in hydrogen recovery. Liquid hydrogen results in the lowest emissions due to its higher pathway efficiency (above 50%); emissions are slightly higher for liquid organic hydrogen carriers (LOHC) and ammonia.
- The emissions reduction offered by carbon-containing hydrogen-based fuels is greatest when the CO_2 source is biogenic or from the air. The emissions intensity of their electricity input should be lower than 160-190 g CO_2-eq/kWh for synthetic methanol and 95-140 g CO_2-eq/kWh for synthetic methane and kerosene to result in lower emissions compared to a fossil fuel. In emissions accounting, the way CO_2 emitted during fuel combustion is allocated along processing steps in the supply chain has a large effect on the total emissions allocated to the individual product.

Overview

In 2023, global production of 97 Mt of hydrogen emitted[92] nearly 920 Mt CO_2 (Chapter 3. Hydrogen production). This is equivalent to the annual energy-related emissions of Indonesia and France combined. In the IEA Net Zero Emissions by 2050 Scenario (NZE Scenario), these emissions must go down by around 10% to 820 Mt CO_2/yr by 2030. At the same time, in this scenario total hydrogen production needs to increase by over 50% to 150 Mtpa, which means that the reduction required in terms of specific emissions is more significant than in absolute terms, with a 40% drop needed by 2030 to reach ~5.5 kg CO_2/kg H_2.

A hydrogen molecule does not contain any carbon, which means the CO_2 emissions do not come from the end use, but rather from the production, processing and transport of hydrogen. Carbon accounting must therefore track the CO_2 emissions at each conversion step in the supply chain. The framework used to account for and report on GHG emissions is of critical importance for the trade of low-emissions hydrogen, especially as traded hydrogen may cross borders and jurisdictions, and the majority of the GHG emissions occur upstream in the supply chain, during production and transportation.

A large number of certification schemes and regulations (see Box 6.3 for clarifications on certification-related terminology) have emerged in the past 3 years (see Figure 7.1), using different boundaries, production routes, definitions, emissions thresholds and methodologies for varying products. Nevertheless, there have been signs of convergence in the past year. The publication of the International Organization for Standardization (ISO) Technical Specification for the hydrogen supply chain from production to consumption gate will set the basis for the ISO standards to be published in the next 2 years. At the multilateral level, the COP 28 Declaration of Intent on mutual recognition of certification schemes, and regional efforts in Latin America for a common certification scheme (CertHiLAC) demonstrate strong commitment to establishing common standards. The IEA H2 Technology Collaboration Programme (TCP) Task 47 and the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) Hydrogen Certification Mechanisms (H2CM) Task Force are two global initiatives that have joined efforts to develop an evidence base on the current certification mechanisms and to support building consensus and mutual recognition across schemes. These efforts must continue in order to ensure that accounting is carried out based on a common methodology for tracking lifecycle emissions as hydrogen crosses borders.

Existing certification schemes currently use a wide range of emission thresholds and labels (Figure 7.1). More than half of the schemes require an emissions intensity

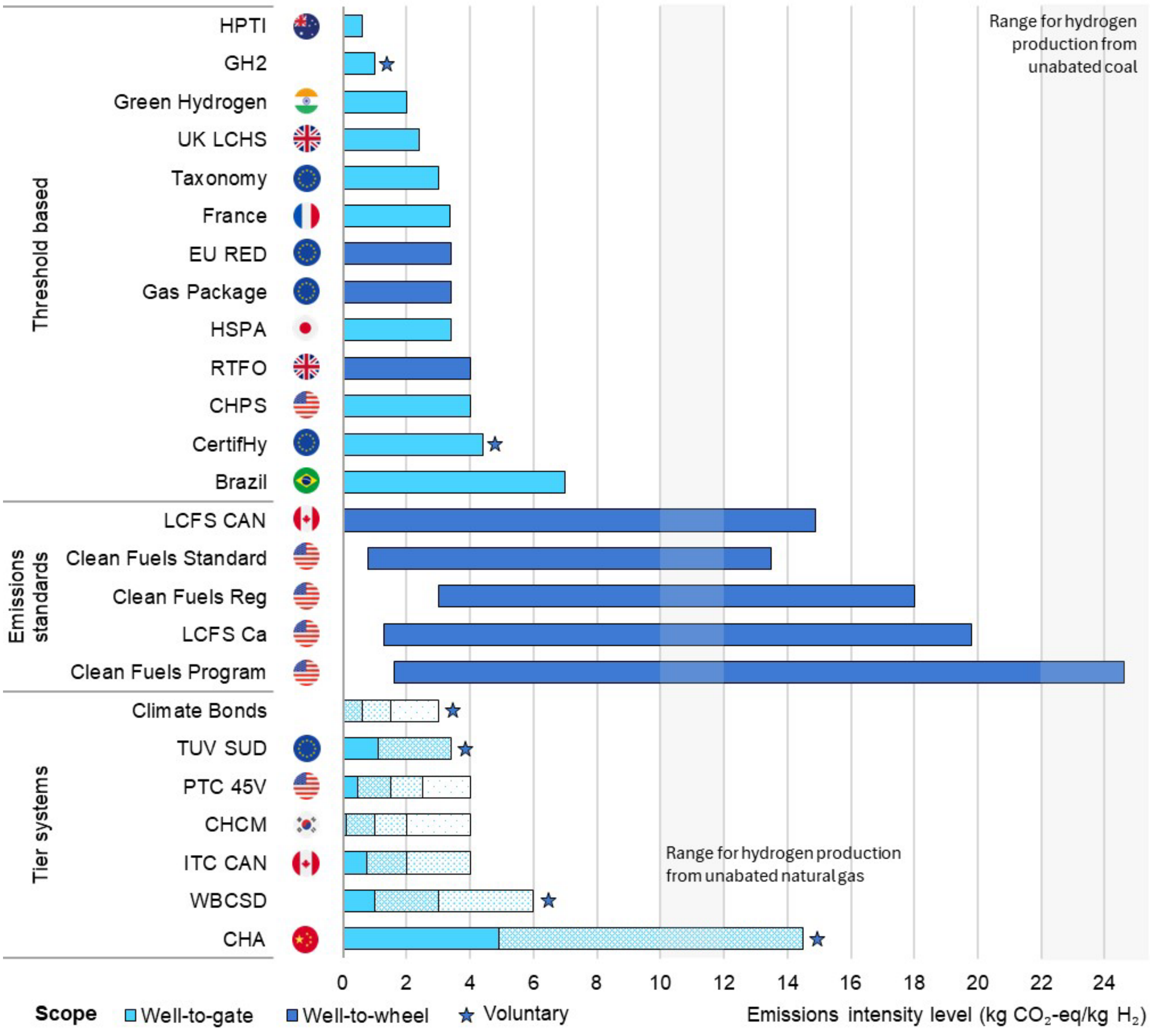
[92] Considering 0 kg CO_2/kg H_2 for hydrogen produced as a by-product in naphtha crackers and steam crackers. Considering a maximum of 10 kg CO_2/kg H_2 emissions would increase up to 1 070 Mt CO_2. This includes direct emissions from hydrogen production and close to 300 Mt of CO_2 utilised in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply

lower than 4 kg CO_2-eq/kg H_2, which is 60-70% lower than the 10-12 kg CO_2-eq/kg H_2 from unabated natural gas, the most common production route today. Of the schemes that allow higher thresholds, six are part of a programme aiming to reduce CO_2 emissions in road transport, where the lower conversion efficiency of internal combustion engines (in comparison to fuel cells) means higher emissions from hydrogen production and transport could still lead to a net emissions benefit (comparing hydrogen use with the incumbent fossil fuel), which explains the use of higher thresholds. Another scheme with a threshold higher than 4 kg CO_2-eq/kg H_2 is used in China, where nearly 60% of hydrogen is produced from unabated coal, which can have emissions of 22-26 kg CO_2-eq/kg H_2. Brazil has recently passed legislation approving an emissions threshold of 7 kg CO_2-eq/kg H_2, more than double the threshold in the European Union, and 3.5 times the threshold of India. At the lower end, Australia has proposed a threshold of only 0.6 kg CO_2-eq/kg H_2 for its Hydrogen Production Tax Incentive (HPTI), which aims to promote the development of renewable hydrogen and should be in place by July 2027. In addition to hard limits, several countries apply schemes with tier systems to define several emissions thresholds, which are associated with progressive financial incentives for producers with lower emissions.

All schemes (except for in the European Union, the UK Renewable Transport Fuel Obligation and H2Global) that have a threshold below 4 kg CO_2-eq/kgH_2 are well-to-gate in their scope. Hydrogen that is traded globally will have higher specific emissions due to transport and conversion, which means that well-to-wheel schemes that have the same threshold as well-to-gate schemes pose more stringent requirements for hydrogen producers, as transport and distribution emissions are also included.

Only two schemes cover hydrogen-based fuels exclusively. One is from H2Global, which is a programme started by the German government aimed at imports. The programme covers well-to-point of delivery and its threshold is similar to others at 3 kg CO_2-eq/kg H_2. The other is a voluntary scheme by the Ammonia Energy Association, originally proposed in 2021 and currently under development. In total, ten schemes (of which five are regulatory) cover both hydrogen and its derivatives. Seven (three regulatory) of these are already operational. European schemes do not define a specific production route, and only specify a GHG threshold that any hydrogen (or derivative) should achieve, as well as the methodology to be used. Ammonia is most common among schemes that explicitly mention the carriers. Steel is exclusively mentioned in the (voluntary) Zero Carbon Certification Scheme.

Figure 7.1 Emissions intensity level of certification schemes and regulatory frameworks for hydrogen and/or derivatives by scope and type of scheme



Notes: RTFO = Renewable Transport Fuel Obligation; RED = Renewable Energy Directive; LCFS = Low-Carbon Fuel Standard; LCHS = Low-Carbon Hydrogen Standard; PTC 45V = Production Tax Credit under section 45V of the Inflation Reduction Act; CHPS = Clean Hydrogen Production Standard; Reg = Regulation; Ca = California; CAN = Canada; ITC = Investment Tax Credit; CHCM = Clean Hydrogen Certification Mechanism; HPTI = Hydrogen Production Tax Incentive; CHA = China Hydrogen Alliance; HSPA = Hydrogen Society Promotion Act; GH2 = Green Hydrogen; WBSCD = World Business Council of Sustainable Development; LHV = lower heating value. Pattern filled bars refer to schemes that use a tier system. Total sample of 25 certification schemes excluding 9 (from a larger sample of 34) that do not assign thresholds. For regions that do not start from zero, the bars represent carbon-crediting schemes with default carbon intensities for defined pathways that are reflected in the figure.

More than half of the certification schemes and regulatory frameworks require carbon intensity lower than 4 kg CO_2-eq/kg H_2.

System boundaries and scope of emissions

This report uses the boundaries and methodology of the ISO Technical Specification (Figure 7.2), which may eventually be used as a common basis for future regional and national methodologies. The supply chain steps covered in the specification are hydrogen production, conditioning, conversion to hydrogen carriers, transport,[93] and reconversion to hydrogen. Emissions associated with the electricity input and upstream and midstream methane emissions are included. Emissions from construction, manufacturing, and decommissioning of assets are excluded from the scope, but their quantification should be provided separately for information. With a well-to-gate scope, only the end use is excluded.

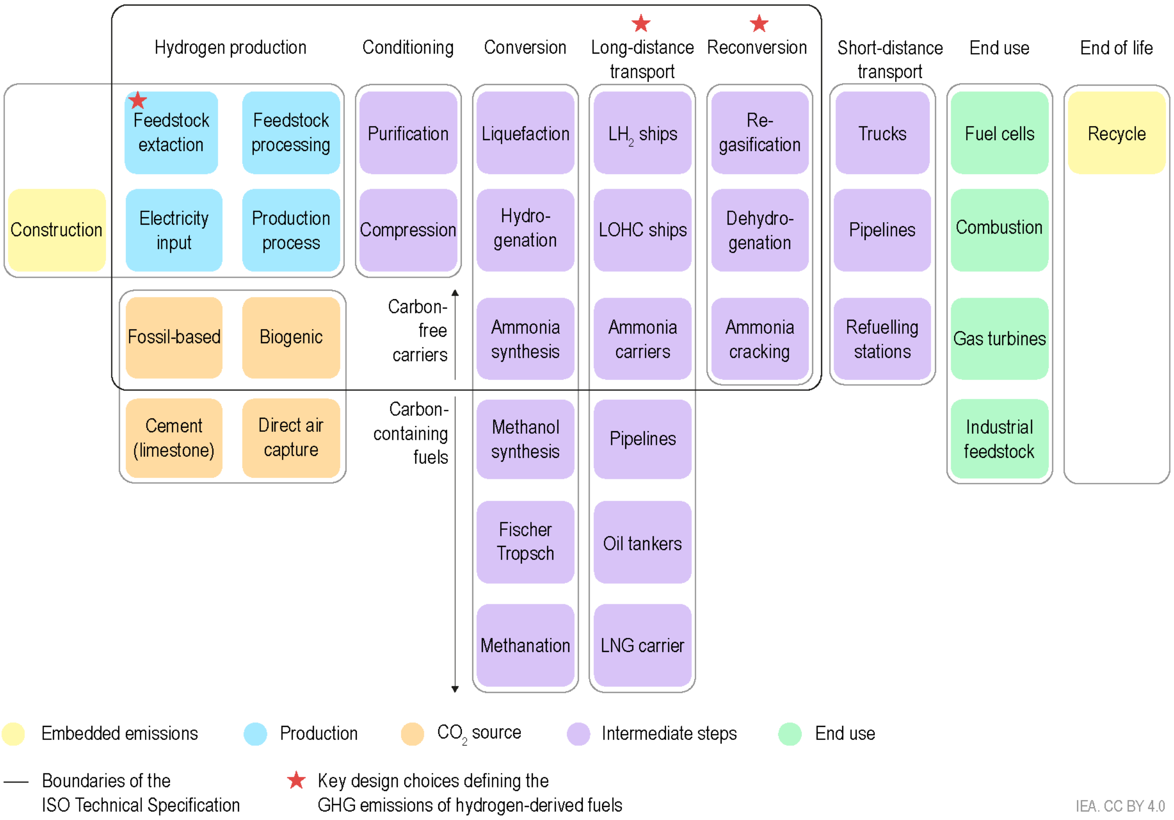
The ISO Technical Specification currently covers hydrogen carriers that are expected to be reconverted back to gaseous hydrogen (liquefied hydrogen, LOHC and ammonia), including cases where they are used directly (as for ammonia). Carbon-containing synthetic fuels such as methane, methanol and other hydrocarbons are excluded from the scope. These can be used directly as fuels due to their higher volumetric energy density (compared to pure hydrogen carriers) and existing infrastructure that facilitates transportation to the end use.

Global warming potential (GWP) (which covers GHG emissions) is one of several categories typically covered in a Life Cycle Assessment (LCA) analysis. The rest of this chapter will focus only on GHG emissions, but the total environmental impact of hydrogen must be assessed considering criteria across all the impact categories. Beyond the environmental aspect, other dimensions such as social aspects or cost can necessitate trade-offs when designing a plant or making a final investment decision on a project, but these factors are not included in this analysis.

Supply chain efficiency is defined in this report as the energy finally delivered as hydrogen compared to the total energy input along the supply chain. As a result, design changes, like the use of hydrogen that has been transported to provide the heat for ammonia cracking and LOHC dehydrogenation, or as a shipping fuel, will decrease the efficiency (and increase the specific GHG emissions), since this hydrogen consumption along the chain reduces the hydrogen finally delivered.

[93] GHG emissions for all transport operations, hub operations, and storage for transport by inland waterway, pipeline, rail, road and sea.

Figure 7.2 Boundaries of the ISO Technical Specification 19870:2023 with respect to the entire hydrogen supply chain from materials to end use



Notes: LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier; LNG = liquefied natural gas. Production pathways covered in the ISO Technical Specification are electrolysis, steam methane reforming, autothermal reforming, chlor-alkali, steam cracking, coal gasification, production from biomass waste.

The ISO Technical Specification covers hydrogen production, conversion, transport, and reconversion to hydrogen.

Emissions intensities of hydrogen production routes

This chapter updates previous IEA analysis on emissions intensities of hydrogen production routes. The updates introduced here are consistent with the ISO Technical Specification, and based on updated data on upstream and midstream methane emissions from 2022, and updated technical parameters for some of the conversion processes. This section focuses on hydrogen production, meaning that the scope is well-to-gate.

For production pathways using natural gas and coal without carbon capture and storage (CCS),[94] direct emissions during hydrogen production represent as much as 75-95% of the total emissions. Hydrogen produced from natural gas emits

[94] For the analysis in this chapter, only carbon capture and storage (CCS) has been considered, since the ISO Technical Specification does not consider carbon capture and use (CCU) among the included hydrogen production routes.

10-12 kg CO_2-eq/kg H_2, with the range coming from the difference in upstream and midstream GHG emissions[95] (Figure 7.3). Emissions from hydrogen production from coal are higher, at 22-26 kg CO_2-eq/kg H_2.

CCS can be used to reduce the direct emissions, with the capture rate and abatement cost depending on the technology pathway and the point of capture. Capture rates for steam methane reforming (SMR) are the lowest (55-70%) when carried out only in the concentrated stream on the process side, which also results in the lowest abatement cost (USD 60-85/t CO_2[96]). When capture is also implemented on the flue gas, which is more diluted and has lower pressure, the capture rate can increase above 90%, but the cost also increases to USD 85-110/t CO_2. Process modelling studies have shown that plant capture rates of 96% and up to 99% can be technically and economically feasible. Using electricity instead of natural gas to achieve the high temperatures needed for reforming is also an option, but this would tackle only the emissions from fuel combustion, which are around 45% of the total, and therefore mitigation of the emissions from the process side would still be required. For autothermal reforming, capture rates can be 93-98% since most of the CO_2 is on the process side at high pressure. The gas partial oxidation (POx) process developed by Shell is reported to yield overall plant capture rates up to 99%, although these high capture rates are yet to be proven in large-scale commercial plants on a continuous basis.

Once CCS is implemented, the upstream and midstream GHG emissions become the dominant factor, accounting for up to 98% of the total emissions when partial oxidation of natural gas with 99% capture is applied. Upstream and midstream GHG emissions can make up to 90% of the total for production from coal (when a 98% capture rate is applied), due to higher residual emissions from carbon capture.

For production using natural gas, the global average upstream and midstream emission intensity in 2022 was 11.3 kg CO_2-eq/GJ_{NG},[97] which corresponds to 20% of the CO_2 produced during the combustion of the natural gas, and is equivalent to about 1.8 kg CO_2-eq/kg H_2.[98] These emissions alone would be four times higher than the lowest threshold defined in the production tax credit in the United States (0.45 kg CO_2-eq/kg H_2) and 60% of the threshold defined in the EU Taxonomy. There is a wide spectrum of natural gas emissions intensity around the world. At the lower bound, Norway has an upstream and midstream emissions intensity of 4.5 kg CO_2-eq/GJ_{NG} (0.7 kg CO_2-eq/kg H_2), compared to up to 27 kg CO_2-eq/GJ_{NG} (4.3 kg CO_2-eq/kg H_2) for Turkmenistan. The solutions to mitigate upstream and midstream emissions are

[95] This includes CO_2 and methane emissions occurring during the production, transport and processing of the fuels.
[96] For merchant plants, i.e. where hydrogen production is not integrated with a specific process.
[97] If not specified otherwise, energy amounts are based on lower heating values.
[98] Assuming an efficiency of 75%. This could increase to 3.8 kg CO_2-eq/kg H_2 if a 20-year time horizon is used for the global warming potential instead of 100 years.

known and cost-effective. In the NZE Scenario, the global average upstream and midstream emissions intensity of natural gas would be halved by 2030.

Reliable methane emissions inventories are critical to establish baselines, define targets and track progress. National emission inventories are known to underestimate these emissions, but other efforts in recent years have made progress in closing this gap. Clear and standardised measurement, monitoring, reporting and verification (MMRV) guidelines are also essential to ensure the interpretation of the emissions measured. For example, in 2020 the United Nations Environment Programme (UNEP) launched the Oil and Gas Methane Partnership 2.0 (its flagship oil and gas reporting and mitigation programme), which has developed guidance for methane measurement. The EU Methane Regulation introduces mandatory MMRV requirements on domestic producers and establishes a transparency platform with country profiles (including non-EU member states exporting to the European Union). There are also government efforts aiming to measure and reduce these emissions like the Global Methane Pledge, which is supported by countries covering 50% of global anthropogenic emissions and targets 30% reduction by 2030 (compared with 2020). In November 2023, the US Department of Energy (DoE) announced an international working group, composed of 14 members, to establish an MMRV framework for providing comparable and reliable information to natural gas market participants.

For production using coal, upstream and midstream emissions can make even a larger difference. Even with a capture rate of 98%, the upper end of upstream and midstream emissions would result in total emissions from hydrogen production above 5 kg CO_2-eq/kg H_2[99] (for coal), which is more than half the most common conventional production route today (from natural gas) and above most low-carbon thresholds that have been defined in certification schemes (see Chapter 6. Policies).

For hydrogen production using water electrolysis, emissions are largely defined by the electricity input. Due to the conversion efficiency of the electrolysis process, every 100 g CO_2/kWh associated with electricity supply results in nearly 5 kg CO_2-eq/kg H_2 in hydrogen production.[100] This means that the emissions intensity of the electricity input needs to be lower than 200-240 g CO_2/kWh to breakeven with the unabated natural gas route. There is a large range around the world: Countries that have a high share of hydropower today (e.g. Norway, Paraguay, Switzerland) or nuclear (e.g. France) achieve emissions intensity lower than 45 g CO_2/kWh, and countries with a high share of gas and coal can have grid emissions intensity above 700 g CO_2/kWh. Nearly 85% of the global electricity production is above this breakeven threshold (on an annual average basis), which means that operating an electrolyser with electricity from the grid on a continuous basis might not make sense in most countries from an environmental perspective. In addition, certifying the use of renewable electricity, and

[99] Assuming an efficiency of 55%.
[100] Assuming an efficiency of 67%.

accounting for the CO_2 emissions associated with the electricity input, might become more difficult when an electrolyser is connected to the grid, and the additional electricity demand could trigger additional fossil-based generation.[101] Today, off-grid configurations are common among proposed projects, which makes the GHG emissions accounting much simpler. At the same time, due to their fast response time, electrolysers can provide increased short-term flexibility to the grid, enabling the integration of renewables as well as seasonal flexibility when coupled with large-scale storage. A hybrid configuration could potentially combine the best of both options, using a small share of electricity from the grid (with GHG emissions tracking) to provide firm capacity and increase utilisation of the assets, while limiting the GHG increase.

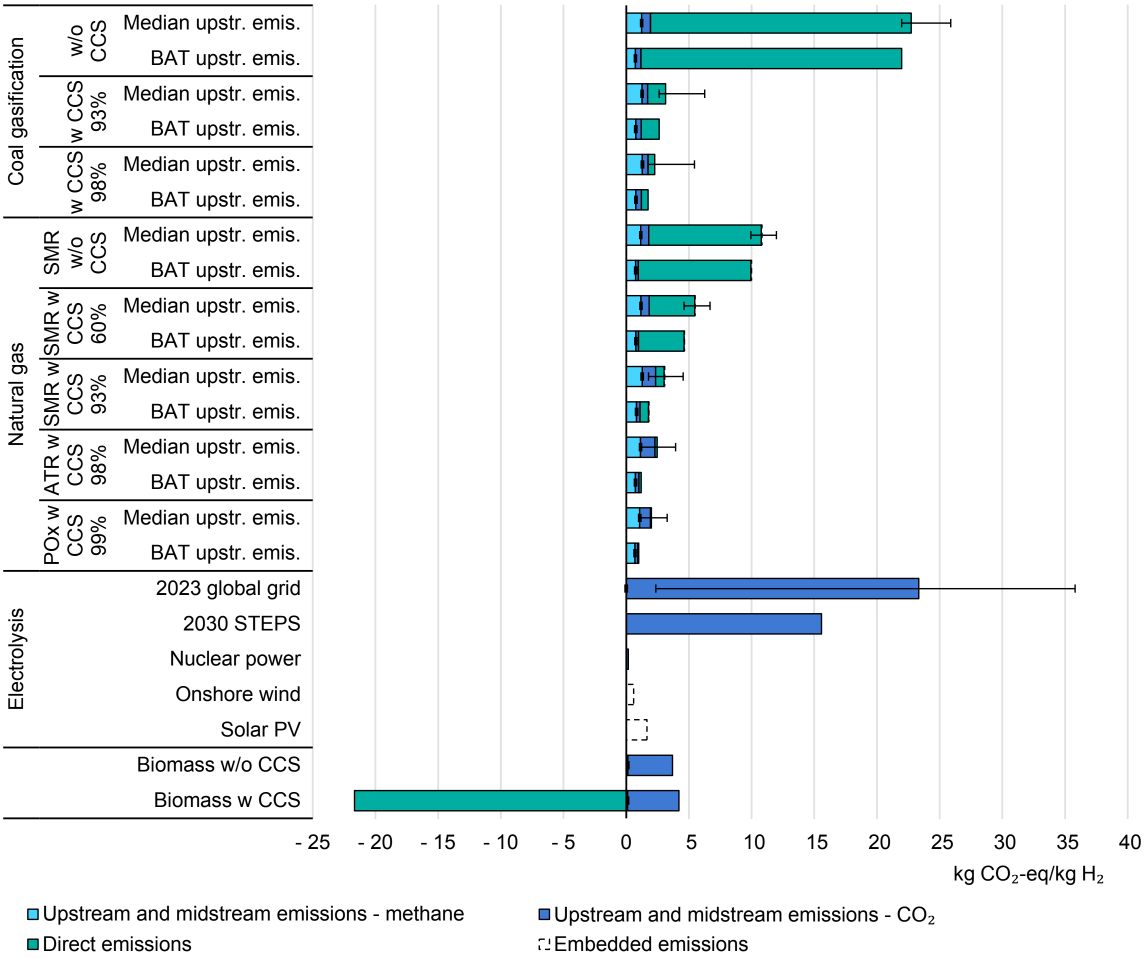
Emissions from construction and manufacturing of all assets (commonly called embedded or CAPEX emissions) are excluded from the boundaries defined by the ISO Technical Specification to determine the GHG emissions intensity of hydrogen, but should be reported for information purposes. For renewables only, they could range from 0.4-2.7 kg CO_2-eq/kg H_2.[102] These emissions are expected to decrease as technology innovation increases efficiency and capacity factors and decreases material intensity, at the same time as the energy used during manufacturing is decarbonised.

Nuclear electricity can be another energy source for electrolytic hydrogen production. Although direct emissions from a nuclear power plant are zero, the nuclear fuel cycle of uranium mining, conversion, enrichment and fuel fabrication results in emissions of 2.4-6.8 g CO_2-eq/kWh. On this basis, the emissions intensity of hydrogen production from nuclear electricity is in the range of 0.1-0.3 kg CO_2-eq/kg H_2.

For hydrogen production from bioenergy, the direct emissions are also considered to be zero. Emissions can, however, occur upstream in the bioenergy supply chains, and the carbon footprint depends heavily on the origin of the feedstock and the processing steps. In the case of using wood chips, these emissions may be 4-18 kg CO_2-eq/GJ[103], resulting in total emissions of 1.0-4.7 kg CO_2-eq/kg H_2 for hydrogen from biomass gasification. Combining such a gasification plant with CCS and a capture rate of 95% can result in negative emissions of -16 to -21 kg CO_2-eq/kg H_2, by effectively removing biogenic carbon from the natural carbon cycle.[104]

[101] This is on top of the additional costs for the grid connection and potential delay this can introduce to the project.
[102] Embedded emissions are 17-53 g CO_2-eq/kWh for solar PV and 8-18 g CO_2-eq/kWh for onshore wind. For SMR, research and project data indicate embedded emissions are in the order of 0.4% of unabated emissions.
[103] GHG emissions from bioenergy supply can vary widely depending on the scope (land use change), type and processing steps.
[104] Hydrogen could be produced along with other co-products and negative emissions should be allocated as per ISO standards to avoid double counting.

Figure 7.3 Comparison of the emissions intensity of different hydrogen production routes, 2022



Notes: BAT = best available technology; CCS = carbon capture and storage; SMR = steam methane reforming; POx = partial oxidation; Median upstr. emis. = global median value of upstream and midstream emissions in 2022; BAT upstr. emis. = best available technology today to address upstream and midstream emissions. Upstream and midstream emissions include CO_2 and methane emissions occurring during the extraction, processing, and supply of fuels (coal, natural gas) or production, processing, and transport of biomass. Error bars for natural gas and coal represent the impact of the observed range of emissions intensities. For natural gas, the lower bound corresponds to best available technology today (4.5 kg CO_2-eq/GJ), and the upper bound to the 95% percentile of the world range (18.8 kg CO_2-eq/GJ). For coal, the lower bound corresponds to the 5% percentile (6 kg CO_2-eq/GJ) and the upper bound to the 95% percentile (23 kg CO_2-eq/GJ) of global upstream and midstream emissions of coal supply. Methane emissions are converted to CO_2-eq with a GWP over a time horizon of 100 years. The 2023 world grid average is based on a generation-weighted global average of the grid electricity intensity, with the error bars representing the 10% percentile (46 g CO_2-eq/kWh) and 90% percentile (702 g CO_2-eq/kWh) across countries. The grid electricity intensities include direct CO_2, methane (CH_4) and nitrous oxide (N_2O) emissions at the power plants, but not upstream and midstream emissions for the fuels used in the power plants. Dashed lines refer to the embedded emissions occurring during the production of onshore wind turbines (12 g CO_2-eq/kWh) and solar PV systems (33 g CO_2-eq/kWh). These embedded emissions are not included in the ISO TS methodology, but are part of the mandatory information to report. Electrolysis refers to low-temperature water electrolysis with an assumed efficiency of 67% (Lower heating value [LHV]). Hydrogen production from natural gas via SMR is based on 44.5 kWh/kg H_2 for natural gas in the case of no CO_2 capture, on 45.0 kWh/kg H_2 for natural gas in the case of 60% capture rate, and on 49 kWh/kg H_2 for natural gas and 0.8 kWh/kg H_2 for electricity in the case of a 93% capture rate. Hydrogen production from natural gas via POx is based on demands of 41 kWh/kg H_2 for natural gas and 0.7 kWh/kg H_2 for electricity in the case of a 99% capture rate. Hydrogen production from coal is based on gasification, with demands for coal of 57 kWh/kg H_2 and for electricity of 0.6 kWh/kg H_2 in the case of no CO_2 capture, demands for coal of 59 kWh/kg H_2 for a CO_2 capture rate of 93% and demands for coal of 60 kWh/kg H_2 for a CO_2 capture rate of 98%. Emissions from electricity demand for CO_2 transport and storage are included.

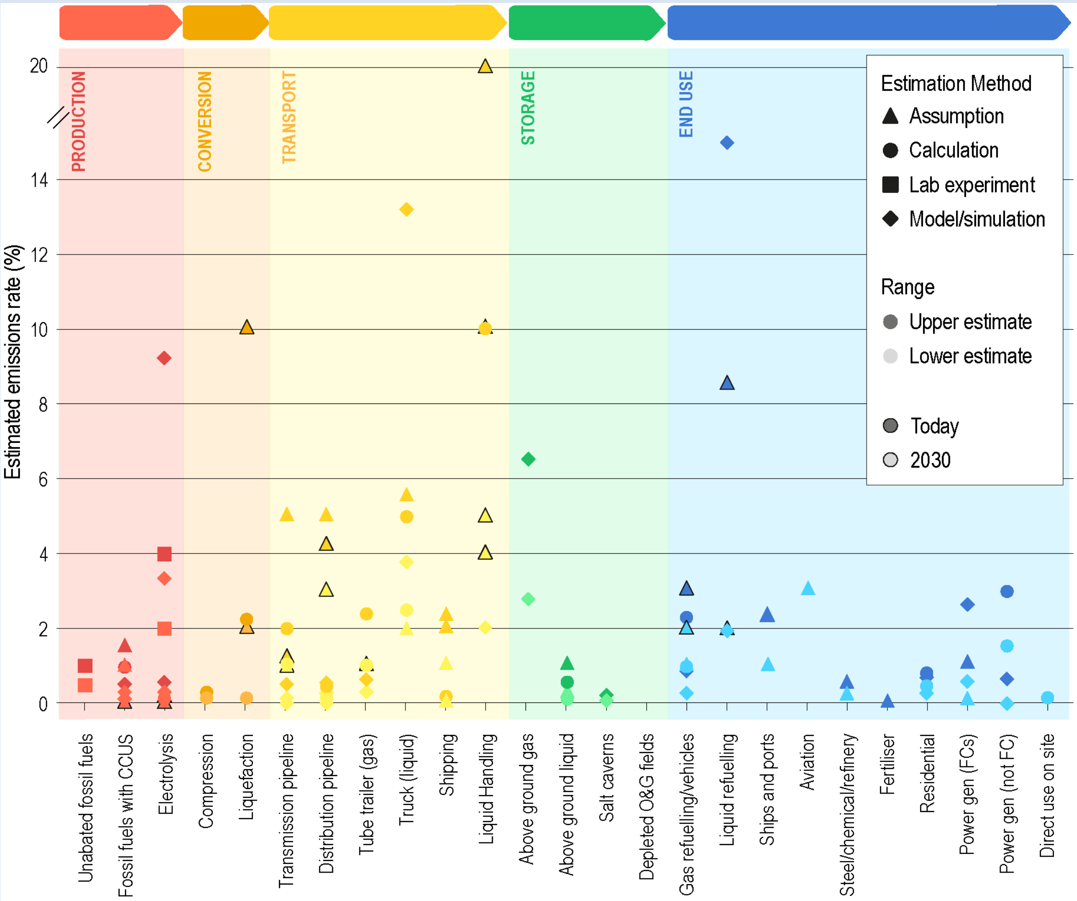
Direct emissions represent the largest share of total emissions for hydrogen production from natural gas and coal, while indirect emissions are the most relevant for electrolysis.

Box 7.1 Potential impact of hydrogen leakage

Hydrogen is an indirect greenhouse gas and its release into the atmosphere (e.g. due to leakage in production, transport and use processes) can lead to climate impacts. There are two main uncertainties regarding hydrogen leakage: the leakage rate at different steps of the supply chain, and the GWP of hydrogen once it has been released to the atmosphere.

The main challenge relating to the leakage rate is that most of the data available is from modelling, rather than field data obtained for existing operating assets, and is largely focused on production. Filling this knowledge gap would require field data or experimental data with actual hydrogen leakage measured along the entire supply chain. The main approach used for modelling is to take leakage rates from natural gas and adjust to hydrogen according to the difference in physical properties. Some of the limited experimental analysis indicates that hydrogen leaks at similar rates to natural gas. Leakage rates* will also depend on the operational practices of the equipment (e.g. venting, purging, boil-off).

Reported potential sources of hydrogen leakage across the supply chain



Note: FC = Fuel cell.
Source: Esquivel-Elizondo, S., et al. (2023), Wide range in estimates of hydrogen emissions from infrastructure, as modified by the IEA.

Hydrogen has an average atmospheric lifetime of 2 (1.4-2.5) years, which means its equivalence over time needs to be calculated to compare it with other GHG and calculate its GWP. Hydrogen does not cause global warming by itself, but has an indirect effect through three mechanisms:

- Hydrogen reacts with hydroxyl radicals, which are the main way methane is decomposed in the atmosphere. This increases the lifetime of methane.
- Hydrogen radicals in the troposphere react with oxygen, thereby producing more ozone (which has a warming effect).
- Hydrogen increases water vapour in the stratosphere (which has a warming effect).

There is a fourth mechanism affecting the formation of (sulphate) aerosols, but this is relatively weak compared to the others. Hydrogen has not yet been included in the IPCC GWP factors, but so far, there have been several fundamental chemistry-transport models assessing its radiative forcing.

Hydrogen GWP values estimated in different literature sources

GWP_{100}	Mechanisms	Source
11.6 ± 2.8	All	Sand et al., (2023)
12.8 ± 5.2 (9.3)	All	Hauglustaine et al., (2022)
12 ± 6	All	Warwick et al., (2023)
11 ± 5 (9.3)	All	Warwick et al., (2022)
3.3 ± 1.4 (3.44)	Tropospheric methane + ozone	Field and Derwent, (2021)
5 ± 1 (3.99)	Tropospheric methane + ozone	Derwent et al., (2020)
4.13	Tropospheric methane + ozone	Derwent et al., (2001)

*Values in parentheses consider harmonisation steps with the same scope as the original studies, and values outside the parenthesis are as reported.

To give a sense of the order of magnitude, if hydrogen were to reach double the leakage level of natural gas (which is about 1%), considering that it is a smaller molecule, and the annual hydrogen flow increases to about 420 Mt by 2050 in line with the NZE Scenario, the hydrogen leakage could be equivalent to about 100 Mt CO_2/yr. This is equivalent to less than 6% of the GHG emissions from gas supply in 2022.

There are efforts underway and planned in the areas of sensor development (improving precision and response time) in the Netherlands, Norway, the

United States; direct measurements (e.g. a research facility in the United States and efforts co-ordinated by the Environmental Defense Fund); and emissions inventories in the Netherlands and the United States. The US DoE allocated USD 8.6 million in FY2023 to six projects developing and validating sensor technologies for hydrogen losses.

More research is needed to better understand both key uncertainties and assess the most cost-effective ways to deal with hydrogen leakage. Furthermore, standards and regulations are needed to manage the reduction of hydrogen leakage and promote transparency and accountability.

*Studies assessing the range of leakage rates by part of the supply chain include CGEP (2022), Cooper et al (2022), Esquivel-Elizondo et al (2023), Frazer-Nash Consultancy (2022), Joint Research Centre (2022), Lakshmanan and Bhati (2024), and Ocko and Hamburg (2022).

Emissions intensities of ammonia production routes

Ammonia production represents about a third of hydrogen demand today. Global production was nearly 180 Mt in 2022, with associated CO_2 emissions of 420 Mt CO_2.[105] Today, about 70% of global ammonia production is from natural gas with the majority of the remainder being from coal (mainly in China). Direct emissions represent more than 80% of the total emissions. Differences in emissions in different regions result from differences in emissions intensity of the upstream and midstream production and in technology performance (efficiency), with a 25-35% difference between the best and worst performers. Ammonia (NH_3) is produced by combining hydrogen with nitrogen from air, and the bulk of emissions are associated with hydrogen production. Since ammonia is a carbon-free molecule, almost all of the input carbon can be captured during the production process, and today about 60% of the CO_2 emissions are typically captured in ammonia plants. Almost none of the captured CO_2 is permanently stored at present, and about 130 Mt CO_2 of the captured CO_2 emissions are then used for urea, and are re-emitted when fertiliser is applied to soils.

Ammonia production from natural gas has a global average emissions intensity of 2.1 kg CO_2-eq/kg NH_3, while use of the best available technology can reduce emissions to 1.9 kg CO_2-eq/kg NH_3 (Figure 7.4). The alternatives to reduce emissions are the same as those discussed for hydrogen regarding the upstream emissions, with the advantage that carbon capture is already part of the process. The capture rate could be increased by targeting the flue gas of the steam boilers, which are the

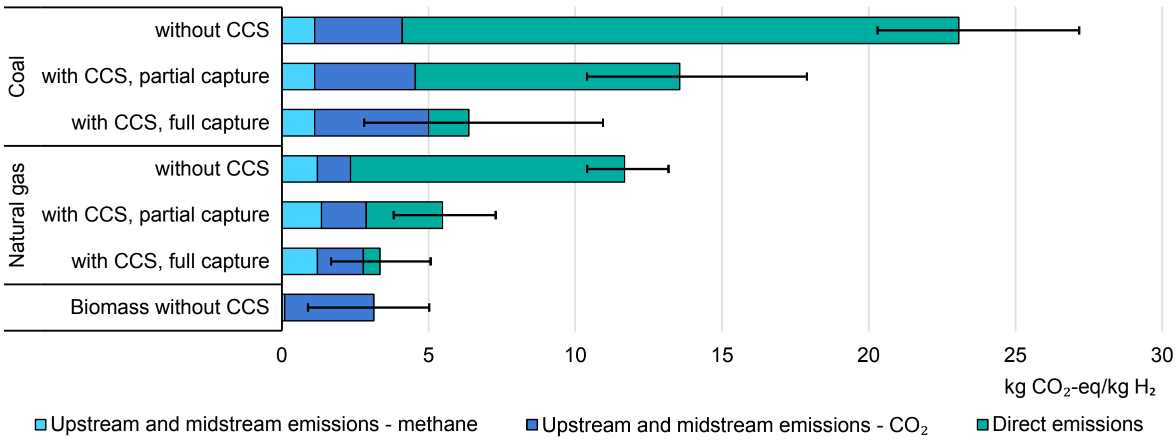
[105] This includes direct emissions and CO_2 used downstream for urea production but excludes upstream and midstream emissions for fossil fuel supply.

second largest CO_2 source, and the CO_2 that is not used for urea could be stored underground. There are also indirect emissions from electricity used in parts of the process, which should also be taken into consideration.

Coal gasification with CCS is another production route for ammonia. The emissions intensity of ammonia production from coal with CCS is in the range of 0.5-2.0 kg CO_2-eq/kg NH_3 (again, depending on the upstream and midstream emissions for coal and electricity supply and the type of coal).

CO_2 emissions associated with the electricity supply govern overall emissions for the electrolytic production pathway. If electricity with global average emissions intensity is used, specific emissions would be almost three times those of production with unabated gas.

Figure 7.4 Comparison of the emissions intensities of different ammonia production routes, 2022



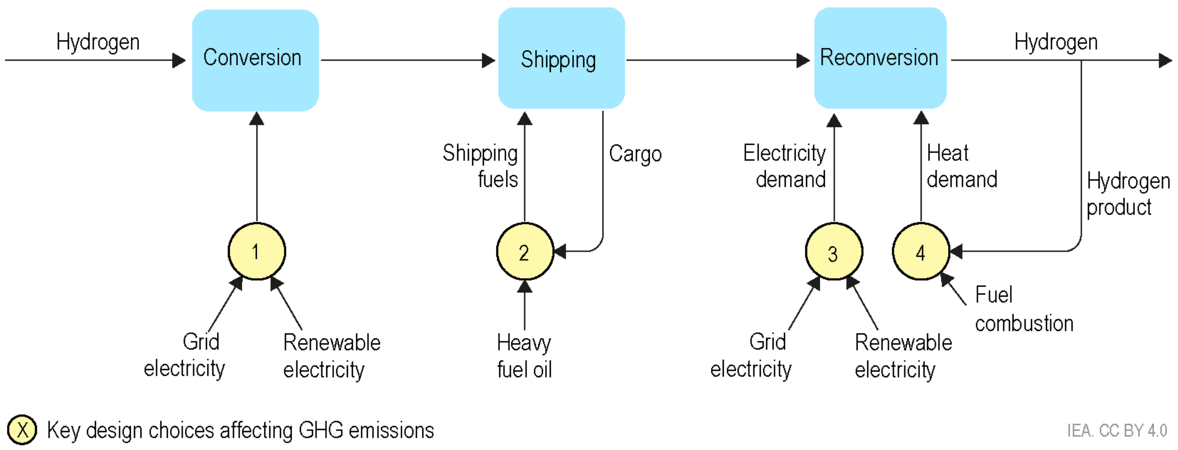
Notes: CCS = carbon capture and storage. Ammonia production from coal is based on coal gasification, while the natural gas route uses steam methane reforming (SMR). Coal with partial capture corresponds to a CO_2 capture rate of 52%, while full capture results in a 93% capture rate. For natural gas, partial capture corresponds to a 75% capture rate, which is an average of the partial capture in an SMR and an autothermal reformer, and full capture to 94%. Error bars reflect the range of upstream and midstream emissions for natural gas, coal and biomass supply. The 2023 world grid average is based on a generation-weighted global average of the grid electricity intensity resulting in 460 g CO_2-eq/kWh. Dashed lines refer to the embedded emissions occurring during the production of onshore wind turbines (12 g CO_2-eq/kWh) and solar PV systems (33 g CO_2-eq/kWh). These embedded emissions are not included in the ISO TS methodology but are part of the mandatory reporting. Electrolysis refers to low-temperature water electrolysis with an assumed efficiency of 67% (LHV).

Emissions from ammonia production from natural gas can be reduced by nearly 70% by using carbon capture with a 94% capture rate.

Emissions intensities of (re)conversion and shipping of hydrogen carriers

As a gas, hydrogen has a low volumetric energy density, and needs to be converted to a form with a higher energy density for transportation over long distances to be economically viable. This process requires energy (and generates emissions), first for conversion to the hydrogen carrier, then for the transport, and then for reconversion of the carrier into pure, high-pressure hydrogen (see Figure 7.5). The carriers that are most commonly considered to enable hydrogen transport over long distances are ammonia, liquefied hydrogen and LOHC. These are also the carriers included in the ISO Technical Specification to date. Other hydrogen carriers that may become available in the coming years include sodium/potassium borohydride and iron oxide powder. Gas pipelines can also be used for transporting hydrogen over long distances, with emissions mainly dependent on the emissions intensity of the electricity used for compression.

Figure 7.5 Hydrogen shipping value chain and design choices affecting GHG emissions



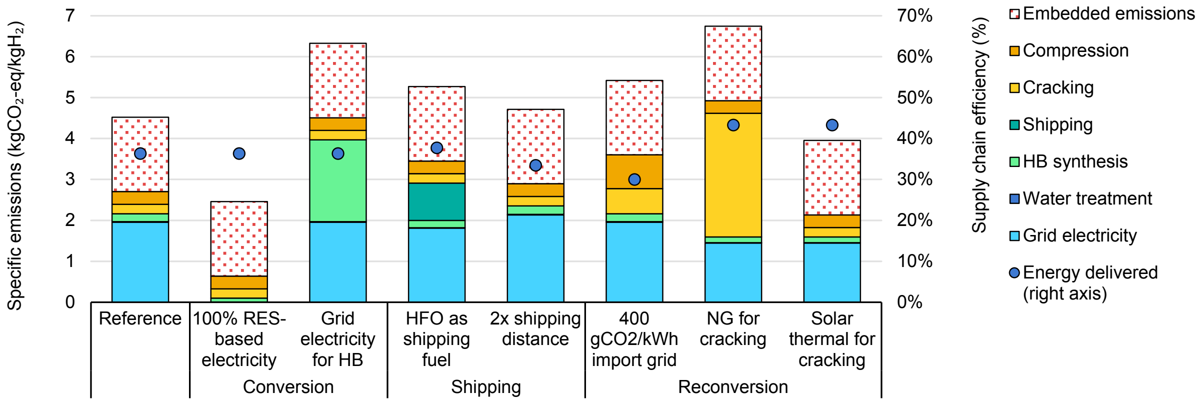
There are four key design choices to be made across different steps in the value chain for shipping hydrogen, and these define the GHG emissions at each step in the process.

Ammonia

The GHG emissions associated with use of ammonia as a hydrogen carrier are determined by different factors across the supply chain (see Figure 7.6). Different cases shown in Table 7.1 demonstrate that individual parameters can change the lifecycle emissions.

The dominant factor in the GHG emissions of ammonia production is the electricity input to the electrolyser. These emissions are directly proportional to the share of electricity that comes from the grid and the emissions intensity of the grid. Meeting only 5% of the electricity input from a grid with an average emissions intensity of 100 g CO_2/kWh would lead to total specific emissions intensity of almost 0.4 kg CO_2-eq/kg H_2. Every conversion step leads to energy losses, which means the energy efficiency of the supply chain is just about 35%. Therefore, any emissions associated with electricity consumption will be increased by a factor of three when expressed in terms of the final hydrogen delivered. These emissions alone would be almost equivalent to the lowest threshold in the production tax credit (45V) in the United States (0.45 kg CO_2-eq/kg H_2). This introduces a trade-off between economic and environmental considerations. From the economic perspective, a small share of electricity from the grid can provide a source of firm electricity and reduce the need to oversize renewable assets and energy storage (either as batteries or hydrogen), but it can lead to higher emissions (in cases where the grid electricity is not low-emissions).

Figure 7.6 GHG emissions intensity for the ammonia supply chain



Notes: HB = Haber Bosch; HFO = Heavy Fuel Oil; NG = Natural Gas; RES = renewable energy sources. The reference case assumes that 5% of the annual electricity consumption of the electrolyser is supplied by the grid and the rest comes from low-emissions electricity sources; ammonia synthesis uses the same average electricity mix as the electrolyser; the shipping fuel is the transported ammonia; and transported hydrogen provides the heat needed for cracking the ammonia. Electricity demand for hydrogen compression to 30 bar (from 1 bar) is included in the import site. Electrolyser efficiency of 66% (LHV) is assumed. Embedded emissions refer to the construction of renewable assets. Upstream and midstream emissions of natural gas included when used as a fuel for ammonia cracking.

The electricity used for the electrolyser and the synthesis unit, and the fuel used for ammonia cracking, are key parameters defining the lifecycle emissions of ammonia.

Table 7.1 Case definition for GHG emissions of the ammonia supply chain

Case	Electricity input (g CO_2/kWh)	Electricity source for Haber Bosch	Shipping fuel	Distance (km)	Import grid (g CO_2/kWh)	Ammonia cracking fuel
Reference	460	RES+Grid	Cargo	10 000	150	Hydrogen
100% RES export grid	**0**	RES+Grid	Cargo	10 000	150	Hydrogen
Grid electricity for HB	460	**Only grid**	Cargo	10 000	150	Hydrogen
HFO as shipping fuel	460	RES+Grid	**HFO**	10 000	150	Hydrogen
2x shipping distance	460	RES+Grid	Cargo	**20 000**	150	Hydrogen
400 g CO_2/kWh import grid	460	RES+Grid	Cargo	10 000	**400**	Hydrogen
NG for cracking	460	RES+Grid	Cargo	10 000	150	**Natural gas**
Solar thermal for cracking	460	RES+Grid	Cargo	10 000	150	**Solar thermal**

Notes: HB = Haber Bosch; HFO = Heavy Fuel Oil; NG = Natural Gas; RES = renewable energy sources. 460 g CO_2/kWh represented the 2023 world grid average based on a generation-weighted global average of the grid electricity intensity. Text in bold represents the parameter changed from the reference case.

Efficiency losses along the supply chain can make embedded emissions in this pathway larger than all the emissions from onsite hydrogen production. These are included in the ISO Technical Specification for information purposes only, but are significant (1.3-2.0 kg CO_2-eq/kg H_2). Besides the electrolyser, the electricity source used for the auxiliary equipment also makes a big difference. A compressor is needed to go from the operating pressure of the electrolyser (1-40 bar) to the operating pressure of the ammonia synthesis (150-250 bar), requiring 0.9-3.8 kWh/kg H_2. Additionally, the air separation unit consumes another 0.5-2.2 kWh/kg H_2. This is an order of magnitude lower than the 50-55 kWh/kg H_2 consumed by electrolysis, but it could result in much higher emissions, given that the compressors are not as flexible as the electrolyser and require closer to 24/7 supply. If the compressors operate only with electricity from the grid, the resulting emissions are 0.4 kg CO_2-eq/kg H_2 for every 100 g CO_2-eq/kWh increase in the emissions intensity of the grid.

In contrast, the emissions intensity of the grid on the importer's side has a much lower influence on the lifecycle emissions. Ammonia cracking is favoured thermodynamically at low pressures and hydrogen needs compression before use. This results in an additional energy consumption of at least 2 kWh/kg H_2 for compressing the hydrogen from 1 bar to 30 bar (at the lower end of typical pressures used for transport by pipeline) and almost 5 kWh/kg H_2 for compression to 700 bar (at the higher end of road transport applications).

Using heavy fuel oil (HFO) as a shipping fuel would result in a specific emissions increase of 0.8 kg CO_2-eq/kg H_2 (for 10 000 km), leading to a net increase of 13% in the specific emissions, despite improving the pathway efficiency by 1.5% points (to 38%). Similarly, the use of natural gas for cracking increases the pathway efficiency by 7% points (to 43%) but increases the specific emissions by 2.8 kg CO_2-eq/kg H_2. Therefore, in both cases, the use of the hydrogen and ammonia transported to provide the energy requirements of different steps of the supply chain leads to lower specific CO_2 emissions, despite the lower supply chain efficiency. Cracking could also be done with waste heat, but would require heat at at least 500°C. Where waste heat is available at this temperature, it is typically utilised locally (either for process heat or power generation) and would therefore need to be replaced, potentially generating additional emissions. Another option is to use solar thermal (coupled with thermal storage), which can achieve temperatures of more than 1 000°C and is not associated with GHG emissions, but could require oversizing to compensate for a lower number of operating hours. In both of these cases, there would still be some emissions from cracking related to the electricity demand.

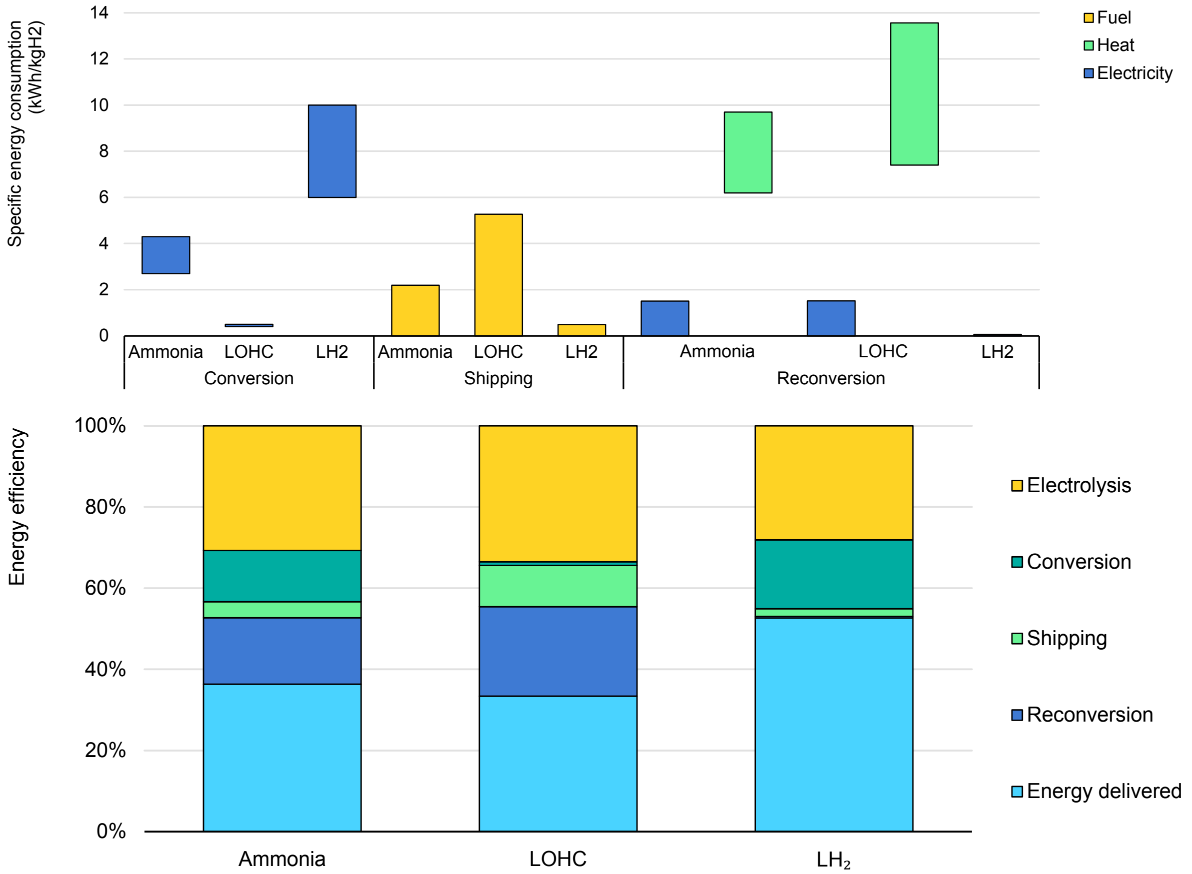
Liquid organic hydrogen carriers

The fundamental difference in emissions intensity for other hydrogen carriers relates to the form of energy used and the part of the supply chain that requires this energy (Figure 7.7). In the case of LOHCs, the first step is to incorporate the hydrogen into the carrier molecule,[106] through a process called hydrogenation, which is exothermic and requires limited electricity. Therefore, there is an energy surplus at the exporting side, which in most cases is assumed to have low-cost renewable energy. The hydrogen content of LOHCs is

[106] The most common molecules considered are benzene, toluene, dibenzyltoluene, benzyltoluene, but a wider range of molecules could be used.

relatively low (0.061-0.072 kg H_2/kg carrier vs 0.176 kg H_2/kg carrier for ammonia), which means a lower amount of hydrogen is transported for the same weight, leading to a higher energy consumption per unit of hydrogen transported in shipping.[107] Similarly to ammonia, LOHC reconversion (i.e. dehydrogenation) requires a significant amount of energy, equivalent to about 35% of the energy contained in the hydrogen molecule.

Figure 7.7 Energy consumption by hydrogen carrier and step in the value chain (top) and pathway efficiency (bottom)



IEA. CC BY 4.0.

Notes: LOHC = Liquid organic hydrogen carrier; LH_2 = Liquefied hydrogen. Bars with a range start from the lower bound instead of the axis. Range of energy consumption captures potential technology improvement to 2050. Values that are expected to change less over time are shown as bars starting from the axis. Values are based on large-scale commercial facilities. Distance of 10 000 km assumed for shipping. Values for LOHC reflect the potential use of different chemical compounds as carriers. Ammonia could be directly used in some applications, which would make the reconversion step unnecessary.

Among hydrogen carriers, ammonia and LOHC require the most energy as heat on the importing side, for reconversion, and liquefied hydrogen is the most energy-efficient pathway.

From a GHG emissions standpoint, the choices to be made about design of the supply chain are similar to those for ammonia. Emissions are lower if the transported

[107] Fuel consumption is proportional to the engine size (power), which is turn proportional to the vessel size in tonnage. In a liquid hydrogen carrier, 100% of the shipping fuel is used to transport the hydrogen, while in an LOHC carrier, only 6-7% is used for this (the other 93-94% is used to transport the carrier). Furthermore, with LOHC, the carrier needs to be transported back to the origin, resulting in additional fuel consumption in comparison to ammonia or liquid hydrogen, which are typically offloaded at the import terminal.

hydrogen is used as a shipping fuel (through onboard dehydrogenation), and as fuel to supply the heat for dehydrogenation at the importing terminal, than if HFO or natural gas are used (Figure 7.8). The GHG emissions for LOHC would be 0.2 kg CO_2-eq/kg H_2 at the importing side for compression and dehydrogenation for every 100 g CO_2/kWh increase in the grid's emission intensity. The rest of the emissions associated with the production route are dominated by the emissions from electrolysis, which is not a differentiator between supply chains. In terms of both total emissions along the supply chain and in efficiency, ammonia results in similar values to LOHC, since the higher electricity consumption for compression at the exporting site is compensated by lower emissions associated with hydrogen recovery from the carrier at the importing site. Unlike LOHC, ammonia can be directly used in some applications, meaning that energy is not needed for reconversion, improving both the GHG emissions and the energy efficiency of the pathway.

Liquid hydrogen

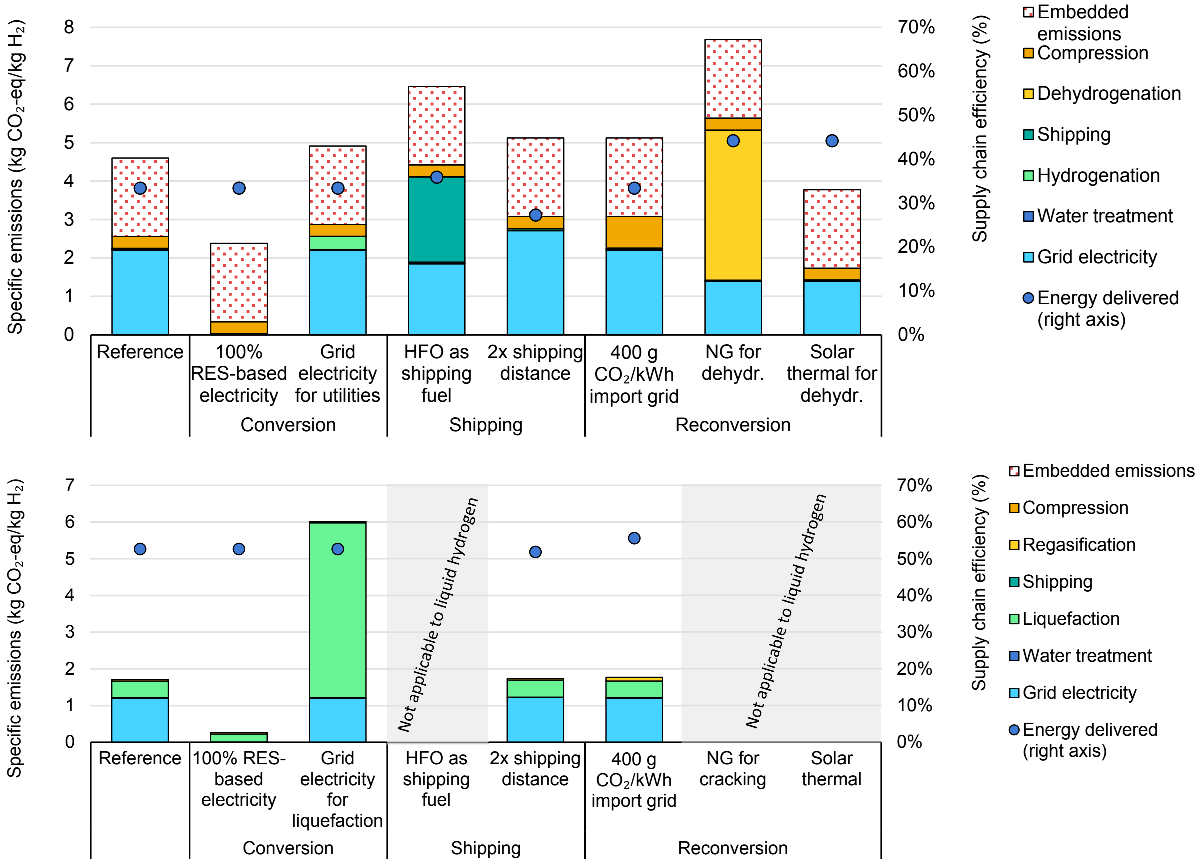
Hydrogen liquefaction requires significant energy (equivalent to 18-30% of the energy contained in the hydrogen), due to its low boiling point (20 K) and associated boil-off losses upon storage and transport. However, its main advantage is that this energy consumption takes place at the exporting side, which is expected to have abundant renewables, meaning low-cost, low-emissions energy should be available. Shipping liquefied hydrogen results in energy losses due to boil-off, but has a low energy consumption at the import terminal since there is no demand for heat nor need for compression.[108] This results in higher supply chain efficiency, which can be 60% higher than that of LOHC (Figure 7.7). However, the high energy consumption for liquefaction means that the source of electricity is critical. With an electricity demand of 6 kWh/kg H_2[109] (mainly for compressors), the emissions from liquefaction are 0.6 kg CO_2-eq/kg H_2 for every 100 g CO_2/kWh increase in the emissions intensity of the grid. This electricity could come from renewables, but this would require a stable supply, as intermittent operation of a liquefaction unit has not been demonstrated. Alternatively, batteries could be used to smooth the electricity input, but would increase costs. For shipping, the hydrogen boil-off from stored liquid hydrogen[110] is sufficient to meet the energy demand of the ship. If more energy is needed (as in the return journey, where the boil-off might not be enough), regasification of additional hydrogen from onboard storage is possible with limited additional costs. In comparison, use of HFO may not be an attractive option since it would increase emissions, energy consumption and costs (due to the need for an onboard re-liquefaction unit).

When these factors are taken into account, the supply chain emissions from liquid hydrogen could be almost 40% lower than those of ammonia or LOHC for similar

[108] A liquid hydrogen pump can be used instead of a compressor which has a much lower energy consumption.
[109] Expected to be the long-term target for liquefaction (currently at 10-12 kWh/kg H_2).
[110] Boil-off rate for commercial vessels is expected to be in the order of 0.1%/day or less.

reference conditions (Figure 7.8), with a large share of this achieved by the higher efficiency (resulting in more final product and lower specific emissions).

Figure 7.8 GHG emissions intensity for liquid organic hydrogen carrier (top) and liquid hydrogen (bottom) supply chains



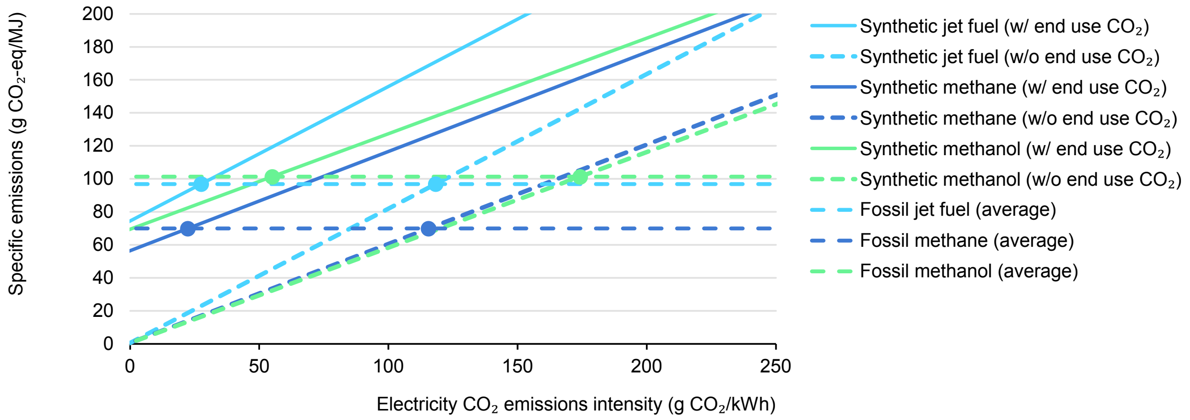
Notes: HFO = Heavy Fuel Oil; NG = Natural Gas; RES = renewable energy sources; Dehydr. = Dehydrogenation. The same set of assumptions and cases are used as in Figure 7.6. “Grid electricity for utilities” assumes that water treatment for electrolysis and for hydrogenation require firm electricity supply from the grid (as opposed to from renewables). Heat demand for dehydrogenation of 12.2 kWh/kg is assumed. Electricity demand for hydrogen compression to 30 bar (from 1 bar) is included in the import site. Electricity demand for hydrogen liquefaction of 10 kWh/kg is assumed. For liquid hydrogen, HFO use for shipping and NG for cracking are excluded, since shipping uses the boil-off from the storage tanks and there is no heat demand associated with hydrogen regasification.

For LOHC, the lowest emissions come from using the hydrogen cargo as a fuel for shipping and for dehydrogenation, while liquid hydrogen has lower emissions overall if there are low CO_2 emissions associated with the electricity used.

Emissions intensity of carbon-containing hydrogen-based fuels

Hydrogen is a versatile molecule that can react with multiple compounds and can be used either as a fuel or as a chemical feedstock. Hydrogen can also be converted to carbon-containing fuels such as methane, methanol or hydrocarbons that can be used directly. Given that these fuels emit CO_2 upon combustion, the origin of the carbon in the fuel is crucial to the overall emissions. If the carbon originates from a fossil source, combustion will make a net positive contribution to CO_2 emissions,[111] and the key question is how to allocate that CO_2 across processes in the supply chain. If the carbon has a biogenic origin or comes from direct air capture, then the fuel combustion does not add to atmospheric carbon, and the key question for carbon accounting narrows down to the emissions associated with the conversion steps.

Figure 7.9 Specific GHG emissions for carbon-containing hydrogen derivatives as a function of CO_2 emissions intensity of the electricity input



Notes: w/ = with; w/o = without. Excludes emissions from construction and manufacturing. Low-temperature direct air capture is assumed using a heat pump with a coefficient of performance of 3 using grid electricity. Compression to operating pressure of the synthesis unit is included. Synthetic fuel "w/ end use CO_2" means that the CO_2 is fossil-based, with CO_2 from combustion having a positive contribution to emissions, while "w/o end use" means the CO_2 is biogenic or from air. Fossil fuel routes include average upstream and midstream emissions and emissions from combustion.

Synthetic fuels need to be produced from electricity with very low emissions intensity in order to have lower emissions than their fossil counterparts.

Conversion to synthetic fuels enables the use of existing distribution infrastructure and end-use technologies, but reduces the supply chain efficiency. The energy efficiency of the synthesis step varies from 57% for synthetic kerosene[112] to 77% for methanation and 86% for methanol synthesis (all exothermic reactions). These

[111] This is incompatible with a net zero emissions system since fossil CO_2 ends up in the atmosphere. The use of fossil CO_2 can still result in emissions reduction since the CO_2 is used twice potentially halving emissions (in case carbon-free energy is used).
[112] Kerosene is co-produced with naphtha and diesel, but the text refers to kerosene only for simplicity. This efficiency includes the product yield of the hydrocracking unit.

efficiency losses translate into lower final product yield, which increases the magnitude of GHG emissions upstream in the value chain.

The two choices about supply chain design with the most influence on the GHG emissions of carbon-containing hydrogen derivatives are the electricity source and the CO_2 source. Figure 7.9 shows the influence of the emissions from the electricity source. The slope is defined by the supply chain efficiency. Synthetic jet fuel is the least efficient, which means every CO_2 molecule emitted upon electricity production is multiplied by a factor of 2.5-3 when expressed in terms of the energy in the product. For synthetic methanol and synthetic methane,[113] while methanol has a higher efficiency for the synthesis step, additional energy is required for compression, since the synthesis operates at higher pressure than methanation (50-150 bar vs 10-70 bar), resulting in a similar slope for both pathways. Considering the range of upstream and midstream GHG emissions from oil and gas production, synthetic jet fuel and methane would equal the emissions of their fossil counterparts when the emissions intensity of the electricity input is 95-140 g CO_2-eq/kWh. Synthetic jet fuel and methane have a similar point of intersection, given that the lower conversion efficiency and higher CO_2 consumption per MJ of product of jet fuel compared to methane is compensated by higher emissions of the fossil fuel reference. For methanol, the electricity emissions intensity required to breakeven with the fossil fuel reference is higher, at 160-190 g CO_2-eq/kWh, due to the higher efficiency and lower (than Fischer-Tropsch) CO_2 use. These values represent the upper bound and best case for synthetic fuels. The breakeven points would be lower if the CO_2 source were fossil-based with full allocation to the synthetic fuel. In this case, the CO_2 emitted upon combustion would be the same for both fossil and synthetic routes. As such, for the synthetic fuels to have lower emissions than fossil fuels, the emissions associated with the CO_2 capture, compression and water treatment of electrolysis would need to be lower than the upstream emissions from oil and gas. This would shift the breakeven points to 5-50 g CO_2-eq/kWh for methane and jet fuel, and 40-70 g CO_2-eq/kWh in the case of methanol. The effect on emissions of other design choices, such as the technology used to supply the heat for carbon capture, will be dependent on the temperature level and heat demand. Heat demand can be nearly zero for processes with concentrated CO_2 streams, such as ethanol or ethylene oxide, going up to 5.3-7.2 GJ/t CO_2 for direct air capture.

Alternatives for the carbon accounting of the CO_2 source

There are two related, but different, key questions for CO_2 emissions accounting. The first relates to the process of sourcing the CO_2, and how the emissions from that process are allocated to the CO_2 stream that is used for the synthetic fuel alongside other products (e.g. electricity) from the same facility. In addition, given that the hydrogen-based fuel is combusted, and the CO_2 is released to the atmosphere, the

[113] Synthetic fuels are also known as e-fuels and include methane, methanol and kerosene (jet fuel), and are a subset of hydrogen derivatives (which also include use as feedstock).

second key question concerns how those emissions are allocated among the stakeholders of the value chain. This section explains both aspects and suggests some alternative options to deal with them.

Allocation of emissions associated with the CO_2 source

The key factors that define GHG emissions accounting for synthetic fuels are the boundaries of the system and the methodological approach used. With regards to boundaries, the options are gate-to-gate (excluding both raw material processing and downstream fuel use), cradle-to-gate (which expands the scope to the raw materials), and cradle-to-grave (which expands the scope to the product use as well). The suggested scope for carbon capture and use applications is cradle-to-grave, but a smaller scope (cradle-to-gate) might be justified in cases where the downstream emissions, technical performance, and end-of-life are identical and the purpose of accounting is to compare different routes.[114] In practical terms, this means that on the supply side of synthetic fuels, the CO_2 used should not be considered as having negative emissions (under the assumption that it is being consumed in the process). Instead, it should be treated in the same way as any other process feedstock, with the emissions associated with its production accounted for in the stream. This is especially important when the CO_2 source is from fossil origin, resulting in net positive CO_2 emissions. Even for biogenic CO_2 sources, the CO_2 used should be counted explicitly at each stage of the life cycle since, for example, in methanation or synthetic kerosene, part of the CO_2 input might end up being released as fugitive methane, which has a higher GWP than CO_2. This may be overlooked if it is assumed that the CO_2 input is equal to the amount that will be emitted later.

The CO_2 source will, in most cases, have been produced as a result of processes that have multiple useful products.[115] For example, cement plants with CO_2 capture emit CO_2 along with the cement (Figure 7.10). This raises the question of how to allocate the CO_2 emissions of the cement plant across its different products (cement, captured CO_2, electricity), with methodological approaches typically using one of two fundamental options:

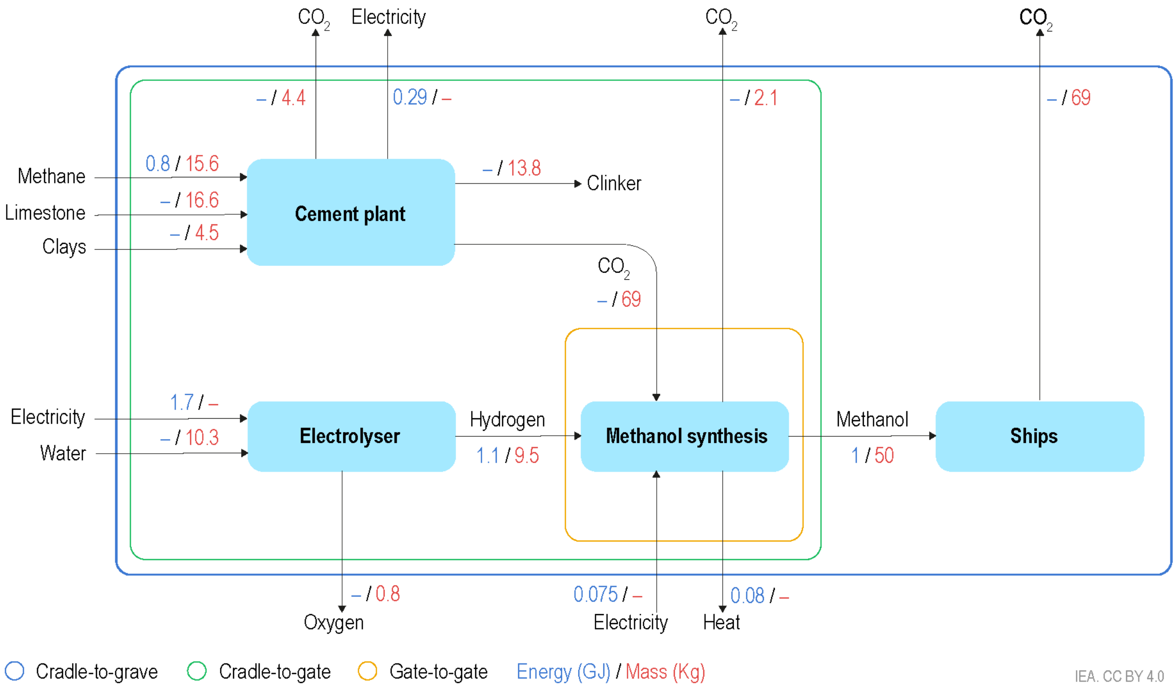
- **Attributional methodology**: Quantifies the environmental impacts of a product or service over its lifecycle as a part of a current system. Total CO_2 emissions from a process are allocated among the products in proportion to their energy content, mass or economic value.
- **Consequential methodology**: Quantifies the environmental impacts of a change in the system. It includes indirect effects and considers the consequences beyond the system under study.

The suggested approach from an LCA perspective is to use a consequential approach and expand the boundaries of the system analysed to include the upstream

[114] This does not mean that the fuel production is considered as CO_2 storage, but it means that the end use phase is out of scope since it does not make a difference when comparing pathways.
[115] Direct air capture is the only exception where CO_2 is the only product.

CO_2 production. This solves the problem of allocation method among products since now all the products are included in the functional unit.[116] Other minor by-products that are not part of the functional unit can still be considered by using the environmental burden avoided from their counterfactual production (i.e. substitution). Expanding the boundaries of the system solves the challenge of accounting for products that have multiple functions, but it may be more difficult to implement in regulation, given that it cuts across processes. The ISO Technical Specification for hydrogen provides guidance in this respect and suggest a hierarchy of steps to follow.

Figure 7.10 Alternative boundary definitions used to account for GHG emissions from methanol using CO_2 sourced from a cement plant



Notes: Some steps are omitted in the figure for simplicity, including methane production and processing, CO_2 transport and water treatment for electrolysis, but should be part of the emissions embedded to the various streams. The additional heat stream for CO_2 capture in the gas power plant is not included, assuming that heat can provided by steam generation in the plant at the expense of lower electricity production. Assuming 94% CO_2 capture for the cement plant. Heat released in methanol synthesis based on direct CO_2 use. Heat and mass balance for the cement plant (integrated with power generation) from IEAGHG (2013).

The choice of boundaries of the system can have a large impact on the GHG emissions considered for the product.

[116] This is usually the output of the process of interest, and it represents the basis used for expressing the emissions.

Table 7.2 GHG emissions for methanol production based on different methodological approaches and boundaries

Case	Approach	GHG emissions (g CO_2-eq/MJ)	Comments
Gate-to-gate	-	-66.9	High negative emissions since the emissions from the raw materials and downstream use are not included.
Cradle-to-gate	Allocation – Economic value	4.2	Only a fraction of the lifecycle emissions, since the use phase is not included. About 45% of the emissions from the cement plant are allocated to the captured CO_2 stream.
Cradle-to-gate	Allocation – Energy balance	2.1	Since the captured CO_2 and cement streams do not have energy content, all the CO_2 emissions from the cement plant are allocated to the electricity output that is co-generated with the cement.
Cradle-to-gate	Allocation – Mass balance	5.8	Since electricity does not have mass, the CO_2 emissions are distributed between the cement product and the captured CO_2 output.
Cradle-to-grave	System expansion with new functional unit	58.6	All the emissions are included, and the functional unit is expanded to cover the electricity (1 GJ of methanol plus 0.29 GJ of electricity).

Notes: Economic value considers an electricity price of USD 70/MWh, a CO_2 price of USD 80/tCO_2 and a cement price of USD 55/t. Values consider avoided burden from co-products assuming heat from a natural gas boiler with 90% efficiency is displaced and specific emissions from oxygen production of 240 g CO_2 per kg of oxygen. Electricity from the grid (for methanol synthesis) assumes a grid emissions intensity of 250 g CO_2-eq/kWh.

Using the approach of system expansion to cover a new functional unit and avoided burden (as shown in the last row of Table 7.2) provides more room for different results. For example, the electricity could be assumed to displace the average electricity mix in the grid on an annual basis, for a specific period, or from a specific power generation technology. The definition of the functional unit is also key. For example, if the functional unit changes to one unit of electricity, a CO_2 benefit could be taken for the avoided burden for the methanol production (presumably from natural gas without capture). This highlights the importance of the design of the regulation and the need for harmonisation across countries to ensure differences in these methodological choices do not become a barrier for trade.

The choice of the approach used is not only a matter of methodology, and could also be influenced by national regulation. For example, the EU Emissions Trading System (ETS) does not favour CO_2 use, and considers the CO_2 to have been emitted when it is used (e.g. for synthetic fuels). A review of the ETS is due in 2026, in which the European Commission expects to assess in more detail the case where CO_2 is used for non-permanent products (such as carbon-based fuels). It will also assess if the accounting should be done at the point of emission to the atmosphere (i.e. downstream accounting), or when the CO_2 is initially captured (upstream accounting). Under the Renewable Energy Directive, synthetic fuels with CO_2 sourced from power plants are only allowed until 2035,[117] whereas those with biogenic CO_2 or CO_2 from direct air capture are allowed for the entire period to 2050. Another example is from the United Kingdom, where an allocation method based on energy is proposed as a way of allocating the emissions of processes that produce synthetic fuels and other co-products.

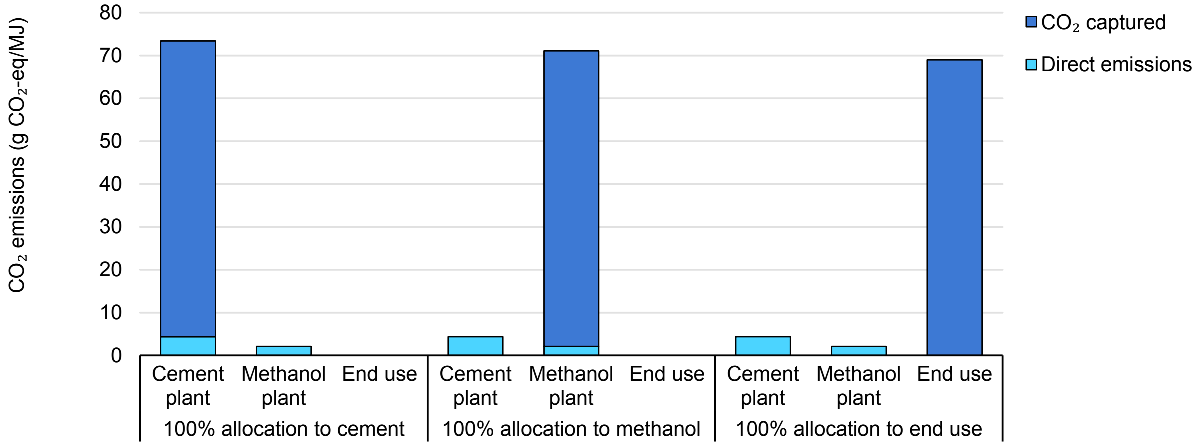
Allocation of CO_2 emissions among stakeholders in the supply chain

In the example of methanol used above (Figure 7.10), allocating the CO_2 emissions from the final use of methanol in ships among stakeholders can make a big difference for each stakeholder in the value chain, since other emissions are relatively small. The emissions could be allocated to the process that originally produced the CO_2 (in the example above, the cement plant) under the logic that since CO_2 is not being stored, then no benefit can be taken by such facility. This is the approach used, for example, in the EU ETS. This would mean higher emissions for this step, since the carbon capture unit consumes additional energy. The result would be an increase of more than 16 times the emissions allocated to that step, in comparison to the case where all the emissions are allocated to another step in the supply chain (Figure 7.11).

The emissions could also be allocated to the synthetic fuel plant, under the logic that if there is no certification scheme in place to differentiate between the low-emissions and carbon-intensive commodities, the synthetic fuel should receive the penalty for the fuel that is combusted downstream. Allocating the emissions to the end use in this way results in the largest difference for different stakeholders, since there are no other emissions produced by this process other than those from combustion. Allocation to this step could be justified under the "polluter pays" principle.

[117] Other ETS facilities (like cement) are allowed until 2040.

Figure 7.11 The result of alternative approaches to allocating the CO_2 emissions from synthetic fuel combustion



There are several ways of allocating the CO_2 emissions from fuel combustion among stakeholders in the supply chain, with significantly different results.

The way that emissions are allocated should also be considered in light of the distribution of the price premium for producing a commodity with lower lifecycle emissions.[118] For example, if the emissions are fully allocated to the end use, but the price premium is received by the synthetic methanol producer, it would result in the same emissions for the end use (as fossil fuels), but with higher operating costs. There must therefore be alignment between these two parameters to ensure that the economic incentives for each stakeholder in the supply chain are sufficient to encourage the shift to the synthetic pathway.

It should be noted that Figure 7.11 shows the extreme cases, and any combination in between is possible. The actual percentages could differ not only across regions, but also over time and technology pathway. These allocation factors could be set by policy makers as part of the regulatory framework for synthetic fuels (or more broadly, for CO_2 use) or be defined by private actors through negotiations for specific projects and applications.

Using different approaches for CO_2 allocation across national regulatory frameworks, both with regards to the CO_2 source and the stakeholders across the value chain, can create a barrier to trade of these carbon-containing products. Producers will need to comply with and certify their products against different regulatory requirements, increasing the complexity of the process and the transactional costs. This highlights

[118] Assuming that the end user is willing to pay for the lower emissions associated with the commodity. This allocation does not refer to the emissions from a single multi-functional process, but instead the allocation among different sequential steps of a supply chain.

the importance of international co-operation on the matter, in the same way as is currently happening for the certification of hydrogen (see Chapter 6. Policies).

Effect of temporal correlation on GHG emissions

Many countries are now defining additional criteria for hydrogen to be classified as renewable, clean or low-carbon and for project developers to apply for funding schemes or other types of policy support. These are most critical for the electrolytic pathway, where most of the emissions are upstream. The most common rules relate to the additional character of the renewable electricity, and the geographical and temporal correlation of hydrogen production and renewable electricity. All these considerations aim to ensure that when the electrolyser uses renewable electricity it does not result in higher emissions from the grid by triggering additional fossil generation.

Policies relating to temporal correlation will need to factor in certain trade-offs. The strictest framework is hourly correlation, which aims to support the use of renewable electricity and emissions reduction. However, this could lead to a cost premium, either due to the need for batteries to ensure a steady supply of electricity, or as a result of lower utilisation of the electrolyser. At the other extreme, annual correlation leads to a lower production cost, but it means, for example, that electricity from solar PV in summer can be claimed to power the electrolyser during a night in winter, a period in which the actual electricity going into the electrolyser could be from fossil generation.

Countries have so far adopted a gradual approach to temporal correlation. In the European Union, monthly correlation is allowed until 2030, with hourly correlation afterwards.[119] In the United States, the draft 45V guidance proposes annual correlation until 2027 and hourly afterwards. In the United Kingdom, 30-minute correlation is used to determine the nature of the electricity consumed in the electrolyser. Australia requires annual rather than hourly correlation (and does not have requirements for additionality), in order for production to be eligible for a tax incentive, noting that compliance will increase operating costs for projects. Similarly, the production-linked incentives from India do not need to comply with any temporal correlation (or additionality) conditions.

A Power Purchase Agreement (PPA) can be a way to procure renewable electricity when connected to the grid. These can take the form of a physical PPA, where the electricity producer and the electrolyser are in the same bidding area, or a financial PPA, where there is no need for a physical connection. Regulation might prevent the use of financial PPAs, or mandate PPAs as a requirement to ensure that electrolysers use renewable electricity. For example, a PPA is not needed in the European Union

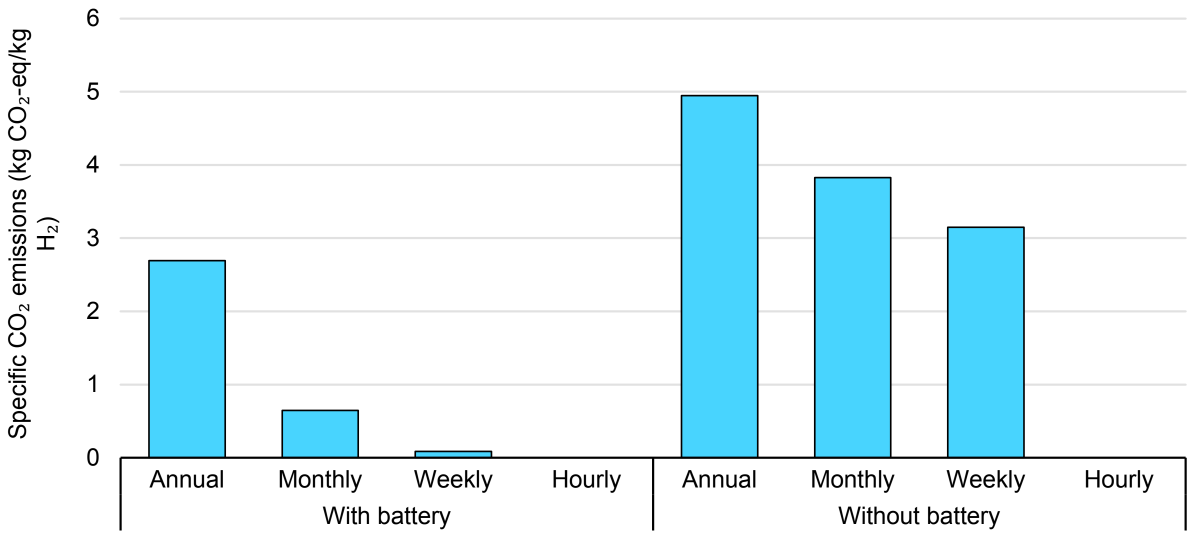
[119] Hourly correlation is not needed for areas with more than 90% renewables over the previous calendar year and when the project integrates renewables, and it is reducing curtailment.

when the electrolyser is integrating electricity that would have otherwise been curtailed, or when the bidding zone had more than 90% renewable electricity in the previous calendar year, but is required in all other cases.

Figure 7.12 shows the effect that temporal correlation could have on the CO_2 emissions from hydrogen production for a sample location in Chile, using the hourly average grid emissions from 2023. In this example, electricity from fossil generation accounts for almost 45%, hydropower and biofuels close to 30%, and the remainder from wind and solar PV. With annual correlation, the renewable assets can be oversized, injecting electricity to the grid and compensating for the grid electricity used in periods of low renewable generation. As the temporal correlation becomes stricter, the specific emissions fall, since it narrows down the options to shift around the renewable electricity (e.g. weekly correlation would not allow for solar PV generation in summer to be used in winter, which is possible under an annual correlation).

Batteries enable lower emissions for two reasons. First, they allow electricity to be stored when renewable generation is the highest, and when the emissions in the grid are the lowest, in order to then be used during times when renewable generation is lower and CO_2 emissions are higher. This then allows hydrogen to be produced during hours when renewable generation is low, when the emissions intensity of the grid is higher, and the CO_2 penalty for using grid electricity for the electrolyser would the highest.

Figure 7.12 CO_2 emissions intensity of hydrogen production with a variable time horizon for temporal correlation, Chile



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Notes: Example at a location in the Atacama Desert in Chile with a capacity factor of 38.5% for solar PV (with 1-axis tracking) and 38.4% for onshore wind. Assumed 50/50 split for the renewable capacity. Battery size of 6 hours for the annual correlation. Electricity surplus to electrolyser demand is assumed to be exported to the grid, with the CO_2 credit based on the grid electricity displaced and varying depending on the average grid emissions factor.

The temporal correlation criteria for renewable generation and hydrogen production can have a large influence on CO_2 emissions from hydrogen production.

The specific additional CO_2 emissions for a less strict temporal correlation will vary depending on the specific electricity mix, the quality of the renewable resources and capacity ratios between the assets. However, additional criteria beyond scope and methodology are also important, given that depending on the accounting rules used, the hydrogen produced by the same assets could appear to have different emissions (Figure 7.12).

Previous research[120] has mixed conclusions depending on the assumptions and boundary conditions. The specific effect of the temporal correlation on production and system cost, as well as facility-level and system emissions will depend on the specific electricity system and market design. Some of the most influential factors are:

- The flexibility of the hydrogen demand to follow renewable production profiles, or alternatively, the availability and cost of hydrogen storage capacities.
- The presence of other flexibility alternatives for the power system (e.g. interconnection, batteries, demand response), which will affect how critical electrolysers are as a source of flexibility.
- Cost factors, such as carbon and fuel prices on the supply side, and the willingness to pay for the renewable hydrogen on the demand side, since these will affect both the electricity mix and the electricity price point at which running the electrolysers is economically attractive.

With these factors in mind, there are several choices to made when designing policies relating to temporal correlation:

- The use of marginal or average emissions when considering the electricity used from the grid and the default emissions factors for GHG calculation.
- How the temporal correlation is implemented. So far, schemes have opted for the balancing to be done on a net energy basis.[121] Another option is to use a carbon basis, and ensure that all the CO_2 produced by the electricity withdrawn from the grid is fully compensated (within the temporal horizon defined), regardless of the net electricity balance.
- Any additional conditions, including exemptions, with a view to market development. There is a trade-off between increasing complexity, which might make compliance (and, therefore, project development) more difficult, and the benefit of covering a broader range of cases and ensuring the use of renewable energy and – more importantly – decreasing emissions. Additional conditions can include renewable energy shares, emissions intensity thresholds, electricity prices, or full-load operating hours of the electrolyser.
- In addition, as the power system is increasingly decarbonised, the electricity grid and its emissions will change. Given the difference between the timeline for grid

[120] See for example: Brauer et. al (2022), Deloitte (2024), Frontier Economics (2021a), Frontier Economics (2021b), Giovanniello et al (2024), Ricks et al (2023), Ruhnau and Schiele (2023), Schlund and Theile (2022).

[121] Every MWh taken from the grid has to be replaced with a MWh of renewable electricity at another point in time within the window of the temporal correlation defined. This might lead to the case where the net emissions are positive despite the net zero balance of energy.

decarbonisation (5-10 years) and the typical time horizon for projects (25+ years), any policy should provide clarity on the evolution of these parameters over time. This will also provide greater clarity for investors.

This long list of considerations for policy design shows the importance of harmonisation of accounting methods and criteria. This is not only critical for national emission inventories, and to avoid double counting,[122] but also for the private sector, to reduce the administrative burden associated with having to navigate multiple schemes with different rules, and ultimately facilitating project investment and execution.

[122] This is relevant when hydrogen is traded across jurisdictions. For example, the exporting country might use an hourly emission intensity based on actual electricity mix, while an importing country might use an average annual value for the previous year. The emissions accounted in each national inventory will not match and there could either be double counting or some emissions that are not accounted for.

Chapter 8. Latin America in focus

Highlights

- Latin America and the Caribbean (LAC) is well-placed to produce low-emissions hydrogen and its derivatives, building on its abundant natural and renewable energy resources and largely decarbonised electricity mix (of which 60% comes from renewables). In 2023, hydrogen demand in the region reached 4 Mt, mostly for use in oil refining and chemicals manufacturing. Almost 90% is produced using natural gas, which contributes to the region's reliance on imports.
- Today, 80% of nitrogen-based fertiliser demand is met by imports, with a trade deficit equivalent to up to 0.4% of GDP. Domestic low-emissions ammonia production could reduce this deficit and improve price stability. LAC holds one-fifth of the world's iron ore reserves, with high-grade ores suitable for hydrogen-based direct reduced iron (H2-DRI). In some world regions, importing hot briquetted iron from LAC instead of iron ore could cut the cost of reduced iron by almost a third.
- Opportunities differ by country. Mexico and Colombia, for example, could leverage large existing hydrogen demand from refineries. Chile's mining sector could use low-emissions hydrogen to decarbonise operations, such as for the production of ammonium nitrate for industrial explosives and for heavy machinery. Brazil accounts for 90% of iron ore trade from LAC and is therefore uniquely positioned to develop H2-DRI for steelmaking. The country's biogenic CO_2 resources are more than sufficient to meet domestic needs for synthetic fuels and urea, opening up export potential. Panama could become a hub for low-emissions shipping fuels and is already targeting 5% of bunkering from hydrogen derivatives by 2030.
- Deployment is still nascent. Based on announced projects, LAC could produce over 7 Mtpa of low-emissions hydrogen by 2030, but only about 0.1% of these projects is in operation, under construction or has reached a final investment decision (FID). The high cost of capital in the region remains a barrier, and could undermine the competitive production costs from its strong renewable resources. In addition, a massive expansion of renewable capacity would be needed – if all hydrogen projects in the pipeline come to fruition, wind and solar PV generation would need to increase by 140% within this decade for hydrogen production alone.
- Action is required in the short term to unlock LAC's potential, balancing domestic demand with export ambitions. Demand creation measures can help close the cost gap, improve energy security by reducing imports of natural gas and ammonia, and create higher value-added export opportunities. Hydrogen hubs can drive economies of scale and integrate supply chains while accelerating learning.

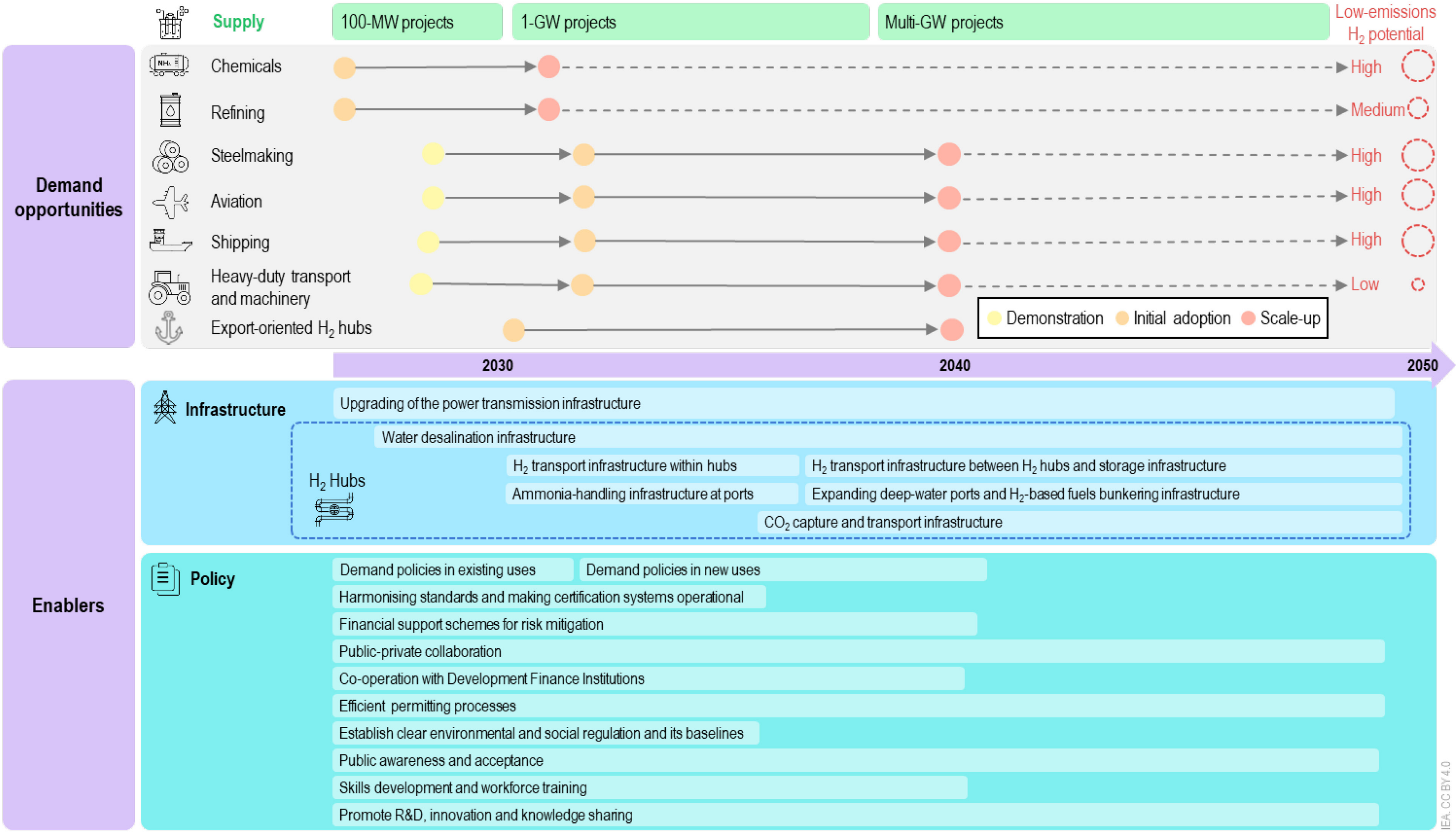
Unlocking the potential of low-emissions hydrogen in Latin America and the Caribbean

In November 2023, the IEA published an in-depth and comprehensive assessment of Latin America and the Caribbean (LAC), the Latin America Energy Outlook. With abundant fossil fuels, renewable energy resources and critical minerals, LAC is well positioned to thrive in the global clean energy transition. The Outlook explores the opportunities and challenges the region faces in meeting its energy and climate goals, while highlighting its opportunities in the global energy system, including for low-emissions hydrogen. Building on these findings, this edition of the Global Hydrogen Review updates and expands the discussion on the potential role of low-emissions hydrogen production and demand, as well as export opportunities as LAC advances towards its energy and climate goals.

As we show in this chapter, low-emissions hydrogen represents a significant opportunity for LAC to meet its climate targets while generating economic growth for the region. Fully realising this potential will hinge on the timely implementation of supportive policies and strategies. Several governments in the region have already laid out their hydrogen strategies, and some have even begun the implementation process. However, many of these plans were developed at a time when there were high expectations for rapid deployment and cost reductions, despite the uncertainties surrounding hydrogen. It was anticipated that low-emissions hydrogen would scale up quickly, catalysing the development of a global hydrogen market, and the plans are therefore strongly focused on exports.

While the sector has made notable progress in recent years, as this report shows, the pace of development has fallen short of initial expectations. This discrepancy highlights a need to recalibrate the aspirational targets and priorities set out in national hydrogen strategies, and to adopt a balanced approach between domestic opportunities and export ambitions. Countries in the region can still adjust their plans, especially as many of the measures outlined in the strategies have yet to be translated into concrete policies.

Figure 8.1 A roadmap for the development of the low-emissions hydrogen sector in Latin America and the Caribbean



Focused policy action, infrastructure development and the creation of an enabling environment can help Latin America and the Caribbean to tap into the long-term economic and climate benefits that could be offered by low-emissions hydrogen.

Overview

Latin America and the Caribbean accounts for 7% of the world's gross domestic product (GDP) and 8% of the world's population. In 2023, LAC accounted for 10% of world oil production, 5% of natural gas and 1% of coal. While the region is now a net exporter of oil and coal, it is a net importer of natural gas. Globally, natural gas production has increased by 30% since 2010, but production in LAC has fallen by 2%. Regional demand for natural gas increased by 14% over the same period, resulting in a persistent trade deficit in natural gas.

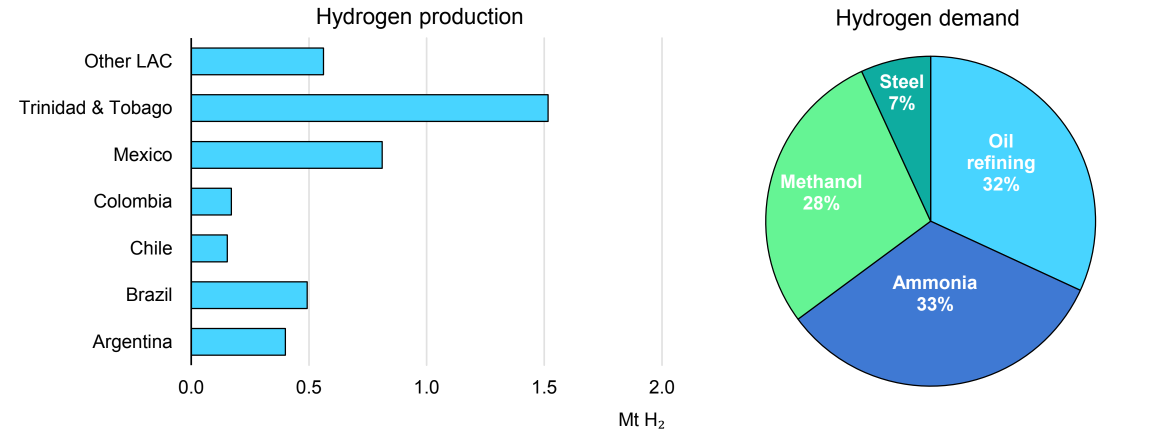
LAC generates about 6% of the world's electricity, more than 60% of which comes from renewable sources,[123] double the global average of 30%. While the region's share of wind, solar PV and geothermal energy is similar to the global average, its share of hydropower is far higher, accounting for more than 40% of electricity generation, compared to about 15% globally. Over the past 15 years, hydropower generation in LAC has remained stable, but its contribution to the overall electricity mix has fallen from over 50% in 2010 due to the overall increase in electricity generation. Despite this, the total share of renewables has increased, driven by significant growth in solar PV and wind generation, particularly in the last 5 years.

Hydrogen production and demand

In LAC, demand for hydrogen reached about 4 Mt in 2023, approximately 4% of the global total of 97 Mt. The majority of demand occurs in the five largest economies: Argentina, Brazil, Chile, Colombia and Mexico, as well as Trinidad and Tobago (Figure 8.2). The latter is the leading hydrogen consumer in LAC due to its chemical industry, which uses hydrogen to produce large volumes of ammonia and methanol for export. In most other LAC countries, oil refineries are the primary consumers of hydrogen. Over the past decade, a decline in oil refining has reduced total demand for hydrogen across the region, as have recent difficulties in securing natural gas at competitive prices for ammonia production, which in 2019 led to the complete shutdown of ammonia production in Mexico and the closure of the only remaining plant in Brazil.

[123] Renewables includes geothermal, hydropower, marine, modern bioenergy and renewable waste, solar and wind.

Figure 8.2 Hydrogen production by country and demand by industrial sector in Latin America and the Caribbean, 2023



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Note: LAC = Latin America and the Caribbean.

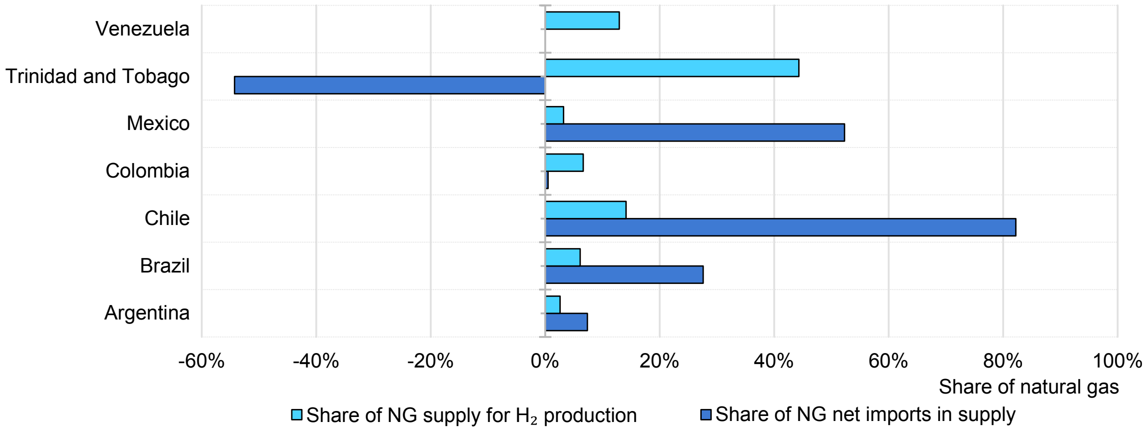
Hydrogen demand reached 4 Mt in LAC in 2023, about 4% of the global total, mostly for oil refining or – especially in Trinidad and Tobago – for chemicals manufacturing.

Today, hydrogen production in LAC consumes approximately 1.5% of the region's total energy supply and accounts for 2% of the total final energy consumption.[124] Almost 90% of this hydrogen is produced by steam reforming of natural gas, resulting in annual emissions of more than 30 million tonnes of CO_2 equivalent (Mt CO_2-eq).[125] In Trinidad and Tobago, more than 40% of natural gas consumption is used to produce hydrogen. In the rest of LAC, this share ranges from 3% to 14% of domestic demand (Figure 8.3). However, if only natural gas imports were considered, the share used for hydrogen production would be higher for most countries. In Brazil, for example, hydrogen production was equivalent to 22% of the country's natural gas imports in 2022, as the country imported nearly 30% of its natural gas demand.

[124] Including non-energy uses, such as the use of hydrogen as a feedstock for chemicals.

[125] This includes direct emissions from hydrogen production and around 15 Mt of CO_2 utilised in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions from fossil fuel supply.

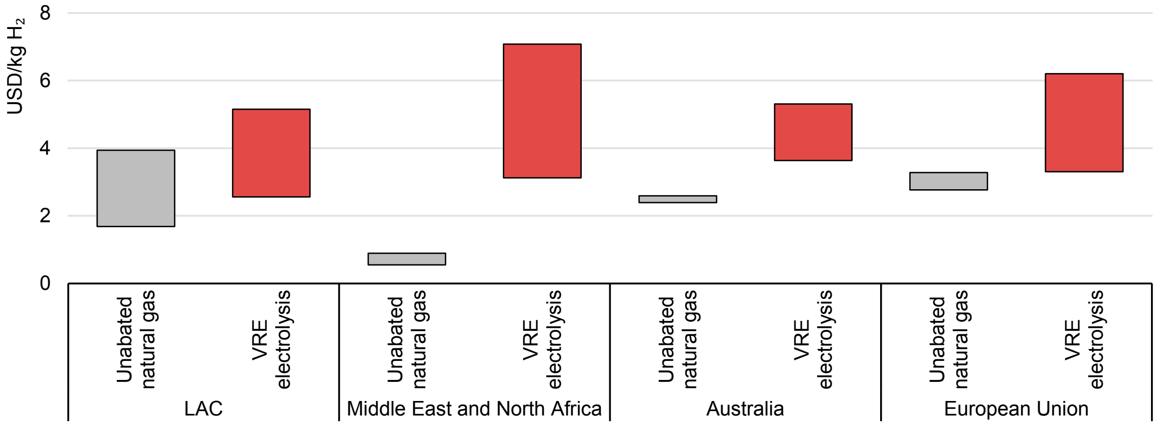
Figure 8.3 Natural gas dedicated to hydrogen production in Latin America and the Caribbean, 2022



Hydrogen production consumes 3-14% of the domestic natural gas use in LAC, with the exception of Trinidad and Tobago, where it accounts for more than 40%.

The region covers about 15% of the Earth's land surface, stretching from the north of Mexico to the southern tip of Patagonia, and is rich in natural resources. Renewable energy represents a major opportunity, given the region's extensive coastlines with strong winds, high solar irradiance, substantial geothermal potential in areas with active volcanic activity, and mighty rivers. With its abundant and cost-competitive renewable energy resources, LAC is well positioned to produce low-emissions hydrogen, which could even be cheaper than domestic natural gas-based production, as it is a net natural gas importer and has higher natural gas prices than regions that are major exporters, meaning that the cost gap would be smaller (Figure 8.4). With ambitious policies and decisive action, the region could reap the benefits of this renewable energy potential, using low-emissions hydrogen production as a catalyst for job creation, more productive industry, and ultimately, greater development. To achieve competitive low-emissions hydrogen production costs, the cost of capital in the region must be comparable to other parts of the world. Without appropriate risk mitigation measures, a higher cost of capital could undermine the benefits of the region's good renewable resources (see Bringing down the cost of capital).

Figure 8.4 Hydrogen production costs by pathway in the Announced Pledges Scenario, 2030



Notes: VRE = variable renewable energy; LAC = Latin America and the Caribbean. VRE includes either dedicated solar PV or dedicated onshore wind or dedicated offshore wind, which results in a cost range. Electrolyser efficiency is 69% (lower heating value [LHV]). CAPEX, OPEX and natural gas prices vary per region. The cost of capital is assumed to be 9% for all regions.

LAC can produce electrolytic hydrogen more cheaply than many other regions of the world, and in some cases even more cheaply than domestic fossil-based hydrogen.

Brazil published a hydrogen roadmap as early as 2005, and Argentina enacted a law to promote hydrogen in 2006. More recently, LAC countries have made progress in the low-emissions hydrogen sector. Chile led the way by publishing the region's first national hydrogen strategy in 2020, focusing on electrolytic hydrogen, followed by Colombia in 2021 and Uruguay in 2023. In 2023, Argentina, Brazil, Costa Rica, Ecuador and Panama also presented their national hydrogen strategies. Several other countries are currently developing strategies and are expected to publish them soon. In 2024, Peru passed a law to promote "green" hydrogen,[126] and Mexico issued its first hydrogen guidelines.

Outlook for low-emissions hydrogen in the Announced Pledges Scenario in Latin America and the Caribbean

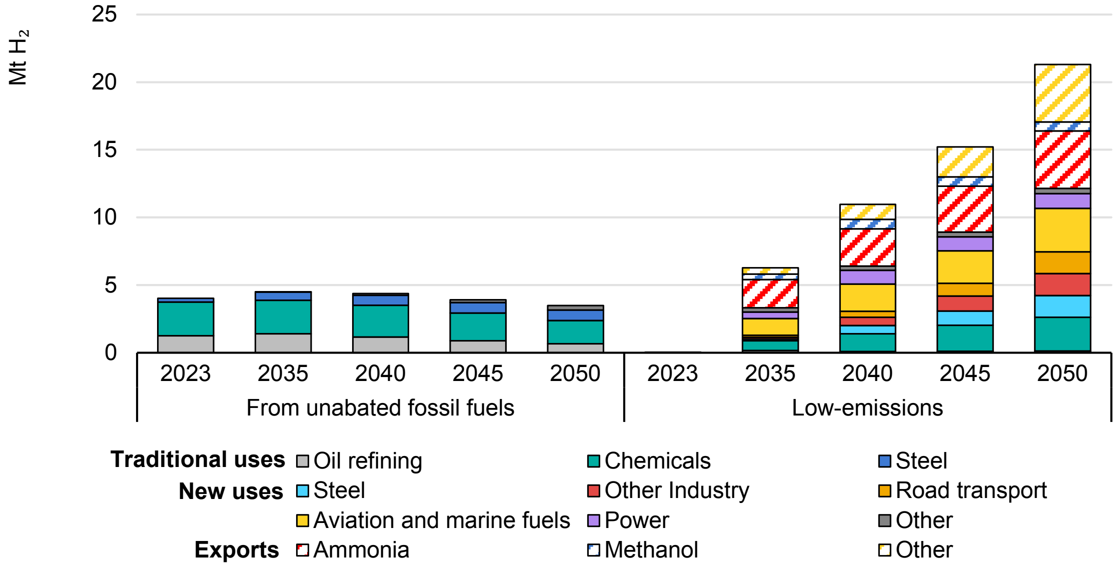
This section introduces results from the IEA Announced Pledges Scenario (APS).[127] As such, it represents an optimistic outlook for the production and use of low-emissions hydrogen not only in LAC, but also elsewhere, as it assumes that pledges and targets made by countries around the world are achieved in full and on time, including climate goals established by nationally determined contributions. In the case of LAC, the APS reflects the net zero emissions pledges made by 16 countries in the region – Antigua and Barbuda, Argentina, Barbados, Brazil, Chile, Colombia,

[126] See Explanatory notes annex for the use of the term "green" hydrogen in this report.
[127] The forthcoming IEA World Energy Outlook 2024 will present detailed results of the Announced Pledges Scenario.

Costa Rica, Dominica, Dominican Republic, Grenada, Guyana, Jamaica, Panama, Peru, Suriname and Uruguay – which together cover 60% of energy-related CO_2 emissions and almost two-thirds of GDP in the region. It also reflects LAC's low-emissions hydrogen deployment goals as defined in their national strategies.

In the APS, global hydrogen demand increases by almost 70% by 2035 and more than triples by 2050 compared to 2023 levels. In LAC, hydrogen demand, excluding demand for exports, increases by about 90% by 2035 and nearly quadruples by 2050 (Figure 8.5). The share of hydrogen demand for use in new applications in LAC accounts for close to 20% in 2035 and 60% in 2050, which would be lower than the world average of 40% and 70%, respectively. In the APS, hydrogen production in LAC is driven by relatively ambitious policy goals for low-emissions hydrogen deployment. However, while some production may be intended for domestic use, LAC's demand policy goals remain somewhat modest and production would be more likely to be directed towards exports to meet overseas demand, mainly in the form of hydrogen-based fuels. About 3 Mt H_2-eq in the APS in 2035, and 9 Mt H_2-eq by 2050 are exported in the form of hydrogen-based fuels, mostly in the form of ammonia to Europe (for shipping applications) and Japan and Korea (for both shipping applications and power generation), but also to Europe as synthetic aviation fuels.

Figure 8.5 Hydrogen and hydrogen-based fuels demand and exports by sector in Latin America and the Caribbean in the Announced Pledges Scenario, 2023-2050



Notes: International bunkering is included in aviation and marine fuel. Exports and demand for road transport, aviation and marine fuel, and power generation include hydrogen that is converted to hydrogen-based fuels. For hydrogen-based fuels, the equivalent hydrogen amount (Mt H_2-eq) corresponds to the stoichiometric hydrogen inputs needed to produce these fuels.

In the APS, hydrogen production in LAC grows by a factor of 2.5 by 2035, driven mainly by exports, as policy targets for domestic demand remain modest compared to those for production.

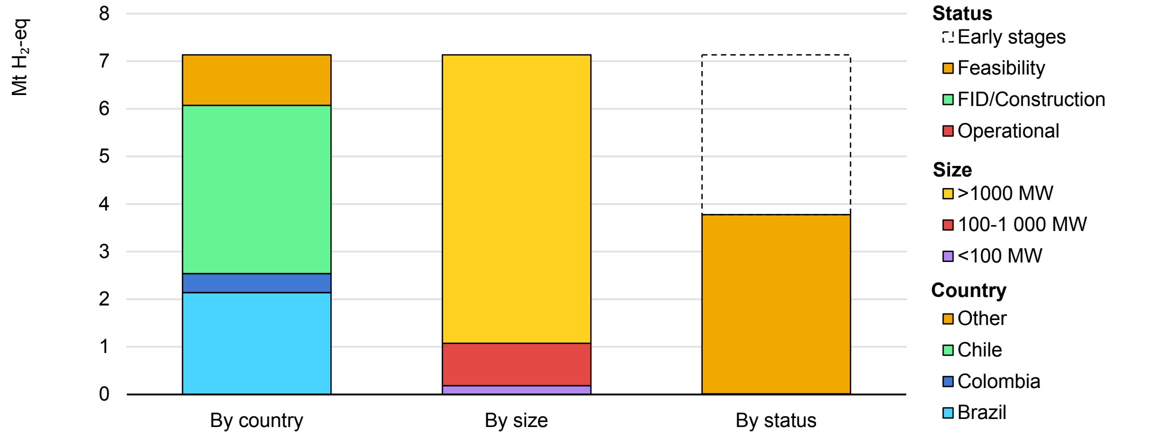
However, realising this export potential hinges on the achievement of climate targets in other regions of the world which are potential importers of these fuels and the achievement of decarbonisation targets for international shipping and aviation, more than on the actions that governments and industry in the region can put in place. The IEA Stated Policies Scenario (STEPS) provides an outlook based on current policy settings, which can give a better sense of the exports of hydrogen-based fuels that could be achieved in the region based on how the energy sector is evolving globally. In the STEPS, hydrogen and hydrogen-based fuels exports from Latin America account for 1.7 Mt H_2-eq by 2035 and close to 6 Mt H_2-eq by 2050. In this case, these exports are driven by the mandates adopted in Europe for the use of hydrogen-derived fuels in aviation and shipping and the supportive policies for the adoption of ammonia in power generation in Japan and Korea.

At the global level, the share of low-emissions hydrogen production accounts for close to 50% of the total in 2035 in the APS, rising to 80% in 2050. In LAC in the APS, the share is significantly higher, reaching 60% in 2035, 10 percentage points above the global average, and 85% in 2050. This highlights the region's potential for significant growth in low-emissions hydrogen production compared to other parts of the world, driven by its abundant renewable energy resources and strong targets. However, more ambitious demand policies would be needed to boost domestic use and enhance the contribution of low-emissions hydrogen to the region's decarbonisation efforts.

Low-emissions hydrogen production

In LAC countries, the only low-emissions hydrogen projects announced so far are based on water electrolysis, although other technologies are being considered. For example, a demonstration project in Brazil is exploring bioethanol reforming to hydrogen. If all announced projects are realised, annual electrolytic hydrogen production could reach more than 7 Mt H_2 by 2030 (Figure 8.6). This would represent around 20% of the world's total announced electrolytic hydrogen production and 15% of all low-emissions hydrogen projects, including those planning to use fossil fuels with carbon capture, utilisation and storage (CCUS), in the rest of the world. However, the status of these projects varies considerably, with only 0.2% in operation, under construction or having reached FID, compared to 8% globally. Around 45% of projects are at a very early stage, which is similar to the global average, while the remainder are undergoing feasibility studies.

Figure 8.6 Announced projects for electrolytic hydrogen and hydrogen-based fuels in Latin America and the Caribbean by country, size and status, 2030



Notes: FID = final investment decision. Only electrolysis projects are included (representing more than 99% of the total announcements for low-emissions hydrogen production in the region). Only projects with a disclosed start year are included.
Source: IEA Hydrogen Production Projects Database (October 2024).

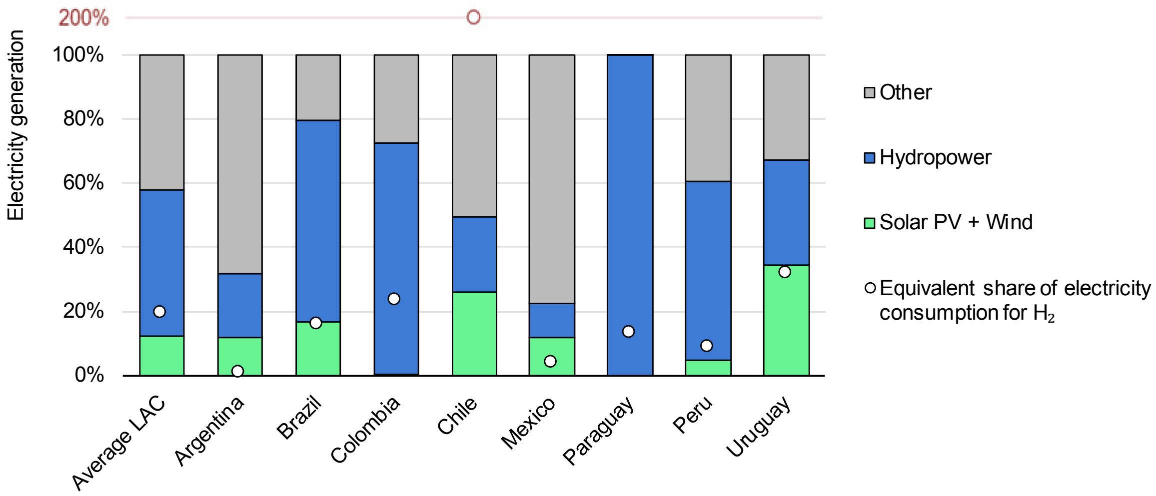
If all announced electrolytic hydrogen production projects materialise, LAC would account for 20% of global production by 2030, with 85% of projects at the gigawatt scale.

If all announced projects in LAC were to materialise, they would require an installed electrolyser capacity of close to 90 GW (45 GW if excluding projects at very early stages of development) by 2030. 85% of these projects would be gigawatt scale, above the global average of almost 80%. Currently, most projects in operation or at FID in LAC are relatively small (<5 MW of electrolysis capacity), with only a few larger initiatives. Notably, a 25 MW electrolyser at Industrias Cachimayo in Peru has been producing hydrogen for ammonium nitrate, used in mining explosives, for nearly six decades. The largest project under construction is Unigel's 60 MW electrolysis project in Brazil for the production of ammonia.

Chile accounts for half the potential production of all project announcements in the region: low-emissions hydrogen production could reach close to 3.5 Mtpa H_2 by 2030 if all projects come to fruition (close to 2 Mtpa H_2 if excluding projects at very early stages of development). Brazil follows with an announced potential production of more than 2 Mtpa H_2 by 2030 (more than 1 Mtpa H_2 if excluding projects at very early stages). Together, Brazil and Chile account for 80% of the potential production from project announcements. Panama and Colombia accounts for the third and fourth largest potential production, with around 0.4 Mtpa H_2 by 2030 each (0.2 Mtpa H_2 if excluding projects at very early stages), with the rest of the countries in the region having announcements for 200 ktpa of low-emissions hydrogen or less.

Producing more than 7 Mtpa H_2 by electrolysis by 2030 would require a significant increase in electricity generation capacity, equivalent to almost 20% of the region's current electricity generation (Figure 8.7). If these projects were to rely solely on dedicated electricity from wind and solar PV, generation from these sources would need to increase by 1.4 times today's levels just for the purpose of hydrogen production. In Brazil and Uruguay, this would mean nearly doubling current wind and solar power generation within this decade. In Chile, a close to eightfold increase in solar and wind generation would be needed, while Colombia would need to rapidly scale up from its current low levels of variable renewable generation.

Figure 8.7 Potential electricity demand for electrolytic hydrogen production from announced projects in Latin America and the Caribbean, 2030, and electricity generation, 2022



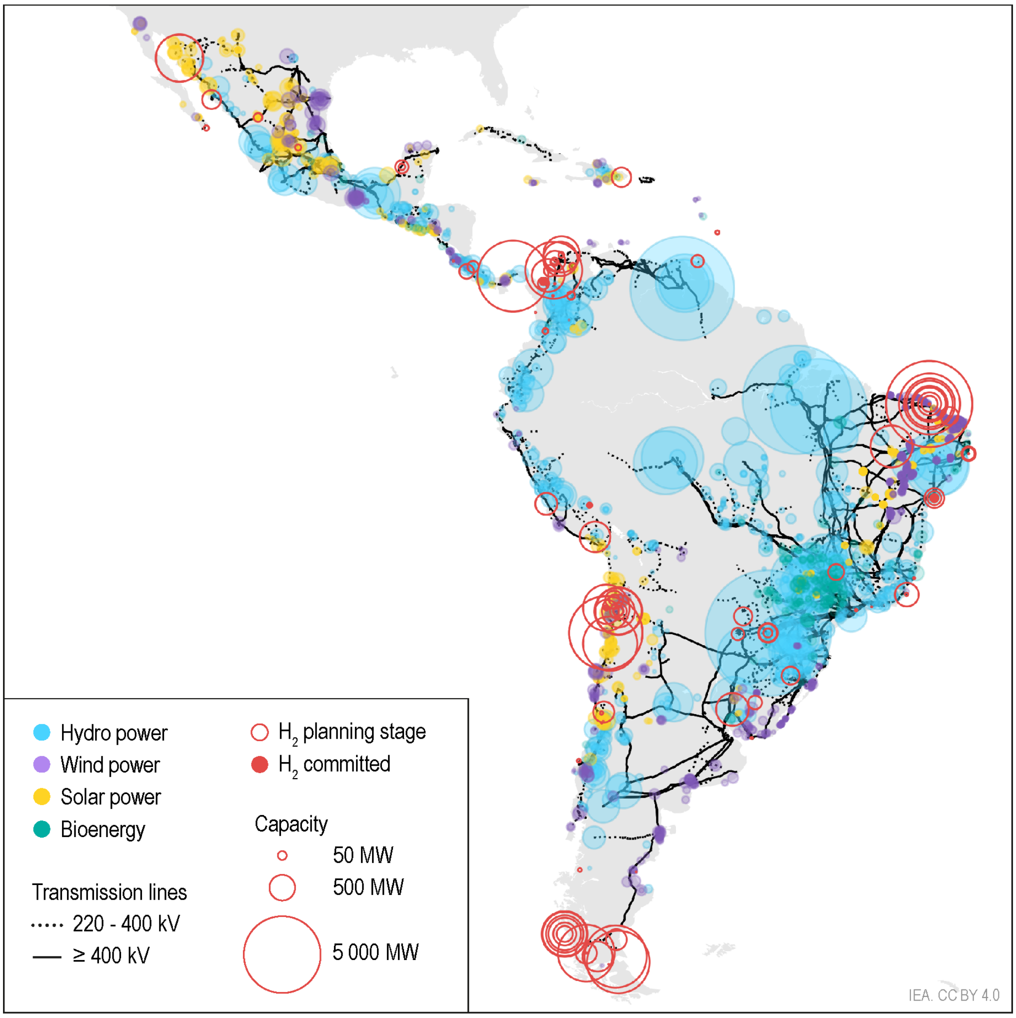
Notes: LAC = Latin America and the Caribbean. Electricity generation data for 2021 instead of 2022 are used for Peru and Uruguay.
Source: IEA Hydrogen Production Projects Database (October 2024).

Announced electrolytic hydrogen projects in LAC by 2030 would consume the equivalent of 20% of the region's current electricity generation.

LAC's extensive hydroelectric resources could help to balance electrolytic hydrogen production in the near term, especially while electricity demand is relatively small. The first low-emissions hydrogen projects approaching the 100 MW-scale have often been located in areas with significant hydropower generation (Figure 8.8). However, if all announced projects were to be realised, the region would need significant investment in new power generation, leading to unprecedented deployment of solar PV and wind within a few years.

While most of the large low-emissions hydrogen projects are planned with dedicated renewable energy plants, they may also be connected to the grid to ensure smoother operation and better management of the variability of renewable energy production. This would also require significant improvements in power transmission and grid flexibility to support the increased capacity, especially in regions that are currently somewhat isolated or lack robust grid connections. These regions could also benefit from surplus electricity from solar PV and wind, minimising curtailment and maximising resource use. It is important to note that the lead times for the planning and construction of major electricity grid assets, such as electricity transmission lines, are often long and typically exceed the development timelines of the production projects that will be connected to them. This underlines the critical need for comprehensive and early planning of electricity transmission networks to accommodate the potential growth of low-emissions hydrogen projects, including a higher regional power integration.

Figure 8.8 Announced low-emissions hydrogen projects in Latin America and the Caribbean, 2030, and installed electricity generation capacity and power transmission lines, 2022



Sources: IEA analysis based on IEA Hydrogen Production Projects Database (October 2024); Open infra map (2023), Electricity grids; Global Energy Monitor (2022), Global renewable power tracker.

The largest electrolytic hydrogen projects planned by 2030 in LAC are in regions with good solar and wind potential, with smaller projects near large hydropower plants.

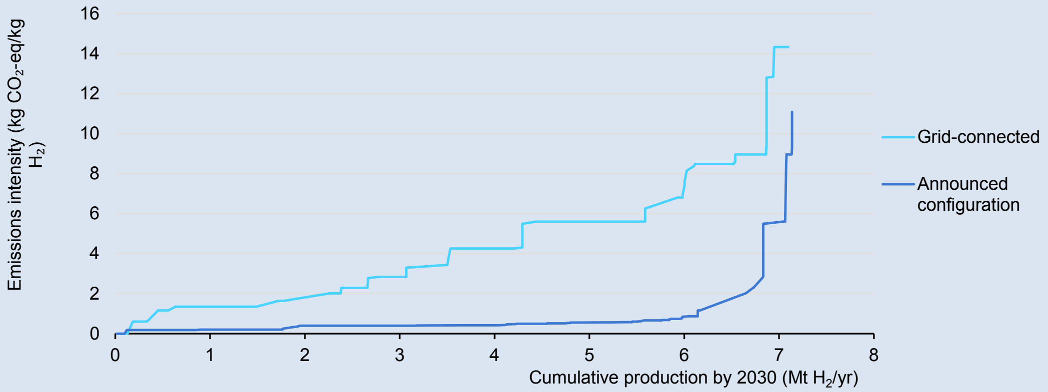
Box 8.1 Potential emissions intensity of announced electrolytic hydrogen projects in LAC

Almost all the announced low-emissions hydrogen projects in LAC plan to produce hydrogen by water electrolysis, for which emissions are determined by the upstream and midstream emissions of electricity generation. Most projects have announced the use of renewable electricity, often using dedicated supplies. However, in many cases the electricity will be supplied through the grid (along with the use of certificates to ensure the renewable origin), or some grid electricity may be used to ensure smoother electrolyser operation and contribute to grid stability. When powered solely by directly connected renewables, hydrogen emissions would be zero (excluding embedded emissions from the assets, see Chapter 7. GHG emissions of hydrogen and its derivatives). However, the use of grid electricity can result in different emission levels depending on the electricity mix and operation. If today's global average grid electricity with a CO_2 intensity of around 460 g CO_2-eq/kWh were to be used, hydrogen would have an emissions intensity of 24 kg CO_2-eq/kg H_2, similar to hydrogen produced from unabated coal.

In LAC, most countries have a grid emission factor below the global average, except for countries in the Caribbean, Suriname and Guyana. As a result of LAC's higher renewable energy penetration, which is more than double the global average, the region's average CO_2 intensity is about 200 g CO_2-eq/kWh, which would result in emissions of about 10 kg CO_2-eq/kg H_2, comparable to hydrogen produced from natural gas reforming. Based on announced projects, by 2030 LAC could produce more than 7 Mtpa of hydrogen (almost all of the total announced production potential) with a carbon intensity below 3 kg CO_2-eq/kg H_2, which would make it compliant with several already-existing regulations around the world, such as the EU Taxonomy (<3 kg CO_2-eq/kg H_2), Japan's Hydrogen Society Promotion Act (<3.4 kg CO_2-eq/kg H_2) and the US Clean Hydrogen Production Standard (CHPS, <4 kg CO_2-eq/kg H_2). Moreover, if all the announced projects were connected to the grid without buying guarantees of origin for the electricity used in its production, the region would still be able to produce 3 Mtpa compliant with the EU Taxonomy and around 3.5 Mtpa compliant with the CHPS.

The emissions associated with hydrogen production will vary significantly depending on the pace of grid decarbonisation and potential disruptions to hydropower generation due to climate change, such as fluctuating rainfall patterns. The strategic use of grid electricity, if properly managed, could offer benefits like minimising the curtailment of renewable energy and improving overall grid stability, making it a potentially valuable complement to dedicated renewable energy sources in hydrogen production.

Emissions intensity of electrolytic hydrogen announced projects in LAC, 2030



Notes: Electrolytic production refers to low-temperature water electrolysis with an assumed overall electricity demand of 50 kWh/kg H_2, including compression to 30 bar. The grid electricity intensities include direct CO_2, methane (CH_4) and nitrous oxide (N_2O) emissions at the power plants, but not upstream and midstream emissions for the fuels used in the power plants. It is assumed that renewable electricity from wind, solar PV, hydropower and geothermal energy has zero upstream and direct emissions. Intensities of grid electricity considered are in line with the projected electricity generation in the APS. Emissions intensity of the year a project comes online is used for the grid-connected configuration.

Low-emissions hydrogen demand

Latin America is experiencing a surge in announced hydrogen production projects, driven primarily by the expectation that a global market will develop, allowing the region to become an exporter of low-emissions hydrogen, rather than by expectations for domestic demand. More recently, however, some countries have begun to explore the potential of their domestic markets, such as Brazil's interest in using low-emissions hydrogen for fertiliser production. Currently, the market for low-emissions hydrogen within the region is limited, with few operational projects (most are demonstration projects) and offtake agreements (mostly preliminary agreements with no binding conditions). The export focus of most of the announced projects highlights the region's potential to become a major player in the emerging global market for low-emissions hydrogen. Realising these ambitious plans within this decade would require addressing uncertainty around regulation and certification for global trade, the lack of export/import infrastructure at the required scale, and limited demand creation in the potential export markets that could facilitate offtake.

With the exception of Costa Rica and Mexico, which have diversified their exports somewhat in the last two decades, most major Latin American economies have simplified their export profiles and reduced the complexity of their domestic economies. This shift has led to a decline in exports of high-value goods and an increased reliance on commodity exports, particularly in agriculture and mining.

Analysis suggests that if the region's low-emissions hydrogen export potential relies solely on commodity exports rather than high-value goods, it will remain more vulnerable to economic shocks. Relying solely on the export of a few commodities is risky. For example, announced projects indicate that 8 Mt of ammonia would be available for export by 2030 (6.5 Mt if excluding projects at very early stages of development), while the current global trade of anhydrous ammonia is 20 Mtpa (see Chapter 4. Trade and infrastructure). The production from announced projects would therefore be close to half of the current global trade volume, and this is unlikely to be fully absorbed by the market in such a short timeframe, especially as technologies for converting ammonia back to pure hydrogen, or for use in new applications as a fuel (such as in shipping and power generation), are not yet mature. To bridge the gap between project announcements and actual implementation, the region will need to stimulate domestic demand for low-emissions hydrogen. This will also need to include stimulating demand within the industrial sector for the production of low-emissions products that could achieve higher value on the global market. Across all projects, the initial scale-up phase will be crucial for gaining the experience and knowledge needed for long-term success, both domestically and in export markets.

In the following sections, we explore the potential for LAC to use low-emissions hydrogen in various applications that would present the best opportunities for the region in the short term, given its major economic sectors today. These include the production of nitrogen-based fertilisers for agriculture, the reduction of iron ore to hot briquetted iron for steel production, the production of bulk explosives and the use of hydrogen in heavy machinery in the mining sector, the production of hydrogen-based fuels for aviation and shipping, and its use in the desulphurisation process during refining.

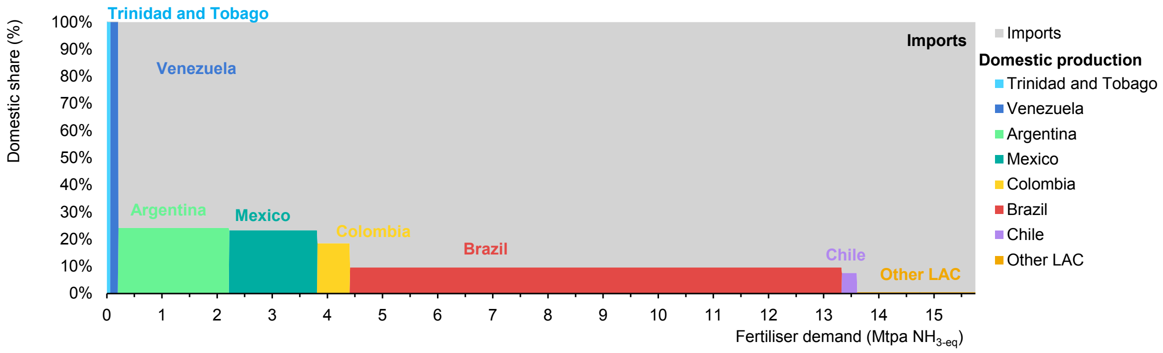
Agriculture: nitrogen-based fertilisers

Ammonia (NH_3) represented about a third of the hydrogen demand in LAC in 2023, with over 85% of production concentrated in Trinidad and Tobago, Brazil and Argentina. Ammonia can be used in its pure form or converted to other nitrogen compounds like urea, nitric acid and ammonium nitrate, among others, that can ultimately be used for agriculture, as well as other applications. At a global level and within LAC, around 70% of ammonia is used for fertiliser applications. Excluding Trinidad and Tobago, the region is a net importer of ammonia (44% of demand)[128] and a net importer of nitrogen-based fertilisers.[129] Fertiliser demand

[128] The region is a net exporter of ammonia (exporting nearly a third of production), but this reflects the distorting effect of Trinidad and Tobago, which exports 80% of its production and represents almost two-thirds of ammonia production in the region.
[129] Hereafter referred to as "fertiliser".

in LAC accounted for almost 16 Mt NH_3-eq in 2021,[130] of which only 20% was met by domestic production (Figure 8.9). A total of 21 countries in the region, representing 10% of LAC's fertiliser demand, satisfy 100% of their demand with imports. This includes countries where agriculture represents more than 10% of the GDP, like Bolivia, Paraguay, Honduras and Nicaragua. Brazil is responsible for almost 55% of LAC's fertiliser demand, of which 90% is satisfied by imports. Argentina, Colombia and Mexico and Argentina represent close to 25% of total demand and import 18-24% of their fertilisers. Prior to the 2022 energy crisis, almost 25% of the fertiliser imports came from Russia, although its share decreased to 16% in 2023. In contrast, the share of imports from China has doubled in the last 5 years from 10% in 2018 to 20% in 2023, with imports from the Middle East and North Africa also increasing from 18% to 24% over the same period.

Figure 8.9 Share of imports and domestic production for nitrogen-based fertilisers in Latin America and the Caribbean, 2021



Notes: Fertiliser demand based on ammonia equivalent (NH_3-eq) using the nitrogen content. Fertilisers included are ammonia, ammonium nitrate, ammonium phosphate, ammonium sulphate, calcium ammonium nitrate, potassium nitrate, urea, urea ammonium nitrate and NPK (nitrogen, phosphate, potassium).
Source: IEA analysis based on FAOSTAT.

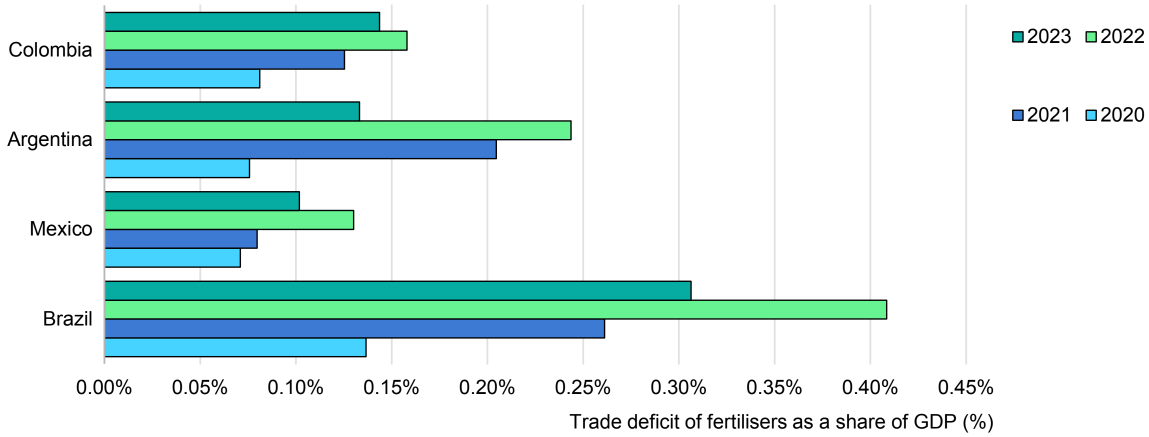
LAC meets nearly 80% of its nitrogen-based fertiliser demand with imports.

This dependence on imports also has a significant economic impact. The annual net trade deficit for fertiliser was equivalent to USD 3.9-4.5 billion during the 2018-2020 period, before sharply increasing to USD 7.1 billion in 2021 and even further to USD 9.1 billion in 2022, as a result of the global rise in natural gas prices. As a reference, the trade value of natural gas imports to the region in 2021 was USD 14.5 billion, and the cumulative investment in bioenergy in Brazil was nearly USD 19 billion over the 2010-2023 period. The country with the largest absolute deficit was Brazil, with the annual trade deficit at USD 4.4-7.2 billion in the last 3

[130] Assuming that all the nitrogen for the nitrogen-based fertilisers comes from ammonia production so that it can be converted to ammonia terms using the nitrogen content of each compound.

years, representing nearly two-thirds of the deficit for the entire region. In relative terms, when considering the different sizes of the economies, the trade deficit is still largest in Brazil, equivalent to 0.25-0.4% of its GDP in the last 3 years (Figure 8.10). This is significant considering Brazil's GDP growth in 2024 is estimated to be 2.2%. For other countries such as Guyana, Honduras, Nicaragua and Uruguay, the share of imports has also fluctuated in the range of 0.3-0.7% of GDP in the last 3 years, with other countries having smaller shares.

Figure 8.10 Traded deficit of nitrogen-based fertilisers in selected Latin American countries as a function of GDP, 2020-2023



Notes: Based on HS code 3102 (Mineral or chemical fertilisers, nitrogenous). Figure is based on primary values and net trade.
Sources: IEA analysis based on data from UN Comtrade and the World Bank

Over the past 4 years, the trade deficit in nitrogen-based fertiliser imports has been between 0.1% and 0.4% of GDP for the largest economies in Latin America.

The trade deficit in nitrogen-based fertiliser imports has fluctuated considerably over the last 4 years, with the deficit in some years being more than twice that of other years. Although this is largely due to the unforeseen energy crisis of 2022, it also reveals one of the challenges of LAC's fossil-based system – the exposure to price volatility due to market disruptions and short-term trends. During the same period, the price of ammonia,[131] mostly produced from hydrogen from natural gas (except in China, where coal-based production is the main route), has fluctuated between USD 230/t NH_3 and USD 1 140/t NH_3 – a factor of almost 5 (Figure 8.11). In contrast, electrolytic ammonia production has the advantage that the largest share of the cost comes from the capital investment and financing costs, which are fixed at the time of making an investment decision, leading to predictable

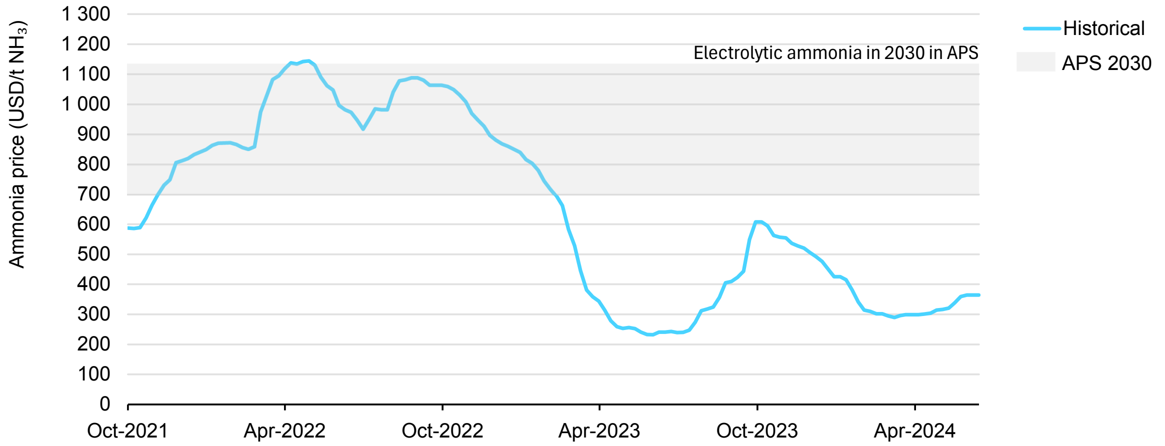
[131] Based on free on-board price of ammonia in the Middle East. The free on-board price is the price of goods at the frontier of the exporting country.

production costs.[132] Displacing some of the fertiliser imports with domestic ammonia and fertiliser production would therefore not only reduce the trade deficit, but also capture the value downstream the value chain (producing fertilisers rather than ammonia) and could also lead to more price stability. If all the demand for ammonia and nitrogen-based fertilisers in LAC were satisfied with 2.8 Mtpa of domestic electrolytic hydrogen production, 35-80 GW of renewable capacity would be required,[133] compared with a total installed capacity of solar PV and wind in the region of 123 GW in 2023. Such a change would require an investment of USD 95-100 billion for the renewable energy, electrolyser and ammonia synthesis units. This investment is of similar magnitude to what Chile would need (USD 74 billion) until 2030 to keep up with expected growth in copper demand accelerated by the energy transition. One limitation of switching to electrolytic ammonia is that the conventional production route from natural gas includes carbon capture, and the captured CO_2 is used for making urea. Urea accounts for 55% of the demand of nitrogen-based fertilisers in LAC and would require over 10 Mtpa CO_2. The fossil CO_2 could be replaced with biogenic CO_2, but this would compete with other CO_2 uses (see Figure 8.19).

If all the announced projects for the production of low-emissions ammonia in LAC materialise, they would produce 2.8 Mtpa H_2 by 2030 (1.8 Mtpa if excluding projects at very early stages of development), equivalent to 16 Mtpa NH_3 (10 Mtpa NH_3), i.e. equivalent to the volume needed to satisfy the domestic fertiliser demand today (although it would compete with ammonia demand as a shipping fuel). This is also significantly larger than the demand for low-emissions hydrogen for ammonia production to be used in fertiliser manufacturing in the APS, which is around 0.6 Mtpa H_2 by 2035 and close to 2 Mtpa H_2 by 2050 for the region. Of this announced capacity, 60% is in Chile, with another 25% in Brazil. The largest project outside these two countries is a 1.65 Mt NH_3 project in Peru, which was undergoing an environmental impact assessment in April 2024. However, close to 40% of the project pipeline is at very early stages of development and the remaining 60% at the feasibility stage, and only one 60 MW project in Brazil and one 50 MW project in Colombia have reached FID. Many of these projects are targeting export, but even if only a small share of them materialise, they would still be sufficient to contribute to improving the trade balance.

[132] Annual production costs will still vary depending on the weather year, and profit will still vary since prices are determined by supply and demand in the market.
[133] Lower bound for onshore wind and upper bound for solar PV. Indicative values since capacity factors are location specific.

Figure 8.11 Ammonia spot prices (2021-2024) in comparison to low-emissions ammonia production costs in the Announced Pledges Scenario in Latin America and the Caribbean, 2030



Notes: APS = Announced Pledges Scenario. Ammonia price at the export point. Historical ammonia price for the Middle East. The range of ammonia production cost for 2030 is based on the cost of electrolytic hydrogen production in the largest LAC economies considering differences in capital cost, cost of capital, and resource quality, and it does not reflect cost uncertainty.
Source: Argus Media (historical prices).

Ammonia price has changed by almost a factor of five in the last 4 years; electrolytic ammonia could enhance price stability in the coming years, while being cost competitive.

There are already efforts to increase domestic fertiliser production in the region. For example, in 2022 Brazil published a national fertiliser plan for 2050, which includes production targets, such as 1.9 Mtpa of nitrogen (2.3 Mt NH_3-eq) by 2030, a 50% reduction of imports by 2040, and at least three low-emissions ammonia plants by 2050. In addition, it also includes financing targets, such as attracting at least USD 10 billion of private capital to expand domestic fertiliser production by 2030. The strategy is now being implemented, with multiple financial incentives in place to promote fertiliser production, including long-term credits from the National Bank for Economic and Social Development (BNDES), which has already funded a fertiliser plant in Paranaguá, and financing for R&D projects through the government financing agency (FINEP).

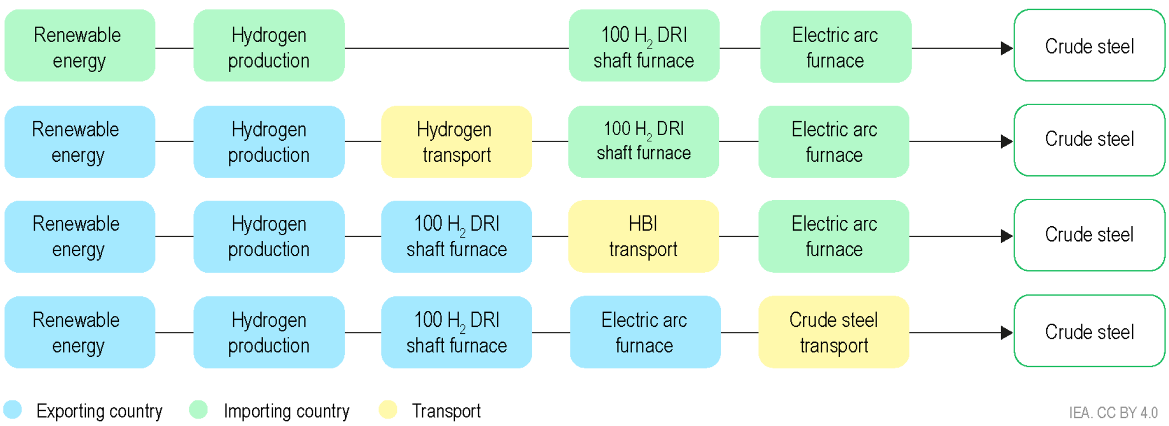
Steelmaking and hot briquetted iron trade

LAC holds about one-fifth of the world's iron ore reserves. In 2022, the iron ore market in the region was valued at USD 50 billion, making it the second largest mining market after copper, which was valued at USD 70 billion. The largest iron ore deposits in the region are located in Brazil, and support both the domestic iron and steel industry as well as significant export activities.

In 2023, the region accounted for 20% of the world's iron ore trade in monetary terms, with Brazil accounting for almost 90% of this. LAC is the largest exporter of iron ore to India, the second largest to China and Europe (after Australia) and the third largest to Japan. It is worth noting that 65% of the region's exports of iron ore were for China, but LAC also imported significant volumes of semi-finished and finished steel products from China, equivalent to more than 40% of the iron ore exports to the region in monetary terms.

The first step of converting iron ore into iron is the most energy- and carbon-intensive, accounting for around 80% of emissions in coal-based steelmaking. Iron ore reduction and steelmaking are currently co-located, strategically positioned in proximity or with efficient trade routes between upstream metallurgical coal and iron ore mines and downstream markets for steel consumption. However, in the future, high energy and hydrogen costs in some regions might encourage the relocation of reduction processes to regions with good renewable energy resources and iron ore deposits, if near-zero production routes are pursued. This shift could realign the supply chain and lead to the emergence of global production hubs for pure forms of iron. Hydrogen-based iron ore reduction produces hot briquetted iron (HBI), a compact form of direct reduced iron (DRI) that can be shipped long distances and later melted into steel in an electric arc furnace (EAF), typically with supplementary steel scrap, which is more abundant in developed economies (Figure 8.12).

Figure 8.12 Potential supply chains for hydrogen-based direct reduced iron steelmaking



Note: DRI = direct reduced iron; HBI = hot briquetted iron.

LAC can attract industrial activity within the iron and steel supply chain, beyond today's export of iron ore, thanks to its potential to produce low-emissions hydrogen at low cost.

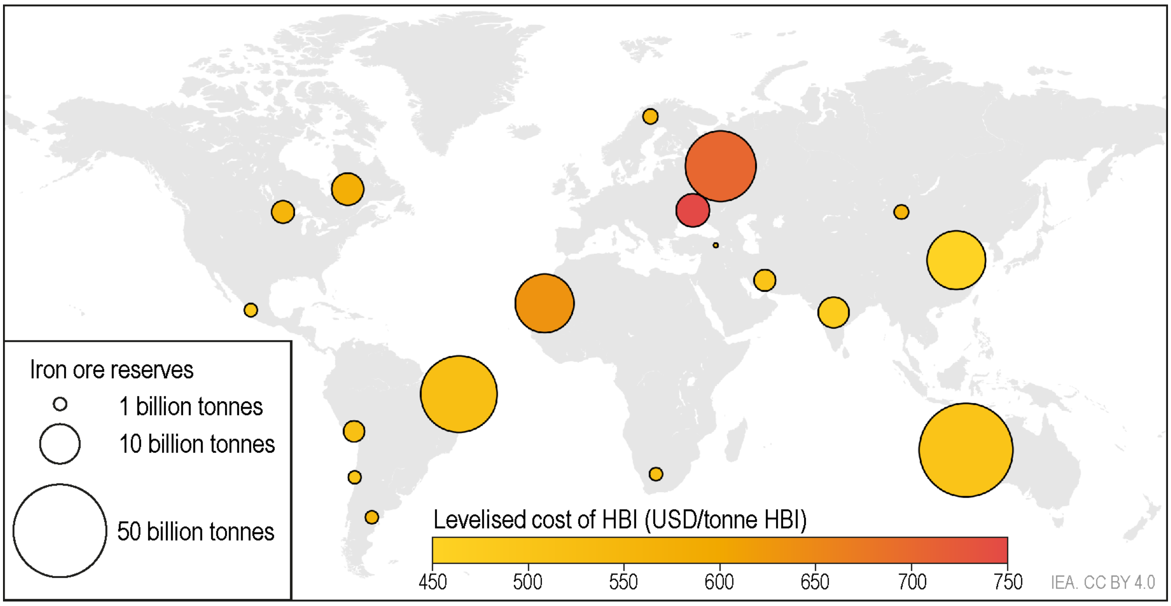
Most existing hydrogen strategies in the region focus on trade options for ammonia, methanol and synthetic fuels, without considering steel produced with low-emissions hydrogen. In contrast, recent hydrogen strategies in Mauritania, Namibia, the United Arab Emirates and the United States have begun to highlight the importance of near-zero emissions steel. [134] LAC has great potential to deploy low-emissions hydrogen-based iron ore reduction technologies (Figure 8.13) to transition from an extractive industry to a manufacturing one, either to export HBI, which adds more value than exporting iron ore alone, or to export steel. In the APS, around 0.15 Mtpa of low-emissions hydrogen is used for steel manufacturing in Latin America by 2035. This demand grows up to 1.5 Mtpa by 2050.

H2-DRI plants require high-grade iron ore, typically containing above 67% iron, which currently represents only 4% of global iron ore shipments. Brazil is the largest producer of high-grade iron ore, and Brazilian mining company Vale expects demand for DR-grade iron ore will increase over time, while demand for the benchmark 62% (blast-furnace-grade) iron ore will decline. As a result, the focus is shifting towards increasing the quality rather than the quantity of the iron ore output. Lower-grade ores could be used in H2-DRI plants after beneficiation, [135] a process that upgrades the quality of the ore by removing impurities and gangue minerals. While Brazil ranks as the second largest iron ore producer globally, behind Australia, 96% of Australian iron ore exports consist of lower-grade hematite, which cannot yet be efficiently processed in electric arc furnaces. Although new technologies are being developed to use lower-grade iron ores more efficiently, LAC would be uniquely positioned to play a key role in supplying iron ore suitable for H_2 DRI production.

[134] See the IEA's report on Achieving Net Zero Heavy Industries in G7 Members for more information on the definition of 'near-zero emission steel production'. In this report, the term is used less precisely to refer to steel production from iron ore with innovative technologies that can achieve substantial reductions in emissions intensity, such as hydrogen-based DRI steel production.

[135] Depending on the degree of beneficiation required and the type of ore, crushing, screening and grinding processes are utilised in conjunction with flotation, gravity or magnetic separation. For low-quality magnetite ores (Fe_3O_4) beneficiation processes are advanced, while further innovation is needed for hematite (Fe_2O_3) and goethite (FeO_2H) ores.

Figure 8.13 Levelised cost of producing hot briquetted iron in the Announced Pledges Scenario 2030 by iron ore reserves in 2022



Notes: HBI = hot briquetted iron. The size of the bubble represents the iron ore reserves aggregated by country. Only those countries whose iron content in the ore averages more than 55% are shown. Beneficiation costs to achieve a specific iron grade are not included. The supply of iron ore is modelled through an international price and not based on the actual production cost at the mining site. No subsidies are included.

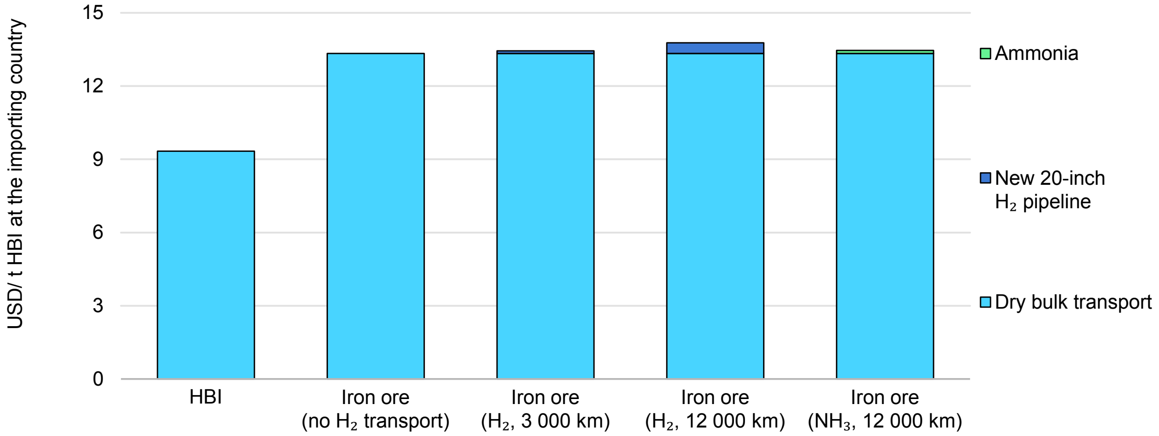
Source: IEA analysis based on data from the US Geological Survey.

LAC can produce HBI cost-effectively compared to other regions of the world, as a result of its vast iron ore reserves and high-grade ores suitable for 100% H_2 DRI.

HBI can be transported in bulk and easily stored (in contrast to ammonia, for example, which is a gas at ambient conditions and must be stored under pressure and transported as a liquefied gas, requiring more complex and costly infrastructure), although some concerns remain around oxidation. Today, iron ore exports represent approximately 30% of the total dry bulk market, making iron ore the largest single commodity within the dry bulk sector, outpacing other major commodities like coal.

HBI is denser than iron ore, which would reduce the transport volume and shipping costs. In addition, transporting hydrogen or hydrogen-based fuels over long distances can cost up to USD 2/kg H_2, and although this has a relatively minor impact on the HBI production cost, as approximately less than 60 Kg H_2 (6% ratio in mass terms) are consumed per tonne of HBI, that cost can also be minimised.

Figure 8.14 Impact of hydrogen and iron ore shipping costs on the cost of producing hot briquetted iron, 2023

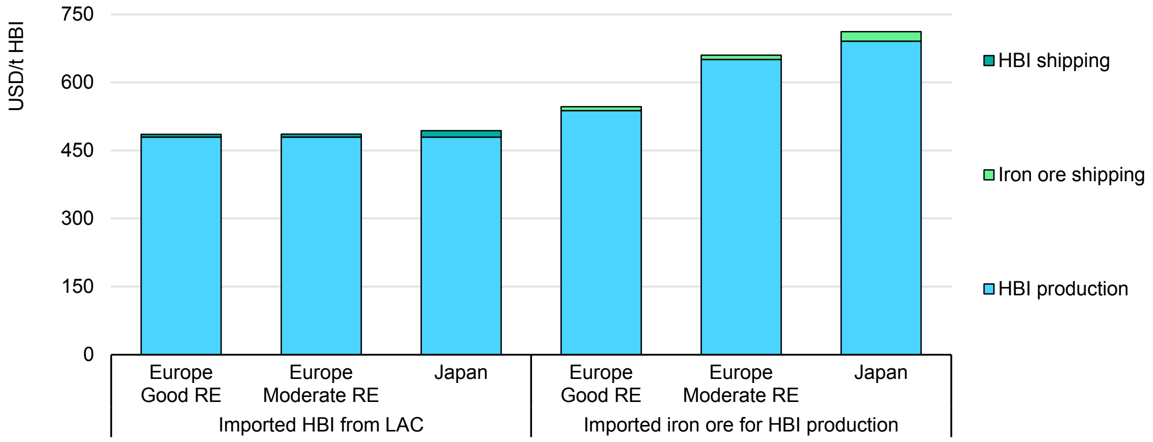


Notes: H_2 = hydrogen; HBI = hot briquetted iron; NH_3 = ammonia. Dry bulk carriers are used to transport iron ore and HBI 12 000 km to their importing country. It is assumed that direct reduction is used to reduce iron ore pellets into metallic iron to achieve a 94% metallisation, i.e. the percentage of metallic iron out of the total iron content (%Fe out of iron oxide [FeO]). Ore cost adjustments are modelled as a function of the Fe-content. Ammonia shipped to provide hydrogen at the DRI facility includes the costs associated with ammonia cracking.

Transporting HBI significantly lowers costs compared to transporting iron ore and hydrogen separately.

In 2023, LAC exported more than 400 Mt of iron ore. If all of this were converted to HBI for export, it would require more than 25 Mt of hydrogen. While unlikely at such scale, as some iron ore importing countries have ample renewable energy resources to produce HBI themselves, there are countries with limited renewable resources that could benefit from locating HBI production in LAC and focusing on domestic steelmaking. This would allow them to produce steel close to the end user and facilitate the recycling of steel scrap using EAFs, whose availability may be limited in iron ore exporting countries. This approach could reduce overall costs by up to a third. If half of LAC's current iron ore exports to Europe, Japan and Korea – approximately 30 Mt of iron ore – were in the form of HBI, the region would need almost 2 Mt of hydrogen to produce around 20 Mt of HBI for export, with an investment for the hydrogen-based reduction process alone of almost USD 20 billion.

Figure 8.15 Comparison of costs of importing hot briquetted iron vs. local production with imported iron ore in Europe and Japan in the Announced Pledges Scenario, 2030



Notes: HBI = hot briquetted iron; LAC = Latin America and the Caribbean; RE = renewable energy. For HBI production, domestic production of hydrogen is assumed, and not imported hydrogen. The cost of HBI reflects its cost at the gate of the steelmaking plant, i.e. the costs associated with HBI production in LAC and shipping HBI (left) and the costs associated with iron ore shipping and HBI production in the importing country next to the steelmaking plant (right). Land transportation costs are excluded.

In regions with moderate renewable energy resources, importing HBI from LAC instead of iron ore could cut the cost of reduced iron by almost a third.

LAC has significant export potential for HBI, but there could also be growing domestic demand for near-zero emissions steel, especially as countries work to meet their decarbonisation commitments. Globally, steelmaking accounts for more than 7% of energy-related GHG emissions. In LAC, steelmaking accounts for around 4% of emissions, totalling more than 65 Mt CO_2 per year – almost equivalent to 80% of all of Colombia's CO_2 emissions from fuel combustion. Although near-zero emissions steel may initially carry a price premium, as technologies mature and prices come down, it could be more easily adopted by certain sectors. Sectors where steel consumption represents a small proportion of costs and is therefore less price sensitive are the most likely candidates. In LAC, around half of steel consumption is in the construction sector, followed by the automotive and machinery sectors, each accounting for more than 16% of steel consumption in 2022. While the construction sector has tight margins, in the automotive sector the steel cost is a small part of the total cost of the vehicle, typically only a few hundred dollars. This would make it easier to absorb the premium for near-zero emissions steel, particularly for premium cars.

If the region were to meet all of its automotive steel needs with 100%-H_2 DRI, it would require approximately 11 Mt of steel (if equivalent to the consumption in 2022, with an estimate of the total apparent finished steel use in the region of 68 Mt of steel). This would require nearly 1 Mt of hydrogen and around 12 GW of electrolyser capacity. In addition, some vehicles produced in the region, particularly in Mexico, are destined for export. Carmakers are increasingly entering into agreements to purchase near-zero emissions steel to reduce their embedded emissions. Examples include GM's agreement with ArcelorMittal, Volvo Cars with SSAB and HYBRIT, Ford with Tata, Volkswagen with Salzgitter and BMW with HBIS. LAC could capitalise on this trend by offering near-zero emissions steel to the automotive industry in the region, thereby also encouraging car manufacturers to locate there, as well as attracting other industries.

Countries such as Brazil, Mexico, Argentina, Peru and Chile have the potential to become major players in the global near-zero emissions steel market. For example, Brazilian iron ore mining company Vale will supply iron ore pellets for the 100%-H_2 DRI plant that Stegra (formerly H2 Green Steel) is constructing in Boden, Sweden. In addition, Vale and Stegra signed an agreement in September 2023 to evaluate the feasibility of producing HBI in Brazil. As there are currently no commercially available 100% H2-DRI plants in the world, innovation and international co-operation, including technology transfer, will be critical. By developing hydrogen-based iron ore reduction and harnessing the region's abundant renewable energy resources, LAC can position itself as a leader in near-zero emissions steel production.

Mining: explosives and machinery

The mining sector contributes around 5% of Latin America’s GDP, a share comparable to that of agriculture, and reaching over 12% in some countries, such as Chile and Peru. The region has some of the world’s largest mineral reserves, including copper, iron ore, gold, silver and lithium, and some of the largest producers. Chile is the world’s leading producer of copper, followed by Peru, and Brazil is the world’s second largest producer of iron ore and fourth largest producer of bauxite. In addition, the region’s mining industry has been growing steadily, driven by significant investments in mining projects.

Mining is a significant emitter of GHGs due to its energy-intensive extraction and processing activities. To improve market access, bolster their reputation and align with stringent environmental, social and governance standards, mining companies are increasingly committing to reduce their emissions. As a result, several companies in the region (e.g. Anglo American, Antofagasta Minerals, BHP, Collahuasi and Codelco) have announced decarbonisation strategies. The use of low-emissions hydrogen could help decarbonise the sector in two main areas in which direct electrification is difficult: explosives and heavy machinery and trucks.

Bulk explosives

Rising investments in mining, particularly in copper, are likely to further support the expansion of the mining sector in LAC and increase the demand for explosives. In LAC, ammonium nitrate fuel oil (ANFO, composed of around 94% ammonium nitrate and 6% fuel oil) is the most frequently used explosive in mining. As interest in sustainable mining practices grows, low-emissions ammonia can be used instead of fossil-based ammonia to produce ammonium nitrate for ANFO and other industrial explosives, helping to reduce upstream emissions from mining.

Leading ammonium nitrate producers, including Enaex (Chile), Incitec Pivot (Australia), and Queensland Nitrates (Australia) have announced low-emissions ammonia projects. Orica has signed an MoU with Fertiberia for the supply of low-emissions technical ammonium nitrate and successfully completed the first test blasts with it in Spain in 2024. It is also worth noting that Industrias Cachimayo in Peru, which became part of Chilean Enaex in 2018, has operated an ammonium nitrate production plant since 1965. This plant uses hydrogen produced by an electrolyser with capacity around 25 MW, which until 2021 was the largest in the world, and since 2022 the plant has been certified to use renewable electricity.

LAC consumed around 1.5 Mt of explosives in 2023 (less than 10% of the global market), predominantly ammonium nitrate used in mining. If all of the demand were met using ammonium nitrate, more than 630 kt of ammonia [136] and more than 100 kt of hydrogen would be required to produce it. Some experts expect an increase in consumption of explosives in the region at a compound annual growth rate between 5% and 8% in the next decade, which would imply that demand for hydrogen could rise to around 180 ktpa by 2032.[137] The use of domestic, low-emissions hydrogen would help to reduce scope 3 emissions from mining companies, positioning them as leaders in sustainable mining practices, while reducing the need to import ammonia for explosives production. Enaex is currently developing the HyEx project in Mejillones (Chile) to produce low-emissions ammonia, with an initial phase producing 18 ktpa by 2025 and subsequent scale-up to 700 ktpa. Enaex aims to meet its current 350 ktpa ammonia import needs for its Prillex America plant (the world's largest explosive grade ammonium nitrate plant), and to access a new export market for low-emissions ammonia.

Heavy machinery

In LAC, the mining sector is a major consumer of energy, accounting for more than 4% of the region's total electricity consumption and almost 2% of its oil

[136] This includes the ammonia used in the production of both ammonium nitrate and nitric acid for ammonium nitrate.

[137] New explosives may also include nitrate-free and ammonia-free explosives solutions for the mining industry, but this potential reduction in ammonium nitrate consumption is not taken into account.

consumption, which is more than twice the global average. This points to both a critical need to decarbonise the mining sector to meet national decarbonisation targets, and a unique opportunity for the region to lead in pioneering solutions at mining sites.

In addition to switching to renewable electricity, a key focus is on reducing emissions from diesel-powered mobile equipment such as haul trucks, bulldozers and excavators. In October 2021, the International Council on Mining & Metals, which includes several mining companies operating in LAC, committed to achieving net zero Scope 1 and 2 GHG emissions by 2050, and launched the Innovation for Cleaner Safer Vehicles initiative to trial both hydrogen fuel cells and battery electric vehicles (BEVs) at surface mining operations. Hydrogen trucks are being considered given that fully electrifying the largest mining equipment may be challenging, requiring batteries in the megawatt hours (MWh) range (compared to less than 100 kWh batteries used in light EVs), which would enormously increase battery size and weight.

As both BEVs and hydrogen fuel cell vehicle technology for large mobile mining equipment are still in the demonstration phase, both alternatives are being considered by mining companies, given that there are uncertainties as to how the performance and cost of the technology will evolve, and thus which option would be the most cost effective. In 2022, Anglo American unveiled a prototype of a hydrogen-battery hybrid truck with a 0.8 MW hydrogen fuel cell capacity and a 290 t payload, and in January 2024, GM and Komatsu announced their collaboration to develop a 2 MW hydrogen fuel cell-powered mining truck with a 320 t payload. Elsewhere, in Australia, other companies such as BHP, Fortescue and Rio Tinto are prioritising batteries over hydrogen.

If the equivalent of 50% of diesel consumption in mining equipment in 2022 in LAC were replaced by low-emissions hydrogen, it would represent a demand for almost 0.8 Mt H_2. Fuel consumption for machinery could grow as mining in the region increases. Low-emissions hydrogen could therefore play a significant role in decarbonising mining in LAC, particularly in energy-intensive mining hubs such as Chile's copper mines, which account for around half of all diesel used by mining operations in the region.

Hydrogen and hydrogen-based fuels for aviation and shipping

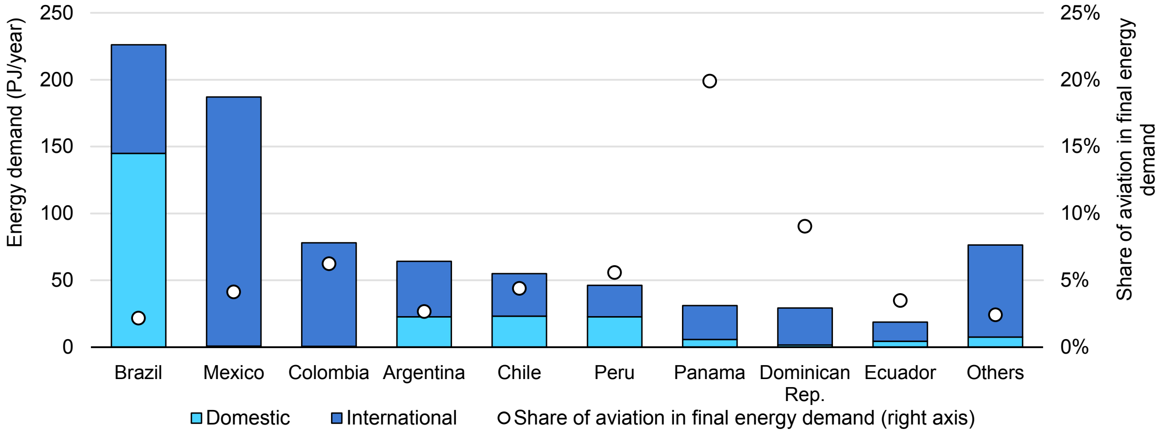
Aviation and shipping are sectors in which emissions are typically thought of as hard to abate, due to the size of the aircraft and vessels, and their long-distance operations, which limit the potential for electrification and increase reliance on fuel-based solutions for decarbonisation. Biofuels, such as biojet kerosene, can contribute to reducing the sector’s emissions, but their potential is limited by the amount of feedstock that can be sustainably sourced. Instead, synthetic fuels, produced from hydrogen and a sustainable carbon source, will become increasingly attractive over time given that the availability of sustainable biomass for biofuel production is limited (see Chapter 2. Hydrogen demand). Hydrogen can improve biomass-to-liquid production (via biomass gasification and Fischer-Tropsch synthesis) by increasing fuel yield. In addition, synthetic fuels can be produced from hydrogen combined with biogenic or atmospheric CO_2 sourced via direct air capture (DAC), although DAC technology remains costly. Harnessing LAC's abundant biogenic CO_2 resources – from bioethanol, biogas or the pulp and paper industry – together with its bioenergy potential, can significantly increase the region's capacity to produce low-emissions fuels for aviation and shipping. In the APS, demand for low-emissions hydrogen for the production of these fuels reaches up to 1.2 Mt by 2035 and more than 3 Mt by 2050.

Aviation fuels

Aviation is the fastest-growing transport mode in LAC. In 2023, the energy demand for aviation exceeded 800 PJ, equivalent to over 3% of the region's total final energy demand.[138] LAC accounts for almost 6% of global energy demand for aviation. Virtually all demand is satisfied with fossil fuels (jet fuel) leading to the emission of around 60 Mtpa CO_2. Demand is concentrated in a few key countries, with Brazil, Mexico and Colombia together accounting for more than 60% of regional aviation energy consumption (Figure 8.16), and being home to 13 of the 15 busiest domestic routes in the region. Within these countries, demand is equally concentrated, and the top five airports in each country represent more than 50% of the national fuel demand. This means that providing sustainable fuel to a relatively small number of airports would be sufficient to shift a relatively large share of the regional demand. There is a large variation in type of journey across countries: in Brazil, almost two-thirds of aviation energy demand comes from domestic flights, while the share in other large countries like Mexico or Argentina is much smaller, and the regional average is 29%.

[138] The total final energy demand excludes demand for international bunkering in aviation and shipping, but it is used here to provide a benchmark.

Figure 8.16 Energy demand for international and domestic aviation for the top consumers in Latin America and the Caribbean, 2023



Notes: Numbers for 2023 are estimates, since complete data for 2023 were not yet available at the time of writing. Fuel use for international aviation reflects fuel consumed by planes with an international destination, irrespective of the nationality of the airline. In some cases, the split in domestic and international aviation is based on estimates.

Aviation demand in LAC is concentrated, with three countries representing more than 60% of the regional energy demand for aviation.

Sustainable Aviation Fuels (SAF), such as biojet kerosene and synthetic jet fuel, can be used as drop-in fuels, requiring little to no modification to existing aircraft and using the existing transport, storage and distribution infrastructure. Currently, the American Society for Testing and Materials standards allow up to 50% of synthetic fuel to be blended with jet fuel, a share that could potentially increase in the future, allowing the use of pure synthetic fuel. Meeting 50% of today's aviation fuel demand in LAC entirely with synthetic fuels would require 30 Mt CO_2 per year[139] for fuel production (see CO_2 supply and demand section). Satisfying 50% of the regional demand with synthetic fuels would require nearly 6 Mtpa of electrolytic hydrogen, which would require 60-70 GW of electrolysis and 80-170 GW of renewable capacity.

SAF production in LAC is currently limited to biofuels, and there is limited support for synthetic fuels, with 19 projects announced and 7 refineries planning to process biofuels. Chile and Brazil are the only countries that have a SAF policy in place. In April 2024, Chile launched a SAF roadmap that includes a workplan for developing a regulatory framework by 2026 and the first domestic SAF pilot plant in 2030, and sets a target of 50% SAF by 2050. Brazil supports SAF uptake through its RenovaBio programme, and the National Aviation Biofuel Programme (ProBioQAV) in Brazil is part of the "Fuel of the Future" Act which was passed by

[139] Future demand is expected to grow, with the extent of this growth dependent on improvements in fuel efficiency and increases in aviation activity.

the Congress in September 2024. The bill introduces a GHG reduction target of 1% in 2027, increasing to 10% in 2037, which could trigger SAF demand, although a large part of it may come from biofuels (SAF from HEFA [hydroprocessed esters and fatty acids]), particularly at the outset. The 2031 10-year energy expansion plan foresees SAF uptake of 1.4% by 2031. Colombia is preparing a SAF roadmap as part of its Climate Action Act to be published by the end of 2024. Alternative policies relevant to SAF include tax exemptions, which are already common in the region for the supply side (see Chapter 6. Policies), mandates, and crediting schemes (as already used in Brazil in the RenovaBio programme, for example).

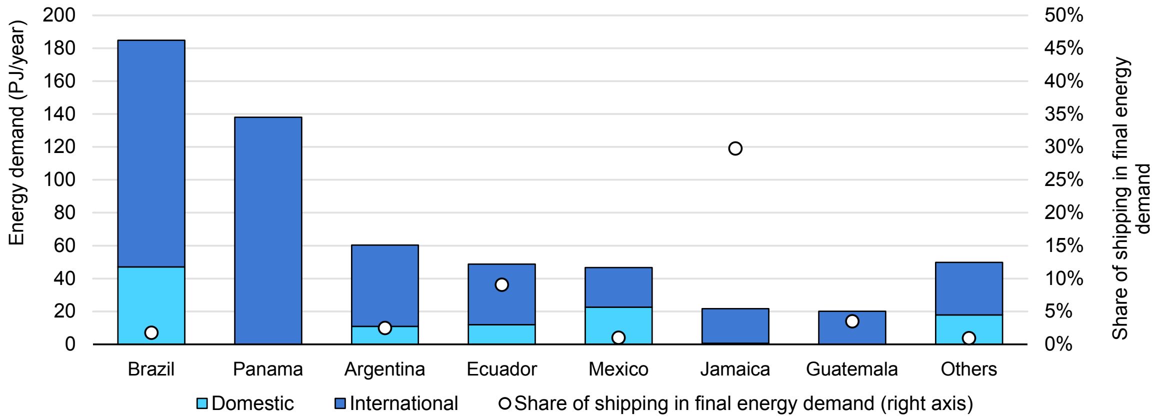
Certification will be critical to scaling up SAF uptake, so that the fuel can be clearly recognised for the lower emissions resulting from its production. Towards this aim, ongoing efforts to certify hydrogen, including from Brazil and Colombia (see Chapter 6. Policies), would need to be extended to hydrogen derivatives like synthetic fuels. This would also require the definition of standards and methodologies for accounting for the CO_2, which is critical to estimating the lifecycle GHG emissions from synthetic fuels (see Chapter 7. GHG emissions of hydrogen and its derivatives). Experience gained from biofuels certification, which already exists in Brazil, would be useful when setting up a certification scheme for synthetic fuels.

Shipping fuels

In 2023, the energy demand for shipping in LAC reached over 570 PJ, representing almost 5% of global energy demand for shipping. This demand is concentrated in a few countries, with Brazil, Panama and Argentina representing over two-thirds of the regional energy consumption for shipping (Figure 8.17). Panama alone accounts for almost a quarter of the total energy demand from shipping, mostly for international shipping due to the traffic through the Panama Canal. Virtually all of LAC's shipping demand is currently satisfied with fossil fuels (fuel oil and gasoil) leading to the emission of over 40 Mtpa CO_2. Over 8 000 ships (almost 8% of the global fleet), with a total tonnage equivalent to 16% of the global total, were registered with Panama's flag in 2022, emitting over 110 Mtpa CO_2,[140] second only to Liberia as the country with most emissions from ships under their flag. The total value of merchandise traded by ship from LAC was USD 1.4 trillion in 2023 (accounting for almost 6% of the global total). In 2022, nearly a 15% of the value trade in both imports and exports were intra-regional. In 2024, LAC represents over 21% of the global shipping tonnage.

[140] Notably, these ships are registered with Panama's flag, but they do not necessarily have to perform journeys from or to Panama ports, so the energy consumption is allocated to the countries that ships depart from or arrive in, and the CO_2 emissions are allocated to international shipping overseen by the IMO.

Figure 8.17 Energy demand from international and domestic shipping for the top seven consumers in Latin America and the Caribbean, 2023



Notes: Energy demand from shipping represents almost 90% of the final energy demand in Panama, but it is excluded to avoid distortion of the secondary Y-axis. Numbers for 2023 are estimates, since complete data for 2023 were not yet available at the time of writing. Fuel use for international shipping reflects fuel consumed by ships with an international destination, irrespective of the nationality or flag of the ship. In some cases, the split in domestic and international shipping is based on estimates.

Three countries represent more than two-thirds of regional energy demand for shipping.

The low-emissions synthetic fuel alternatives for shipping considered in this report are ammonia and methanol, and the pipeline of demonstration projects for alternative fuels is growing. By mid-2023, there were more than 370 pilot projects around the world, but just 2% of these were in Latin America. However, even if these fuels reach cost parity with heavy fuel oil, their widespread use as shipping fuels will require significant investments in compatible bunkering infrastructure and ships.

The investment needs for fuel supply can also be significant. For example, satisfying 10% of the current fuel demand from shipping in the region would require 3.1 Mtpa of ammonia (0.5 Mtpa of hydrogen). Producing this amount would require 5-7 GW of electrolyser capacity and between 7 GW of onshore wind or 15 GW of solar PV. The total production that could be achieved if all announced projects for low-emissions ammonia are realised (almost 2.8 Mtpa of hydrogen by 2030, or 1.8 Mtpa if excluding projects at very early stages of development) would be more than enough to satisfy this demand. However, part of this will be used to satisfy the existing ammonia demand as industrial feedstock (mainly for fertilisers). About 0.2% of this capacity is in operation, has reached FID or is at the construction stage, and almost 40% is at the concept stage, so there is a great deal of uncertainty about most of these projects.

Panama adopted a hydrogen strategy in April 2023, which sets targets for 2030 of 5% of bunkering supply being from hydrogen derivatives, including domestic production of 0.5 Mtpa H_2. By 2040, these would increase to 30% and 2 Mtpa H_2, respectively, and by 2050, to 40%. Brazil has a dedicated Marine Fuels subcommittee within its Fuels of the Future Act. At COP 26, Chile and Costa Rica signed the Clydebank Declaration, an initiative to support the development of green shipping corridors between two or more ports, with a collective target to have at least six green shipping corridors by 2025. Nevertheless, out of 44 green corridor initiatives globally in 2023, only 4 are in Latin America.[141]

CO_2 supply and demand

CO_2 embedded in synthetic fuels and urea is ultimately released upon final use. As such, for these fuels to be sustainable, the CO_2 must be biogenic or directly captured from the air (see Chapter 7. GHG emissions of hydrogen and its derivatives). If fossil CO_2 is used, overall emissions are reduced, since the CO_2 is used two (or more) times, but the system cannot achieve zero emissions. Another option is to use CO_2 from unavoidable CO_2 emissions, such as in cement production, where two-thirds of the CO_2 emissions are process emissions (limestone) rather than from fuel combustion.

Carbon-containing low-emissions jet fuel and methanol for shipping would require a massive increase in CO_2 utilisation. DAC of CO_2 could provide a potentially unlimited source of CO_2 feedstock with no geographic constraints, but it is expected to remain a high-cost option in 2030. In the short term, therefore, it seems more likely that biogenic CO_2 sources would be used.

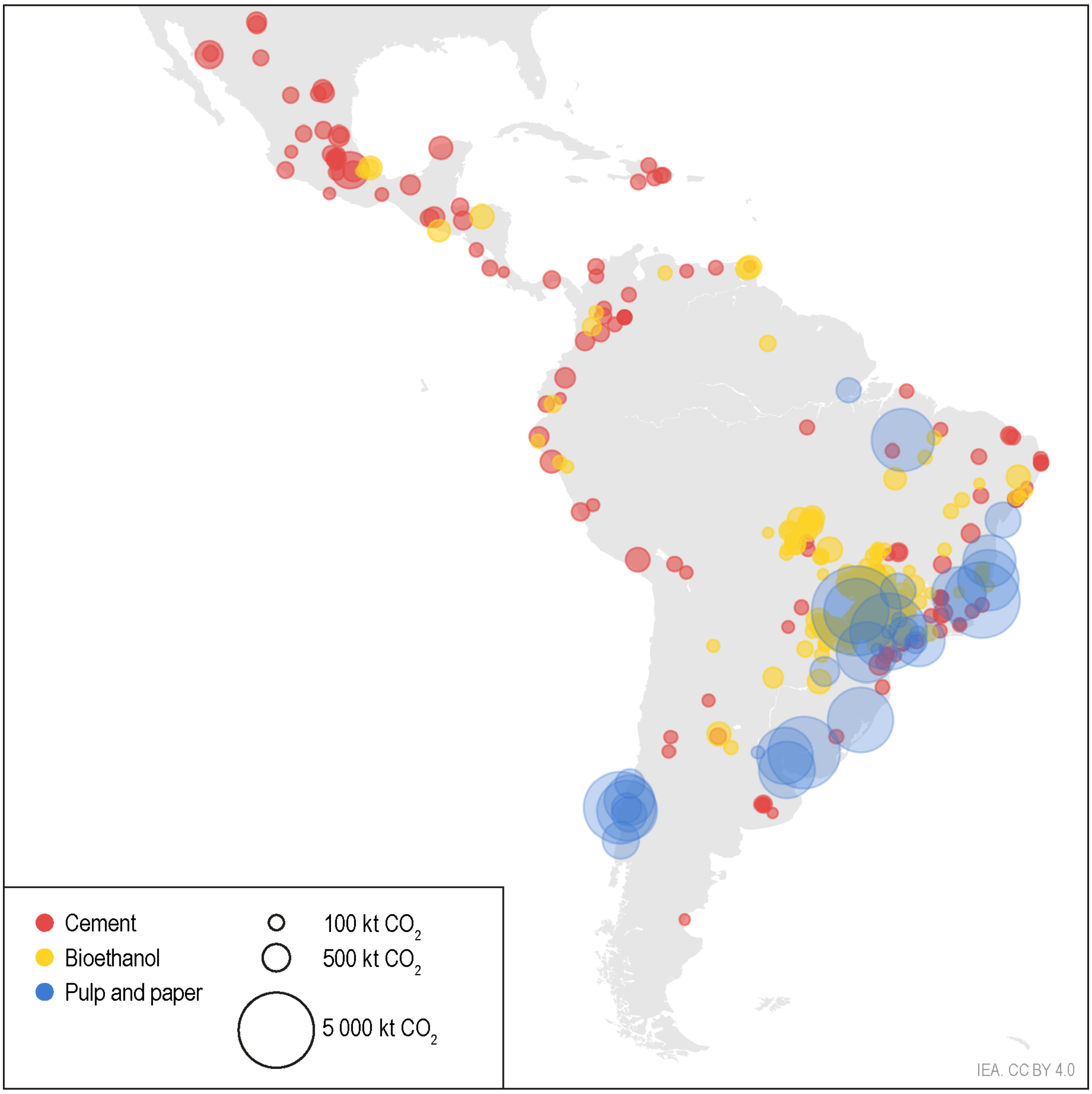
Biofuels production offers a significant potential synergy, as by-product CO_2 from bioethanol and biogas plants is among the cheapest (USD 20 – 30/t CO_2) sources of CO_2, as it is concentrated. As these resources may not be enough to cover the entire demand, they could be supplemented by CO_2 from pulp making, albeit at a higher cost (USD 70 – 80/t CO_2), as the CO_2 is more dilute in the flue gas.

Pulp and paper production is the largest source of biogenic CO_2. Pulp production in LAC was nearly 34 Mt in 2022, resulting in a potential supply of around 70 Mtpa CO_2.[142] Almost three-quarters of production came from Brazil, which together with Chile and Uruguay represented almost 96% of regional production. In Brazil, Eletrobras, a major utility company, and Suzano, a pulp and paper company, are exploring the production of synthetic fuels from biogenic CO_2 and renewable hydrogen. Similarly, there is a large potential for biogenic CO_2 as a by-product of ethanol production,[143] with Brazil representing almost 85% of the regional production capacity. In 2023, Brazil produced 33.6 billion litres of ethanol (30% of

[141] Of which three are in Chile (copper concentrate to China, sulfuric acid for mining, and aquaculture), and one is in Panama.
[142] Assuming a co-production of 2-3 tonnes of biogenic CO_2 per each tonne of dry-pulp, depending on the process configuration and the type of feedstock.
[143] Additional biogenic CO_2 resources in the region, such as those from the combustion of sugar cane bagasse and other residual biomass, are not included in this report.

global production) compared to 2.3 billion litres in the rest of LAC. For cement, Brazil and Mexico are the only LAC countries in the global top 14 producing countries, and together they represent less than 3% of global production.

Figure 8.18 Available biogenic and unavoidable CO_2 sources in Latin America and the Caribbean, 2023



Note: Only plants that emit more than 90 ktpa CO_2 are illustrated.
Source: IEA analyses based on IEA (2024), Renewables 2023; Climate TRACE (2024), Emissions Map.

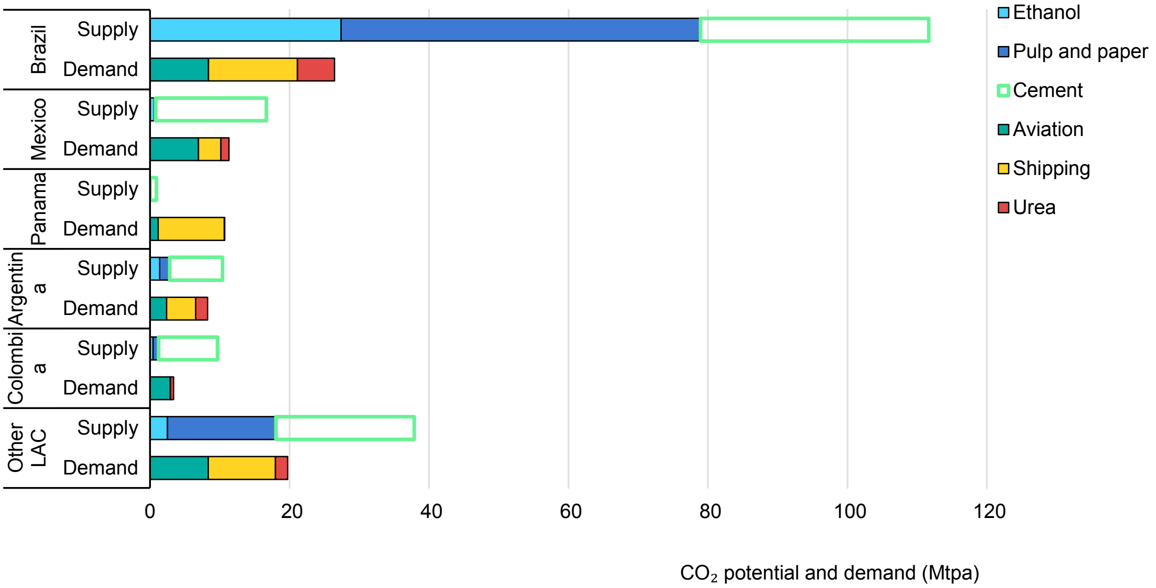
In LAC, there are large CO_2 resources from the pulp and paper industry and from decentralised bioethanol plants, which may require CO_2 handling infrastructure.

As an alternative, CO_2 from cement plants could also be used. While the use of this CO_2 in the production of synthetic fuels is not carbon neutral, it has been accepted by some regulations as a transitional measure to create scale, reduce costs and build up the market while other CO_2 sources become available at scale and more competitive cost. This is the case in the European Union, where nonpower CO_2 sources covered under the Emissions Trading System (which includes cement), can be counted within Renewable Fuels of Non-Biological Origin (RFNBO) regulations until 2041. Using 20-70% of the CO_2 from cement production would be enough to cover the CO_2 supply gap in most countries, even if alternative materials and technological change reduce this source of CO_2.

The geographical location of available biogenic CO_2 and places where it could be used must also be considered (Figure 8.18). For example, the bioethanol plants in Brazil are mostly located in the centre and south-west, and while that region also has the largest airports (São Paulo, Campinas, Rio de Janeiro) and largest port (Porto de Santos), there is also demand in the east of the country (e.g. in the states of Ceará and Piauí), which is relatively far from the biogenic CO_2 supply. Resolving this would require either CO_2 transport infrastructure (if volumes are large enough to justify it) or DAC – both at additional cost – or tapping into other unavoidable CO_2 sources, like cement.

Overall in LAC, 30 Mt CO_2 would be needed to satisfy 50% of today's aviation demand with synthetic jet fuel, nearly 40 Mt CO_2 to satisfy 100% of today's shipping demand with methanol, and 10 Mt CO_2 to meet all of today's urea demand, together these would be equivalent to 100% of LAC's potential supply of biogenic CO_2. The largest CO_2 demand would be from Brazil, at over 26 Mtpa CO_2, but Brazil also has the largest potential supply of biogenic CO_2, being the regional leader in ethanol and pulp and paper, with the result that potential supply is almost four times the demand. While there is more than enough biogenic CO_2 in the entire region, countries such as Argentina, Colombia, Ecuador or Mexico may face a domestic shortage, and need to explore alternative CO_2 sources. Meanwhile, countries with a surplus of biogenic CO_2, such as Uruguay or Brazil, could strategically use this surplus to produce and export low-emissions hydrogen-based fuels, creating added value compared to exporting hydrogen alone.

Figure 8.19 CO_2 supply potential and CO_2 demand for synthetic fuels and urea, 2023



Notes: Only ethanol plants larger than 120 million litres are included; 50% of energy demand for aviation considering a maximum blending of synthetic fuels; 100% of supply shown for pulp and paper and cement and 100% of demand shown for urea production and methanol for shipping. Demand for domestic and international aviation and shipping included.

Sources: IEA (2024) Renewables 2023, Food and Agriculture Organization, Climate Trace, International Fertilizer Association.

Some LAC countries have a surplus of biogenic CO_2 compared to domestic needs for urea or aviation and shipping fuels, while others have limited supplies and will need to find alternative sources.

Refining

Refining throughput in LAC was nearly 3.8 mb/d in 2023 with more than half from Brazil alone. Hydrogen demand in refineries is proportional to the throughput and the sulphur content of the crude.[144] Total hydrogen demand was about 1 Mt H_2 in 2022, with most of the demand concentrated in Brazil (300 kt H_2), Mexico (200 kt H_2), Colombia (140 kt H_2), and Argentina (110 kt H_2). In the future, electric vehicle (EV) adoption could reduce the demand for oil, and thus decrease refinery throughput and shift the product slate from gasoline to diesel. These two factors could affect the total hydrogen demand and the share of dedicated hydrogen production. However, EV sales are relatively low across LAC, with only Costa Rica reaching a share greater than 4% in 2023, a threshold that was surpassed in China – the world's leading EV market – in 2018. On the basis of already implemented and announced policies, oil demand in LAC is expected to remain flat to 2030, but a larger reduction in demand could start impacting hydrogen demand post-2030.

[144] Hydrogen is used in refineries for hydrotreatment (removing impurities, especially sulphur) and hydrocracking (upgrading heavy residual oils into higher-value products).

Refining could be a leading sector for the deployment of low-emissions hydrogen in LAC, given that hydrogen is already used and no modifications would be needed in order to switch. The sector could also provide economies of scale. A refinery of 100 kb/d capacity could require an electrolyser of nearly 500 MW to fully satisfy its hydrogen demand. Large-scale projects of this kind could be especially valuable for developing experience at the national level among project developers, financial institutions, engineering and construction companies, and other stakeholders in the supply chain. Chile already has a 1 MW project under construction in Magallanes, and Colombia has 60 MW projects undergoing feasibility studies for the Cartagena and Barrancabermeja refineries.

National oil companies could play a role in the uptake of renewable hydrogen in refineries. In Colombia, Ecopetrol has set a target to reduce CO_2 (scope 1 and 2 emissions) by 25% (compared to 2019) and estimates a potential hydrogen demand of 1 Mtpa in 2040. Further, it estimates that low-emissions hydrogen could deliver 9-11% of its 50% CO_2 reduction target (scope 1-3) by 2050, with investment needs of USD 2.5 billion. In Brazil, Petrobras targets a 30% reduction in absolute CO_2 emissions by 2030 (from a 2015 baseline). Towards this goal, it foresees an investment of USD 300 million in hydrogen and CCUS for the 2024-2028 period (out of a total investment of USD 102 billion). Petrobras aims to increase its R&D budget for low-carbon technologies from 15% in 2024 to 30% in 2028, has set up a USD 1 billion fund for the decarbonisation of its scope 1 and 2 emissions, and has joined the national hydrogen association (ABH2). In Mexico, in March 2024 Pemex published its 2050 sustainability plan, which includes low-emissions hydrogen imports from the United States starting in 2030-2035, and domestic production from 2035. In Argentina, YPF published its 2023-2027 business plan in September 2023, targeting a 30% reduction in emissions intensity by 2030 (compared to 2017). Renewable hydrogen from wind power in Patagonia is covered, but no specific capacity or investment targets are defined.

Moving towards implementation

LAC has significant potential for cost-competitive production of low-emissions hydrogen and can count on existing demand for hydrogen, both directly and through imported products such as fertilisers. However, despite this potential, only 0.1% of announced low-emissions hydrogen projects for 2030 have reached FID, with 85% of these projects targeting the gigawatt scale and requiring multi-billion-dollar investments. This has led to doubts about the achievability of hydrogen announcements in the region, and to considerable uncertainty about how many of these projects will materialise in the next decade. As a result, it is not clear that LAC will be able to exploit the opportunities that the development of a low-emissions hydrogen industry could bring about.

In this section, we outline the role that regional hydrogen hubs could play in helping governments and industry stakeholders to kick-start the development of supply chains for low-emissions hydrogen and hydrogen-based fuels in LAC.

Creating the first hydrogen hubs in LAC

The terms hydrogen hub, hydrogen cluster and hydrogen valley are often used interchangeably to refer to a network of hydrogen and hydrogen-based fuel producers and potential users – and infrastructure connecting the two – within the same geographical area. These hubs can act as nodal centres for the development of larger networks and present several benefits in this moment of early market stage development, such as:

- Creation of scale through pooling supply and demand.
- Enhanced co-operation among co-located stakeholders, gaining access to a wider range of diverse skills and strengths.
- Limiting the need for new hydrogen infrastructure, and enabling its shared use among a larger group of stakeholders, who also share any risks associated with its development.

Overall, these benefits result in lower production and transport costs by maximising asset utilisation and enabling economies of scale. Through the development of hydrogen hubs, LAC can progressively scale up low-emissions hydrogen production and use, and in parallel create a skilled workforce that can gain experience as the sector matures. Rather than targeting gigawatt-scale projects from the outset, as more than 85% of announced projects do, the region could instead identify and develop its first scalable projects in the hundreds of megawatts. This approach would allow the region to avoid making errors associated with over-optimistic expectations (which have been seen elsewhere), thereby creating a more sustainable path for hydrogen to play a role in the economy.

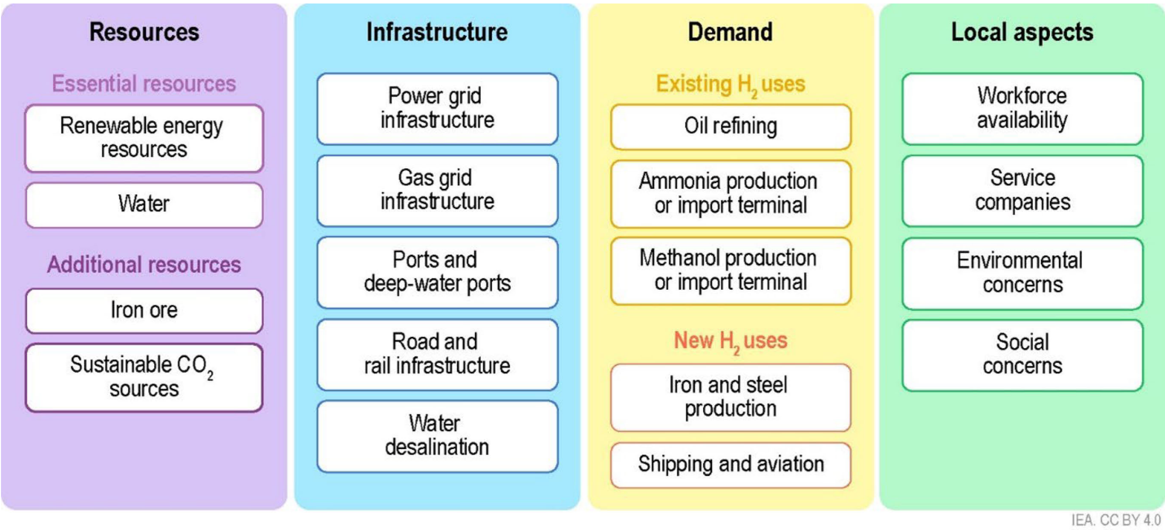
Some countries have already taken the first steps for the development of hydrogen hubs and have committed significant funding to this aim, such as the Regional Clean Hydrogen Hubs (H2Hubs) programme in the United States, the Regional Hydrogen Hubs programme in Australia and the Hydrogen Valley Facility in the European Union. Brazil has announced the Pró-Hubs Program, with the first call for proposals expected in 2024. Hydrogen hubs have the potential to help LAC countries accelerate low-emissions hydrogen production and uptake, and some countries are already starting to assess this opportunity.

Factors to identify the potential for hydrogen hubs

Identifying the right locations for hydrogen hubs is fundamental to increasing their chances of success. Several factors need to be considered, such as the availability of abundant renewable energy resources like solar, wind or hydroelectric power. Hub locations should have sufficient electricity transmission capacity and be close to centres of demand. In addition, access to sustainable CO_2 sources may enable the production of low-emissions hydrocarbon fuels, creating further opportunities. Existing infrastructure and the possible need for upgrades can also impact the feasibility of the development of a hydrogen hub. This includes addressing potential bottlenecks in the electricity transmission network and extending it where necessary, the availability of natural gas infrastructure and the technical and economic feasibility of repurposing it for hydrogen and hydrogen-based fuels, the presence of port facilities and the potential need to develop new storage and bunkering capacities at those facilities, and the existence of deep-water port terminals for the export of liquefied gases, such as ammonia. Other social and environmental factors can enable or hinder the successful development of a hub. For example, the availability of water resources is crucial, requiring an assessment of freshwater availability to avoid conflicts with other users, as well as consideration of the need to develop infrastructure for desalination, distribution and wastewater treatment.

By considering all these factors (Figure 8.20), regions can effectively assess and identify the locations potentially best-suited to hydrogen hubs that could make use of their natural resources and infrastructure assets to support the deployment of low-emissions hydrogen. This comprehensive approach will ensure that as many as possible (if not all) the necessary components are in place to facilitate the first hydrogen hubs.

Figure 8.20 Factors affecting the potential location of hydrogen hubs



The potential for hydrogen hubs in different locations is influenced by a combination of resources, infrastructure and existing and scalable demand, as well as other local factors.

Types of hydrogen hubs in Latin America and the Caribbean

There is no standardised taxonomy to classify the different archetypes of hydrogen hubs. For example, the Hydrogen Valleys Platform of Mission Innovation's Clean Hydrogen Mission described three archetypes of hydrogen valleys based on their size, the main end-uses for hydrogen considered in each valley, and the potential for exports of hydrogen and hydrogen-based fuels. The development of hydrogen hubs can follow different strategies based on resource availability and current and future demand. Moreover, it is important to note that a hydrogen hub can serve multiple purposes and can evolve over time as the hydrogen market matures. Based on the analysis performed in this report, we have defined three potential hydrogen hub archetypes that are particularly well suited to the characteristics of the LAC region, and that can help the region to scale up the production and use of low-emissions hydrogen in the short and medium term (Figure 8.21).

Hydrogen industrial demand hubs

Globally, manufacturing activities that produce, transport and consume large amounts of energy are typically concentrated in major industrial centres. These industrial centres bring large existing hydrogen demands (in refineries, fertiliser plants and chemical plants), which will require low-emissions hydrogen to replace unabated fossil-based hydrogen and decarbonise their operations, together with other large industrial producers (like steel plants, glass and ceramic manufacturers and other industrial operations that require high-temperature heating), for which low-emissions hydrogen can play an important role in replacing fossil fuels to abate their GHG emissions. These industrial centres offer a unique opportunity for hydrogen demand hubs to emerge nearby and make use of the enormous demand that is potentially available. In LAC, many such industrial centres are located in or close to areas with good renewable energy potential, which could facilitate the production of low-emissions hydrogen near to the end users, thereby limiting the need to develop specific infrastructure, which would be a costly and lengthy process. Moreover, these hubs can attract additional industries to locate nearby, due to the combination of low-cost renewable energy, enabling infrastructure, and essential feedstocks, such as iron ore for near-zero emissions steel production or sustainable CO_2 for methanol production.

The list below includes some examples of regions in LAC, which – based on their industrial activities, good renewable energy resources and existing infrastructure – have the potential to become hydrogen industrial demand hubs:

- Brazil: The southeastern and southern regions of Brazil, particularly around Rio de Janeiro, São Paulo and Minas Gerais, which are all major industrial centres. These areas are home to extensive refining and steelmaking activities. São Paulo and Mato Grosso do Sul have significant CO_2 resources, and the port of Tubarão in Espírito Santo, which is one of the world's largest iron ore export terminals, offers potential for the export of HBI.

- Colombia: The areas around Cartagena and Barranquilla have relevant industrial activity, particularly oil refining, ammonia production and fertiliser manufacturing. Barranquilla also has an ammonia receiving terminal at its port. The region has strong potential for renewable energy.
- Mexico: The northeast region, particularly around Nuevo León, which is the country's leading region in terms of industrial production. Nuevo León has significant industrial activity relevant to hydrogen production and use, including oil refining and steel production. The region benefits from good renewable energy potential in neighbouring Tamaulipas, and has the potential to develop a corridor to adjacent states such as San Luis Potosí and Guanajuato, which also have steelmaking and refining activities.
- Chile: The Antofagasta region, located in the Atacama Desert, offers high solar irradiation potential, i.e. low-cost solar PV electricity. The region's proximity to domestic demand areas, including the mining sector, and already existing infrastructure, including port terminals, desalination plants and railway access, facilitate the potential for hydrogen production and export.
- Argentina: Bahía Blanca has potential as a hydrogen hub due to its industrial port with an ammonia plant using natural gas. It is located in an area with strong wind conditions and carbon sources from existing industries that could be used for hydrogen-based fuels.

Hydrogen bunkering and distribution hubs

Major ports and airports are expected to play an important role in the scale-up of production and use of low-emissions hydrogen and hydrogen-based fuels. They will be particularly well positioned to become hubs focused on the storage and bunkering of these fuels, which could support the decarbonisation of shipping and aviation activities, and also enable trade of low-emissions hydrogen-based fuels as global markets develop.

Many ports and airports in LAC have access to low-cost renewable energy and abundant feedstocks of sustainable CO_2, meaning that demand in shipping and aviation is located in places with strong potential to produce low-emissions jet fuel, methanol and ammonia for the decarbonisation of these activities. In Mexico, plans have been announced to offer hydrogen-based fuel for bunkering at the port of Salinas Cruz, Oaxaca. This initiative is linked to the Interoceanic Corridor of the Isthmus of Tehuantepec, which aims to link the Atlantic and Pacific coasts, increasing the role of their ports. In addition, the nearby refinery could become a major user of hydrogen in the future, further enhancing the strategic importance of the port.

Other major ports in the region, which are part of today's major transport corridors, may not be able to count on world-class resources for the production of low-emissions hydrogen-based fuels, or may have limited space available for production. However, they can still act as distribution clusters, importing low-emissions hydrogen-based fuels from other regions, storing and bunkering these fuels for ships, or enabling their global trade. A clear example is Panama, which today accounts for one-quarter of all fuel used for international bunkering in LAC, given the importance of the Panama Canal, and has set targets for the provision of hydrogen-based fuels for bunkering through 2050.

Hydrogen supply hubs

There are several regions across LAC that have extraordinary renewable energy potential and sufficient space to accommodate large-scale generation, but are relatively remote, with limited industrial demand. Some have access to existing port infrastructure or could develop it in a relatively short space of time. These areas could provide a great opportunity to develop hydrogen supply hubs with a focus on the production of hydrogen and hydrogen-based fuels for export, either to other LAC countries or to global markets once they develop. In some areas, access to sustainable CO_2 could further enhance competitiveness in the production of low-emissions carbon-based fuels. Initially, these hubs would focus on the production of low-emissions hydrogen and hydrogen-based fuels for export. As the market matures and infrastructure development progresses, hubs of this kind could eventually attract energy-intensive industries to the regions, leveraging the abundant renewable energy resources, leading to the creation of jobs and wealth.

Magallanes in Chile, La Guajira in Colombia, or Ceará (through the Port of Pecém) and Pernambuco (Port of Suape) in Brazil each combine excellent renewable energy potential (particularly onshore and offshore wind) with limited industrial activity, and are excellent examples of regions that could become hydrogen supply hubs. Brazil is building the Transnordestina railroad, a rail network that will connect the ports of Pecém and Suape to the state of Piauí, facilitating the transport of iron ore and fertilisers, among other commodities, and improving the regions' logistical capabilities.

Uruguay could also become an example, thanks to its strong renewable energy potential, experience in handling large shares of variable renewable energy in the matrix, and available CO_2 from the pulp and paper industry. However, the remoteness of some of these regions often means they encompass vast natural areas that require protection. Moreover, many of them are home to indigenous communities, which brings additional social considerations when assessing the opportunities and challenges of developing hydrogen hubs in these regions.

Figure 8.21 Potential first hydrogen hubs in Latin America and the Caribbean

Several hydrogen hubs could emerge in LAC for different purposes, such as industrial demand aggregation hubs, bunkering hubs or supply hubs in more remote areas.

These hub types provide a framework for understanding the different roles that hydrogen hubs can play. They highlight the flexible and dynamic nature of hydrogen hubs, which can adapt and expand their functions as technologies and markets evolve.

Near-term actions to foster first hydrogen hubs

Policy makers have a critical role to play in enabling the emergence of hydrogen hubs given the absence of a market and limited low-emissions supply. In this section, we consider essential areas for policy action, looking at the current status of each area, its relevance, challenges and alternatives for policy makers.

Certification

Certifying hydrogen and hydrogen-based fuels (as well as the end-products manufactured with them) is fundamental for LAC countries, given the focus on exports and need for emissions accounting as hydrogen crosses borders. LAC countries will also need to ensure interoperability between their schemes and those of the export markets, and to understand how such requirements can be adapted to the local context. Certification is also essential when considering hydrogen derivatives and carbon-based fuels, due to the additional conversion steps and requirement for CO_2. In the LAC context, as the market matures, a critical feature of certification will be the inclusion of sustainability attributes beyond GHG emissions, to cover aspects such as land use, water consumption and social impacts.

The region is not starting from scratch (see Chapter 6. Policies). Brazil is developing a voluntary certification scheme and has defined a GHG threshold of 7 kg CO_2-eq/kg H_2 for low-emissions hydrogen, as well as a preliminary governance structure and roles for government agencies. This is higher than the 3.4 kg CO_2-eq/kg H_2 defined for renewable hydrogen in the European Union[145] and the 4 kg CO_2- eq/kg H_2 defined for clean hydrogen in the United States. Colombia has defined different types of hydrogen and has suggested the introduction of a certification scheme, with initial efforts on certification emerging from a voluntary scheme spearheaded by the private sector, which is currently under development. Chile is developing a support study that will inform the design of its own certification scheme. The region is already striving for harmonisation. At COP 28, 14 LAC countries endorsed a regional certification scheme (CertHiLAC) that is consistent with international standards, but considers the specificities of the region. At the international level, Antigua and Barbuda, Brazil, Chile, Paraguay and Uruguay endorsed the declaration of intent for the mutual recognition of certification schemes launched at COP 28, which seeks to facilitate mutual recognition and to use the ISO Technical Specification to drive standardisation across countries. The Netherlands, together with Chile and Uruguay, have assessed the local conditions for compliance with EU regulation for hydrogen derivatives, extending beyond GHG emissions to cover water and social criteria as well. Findings include that Uruguay and Chile can be each considered as a single bidding zone, which means no efforts are needed to demonstrate compliance with the geographical correlation criterion in the regulation, but additional work would be needed to translate this concept to more LAC countries.

145 The standard for the European Union is well-to-wheel, while the standards for Brazil and the United States are well-to-gate (a smaller scope than well-to-wheel).

Both countries can use the guarantees of origin scheme in place for the renewable input for hydrogen. Chile is expected to be a high water stressed-region, and ensuring compliance with the social standards might require further efforts.

The next step for LAC countries is to provide more detail on the certification schemes and how to operationalise them. This means going from definitions of terms to specific rules for GHG accounting, boundary definitions, criteria for energy and material input, links with incentives, and clarity on how these rules will change over time (if at all), as has been done in other regions. This is essential for project developers, who need clarity on the criteria they will need to navigate and on whether they will need to comply with multiple schemes (since many of the projects announced are targeted for export), which would also provide better long-term visibility on the financial outlook for their projects. LAC countries should ensure consistency not only with the schemes from large importers, but also with the ISO Technical Specification. This would facilitate mutual recognition of certificates and allow a certain level of interoperability with other markets.

Most schemes and initial efforts have focused on hydrogen as a final product. Yet as we show in this chapter, the production of hydrogen derivatives represents an opportunity to capture more value from the supply chain, to develop domestic industry, and to increase the overall macroeconomic benefit. Certification schemes should, therefore, also work towards broadening their scope to include hydrogen derivatives, ensuring consistency with parallel efforts for various commodities (e.g. steel), as well as for the CO_2 input in case of carbon-derived fuels.

LAC countries could also consider how incentives align with certification schemes. Several LAC countries have tax incentives in place, but so far, there is little correlation between the GHG mitigation provided by projects and the incentives they are eligible for. This will be especially important to consider as the market scales up.

Opportunities for national oil companies

National oil companies (NOC) in LAC have ambitious decarbonisation plans, large annual investment budgets, and a skilled labour force that could be transferred to clean technologies like hydrogen. They operate the refineries that use hydrogen at large scale today, and which produce oil derivatives that are used by the petrochemical industry, which will also need to transition to low-emissions hydrogen. This provides an opportunity to build on existing relationships with other stakeholders in LAC's industrial demand hubs to unlock synergies in hydrogen supply, and in infrastructure planning and development. NOC also have close ties to national governments and have a large share of national gas production. All these factors put them in a unique position to make investments in low-emissions hydrogen, allowing them to develop experience and become frontrunners in this area, and to diversify their portfolios by tapping into a new market with different price dynamics (to oil and gas).

The region's NOC could leverage their substantial balance sheets to venture into hydrogen development, and some are already doing so. Brazil, Colombia and Mexico have the largest NOC in the region, with combined assets worth almost USD 350 billion and average annual investments of USD 26-45 billion in the past couple of years. To give a sense of the magnitude of these numbers, satisfying the entire current hydrogen demand in LAC with renewable hydrogen would require an investment in the order of USD 95-100 billion (including for the renewables assets).

NOC could also tap into newly issued debt and equity. With regards to debt, one challenge for NOC is that their bonds are not investment grade, which would limit access to international debt markets, so they would need to rely on domestic public funds. Furthermore, existing liabilities and interest repayment can present challenges for acquiring new debt (e.g. total debt for Pemex [Mexico] was over USD 105 billion in 2023, equivalent to 5.6% of national GDP, and most of it in hard currency). This still leaves open the possibility to raise new equity. For example, Petrobras (Brazil) had a market valuation of over USD 100 billion at the end of 2023.

Demand creation measures

Policy makers have several available tools to help create a market for low-emissions hydrogen, such as measures that target volume or price. One is in the form of regulation, such as quotas for specific applications. While there are no quotas legislated yet, some LAC countries have introduced sectoral targets that go in this direction. For example, Colombia has proposed a 40% target for low-emissions hydrogen in the industrial sector (for existing applications) in its hydrogen strategy and Panama has a target of 5% of bunkering supply being from hydrogen derivatives (for new applications). Demand-side incentives will be needed in order to achieve these targets.

While most LAC countries have an explicit target for hydrogen production or electrolyser capacity, there are few examples of targets for end-use sectors. One reason for this is the focus on exports rather than domestic demand, which means that the development of the domestic hydrogen industry is dependent on uptake in other regions and the emergence of a global market. To reduce this risk, a phased approach for the development of the hydrogen industry could be used, starting with domestic demand. Many strategies already consider this approach, which should be carried through into implementation. Where already in place, targets for the demand side should be translated into specific laws or incentives. For example, Argentina, Chile and Colombia have set targets for end-use applications in their strategies. The next step would be to identify the concrete actions, funding programmes or laws that would be needed to increase the chances of achieving those targets. Similarly, several LAC countries have tax incentives in place (see Chapter 6. Policies), but all these incentives are related to electrolysers (i.e. the supply side). There are no examples of equivalent tax incentives for the demand side. This is an area where learning from international practices (e.g. the ReFuelEU regulation in the European Union, which sets specific targets and milestone years for hydrogen-derived fuels in aviation, or H2Hubs in the United States) would be useful. An approach that seeks a balance between supply-side and demand-side incentives could help trigger domestic demand and promote a shift of existing applications to low-emissions hydrogen.

An advantage of the hydrogen hubs approach is the natural demand aggregation and synergistic effects of multiple users. While many stakeholders within the same geographical areas already interact, hydrogen hubs also bring in new actors like project developers, equipment manufacturers, infrastructure and port operators. Policy makers could facilitate the emergence of new projects and hubs by setting up platforms where these different actors can connect (see Box 2.2). This is already happening to some extent through national hydrogen associations, and regionally through H2LAC, but public platforms that both connect stakeholders and provide an overview of the incentives in place and the administrative processes to follow, with a single point of contact, would facilitate project development. Governments could also explore the option of using state owned enterprises (SOEs) – particularly NOC – as demand aggregators. SOEs could launch calls for tenders for low-emissions hydrogen (and derivatives) and issue long-term contracts for purchasing them at a fixed price, which could provide offtake certainty (a key risk preventing projects from moving ahead – see Box 3.1) and contribute to price discovery and transparency. The hydrogen (and its derivatives) purchased could then be sold to a larger pool of potential domestic end users, as aggregating demand enables economies of scale that individual companies would find difficult to achieve if they purchased separately. The government of India is currently piloting this procedure with the Solar Energy Corporation of India (see Chapter 2. Hydrogen demand),

Long-term planning

Enabling infrastructure is an essential requirement for hubs development. At the same time, some infrastructures, like gas, hydrogen, or electricity transmission networks, are natural monopolies, which means public regulation is needed for their operation and financial viability. Policy makers could incorporate hydrogen in the long-term planning for critical infrastructure (see Figure 8.20), especially as these assets typically have long lead times that are expected to be rapidly outpaced by the growth in hydrogen flows. For example, high-voltage power lines can take more than 8 years to build, and gas pipelines (which could provide an indicator for hydrogen pipelines) can take 6 to 12 years to build. In contrast, should all the announced projects materialise, hydrogen production in LAC countries would nearly triple in less than 6 years. Power transmission lines are especially critical given the potential mismatch between those sites with good renewable resources and the existing grid. Long-term planning needs are not limited to energy infrastructure: For hydrogen supply hubs in remote areas, road and transport infrastructure, water and waste management facilities, and health and education facilities for workers and their families will also be critical.

Policy makers need to carry out integrated planning across networks. For example, bunkering of hydrogen-derived fuels requires not only port expansion and storage facilities, but also co-ordination with upstream infrastructure to ensure a reliable and steady supply. Similarly, as renewable hydrogen scales up, the effect of electrolysers on electricity demand, and their potential role in providing flexibility, means the electricity system will be more tightly integrated with other commodities, and will require integrated system planning.

Beyond planning measures, regulation of hydrogen pipelines is not yet in place. Defining the standards and regulations that these assets would need to comply with, the methodology for tariff-setting, and the conditions for network access would provide clarity for projects aiming to use them (see Chapter 4. Trade and infrastructure).

Policy makers can also accelerate the development of hydrogen projects by shortening the times needed for the various planning processes like environmental impact assessment, permit application and examination, and grid connection, among others. This includes ensuring there are enough qualified staff in the relevant government agencies to process a growing number of applications, and reducing the need for project developers to undertake multiple processes in parallel with different agencies. For example, a successful model applied for renewables deployment in Europe and the Middle East has been to undertake environmental assessments in dedicated areas, and then provide clearance for individual projects to skip this step in those areas. A pre-assessment of this kind could cover not only environmental aspects, but also community engagement to ensure that the local community is aware of the benefits of projects even before specific projects are identified. In LAC, Iberdrola Brazil is creating a biodiversity corridor connecting forest and permanent conservation areas, for example.

Social acceptance

Many projects are expected to be developed in remote regions, often in natural protected areas with a strong presence of indigenous communities, which account for around 8% of the population in LAC. Low-emissions hydrogen projects would occupy a significant amount of land, not only for the renewable energy generation assets, but also for the enabling infrastructure, which may cross different jurisdictions. Engaging with local and indigenous communities is of primary importance to ensure that projects offer them socio-economic benefits, including the creation of jobs and the improvement of their livelihoods.

Failure to incorporate the voices of these groups at the early stages of planning could become a barrier to the development of hydrogen projects. Clean energy projects are already facing opposition from local communities in the region, who have raised concerns about the lack of consultation, the need for assessment of environmental and social impacts, and a lack of understanding of policy makers and project developers of the relationship between communities and their lands. Notably, several renewable energy projects in the Colombian Guajira have been halted, partly due to conflicts with local communities. Permitting delays due to community acceptance concerns have resulted in projects under development in the region being deferred by up to 3 years. In the case of hydrogen, challenges to social acceptance are already arising in regions more advanced in the production and uptake of low-emissions hydrogen, such as Europe (see Box 3.1). LAC governments should incorporate lessons learnt by governments that have already taken these first steps, in order to avoid repeating mistakes that are now resulting in project delays.

With regards to the protection of indigenous territories, adherence to the free, prior and informed consent process is crucial. This is a legal mechanism derived from the International Labour Organization Convention, and ratified by most countries in LAC, and the United Nations Declaration on the Rights of Indigenous Peoples. The consultation process used to obtain consent, while not always implemented, is essential to ensuring that the rights and interests of indigenous communities are respected and that they are fully informed and involved in decision-making processes. Governments have a key role in implementing these consultation processes, which should happen in early stages of the project to ensure there is enough time to survey concerns and incorporate action into the project planning. Policy makers can define how this process should be undertaken, who should be involved (such as government at national, regional and local levels, government arms-length agencies, private developers, civil society groups and representatives of the local communities), and how to co-ordinate the different stakeholders involved to ensure a robust but streamlined procedure, as well as how to assess how hydrogen projects could impact local communities.

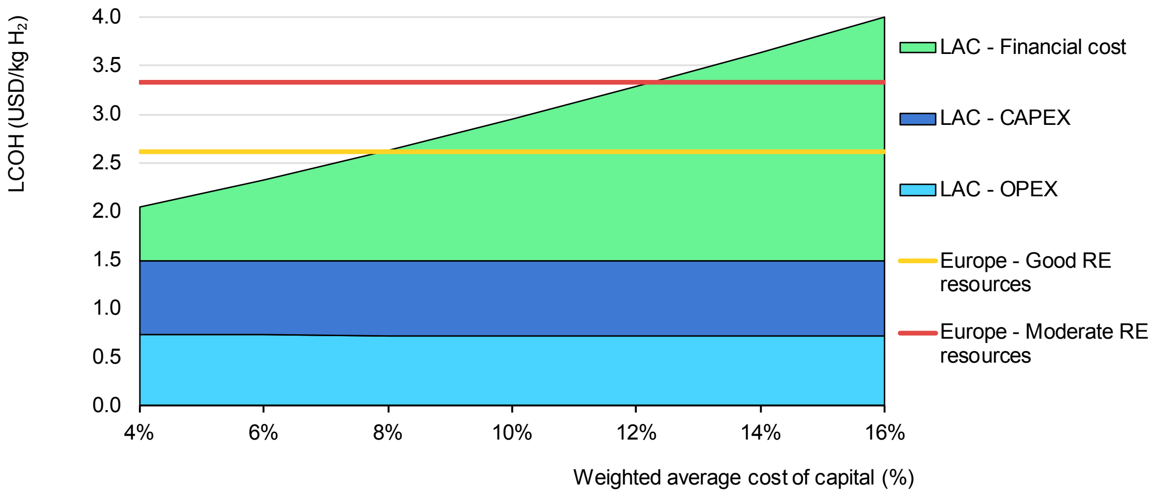
Bringing down the cost of capital

The cost of capital is critical to the cost of producing renewable hydrogen

Unlike fossil-based hydrogen production, renewable hydrogen does not have any fuel costs – all the major costs, including the electricity price and electrolyser, are capital costs. The only recurring costs are the operation and maintenance costs of the renewable electricity source and the electrolyser, which are in the order of I 1-2% of CAPEX for solar PV, 2-3% of CAPEX for onshore wind and 3% for the electrolyser. This means that how the initial capital is financed has a critical effect on the cost of production. Yet the cost of capital is higher in emerging economies than developed ones. For solar PV and electricity storage, the cost of capital, in nominal terms, is on average 4-7% points higher for emerging economies. In absolute terms, the cost of capital for solar PV, for example, was 10.5-12% in Brazil and Mexico in 2022, compared to 4.1-5.2% in Germany and the Netherlands.

This can make a big difference to the levelised cost of hydrogen production (Figure 8.22): A difference of six percentage points can result in a cost premium of about USD 1/kg H_2. Assuming that the cost of capital is 4% for renewables in developed markets, Latin American countries with better quality renewable resources could find that this advantage is undermined if the cost of capital is higher by 4-8 percentage points. Moreover, this is without considering the additional conversion steps and efficiency losses necessary to export the hydrogen from LAC. If these costs are also taken into account, the differential in cost of capital would need to be reduced further in order to reach a breakeven point.

Figure 8.22 Impact of cost of capital on hydrogen production costs in Latin America and the Caribbean vs Europe in the Announced Pledges Scenario, 2030



Notes: LAC = Latin America and the Caribbean; LCOH = levelised cost of hydrogen; RE = renewable energy. For Europe, a cost of capital of 4% is used. A technology risk premium of 2% is assumed for the electrolyser.

A cost of capital premium of 4-8 percentage points could result in higher hydrogen production costs in LAC than in advanced economies, despite better quality renewable resources.

Multiple types of risks affect the cost of capital

There are two types of risks that drive up the costs of hydrogen projects in LAC. Those specific to hydrogen, such as technology, infrastructure and offtake, and those which are country-related (and applicable to any clean technology project), such as macroeconomic, policy and regulatory risks or social acceptance. How relevant these risks are will depend on the national context, but country-related risks could dominate the cost of capital. This is especially true in countries where political instability or potential regulatory changes decrease the certainty and visibility that investors have for future project cash flows and returns on investment. A credit guarantee can be an effective way to mitigate political risk, both in terms of decreasing the cost of capital (with a more pronounced effect for countries considered riskier) and increasing the mobilisation ratio of public and private capital (30-100 times) with capital that might not need to be disbursed. For example, for a renewable hydrogen project using solar PV in Namibia, a political risk guarantee (covering non-payment of loans and bonds caused by political events) could reduce the cost of capital by almost 4 percentage points, a revenue guarantee[146] could reduce the cost of capital by 3.5 percentage points, and a performance guarantee[147] by another 0.5 percentage points.

Risks also depend on the specific stage of project development. For example, due to the absence of a hydrogen market, securing offtake with a suitable price point, for the entire capacity of the project, and over as long a term as possible, is the most critical measure for addressing the volume and price risk. Beyond securing the hydrogen purchase agreement, reducing risk is also influenced by the credibility of the counterparty, who should ideally have a track record in the country and project development experience. In contrast, post-FID, completion risks are the most relevant, especially for first-of-a-kind plants where unforeseen factors can lead to cost overruns and delay in project execution. Some of the options to mitigate this risk are an engineering, procurement and construction wrap, in which there is a single construction contract with the main contractor who is responsible for the sub-contracts for specific packages, or a completion warranty, where there is a financial contract paid out in full upon completion of the plant on time and on budget.

Strategies for reducing the cost of capital

The capital structure of a project is defined by the shares of equity and debt. These two types of capital have different risk and return profiles, which result in the cost of equity being higher than the cost of debt. They also have different capital

[146] This can mitigate the offtake risk and reduce payment volatility, thereby increasing the certainty of the cashflow needed to repay the investment and provide a return on investment.
[147] This can be issued by the original equipment manufacturers (OEMs) to guarantee the performance of a technology within agreed key performance indicators (KPIs).

providers. The average cost of capital considers the share of these types of capital. Since each has a different risk profile, different mechanisms can be used to reduce each type of capital. Projects can be financed from the balance sheet of companies, in which case the company credit record is exposed to the project performance but debt can be secured at a lower cost, or through project finance, where the cost of capital is evaluated based on the project cashflows and equity from the companies is not exposed to project failure.

Governments can use different strategies to bring down the cost of capital at different stages of project development. While overall strategies and integration in long-term planning can be the most relevant factors at the conceptual stage, a clear regulatory framework is critical at the feasibility stage. Financial measures such as grants, concessional loans, tax incentives or mezzanine instruments are also important when the profitability of the project is being assessed prior to FID. Guarantee of property rights, consistency of legal framework, tax and incentive stability are critical for the operational phase.

Financial measures used by governments have varying degrees of effectiveness in mitigating risks relating to the cost of capital and mobilising additional capital. For example, grants and tax incentives directly decrease the cost for the private sector but are limited and not fiscally sustainable (since there is no capital return).[148] A grant could reduce the share of equity, thereby reducing the overall cost of capital (since the cost of equity is higher). Concessional loans decrease the cost of debt and improve fiscal stability, but may have a smaller effect on the cost of capital for the first few projects that could be financed with higher shares of equity, due to the higher risk.

Non-financial instruments can also be used to reduce risks, such as streamlined permitting processes, as have been initiated in Chile, and the provision of clear environmental assessment guidelines. Additionally, governments have an essential role in facilitating early communication with and participation of communities affected by hydrogen projects.

Development Finance Institutions (DFI) also have different tools at their disposal to decrease the cost of capital. Project financing tools include de-risking mechanisms such as credit guarantees, equity co-investments and preferential finance in the form of concessional finance, blended finance, or finance in local currency. Other tools include support for knowledge sharing, capacity building and technical assistance in policy and regulatory design, as well as standard-setting tools such as sectoral lending strategies and environmental and social frameworks. DFIs can also facilitate strong offtake agreements by improving the

[148] A 1-GW of electrolysis project could cost USD 3-4 billion to satisfy the equivalent of half of the current hydrogen demand in Colombia or Chile today with that project alone representing close to 1% of the GDP.

financial and technical strength of the sponsors or support infrastructure development or access to shared infrastructure. For example, in LAC, the World Bank provides technical assistance for hydrogen projects to Argentina, Brazil, Colombia, Costa Rica and Panama, and concessional finance including USD 150 million for Chile (approved in FY23), USD 135 million for Brazil (for approval in FY24), and potentially Colombia as well (under discussion). The International Finance Corporation has six approved engagements in LAC, including renewable hydrogen for storage (Barbados, USD 155 million), fertiliser (Colombia, USD 106 million), road transport (Costa Rica) and methanol (Mexico). The Inter-American Development Bank has also provided extensive technical assistance for strategy development, feasibility and market studies to Chile, Colombia, Brazil, Mexico, Panama, Trinidad and Tobago, and Uruguay.

In Chile, a "Green Hydrogen Facility" will provide USD 1 billion of private and public funds to provide CAPEX support and risk mitigation, with the expectation of mobilising USD 12.5 billion in total. In Brazil, the Climate Investment Fund has granted USD 70 million of funding to the industrial and port complex in Pecém to build shared hydrogen infrastructure and an innovation centre for renewable hydrogen.

In the private sector, strategies to decrease the cost of capital could include recourse financing. Even though this entails risks for the company behind the project, potentially impacting its creditworthiness, it could lead to a lower cost of debt or longer tenor. Given the higher risk associated with early projects, higher shares of corporate finance are expected in the early stages of market development, with a transition to project finance characteristic of renewables or infrastructure projects as the market matures. Learning from deployment, as well as standardisation of the design, modular design, and manufacturing excellence can all help to facilitate future replication and avoid delays and cost overruns introduced by tailored projects. An example is the pilot phase of the Haru Oni project by HIF Global in Chile for a 1.2 MW electrolyser using wind power and biogenic CO_2 to produce synthetic fuels starting with e-gasoline (to be exported to Germany), and potentially expanding to SAF and liquefied petroleum gas (LPG). Offtake risk was tackled by an offtake agreement with Porsche, and the technology and investment risks were reduced by involving a consortium of companies specialised in different steps of the process.[149] Project finance was used, and the project is owned by HIF Global which is a US holding company for equity financing, with local subsidiaries that can raise debt. The pilot phase was financed with USD 260 million of capital increase by the holding company, USD 50 million of equity, and USD 10 million as a grant from the German government.

[149] Enel Green Power for the renewable electricity supply, Global Thermostat for the CO_2 supply, Exxon Mobil for the methanol-to-gasoline technology (which was built by Sinopec), and Siemens energy for the supply chain integration

Experienced gained through project start-up is a crucial first step for reducing the cost of capital

Today, only eight hydrogen projects have taken FID in LAC and only two of those have an electrolyser capacity larger than 50 MW. One of the first steps to decrease the cost of capital is to move more projects beyond FID. This would not only build experience through learning from smaller projects, which would reduce technology and construction risks, but would also provide an opportunity for financial institutions to become familiar with the risks and mitigation options for hydrogen projects.

Annex

Explanatory notes

Projections and estimates

Projections and estimates in this Global Hydrogen Review 2024 are based on research and modelling results derived from the most recent data and information available from governments, institutions, companies and other sources as of August 2024.

Terminology relating to low-emissions hydrogen

In this report, low-emissions hydrogen includes hydrogen which is produced through water electrolysis with electricity generated from a low-emission source (renewables, e.g. solar, wind turbines or nuclear). Hydrogen produced from biomass or from fossil fuels with carbon capture, utilisation and storage (CCUS) technology is also counted as low-emissions hydrogen.

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-emissions feedstocks and hydrogen-based fuels made using low-emission hydrogen and a sustainable carbon source (of biogenic origin or directly captured from the atmosphere).

The IEA does not use colours to refer to the different hydrogen production routes. However, when referring to specific policy announcements, programmes, regulations and projects where an authority uses colours (e.g. "green" hydrogen), or terms such as "clean" or "low-carbon" to define a hydrogen production route, we have retained these categories for the purpose of reporting developments in this review.

Terminology for carbon capture, utilisation and storage

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 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. in urea production, CCU is specified.

Scenarios used in this Global Hydrogen Review

This Global Hydrogen Review relies on two scenarios to track progress on hydrogen production and use:

- The Stated Policies Scenario (STEPS) explores how the energy system would evolve if current policy settings are retained. These include the latest policy measures adopted by governments around the world but do not assume that aspirational or economy-wide targets will be met unless they are backed up with detail on how they are to be achieved.
- The Announced Pledges Scenario (APS), illustrates the extent to which announced ambitions and targets can deliver the emissions reductions needed to achieve net zero emissions by 2050. It includes all major national announcements, both 2030 targets and longer-term net zero or carbon neutrality pledges, regardless of whether these announcements have been anchored in legislation or in updated Nationally Determined Contributions
- The Net Zero Emissions by 2050 Scenario (NZE Scenario) is a normative scenario that sets out a pathway to stabilise global average temperatures at 1.5°C above pre-industrial levels. The NZE Scenario achieves global net zero energy sector CO_2 emissions by 2050 without relying on emissions reductions from outside the energy sector.

Project status

For the analysis of the pipeline of announced, four potential statuses have been considered:

- Operational: includes projects that are already producing hydrogen, even if they were in a ramp up period and had not achieve their full production capacity.
- Final investment decision: includes projects that have started construction or that have taken a firm investment decision.
- Feasibility studies: includes projects that are undertaking pre-feasibility studies, feasibility studies or front-end engineering design.
- Early stage: includes projects at very early stages of development, e.g. only a co-operation agreement among stakeholders has been announced or a general announcement of the intention to develop a project has been made.

Currency conversions

This report provides the stated values of programmes and projects in the currency stated in their announcement. These values, in many instances, are converted to US dollars for ease of comparison. The currency exchange rates used correspond to an average value for the year of the announcement based on World Bank exchange rates. For 2024 values, average exchange rates are based on the International Monetary Fund.

Sources of information

For Argus Hydrogen and Future Fuels Service, all data and information used to develop aggregated data is provided “as is” without warranty of any kind, and Argus has no responsibility or liability to any party with respect to use of those extracts or aggregated data. Views or opinions set out in this report are not approved by or representative of Argus Media.

Abbreviations and acronyms

ABS	American Bureau of Shipping
AEM	anion exchange membrane
ALK	alkaline
ANFO	ammonium nitrate fuel oil
APS	IEA Announced Pledges Scenario
ARPA-E	Advanced Research Projects Agency-Energy
ASEAN	Association of Southeast Asian Nations
ATR	autothermal reformer
AUD	Australian dollars
BAT	best available technology
BEV	battery electric vehicle
BF	blast furnace
BoP	balance of plant
BRL	Brazilian reals
CAD	Canadian dollar
CAGR	compound annual growth rate
CAPEX	capital expenditure
CCER	China Certified Emissions Reduction
CCfD	carbon contract for difference
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CEM	Clean Energy Ministerial
CfD	contract for difference
CH_4	methane
CHA	China Hydrogen Alliance
CHCM	Clean Hydrogen Certification Mechanism
CHN	Yuan renminbi
CHP	combined heat and power
CHPS	Clean Hydrogen Production Standard
CO_2	carbon dioxide
COP	Conference of the Parties
DAC	direct air capture
DKK	Danish kroner

DME	dimethyl ether
DoE	Department of Energy (United States)
DRI	direct reduced iron
EAF	electric arc furnace
EBRD	European Bank for Reconstruction and Development
ECOWAS	Economic Community of West African States
EIB	European Investment Bank
EMDE	emerging markets and developing economies
ENNOH	European Network of Network Operators for Hydrogen
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
EPO	European Patent Office
ETF	exchange-traded fund
ETS	Emissions Trading Systems
EUR	Euro
FC	fuel cell
FCEV	fuel cell electric vehicle
FEED	front-end engineering design
Fe_2O_3	hematite
Fe_3O_4	magnetite
FeO	iron oxide
FeO_2H	goethite
FID	final investment decision
FT	Fischer-Tropsch
FY	fiscal year
G7	Group of Seven
G20	Group of Twenty
GBP	British pound
GHG	greenhouse gases
GHR	gas-heater reformer
GHR	Global Hydrogen Review
GoO	Guarantees of origin
GWP	global warming potential
H_2	Hydrogen
H2-DRI	Hydrogen-based Direct Reduced Iron
H2I	The Hydrogen Initiative
HB	Haber Bosch
HBI	hot briquetted iron
HC	hydrocarbon
HD	heavy-duty
HEFA	hydroprocessed esters and fatty acids
HFO	heavy fuel oil
HPTI	Hydrogen Production Tax Incentive
HRS	hydrogen refuelling stations
HSPA	Hydrogen Society Promotion Act

HT	high throughput
HVDC	high voltage direct current
ICE	Internal Combustion Engine
IDB	Inter-American Development Bank
INR	Indian rupees
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Projects of Common European Interest
IPF	international patent family
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRA	Inflation Reduction Act
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
ITC	Investment Tax Credit
JPY	Japanese yen
LAC	Latin America and the Caribbean
LCA	Life Cycle Analysis
LCFS	Low-Carbon Fuel Standard
LCOH	levelised cost of hydrogen
LD	light-duty
LH_2	liquefied hydrogen
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
MDB	multilateral development banks
MeOH	methanol
MMRV	measurement, monitoring, reporting and verification
MoU	Memorandum of Understanding
N_2O	nitrous oxide
NASDAQ	National Association of Securities Dealers Automated Quotations
NG	natural gas
NH_3	ammonia
NOC	national oil companies
NOK	Norwegian kroner
NO_x	nitrogen oxides
NPK	nitrogen, phosphate, potassium
NZE	IEA Net Zero Emissions by 2050 Scenario
OPEX	operating expenditure
PCI	Projects of Common Interest
PEM	proton exchange membrane
PMI	Projects of Mutual Interest
PO_X	partial oxidation
PPA	power purchase agreement
PV	photovoltaic
RCS	regulations, codes and standards
RD&D	research, development and demonstration

RED	Renewable Energy Directive
RES	renewable energy sources
RFNBO	renewable fuels of non-biological origin
RRP	Recovery and Resilience Plans
RTFO	Renewable Transport Fuel Obligation
SAF	sustainable aviation fuel
SEK	Swedish kronor
SMR	steam methane reformer
SOE	state-owned enterprise
SOEC	solid oxide electrolyser
SOFC	solid oxide fuel cell
STEPS	IEA Stated Policies Scenario
TCP	Technology Collaboration Programme
TRL	technology readiness level
TSO	Transmission System Operators
TTF	Title Transfer Facility
UNECE	United Nations Economic Commission for Europe
UNEP	United Nations Environment Programme
UNIDO	United Nations Industrial Development Organization
USD	United States dollars
VAT	value added tax
VC	venture capital
VRE	variable renewable electricity
WBSCD	World Business Council of Sustainable Development
WTI	West Texas Intermediate
ZEMBA	Zero Emission Maritime Buyers Alliance
ZETI	Zero-Emission Technology Inventory

Units

°C	degree Celsius
bar	metric unit of pressure
bbl	barrel
bcm	billion cubic metres
CO_2-eq	carbon dioxide equivalent
g	gramme
GJ	gigajoule
GW	gigawatt
GWh	gigawatt-hour
GW/yr	gigawatts per year
inch	inch
kg	kilogramme
kg CO_2-eq	kilogramme of carbon dioxide equivalent
km	kilometres
kt	kilotonnes
ktpa	kilotonnes per year

kW	kilowatt
kW_{el}	kilowatt electric
L	litre
MBtu	million British thermal units
Mt	million tonnes
Mt CO_2	million tonnes of carbon dioxide
Mt H_2-eq	million tonnes of hydrogen equivalent
MW	megawatt
MWh	megawatt-hour
Nm^3	normal cubic metre
ppb	parts per billion
t	tonne
t CO_2	tonne of carbon dioxide
TWh	terawatt-hour

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