Global Hydrogen Review 2026

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Abstract

The IEA's *Global Hydrogen Review 2026* provides an update on hydrogen production and demand worldwide and identifies the latest developments relating to policy, infrastructure, trade, investments and innovation.

The report is an output of the Clean Energy Ministerial Hydrogen Initiative and is intended to provide an update to energy sector stakeholders on the status and future prospects of hydrogen, and to inform discussions at the Hydrogen Energy Ministerial Meeting organised by Japan.

The conflict in the Middle East is impacting global supplies of hydrogen and hydrogen derivatives, such as fertilisers, exposing vulnerabilities in their supply chains. As energy security concerns move higher up the policy agenda, this year's report considers the potential contributions of low-emissions hydrogen and hydrogen derivatives to enhancing energy security. It takes stock of deployment to date to assess the level of hydrogen uptake that could be achieved by 2030.

This sixth edition of the Global Hydrogen Review includes novel analysis on what constitutes an acceptable cost for low-emissions hydrogen across multiple applications and regions. It concludes with a special focus chapter exploring challenges and opportunities for the development of new supply chains for low-emissions hydrogen-based products in Africa.

The report is published alongside updates to the Hydrogen Production and Infrastructure Projects Database and the online Hydrogen Tracker. These resources allow users to explore project-level information and data on announced and operational projects for the production of low-emissions hydrogen and for the development of hydrogen infrastructure. It also includes information on signed offtake agreements for low-emissions hydrogen and hydrogen derivatives, and details on more than 1 000 hydrogen policies worldwide that have been announced or implemented since 2020.

Acknowledgements, contributors and credits

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Table of contents

Executive summary

The conflict in the Middle East has disrupted global production and trade of hydrogen-based products

The Middle East is a major producer of hydrogen-based products, and the conflict has strongly impacted their production. The Middle East is home to around one-sixth of global hydrogen production, the majority dedicated to the production of chemicals, fertilisers and refined oil products. The region accounts for more than 10% of global refining capacity, ammonia and urea production, and close to 17% of methanol production. Several refineries and petrochemical plants have halted operations due to supply disruptions and the impossibility of exporting their products or to military attacks, which in some cases have damaged hydrogen production units. Restarting operations and reaching pre-conflict activity levels will take weeks and even months in the case of damaged facilities.

The consequences of the conflict reach far beyond the Middle East as the region is a major player in global trade for hydrogen-based products. Much of the production output of the region is exported. The region makes up over one-quarter of global trade in ammonia, almost 40% of urea trade and almost 45% of methanol trade, and one-third of its refining capacity is export-oriented. The closure of the Strait of Hormuz has severely disrupted the supply of all these products. Port infrastructure outside the Persian Gulf has also been hit by attacks, further limiting export capabilities. The production of hydrogen-based fuels outside the Middle East has been affected, particularly in Asia, where countries are very dependent on natural gas imports from the Middle East – one-quarter of ammonia production in Bangladesh, India and Pakistan uses natural gas imported from the region. As a consequence of these disruptions, global markets for fertilisers, refined products and chemical products are suffering shortages and price volatility.

Global fertiliser markets have been particularly affected, with potential implications for the food supply chain. The closure of the Strait of Hormuz has constrained trade flows for ammonia, urea and sulphur, all of which are essential for fertiliser production. In addition, production outages due to shortages in gas supply and high gas prices in several countries (including Bangladesh, India and Slovakia) have further tightened supply. As a result, fertiliser production costs have increased worldwide, as urea prices doubled between January and May 2026. These pressures have been compounded by rising natural gas prices and export restrictions imposed by major suppliers. Even modest reductions in fertiliser use can lead to declines in crop yields, posing risks to the food supply chain. The risk is particularly acute in import-dependent agricultural economies, such as

Morocco, which meets all its demand for ammonia with imports, 40% of which come from the Middle East, or Brazil, Australia, South Africa and Thailand, which meet all their demand for urea with imports (40-85% from the Middle East).

Hydrogen-based fuels can help to diversify the energy sector, but their impact will not be immediate

Governments are considering strategies to mitigate the impacts of the ongoing energy crisis and potential future crises, and hydrogen can support in increasing diversification. Diversification is a key element of energy security, and the way hydrogen and hydrogen-based fuels are produced, as well as their use, can play an important role. For example, countries can increase and diversify the use of domestic energy resources by using electrolysis rather than gas or coal for producing hydrogen-based products such as fertilisers and methanol, and shipping and aviation fuels. Governments can support the development of new supply chains for low-emissions hydrogen and hydrogen-based products, diversifying fuel supply and enlarging the pool of suppliers compared to oil and gas supply.

Hydrogen and hydrogen-based fuels can play a role supporting energy security in the long-term, but they are not ready at scale to alleviate immediate pressures. Uptake of low-emissions hydrogen and hydrogen-based fuels will not happen overnight, and the existing and committed level of production is not sufficient to provide an immediate response to the current moment in energy markets. Several large projects will come online before 2030, but it will take time to build the scale needed to make a significant contribution. In addition, this will require the development of common infrastructure to store, transport and distribute hydrogen and hydrogen-based fuels to different end-users.

Policy support will remain necessary to close the cost gap with incumbents and enable short-term uptake. In the near term, low-emissions hydrogen production will remain more costly than fossil-based hydrogen in most parts of the world, apart from China, where renewable hydrogen could become cost-competitive by 2030. In the rest of the world, the short-term adoption of low-emissions hydrogen and hydrogen-based fuels will entail a cost premium. Higher fossil fuel prices can significantly reduce the cost gap, as can falling costs of low-emissions hydrogen production. But it would require extended periods of higher fossil fuel prices to make a difference in de-risking projects and triggering sustained investment decisions.

Low-emissions hydrogen progressed in 2025 but persistent barriers are preventing sustainable growth

Global hydrogen demand surpassed 100 million tonnes (Mt) in 2025, driven by growth in traditional sectors. Hydrogen use in industry and refining accounted for almost all demand in 2025. Hydrogen demand in new applications is increasing and is expected to grow faster in the near term, but it still represents a very minor share of global demand. However, slow and uncertain policy implementation is failing to address the main barriers – particularly high costs, uncertain demand, unclear or complex regulations and lack of infrastructure – and preventing faster uptake.

Low-emissions hydrogen production grew by 20% in 2025 to reach almost 1 Mt, but progress is concentrated in a small number of projects. Low-emissions hydrogen production is expected to see another record year in 2026 and reach more than 1% of global production for the first time. This is thanks to some initial policies to support production, mostly in China and Europe, and to develop international supply chains in Japan. These policies have helped to unlock final investment decisions (FIDs) in a small number of projects, but are insufficient to create scale, reduce costs and ensure sustainable growth.

As well as near-term action to address barriers, long-term objectives need to be renewed to provide clarity and facilitate stable growth. The low-emissions hydrogen sector has achieved impressive success since 2020, and growth is expected to accelerate in the second half of this decade. Efficient policy implementation and regulation is needed to stimulate demand and to develop workable frameworks for targeted support as well as enabling infrastructure. This can further accelerate uptake in the near term, but it will be insufficient to meet announced ambitions by 2030. Governments should update hydrogen strategies and long-term deployment targets to reflect changing market realities, building on lessons from the first wave of policy initiatives in the early 2020s, and responding to new opportunities arising from heightened energy security concerns.

The short-term outlook for low-emissions hydrogen remains uncertain with large differences across regions

The pipeline of announced projects for low-emissions hydrogen production has shrunk to 27 Mt by 2030, mostly due to delays post 2030 and cancellations. Since the assessment presented in the Global Hydrogen Review 2025 (GHR-25), some 300 ktpa of additional production has reached FID, but investment momentum slowed in 2025. Committed projects and those with strong potential to be in operation by 2030 declined from 10 Mt to just above 6 Mt compared to the GHR-25, due to delays in investment decisions. Around 80% of the production with strong potential targets the production of chemicals, use in refining, and production of low-emissions based fuels, which are applications where hydrogen-based fuels could more promptly support diversification goals. There is currently 22 Mt of potential production in announced projects that may lose any chance to begin operation by 2030 if investment decisions are not taken by early 2027. Two-thirds of this potential production is in Europe, North America and Latin America.

China shows signs of deceleration in electrolysis deployment, but the short-term outlook is positive due to recent policy developments. Global installed electrolysis capacity doubled in 2025 to exceed 4 GW, with China behind nearly three-quarters of new installations. Low technology cost and experience with large projects have facilitated faster growth in the country. However, unsustainable internal competition driven by surplus capacity is leading to market consolidation. New FIDs in production projects also fell for the first time in 2025. Electrolyser manufacturers are starting to expand their overseas markets to ensure business continuity. However, since the second half of 2025, the government has announced new support schemes to expand use of hydrogen and hydrogen-based fuels to new sectors and reduce reliance on fossil fuel imports. This is expected to reinvigorate investment activity in the coming years.

In Europe, the first large-scale projects are expected to come online in 2026, but slow policy implementation is delaying scale-up. Low-emissions hydrogen is slowly growing in Europe thanks to some national and EU-wide support programmes and regulations. Transposition of the EU Renewable Energy Directive targets for the use of renewable fuels of non-biological origin (RFNBO) in transport into national legislation has pushed forward projects, particularly for use in refining. However, this has been a slow process, and the implementation of other key regulations remains unclear, slowing investment and scale-up.

Other markets are experiencing some initial progress thanks to early policy support, but the outlook remains uncertain due to lack of regulatory clarity. In North America, some large projects based on carbon capture, utilisation and storage have reached FID. However, most projects under development in the region are export-oriented, and their bankability relies on the creation of markets for low-emissions hydrogen-based products overseas. Today this is only occurring through policy instruments in Japan and the European Union, but recent developments have increased uncertainty for project developers. In India, the tenders of the Solar Energy Corporation India and several refineries have led to offtake contracts, but whether all the deals will move forward will depend on the availability of government incentives, which is still unclear.

Demand for low-emissions hydrogen remains the crucial missing piece for the sector to take off

Offtake agreements remain insufficient to unlock large-scale investment in low-emissions hydrogen production. New offtake agreements were broadly unchanged in 2025, at around 1.7 Mt. Only around 20% of newly signed volumes were backed by firm contractual commitments, concentrated in refining, industry and power generation. This highlights the persistent challenge of demand creation, which has been widely reported by project developers as a key barrier to investment. For the first time, trade-oriented agreements overtook domestic-use agreements in 2025, thanks to policies in Japan and Europe.

The refining and chemicals sectors lead adoption of low-emissions hydrogen, as demand creation policies gather momentum. Based on committed projects, 2.5 Mt of low-emissions hydrogen (60% of global committed production) is expected to be consumed in refineries and industrial facilities by 2030. Demand creation measures targeting refining (in Europe) and industry (mostly in China) are emerging, although their implementation has often been slow. Additional initiatives in public procurement for low-emissions hydrogen-based fuels and products, demand aggregation mechanisms and targeted support programmes, particularly in existing industrial applications, could help strengthen market formation, but they will need to be enacted rapidly and efficiently to make an impact by 2030.

Hydrogen can offer long-term development opportunities for Africa, but significant challenges lay ahead

Development of low-emissions hydrogen production projects in Africa will require a clear focus on how they can contribute to wider development goals. Nearly 600 million people in Africa lack access to electricity, energy demand and GDP per capita are far lower than in advanced economies, and the electricity grid remains largely underdeveloped. Hydrogen development risks competing with these policy priorities but – if well designed – could instead support them by catalysing investment, mobilising finance, developing infrastructure and contributing to industrial development. Strategies and roadmaps for hydrogen will need to be linked with overall electricity sector planning. For example, government support or concessional financing for renewable hydrogen projects could be tied to conditions to improve access to electricity and water in a region.

Low-emissions hydrogen can support industrial development, food security and trade. Africa's fertiliser use remains below the global average, and many countries depend on imports, 35% of which come from the Middle East. Expanding competitive domestic low-emissions ammonia production could improve access to nitrogen fertilisers and reduce exposure to price volatility, while supporting food production. Hydrogen could help African countries move up the value chain in steel production, reducing dependence on imports and boosting industrial activity. Over 80% of Africa's ironmaking capacity is based on direct reduced iron, providing a basis for blending hydrogen with natural gas in existing and new plants.

Hydrogen demand and production in Africa remains small but has long-term potential. Hydrogen demand reached 3.1 Mt in 2024, equal to around 3% of global demand and concentrated in a handful of countries, led by Egypt, Algeria and Nigeria. Ammonia production represents nearly three-quarters of hydrogen use, with supply overwhelmingly based on natural gas. Africa has vast renewable energy resources that could support competitive low-emissions hydrogen production, yet deployment remains at an early stage, with high financing costs being the main barrier. Around 6 kt of low-emissions hydrogen is produced today, and only 1 of the 31 projects announced for 2030 has reached FID.

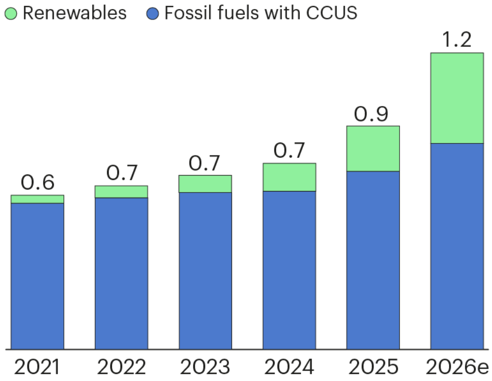
Targeted policies and investment are needed to unlock deployment. Near-term progress will depend on reducing financing costs for project development, using instruments like blended finance mechanisms, credit guarantees, insurance instruments and support for offtake agreements. Governments need to balance domestic hydrogen use with export opportunities while accelerating renewable energy deployment, which can create positive spillovers for the broader energy system. Developing infrastructure plans, certification schemes and industrial hubs around existing demand centres and strategic ports can help lay the foundations for long-term growth.

Global Hydrogen Review Summary Progress

Production

Low-emissions hydrogen

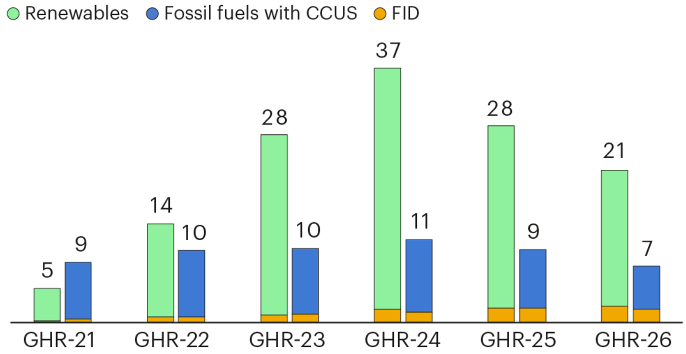
Mtpa



90% growth since 2021

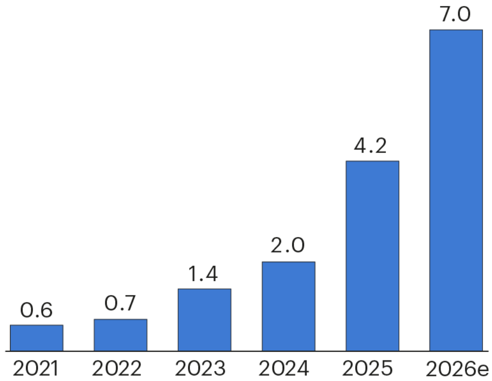
Low-emissions hydrogen production from announced projects by 2030

Mtpa



Electrolyser installed capacity

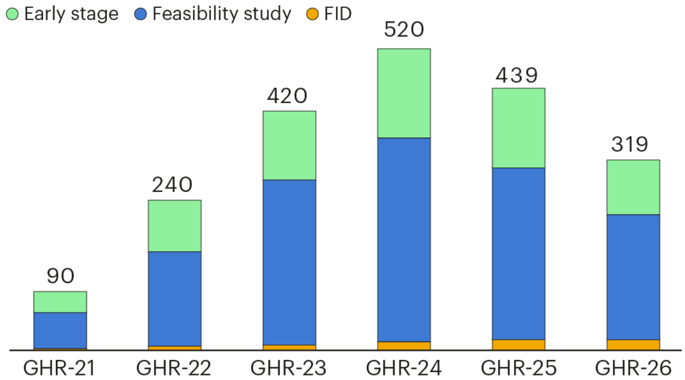
GW



13x growth since 2021

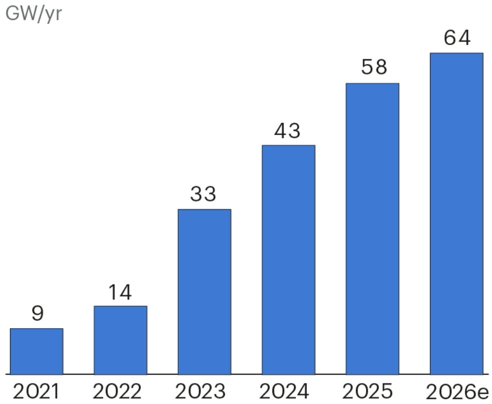
Announced electrolyser projects by 2030

GW



Electrolyser manufacturing capacity

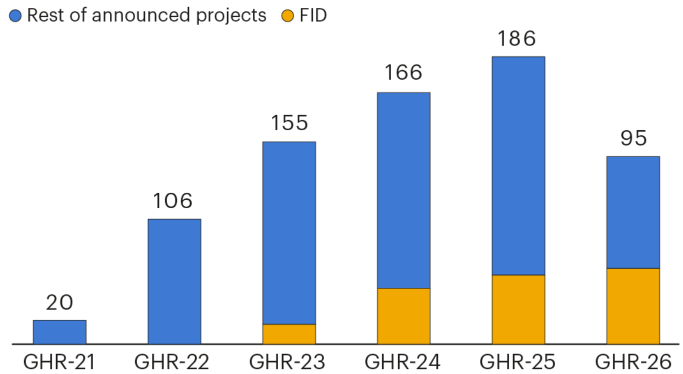
GW/yr



7x growth since 2021

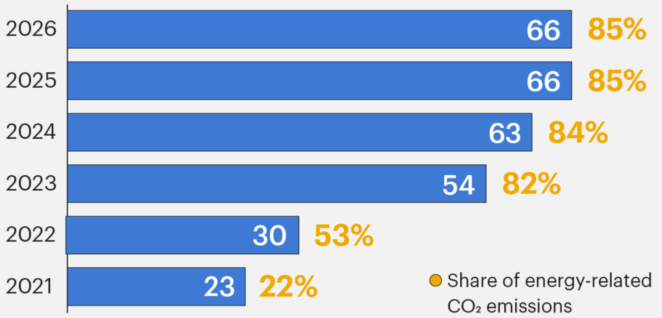
Announced electrolyser manufacturing capacity by 2030

GW/yr



Policies

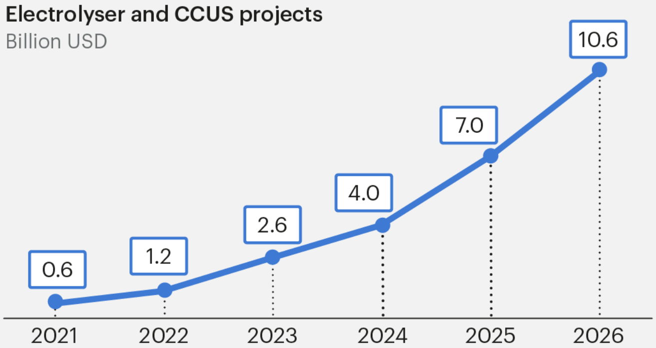
Number of hydrogen strategies



Investment

Electrolyser and CCUS projects

Billion USD



Note: 2026e = Estimated based on announced projects. FID = Final Investment Decision.

Introduction

The global energy system is facing a period of heightened uncertainty. Escalating tensions and conflict in the Middle East have placed renewed stress on international energy markets over the past year, highlighting the vulnerability of energy supply chains to geopolitical disruptions. The region remains central not only to oil and natural gas markets, but also to the production and trade of key petrochemical and industrial commodities. Recent disruptions have contributed to price volatility and concerns about the security of global trade routes and supply chains, affecting a broad range of energy-related products.

These impacts extend to hydrogen and hydrogen-based products. Ammonia, methanol and refined oil products play a critical role in sectors such as agriculture, chemicals, shipping and aviation. Disruptions to supply chains and higher production costs have reinforced the importance of diversifying sources of energy and industrial feedstocks. In this context, low-emissions hydrogen and hydrogen-based fuels are increasingly viewed not only as tools for decarbonisation, but also as potential contributors to energy security and supply resilience.

Governments and industry are therefore paying growing attention to the role that hydrogen can play in building more diversified and resilient energy systems. Low-emissions hydrogen can support the production of fuels, chemicals and industrial materials from a wider range of domestic energy resources, reducing exposure to imported fossil fuels and enhancing industrial competitiveness. As energy security concerns move up policy agendas, these benefits are becoming an increasingly important driver of interest in hydrogen.

At the same time, progress in the hydrogen sector continues to fall short of the expectations that emerged at the beginning of the decade. Ambitious strategies, funding programmes and project announcements have established low-emissions hydrogen as a key element of many energy transition plans. However, deployment has advanced more slowly than anticipated. High production costs, uncertain demand, infrastructure bottlenecks and lengthy permitting processes remain significant barriers. In many regions, the implementation of policies designed to create demand for low-emissions hydrogen and hydrogen-based fuels has also progressed more slowly than expected.

Nevertheless, important advances continue to be made. Low-emissions hydrogen production is expanding, investment remains strong and innovation across the value chain is progressing. New applications are emerging in sectors such as industry, shipping and aviation, while governments continue to develop regulatory frameworks and support mechanisms.

This sixth edition of the Global Hydrogen Review examines these developments and assesses the status of hydrogen worldwide. It reviews trends in demand, production, trade, infrastructure, investment, innovation and policy. In addition, the report includes novel analysis on what constitutes an acceptable cost for low-emissions hydrogen across multiple applications and regions, and a special focus chapter exploring challenges and opportunities for the development of new supply chains for low-emissions hydrogen-based products in Africa.

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, Costa Rica, the European Commission, Finland, Germany, India, Japan, the Netherlands, New Zealand, Norway, Portugal, Republic of Korea (hereafter “Korea”), Saudi Arabia, South Africa, the United Arab Emirates, the United Kingdom and the United States.

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, 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 1. Key questions about hydrogen

How has the conflict in the Middle East affected supplies of fertilisers and chemicals made from hydrogen?

The effects of the conflict in the Middle East extend far beyond disruption to oil and natural gas supplies through the Strait of Hormuz.[1] The conflict has also impacted the worldwide supply of goods made from hydrogen – notably chemicals such as urea used in fertilisers, ammonia and methanol. Fertilisers based on urea account for more than half of global demand for nitrogen fertiliser today, and ammonia is a feedstock for urea and other nitrogen-based fertilisers.[2] Methanol is used for the production of other chemicals, such as olefins used in plastics. In 2025, global production of ammonia required around 34 Mt of hydrogen, and the majority of the ammonia was used to produce fertilisers. Global methanol production corresponded to a hydrogen demand of 16 Mt in 2025. Overall, ammonia and methanol production accounted for around half of global hydrogen demand.

In 2024, the Middle East was responsible for around 11% of global ammonia production of 190 Mt, 13% of urea production of 200 Mt and 17% of methanol production of 120 Mt, and was a major producer of hydrogen for these purposes (Box 1.1). Much of this output is exported: the Middle East accounts for more than one-quarter of international ammonia trade (of 16 Mt) and almost 40% of global trade in urea (of 54 Mt). The closure of the Strait of Hormuz therefore has major impacts on global fertiliser markets and, consequently, on food security. For methanol, the dependency on the Middle East is even higher, with the region being responsible for almost 45% of global methanol trade (of 39 Mt).

Approximately 60% of urea exports and 70% of ammonia and methanol exports from the Middle East pass through the Strait of Hormuz. Bahrain, Kuwait, Qatar, and the United Arab Emirates rely on the Strait for their export routes. While Saudi Arabia has access to alternative ports on the Red Sea, its chemical production plants are primarily situated along the Persian Gulf.[3]

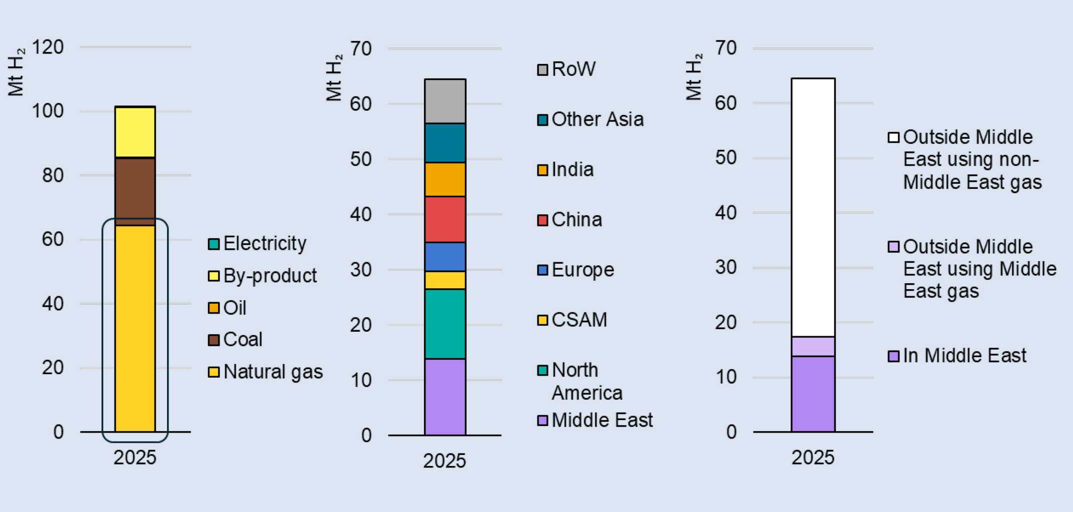
[1] 25% of seaborne oil trade passes the Strait and 20% of global liquefied natural gas (LNG) trade.
[2] Nitrogen fertilisers refer to fertilisers in which nitrogen is the primary nutrient, including ammonia, urea, ammonium nitrate, ammonium sulphate and calcium ammonium nitrate, excluding fertilisers containing phosphorus or potassium.
[3] As a reaction to the crisis, the fertiliser producer Fertiglobe has started to transport fertilisers out of the United Arab Emirates via trucks to circumvent the Strait of Hormuz.

Box 1.1 How much hydrogen production depends on the Middle East?

In 2025, almost 65% of hydrogen produced globally was produced from natural gas, and 21% of this came from the Middle East. The region is an exporter of LNG, meaning that hydrogen production elsewhere may also depend on its gas exports (accounting for an additional 6% of global hydrogen production from natural gas). Overall, 27% of hydrogen made worldwide from natural gas relies on supplies from the Middle East. India, the world's third-largest hydrogen producer, relies on gas imports from the Middle East for 34% of its hydrogen production from natural gas.

With regards to low-emissions hydrogen production, the Middle East is home to the largest renewable hydrogen production project under construction in the world, Saudi Arabia's NEOM Green Hydrogen Project at the Red Sea, with an electrolyser capacity of 2.2 GW. An even larger project, the Yanbu Green Hydrogen Hub, also at the Red Sea, with a planned electrolyser capacity of 4 GW, is undergoing front-end engineering design. Few other projects for low-emissions hydrogen production are being planned in the region, which accounts for roughly 10% of the committed low-emissions hydrogen production worldwide (i.e. from projects that are operational, under construction or have reached final investment decision [FID]), with 430 ktpa. Around half of these projects would rely on the Strait of Hormuz for exports. With the exception of the NEOM project, only a few renewable hydrogen projects in the Middle East have reached FID, representing 350 MW in electrolyser capacity (compared to 29 400 MW globally, excluding NEOM).

Global hydrogen production by fuel and hydrogen production from natural gas by region and gas supplier, 2025



Notes: CSAM = Central and South America; RoW = Rest of World.

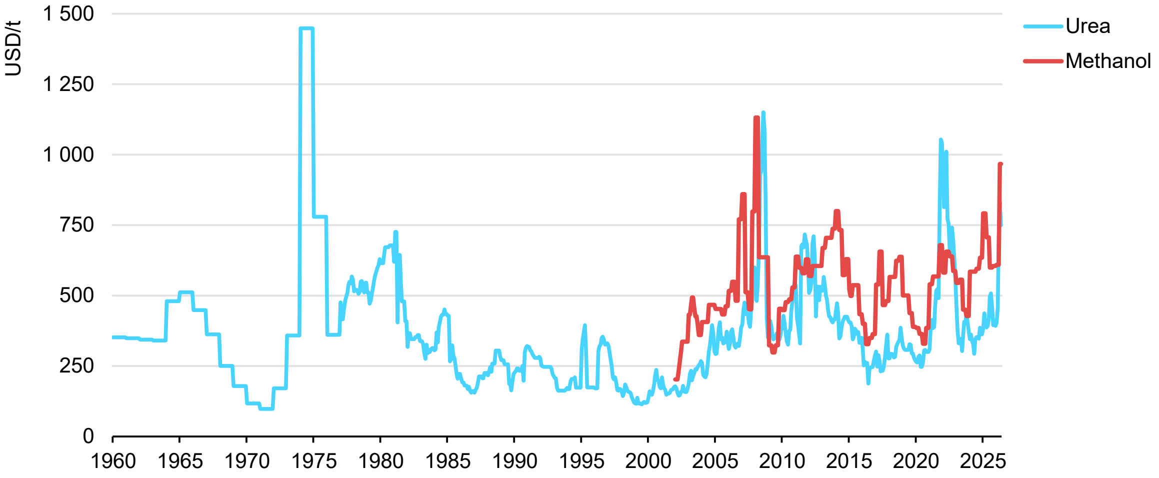
Disruptions to the Hormuz trade route have significantly affected fertiliser markets – impacting urea, ammonia, and natural gas supplies, among others. These trade issues, combined with rising natural gas prices, have increased fertiliser production costs globally. Urea prices, for example, doubled between January and April 2026, but started to decline in May 2026 (Figure 1.1). Other types of fertilisers are also affected: ammonia is used in the production of phosphorus-based fertilisers, and sulphur in the form of sulphuric acid is a feedstock required in the production of both phosphorus-based and potassium-based fertilisers. The Middle East is responsible for nearly 50% of global seaborne trade of sulphur, meaning that supplies of these fertilisers have also been affected by the conflict. This was further aggravated by the announcement by the People's Republic of China (hereafter, "China") of a halt to exports of sulphuric acid in May 2026.

Several fertiliser plants were forced to halt production in response to the conflict. In Qatar, QAFCO paused urea production at its Mesaieed site (the largest urea production complex in the world, with a production capacity of 5.6 Mtpa) in March, after drone strikes on QatarEnergy's LNG facilities. In Iran, which has a total capacity of 9 Mtpa of urea, exports have ceased due to the conflict. Production outside the region has also been affected: Bangladesh suspended four out of five urea plants due to gas shortages in March, with three resuming operations by May. Urea and ammonia producers in Austria, France, India, Pakistan and Slovakia also reduced operations, brought forward annual maintenance work, or temporarily shut down their plants.

If farmers are forced to use less fertiliser, the effects can be significant; even a modest reduction in fertiliser use can lead to a disproportionately large decline in crop yields, particularly in regions where utilisation rates are already low. The impact of high fertiliser prices and shortages could also have longer-lasting impacts. In some parts of the world, such as Europe, many farmers had already secured fertilisers for the spring planting season before the conflict began, but faced higher prices when ordering fertilisers in April and May ahead of the autumn planting season.

Governments have responded with various measures to address potential fertiliser shortages and to support farmers. For nitrogen fertilisers and ammonia, these measures include export restrictions (for instance in Russia and Egypt), lifting of tariffs or import restrictions (e.g. in Türkiye, United States, European Union), sourcing new supplies (e.g. tenders for additional urea supplies in India) and the introduction of price controls or subsidies for fertilisers (e.g. India, Benin). In May 2026, the European Commission presented its Fertiliser Action Plan to support farmers that are facing rising fertiliser costs and scarcity, reinforce domestic production and reduce Europe's dependency on imports.

Figure 1.1 Historical development of urea and methanol prices, 1960-2026



Notes: Urea prices are for prilled urea on a free-on-board (fob) basis in the Middle East since beginning of March 2022, and before fob at the Black Sea. Methanol prices are European posted contract prices for Europe. Prices are in real US dollars for the year 2025.
Sources: World Bank; Methanex.

Urea and methanol prices drastically increased between the beginning of the year and April 2026, marking another historical price spike in these markets.

Methanol markets were also hit by the conflict, with methanol prices increasing by 60% between January and May 2026. Methanol is mainly used by industry as a feedstock for other chemicals, such as olefins used to produce plastics or formaldehyde used to make chipboards. The price impact on consumers may therefore be dampened compared to the impact of fertiliser price hikes on food prices.

The degree to which countries depend on imports from the Middle East and are impacted by physical supply disruptions varies. Morocco and India are the key importers of ammonia from the Middle East, accounting for 70% of all ammonia exports from the region in 2024. Morocco is the largest importer of ammonia globally (3.6 Mt), and has no domestic ammonia production (Figure 1.2). The country relies on the Middle East for 40% of its ammonia imports (1.5 Mt). In absolute terms, India is the largest importer of ammonia from the Middle East, importing 1.9 Mt, which covers nearly 10% of its demand.

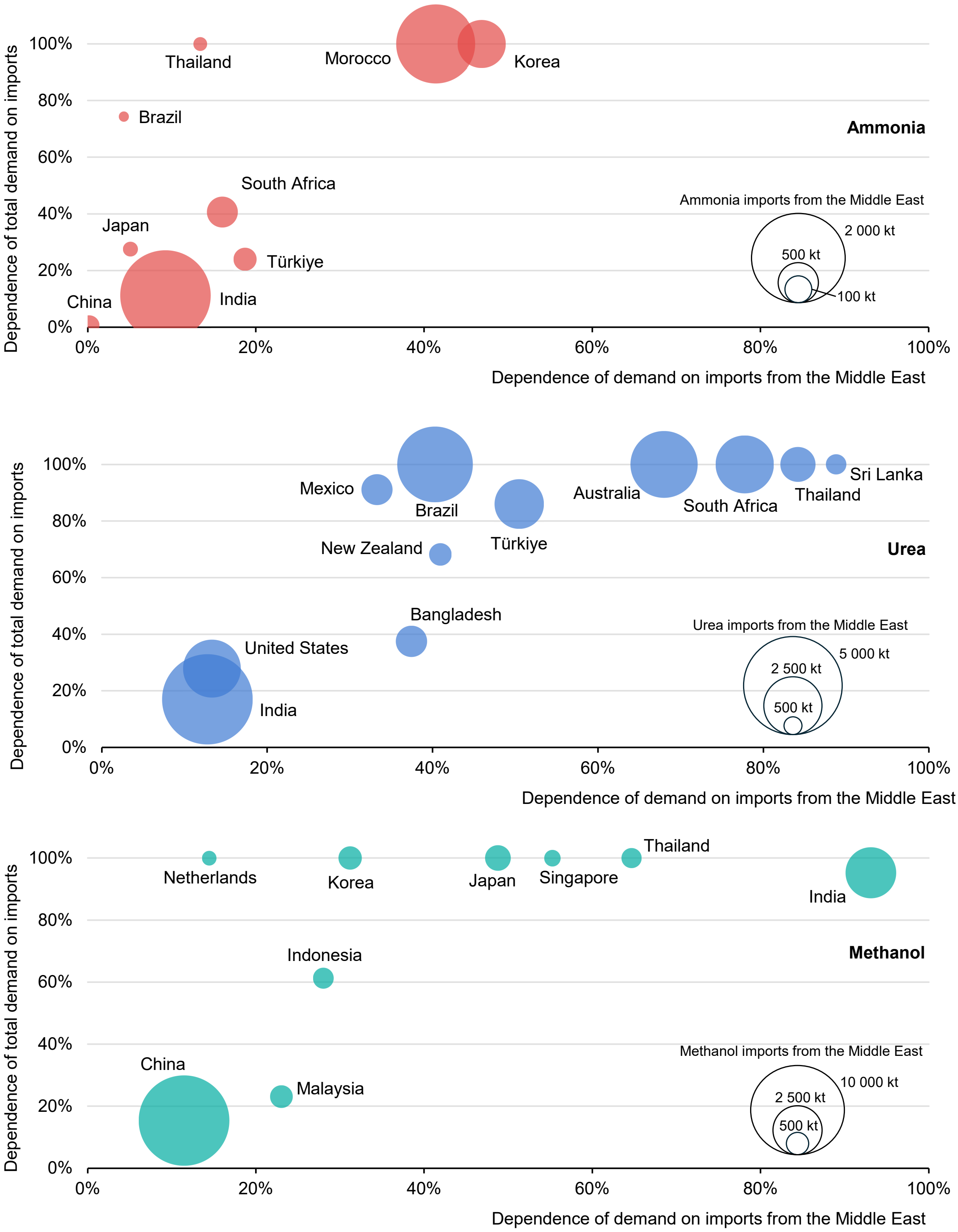
With regards to urea, Brazil is the largest importer in absolute terms from all countries (8.3 Mt). Brazil covers almost 40% of its demand through imports from the Middle East (3.3 Mt). India ranks second in total imports (6.4 Mt) and is the largest importer from the Middle East (4.8 Mt) but only relies on Middle East urea imports to cover 13% of its demand.

China is the world's largest importer of methanol, accounting for over half of the Middle East's methanol exports. However, imports from the Middle East constitute only approximately 10% of China's total methanol consumption. In contrast, India relies on the Middle East for 93% of its methanol consumption, though India's consumption remains significantly lower than China’s, at 3 Mt compared with 80 Mt in 2024.

The conflict in the Middle East is not the first crisis to have hit fertilisers and chemicals made from hydrogen. Russia’s full-scale invasion of Ukraine in 2022, and the resulting spike in natural gas prices, particularly in Europe, affected hydrogen production from natural gas. Inflationary trends also increased prices for various energy technologies, including electrolysers and renewable technologies, such as solar PV and wind turbines used in the production of renewable hydrogen, and affected the financing costs of renewable hydrogen projects. Fertiliser markets were also affected, with average annual urea prices in 2022 being one-third higher than in 2021 (Figure 1.1), contributing, among other factors, to average annual prices for cereals and dairy products in 2022 being 18-25% higher than in 2021.

Although the very high prices seen in 2022 for hydrogen and hydrogen-based feedstocks from natural gas often exceeded the production costs of alternatives based on renewable hydrogen, the price spikes were too brief to justify major investments in renewable ammonia or methanol production plants, which typically operate for 20-50 years. Similarly, renewable hydrogen cannot provide an immediate response in the current crisis, but it can become an important element of strategies to improve long-term energy and food security. At the same time, it can provide additional benefits such as emission reductions, economic growth from domestic chemical and fertiliser industries, and reduced import dependencies.

Figure 1.2 Dependencies of countries on ammonia, urea and methanol imports from the Middle East and total dependencies on imports, 2024



Sources: IEA analysis based on data from BACI, IFASTAT and Argus Global Methanol Balances, All rights reserved.

Dependency on imports from the Middle East for ammonia, urea and methanol varies, but is particularly high in emerging markets and developing economies.

How can hydrogen and hydrogen derivatives contribute to energy security and in what timeframe?

Energy security has been defined by the IEA as the uninterrupted availability of energy sources at affordable prices. The scope of energy security has broadened in recent years, from an initial focus on ensuring that supplies were adequate, to also encompass diversity, flexibility and resilience in the energy system. Today, energy systems are undergoing rapid transformations due to shifting demand patterns, increasing electrification and technological breakthroughs. At the same time, the global context has become more complex, with supply shocks, regional conflicts, extreme weather events and intensified geopolitical tensions.

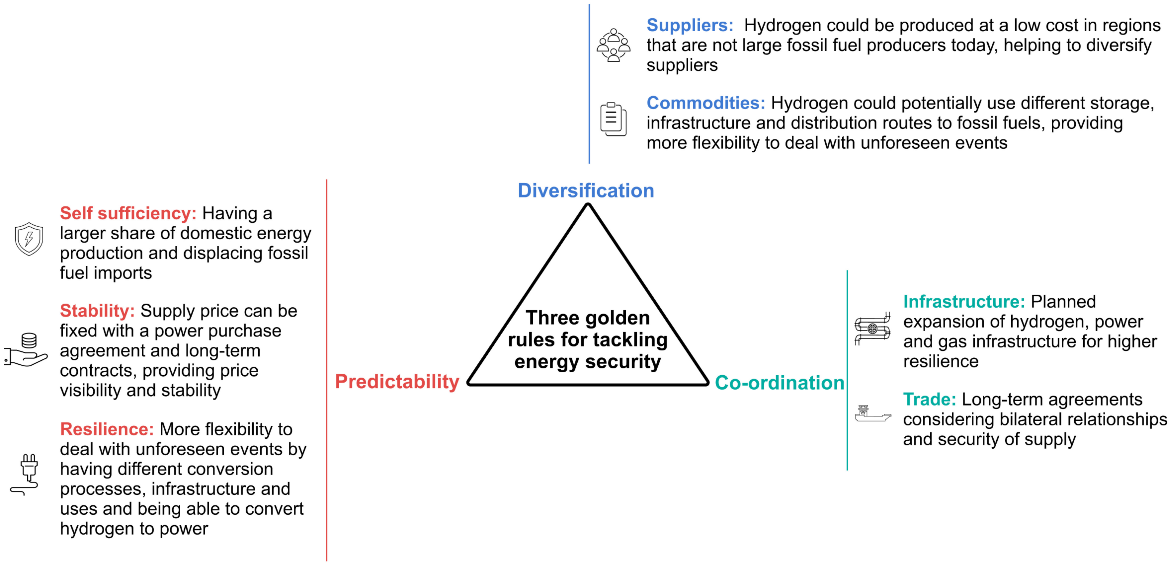
Against this backdrop, policy makers are increasingly considering the role that hydrogen can play in enhancing energy security. There are multiple ways that hydrogen can contribute to energy security (Figure 1.3):

- **Increased domestic production**. Hydrogen can provide a way to use domestic resources to satisfy demand in applications where electrification is more difficult (such as in synthetic fuels for aviation), increasing the overall share of domestic energy supply. For energy-importing countries, if hydrogen is produced from renewables, then this can mean displacing fossil fuel imports that are exposed to disruptions in the producing countries, or to maritime chokepoints. For energy-producing countries, domestic hydrogen production can translate into higher flexibility to achieve other policy goals, such as affordability, or provide another commodity to increase exports. Thanks to hydrogen's versatility, each country could use their own available mix of resources to produce hydrogen.
- **Price security**. Renewable hydrogen can provide visibility and price certainty over a long period of time when the demand is tied to an offtake agreement and the supply is covered by a power purchase agreement. This would most likely be the case in the near term, as market liquidity is not sufficient to have a spot market. This benefit mostly relates to renewable hydrogen, since hydrogen produced with carbon capture, utilisation and storage (CCUS) remains exposed to the price volatility of the fossil fuel market.
- **Diversification**. Hydrogen could allow countries to diversify the supply mix of countries and fuels. While today's oil and gas production is highly concentrated, renewables are widely available, which provides an opportunity for importers to tap into a broader network of suppliers across a different set of countries. Furthermore, hydrogen prices could be uncorrelated to fossil fuel prices, providing a hedge against price spikes. Importers could also consider bilateral relationships and reduced dependence on single countries or trading routes. Diversification extends to the end-use, where additional investment might enable some switching between commodities, depending on prices and availability for applications where multiple fuels can be used, such as power generation, shipping and aviation.
- **Security of supply**. Hydrogen can improve the resilience of the system, as developing necessary infrastructure for hydrogen production could provide

additional assets or supplies that can be used during unforeseen events. This would entail investment in terminals, pipelines and storage that can provide additional routes for energy flows or volumes in order to satisfy demand. Hydrogen could be stored in large quantities in underground reservoirs, like today's natural gas storage, to be used when there is a shortage of supply. It can also be stored as a derivative, like ammonia or synthetic fuel, allowing for the use of existing infrastructure and to tap into different end-uses.

Figure 1.3 Pathways for hydrogen's contribution to energy security

Hydrogen can contribute to energy security in several ways



Hydrogen can improve energy security by offering higher resource security, increasing diversification, enhancing security of supply and providing price security.

Share of energy imports can be used to estimate hydrogen's potential contribution to self-sufficiency. One common metric used to assess market concentration is the Herfindahl–Hirschman Index (HHI)[4], which allows for a relative comparison. A monopoly would be equivalent to a value of 10000 in the HHI scale, and a fully diversified market would tend to 0.

The largest economies, where the largest share of global energy is today, can be split into three groups based on dependence on imports and import diversification (Figure 1.4). Germany, Japan and Korea all satisfied more than 70% of their energy demand with imports, and have relatively concentrated supply. In these three cases, the largest exporter represents more than 25% of the imports. Renewable hydrogen could help these countries to displace some imports and

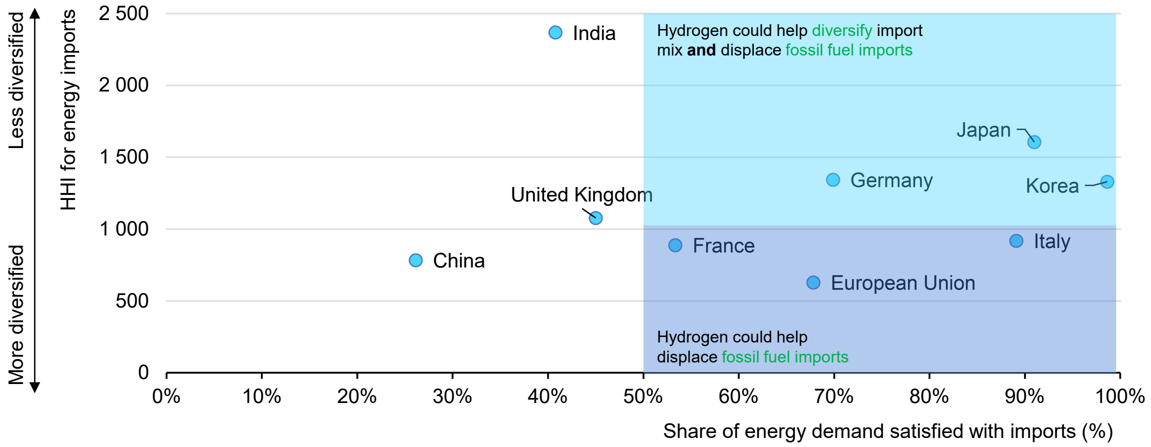
[4] The index is dimensionless and does not have any exact boundaries to define a diversified mix. It is calculated by finding the sum of the squares of the shares for each importer or exporter and multiplying the result by 10 000.

diversify the country mix from where they import. While the domestic renewable potential might not be enough to satisfy all the electricity and hydrogen demand, these countries are still pursuing some domestic hydrogen production. Germany estimates that 30-50% of the hydrogen demand in 2030 could be satisfied with domestic production. Korea has proposed a new strategy to diversify away from fossil fuels by accelerating domestic renewable deployment, phasing out coal by 2040 and producing hydrogen from renewables and nuclear. Japan is aiming to accelerate the restart of nuclear reactors and secure domestically produced energy aligned with the 7th Basic Energy Plan that stresses the importance of diversifying the supply mix.

A second group, including France and Italy, already have a diversified mix of exporters, but still use imports to satisfy more than 50% of their total energy demand. In this group, hydrogen could displace some of these imports. In the European Union, this could be achieved through collaboration among member states.

The last group of countries satisfy a smaller share of their energy demand with imports, but could still benefit from hydrogen use, for example to replace other domestic resources with different impacts on affordability, pollution or sustainability, among other characteristics. Furthermore, these countries could also export more domestic fossil fuel resources or hydrogen, creating additional economic benefits.

Figure 1.4 Share of energy imports and degree of diversification of selected energy importers, 2023



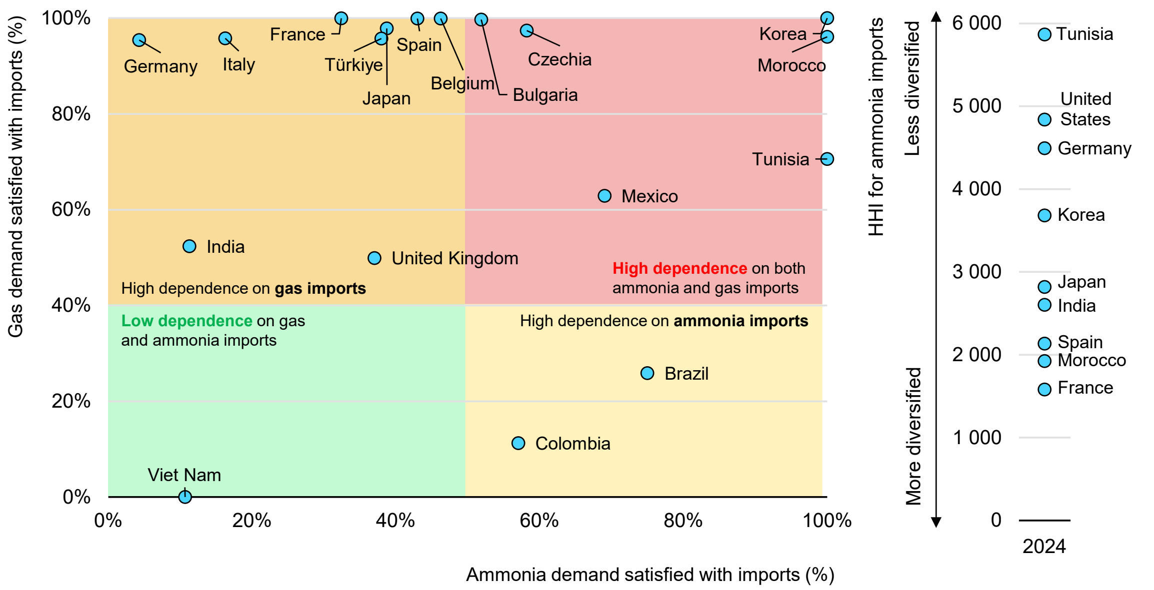
Notes: HHI = Herfindahl–Hirschman Index. Share of energy imports is based on energy flows. Imports of clean technologies are excluded.

Hydrogen could improve energy security by diversifying the energy import mix and decreasing dependence on fossil fuel imports.

For energy importers looking to diversify the supply mix, current oil and gas use cannot be fully replaced with hydrogen. Hydrogen has higher transport costs that make satisfying the end-use more expensive. Even in the case of conversion to synthetic fuels that could benefit from low transport costs, the production cost could still be several times higher than conventional oil.

While displacing other energy commodities with hydrogen across end-use sectors would require a deeper transformation of the energy system, changes in current hydrogen uses could occur over a shorter timeframe. In 2024, 9% of global ammonia production and 33% of methanol were globally traded. For ammonia, some of the largest importers are the European Union, India, Korea, Morocco and the United States, which together represent about two-thirds of the global trade. European countries, Japan and India have relatively low import dependence to satisfy ammonia demand and have a diversified import mix (Figure 1.5). However, they rely on natural gas imports for their domestic ammonia production. While import dependence within the supply chain can be high, these commodities exhibit different market dynamics, offering greater flexibility. Korea and Morocco rely almost completely on imports for both commodities. In contrast, China and the United States satisfy nearly all their ammonia demand with domestic production and are self-sufficient for the feedstock used (coal and natural gas, respectively). While this has been the case in China for the entire past decade, the United States decreased its imports from 34% in 2013 to just 5% in 2024.

Figure 1.5 Import dependence for ammonia and gas production (left) and Herfindahl–Hirschman index (right) for selected countries, 2024



Notes: HHI = Herfindahl–Hirschman index. Countries shown on the left represented around two-thirds of global ammonia imports in 2024.
Source: IEA analysis based on International Fertilizer Association for ammonia demand and trade.

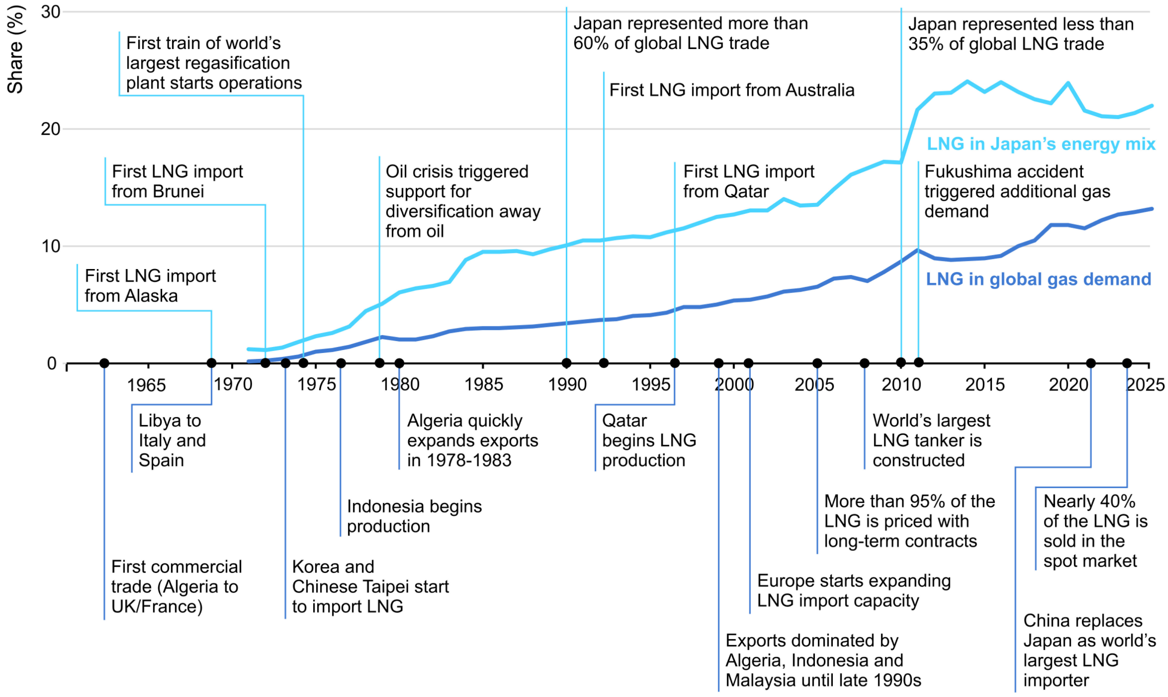
European countries, Japan and India have relatively low reliance on ammonia imports but have a high import dependence on the feedstock for ammonia production.

Hydrogen introduces flexibility in how countries manage import dependence across the supply chain, due to the multiple transformation steps involved in its use. For example, for iron and steel, countries can choose different points along this chain for domestic production or imports. At one end, a country may prioritise energy security by producing steel fully domestically, accepting higher costs to retain control, while still importing iron ore. At the other end, it may minimise costs by importing finished steel. Between these extremes, intermediate strategies exist, such as importing direct reduced iron and completing steel production locally. These choices are not driven by energy security alone, and also involve trade-offs related to industrial policy, economic activity, employment and affordability.

The contribution of hydrogen to energy security will not appear overnight. There are two main time lags to consider. Firstly, a single project can take 2-4 years (or longer for initial projects in a country without previous experience on this type of projects) from announcement to FID. After reaching FID, reaching full production can take another 1-4 years, and longer in regions with more complex permitting and regulation, or for projects that require more co-ordination among stakeholders. Secondly, it takes time for the cumulative production from several projects to start making a significant contribution to energy flows. This goes beyond a single project and requires common elements like infrastructure development, such as a pipeline network to supply H_2-DRI or power plants, or supply and bunkering infrastructure for use for shipping fuels or ammonia storage. While initial deployment must be underpinned by policy and economic support, there should be a clear perspective for the phase-out of support in the longer term, otherwise increasing energy security with hydrogen could come at a high cost.

LNG can provide a historical proxy on the time needed to ramp up (Figure 1.6). Like hydrogen, there was no price benchmark for LNG in its early days, there was a lack of infrastructure, and there was therefore the need for long-term offtake agreements to enable development. While natural gas liquefaction was first carried out more than a century ago, the first international LNG shipment took place in 1959, and the first purpose-built LNG carrier entered into service in 1964. Japan, one of the pioneers in importing LNG and the leading LNG importer until 2021, started importing LNG in 1968 from Alaska. In the 1970s, production started to ramp up in Indonesia and Algeria, while Korea and Chinese Taipei also became importers. At the same time, oil crises and price spikes led to support to diversify away from oil. In 1990, Japan represented nearly three-quarters of global trade and LNG represented about 10% of the energy mix. Two decades later, Japan's share had decreased to less than 35% and LNG represented about 17% of the energy mix. Nearly five decades after the first shipment, LNG still met less than 15% of global gas demand.

Figure 1.6 Timeline of the liquefied natural gas evolution in Japan's energy mix and global gas demand along with key milestones, 1964-2025



Note: LNG = Liquefied natural gas.

It took more than three decades for LNG to satisfy 5% of global gas demand and 13% of the energy mix in Japan, which was the world's largest LNG importer until the early 2020s.

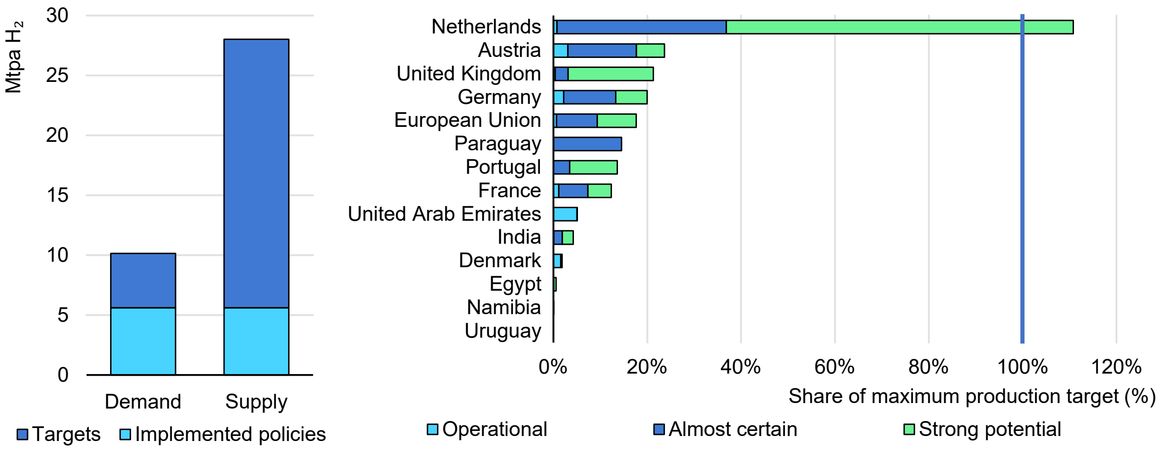
Hydrogen offers a flexible pathway for countries to strengthen energy security, including by expanding domestic energy supply and improving system resilience. Its value lies in its adaptability to different national contexts, allowing governments to align hydrogen deployment with their specific resource base and infrastructure. However, realising these benefits requires sustained long-term investment and robust policy frameworks to ensure that hydrogen systems are operational and reliable when disruptions occur. Moreover, energy security should not be pursued in isolation, policy makers must weigh hydrogen's role against other priorities, including affordability, market readiness, industrial capacity, and the energy mix.

Are announced hydrogen targets for 2030 within reach given realistic project delivery timelines?

There has been strong policy momentum behind low-emissions hydrogen since the early 2020s, when numerous governments worldwide announced strategies outlining a route for adoption. These strategies established ambitions for deployment within this decade, including targets for the production and use of low-emissions hydrogen. Some governments then announced support schemes to achieve these objectives, and this support has played a fundamental role in the initial growth seen in the sector. Low-emissions hydrogen production globally reached close to 1 Mt in 2025, compared with less than 0.6 Mt in 2020.

However, growth has been far smaller than was envisaged by the loftier ambitions announced in the early 2020s. Slow and uncertain implementation of key policies has hindered faster uptake, particularly on the demand side, where both the targets established in the strategies and the funding provided has been much lower than on the production side (Figure 1.7). The likelihood of achieving the announced targets by 2030 is now in question, calling for a reconsideration of how to align ambitions and implemented policies with the reality of the market.

Figure 1.7 Government targets for low-emissions hydrogen production and demand globally and selected individual targets for production, 2030



Note: China is excluded from the chart to avoid distorting the scale and because its 2030 target is 300 ktpa while its project pipeline with all projects up to strong potential equals more than six times this target.

Only China and the Netherlands are on track to meet their announced targets for production of low-emissions hydrogen by 2030.

At the time of writing, targets for low-emissions hydrogen production globally by 2030 add up to almost 27 Mtpa, 30 times higher than the global production in 2025. Not all of this will materialise, but production is nonetheless expected to keep growing strongly in the second half of this decade thanks to existing incentives and policies. Based on projects that have at least taken an FID, production is expected to surpass 4 Mt in 2030, if projects are successfully completed on time. A further almost 2 Mtpa could be produced by projects that have strong potential to be operational by 2030 – if policies are implemented to stimulate demand and to close the cost gap with hydrogen from unabated fossil fuels. This is, nonetheless, well below the announced targets.

Only China – which could already meet its goal of producing 300 kt of renewable hydrogen[5] by 2030 in 2027 – is on track to meet its production target. The Netherlands, which delayed its target in 2025[6] (from 3-4 GW of installed electrolysis capacity by 2030 to 2035, aiming for 1.2 GW by 2030) could meet its new target if all projects with strong potential are realised.

Achieving government ambitions will require a significant acceleration of deployment before the end of the decade. Low-emissions hydrogen production globally grew at an average annual rate of almost 10% between 2020 and 2025 (Figure 1.8). Based on projects with committed investment, growth is expected to reach an average annual rate of close to 40% until 2030. This is higher than the rates achieved by nuclear energy during its fastest growth period (25% between 1960 and 1985), but is comparable to the growth observed by LNG in the 1970s (35%) and by solar PV and onshore wind in the last two decades (35-38%). By contrast, meeting government targets for 2030 would require reaching an annual average growth rate of 100%, which is even higher than the explosive growth in electric vehicles seen in the past decade (70%).

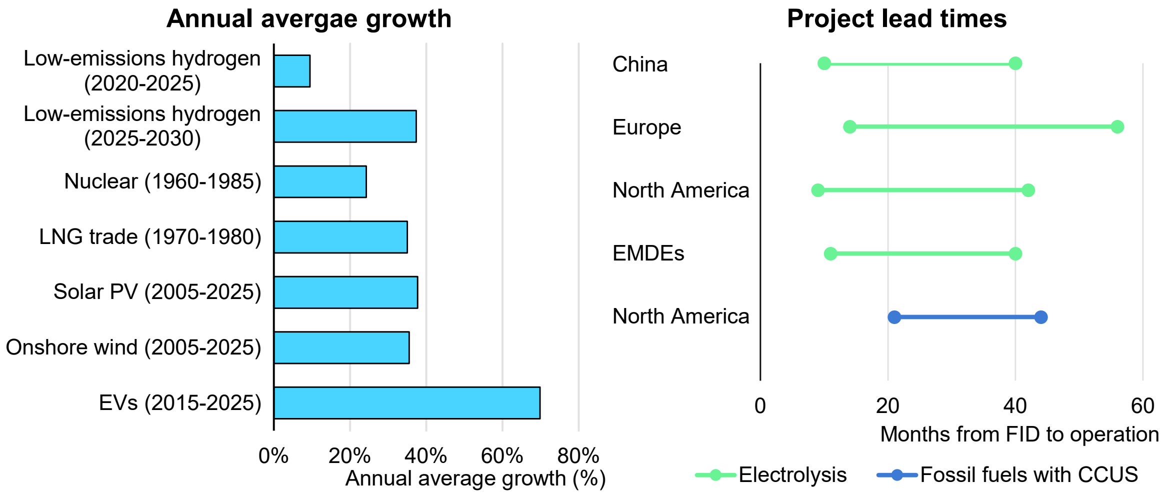
The gap between stated ambitions and actual deployment varies, but it is significant in all countries. The production of low-emissions hydrogen in the United Arab Emirates would need to grow by a factor of 20 between 2025 and 2031 to meet its Hydrogen Strategy target. In the European Union, installed electrolysis capacity would need to grow by a factor of 70 to meet the ambition set in the EU Hydrogen Strategy (currently under revision). Even in the case of countries that have recently downscaled their previously announced ambitions, such as Chile (from 25 GW by 2030 to 8-15 GW by 2035), deployment would need to grow by factors of several hundred in the next decade.

Meeting government ambitions to produce renewable hydrogen would also require a significant acceleration in the deployment of renewable power capacity. At the same time, renewable power capacity is also required to meet growing demands in other sectors (including from fast-growing new sources of demand such as data centres). For example, Egypt's renewable hydrogen production target of 1.5 Mtpa by 2030 would require around 19 GW of electrolysis according to its National Low

[5] For comparison, this would require an electrolysis capacity of around 3 GW assuming an electrolyser efficiency of 60% and 5 000 full load hours per year.
[6] Netherlands pushes back 3-4GW electrolysis goal to 2035, Argus Media Group. All rights reserved (17 September 2025).

Carbon Hydrogen Strategy. However, at the end of 2025, the country had only around 8 GW of installed renewable capacity. With the growth rate observed in the last 5 years (around 7%), it would take another 19 years to install another 19 GW of capacity to be used exclusively for hydrogen production in order to meet the government target. Installing an additional 19 GW by 2030 would require nearly tripling the growth rate (18%) and dedicating all new installed capacity exclusively to hydrogen production.

Figure 1.8 Average annual growth rates for selected technologies compared with historical and expected growth rates until 2030 for low-emissions hydrogen, and hydrogen project lead times



Notes: CCUS = carbon capture, utilisation and storage; EMDEs = emerging markets and developing economies; EVs = electric vehicles; FID = final investment decision; LNG = liquefied natural gas; PV = photovoltaic. Low-emissions hydrogen (2025-2030) in the figure on the left considers projects in operation, under construction or that have reached FID, targeting operation before 2030. Project lead times based on data for 50 projects starting operation between 2020 and 2026.

Sources: IEA analysis based on IEA (2026), Global Electric Vehicle Outlook 2026; International Atomic Energy Agency Power Reactor Information System; IEA (2026) IEA Hydrogen Production Projects Database (June 2026).

Low-emissions hydrogen production is expected to grow faster in the coming years, but the deployment level by 2030 will be set in the next 2 years due to project lead times.

Achieving 2030 targets strongly depends on the potential to reach investment decisions soon. Based on experience from large-scale projects that reached operation in the last 5 years, typical project lead times between reaching FID and starting operation vary between 1-4.5 years for electrolysis, and between 2-3.5 years for CCUS projects. These ranges are influenced by the size of the project, the experience of the partners involved (particularly by those that have managed to scale up project size in recent years) and domestic regulations. Consequently, Chinese developers have been able to build and start operating electrolysis projects above 50 MW in less than a year, whereas smaller projects in Europe and North America tend to require 1.5-3.5 years before operation. Meeting the 2030 targets would require around 22 Mtpa of low-emissions hydrogen production to reach FID between 2026 and 2027, a 12-fold increase compared with the production reaching FID between 2024 and 2026.

For projects to reach FID, there are several necessary framework conditions that need to be fulfilled. Projects need to be able to secure offtake, and to access support from schemes that can reduce the cost gap with unabated fossil fuel-based production. They require an operating environment in which regulations are workable, and that hydrogen-specific infrastructure (to connect producers and users) and enabling infrastructure (particularly electric grid and CCUS networks) are available. Although the number of projects managing to meet all these conditions has grown in recent years, most are struggling to do so, and this has occasionally led to project cancellations, delays and reductions in size. There are several policy options that can play a key role in overcoming these barriers:

- **Demand-pull policies and regulations**: At this early stage of market development, policy is fundamental to create demand and provide long-term clarity about demand coming from the market, in order to facilitate offtake. Notably, several refining-oriented projects in Europe reached FID once there was clarity on the transposition into national legislation of the transport targets of the Renewable Energy Directive (RED). Regulations that encourage use of low-emissions hydrogen and hydrogen-based fuels (such as binding quotas, mandates or fuel standards) can be complemented with support schemes (such as contracts for difference or end-user incentives) to help first movers. In addition, governments can take a more proactive role in the creation of demand through public procurement of low-emissions hydrogen-based products, demand aggregation mechanisms (such as buyers coalitions), the establishment of market intermediaries that absorb part of the risk taken by users and producers (following the approach taken by H2Global), or the provision of state-backed guarantees for offtake.
- **Improved design of support schemes**: The first support schemes have managed to mobilise private investment and several projects have moved forward. However, several projects have had to return funding that had been awarded due to their inability to progress into advanced stages. Future calls under these schemes could implement lessons learned in order to improve scheme design. This includes the establishment of eligibility criteria (such as the presence of a solid offtake agreement or capacity for self-offtake, permits in place for access to enabling infrastructure, completion of front-end engineering design and a clear business plan to close the cost gap with incumbent technologies) to ensure that support reaches shovel-ready projects with more chances of being successfully completed. In addition, the schemes should take into consideration realistic project lead times, particularly for projects that are aiming to scale up novel technologies. Finally, the schemes should try to fast track the application process to avoid long delays that lead to higher development costs, and during which the viability of the projects can change.

- **Accelerating permitting and facilitating access to enabling infrastructure**: Efficient permitting and easy access to enabling infrastructure can significantly reduce project lead times. Successful initiatives in renewable energy deployment (such as the European Union's Renewable Acceleration Areas or land concessions in countries like Egypt, Morocco and the United Arab Emirates) can be replicated and adapted to the case of low-emissions hydrogen projects. In addition, governments should work to minimise delays in the development, reinforcement and modernisation of this infrastructure, since limited availability of CO_2 networks and electric grid congestion are becoming important bottlenecks for hydrogen scale-up.

The progress achieved by the hydrogen sector since 2020 is impressive, and the accelerated growth expected in the second half of this decade is comparable to the success stories observed in other clean energy technologies. Deployment can be accelerated even further if enabling policies are implemented. However, the short time remaining until the end of the decade, combined with the gap between current deployment and the announced ambitions for 2030, suggest that many of these targets are unlikely to be met under the current conditions.

Governments should consider a recalibration of announced ambitions to reflect market realities, as well as respond to drivers that have recently gained more prominence, such as energy security and supply diversification, in order to bolster their hydrogen strategies. This recalibration can take into account lessons learned from the first wave of strategies launched in early 2020s. These include the need for shorter review cycles given the early stage of the market, implementation of gradual and dynamic regulations that can be adapted according to market maturation, and use of a holistic approach for developing the full value chain of low-emissions hydrogen that takes into consideration cost developments not only for hydrogen, but also for other competing technologies. The recalibration should also consider the establishment of longer-term targets to steer private investment. However, targets alone will not be sufficient to steer private investment. Any targets will need to be accompanied by a rapid roll-out of the policies and incentives required for their achievement.

Is geological hydrogen approaching commercial readiness as exploration interest grows?

Interest in geological hydrogen has grown sharply, supported by rising private capital and a growing pipeline of exploration projects. However, resource potential remains highly uncertain and needs to be physically validated through drilling. Potential estimates are not available for any single well, and only a share of this resource is likely to be technically and economically recoverable. While some assessments suggest global occurrences of at least 1 billion tonnes H_2 – and a best estimate of around 5.6 trillion tonnes H_2 – production potential may be significantly lower than resource availability. For example, if 1% of the best-estimate resource were recoverable, it would be equivalent to around 560 years of today's hydrogen consumption. Despite momentum, exploration remains at a pre-commercial stage, and further work is needed to better characterise resource fundamentals, validate appropriate extraction technologies, and establish the economics of production.

Geological hydrogen refers to hydrogen generated in the Earth's subsurface. It includes natural hydrogen, produced through naturally occurring geological and geochemical reactions,[7] and stimulated geological hydrogen, induced or accelerated by anthropogenic interventions. Natural hydrogen relies on finding and exploiting existing accumulations, whereas stimulated approaches seek to improve predictability and reduce exploration risk by inducing hydrogen generation. Methods include stimulated mineralogical reactions, such as artificial serpentinisation or mineral carbonation,[8] and in-situ hydrocarbon conversion.[9]

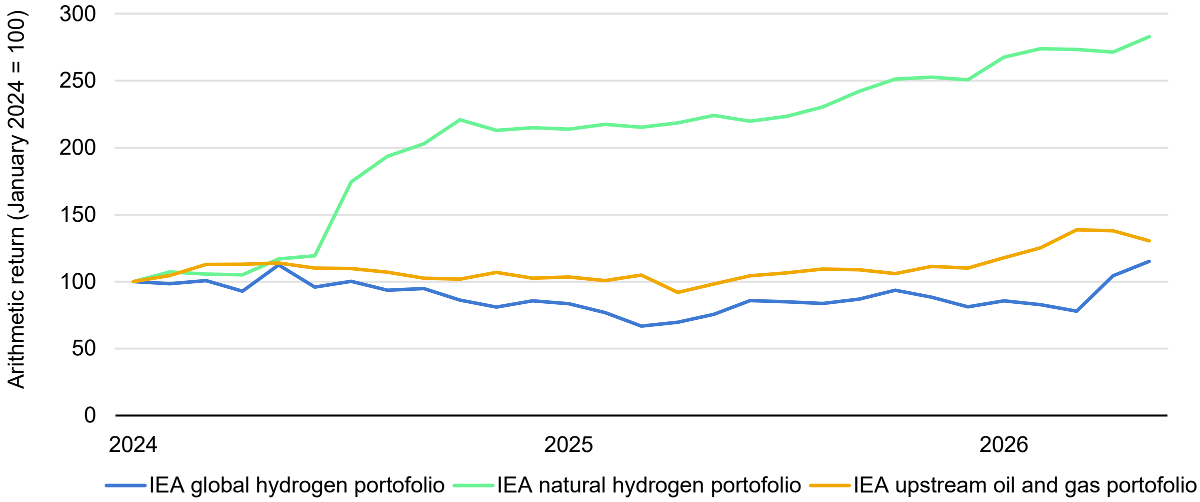
Natural hydrogen occurrences have been documented across diverse geological settings over the past century. However, these have received limited attention because high reactivity and diffusivity were thought to limit accumulation. The accidental discovery of a natural hydrogen well in Bourakébougou, Mali, during water drilling in 1987, attracted little interest for more than two decades. Since 2012, the well has produced around 5 tpa H_2 (100 barrels of oil equivalent per year), which is used for power. In 2024, researchers identified a hydrogen reservoir in Albania's Bulqizë ophiolite,[10] outgassing at least 200 tpa H_2 from an underground mine, which points to the potential for natural hydrogen accumulations in some ophiolite systems. The sector is therefore moving beyond

[7] Several formation mechanisms of natural hydrogen have been identified, of which serpentinisation is considered the most significant: reactions between water and iron-rich rocks that generate hydrogen that accumulates in subsurface reservoirs.
[8] Hydrogen production from water and CO_2 injection into ultramafic rocks for mineral carbonation and CO_2 storage while co-producing hydrogen. This approach may offer dual benefits by combining hydrogen production with permanent CO_2 storage.
[9] Further details on these technologies are available in the ETP Clean Energy Technology Guide.
[10] Ophiolites are a distinctive assemblage of mafic and ultramafic rock formations whose iron-bearing minerals can generate hydrogen through serpentinisation.

proving that natural hydrogen occurrences exist, and towards assessing where commercially viable accumulations may form, how they can be identified before drilling, and whether reservoirs can sustain commercial flow rates.

Recent market developments underline growing expectations around geological hydrogen (Figure 1.9). A stock-return index of publicly listed companies active in natural hydrogen exploration had tripled by May 2026 relative to its 2024 base year, far outpacing the more modest gains recorded by broader hydrogen-related and upstream oil and gas company portfolios. Before mid-2024, the natural hydrogen portfolio had moved more closely in line with these broader portfolios.

Figure 1.9 Indexed stock returns of selected companies in natural hydrogen exploration, hydrogen-related activities, and upstream oil and gas, January 2024-May 2026



Notes: Portfolio indices are constructed from monthly stock returns, with January 2024 set equal to 100. Monthly portfolio returns are calculated as the equal-weighted average return of the companies included in each portfolio and compounded to show cumulative performance over time. The IEA natural hydrogen portfolio comprises 11 publicly listed companies whose market value may be affected by the outlook for natural hydrogen, selected with reference to the NatH2 Index. Included tickers are EONE CN, GTC LN, GHY AU, HDRO CN, HHEXF US, HYT AU, MAXX CN, PRM AU, QIMC CN and REVX CN. The IEA global hydrogen technology portfolio comprises 55 publicly listed companies, with tickers listed in Chapter 6, and the IEA upstream oil & gas portfolio comprises 37 publicly listed companies active only in upstream and midstream activities. 2026 data are up to May 2026.

Source: IEA analysis based on Bloomberg terminal data.

Natural hydrogen exploration stocks delivered nearly threefold returns, far outpacing modest gains in hydrogen-related and upstream oil and gas portfolios.

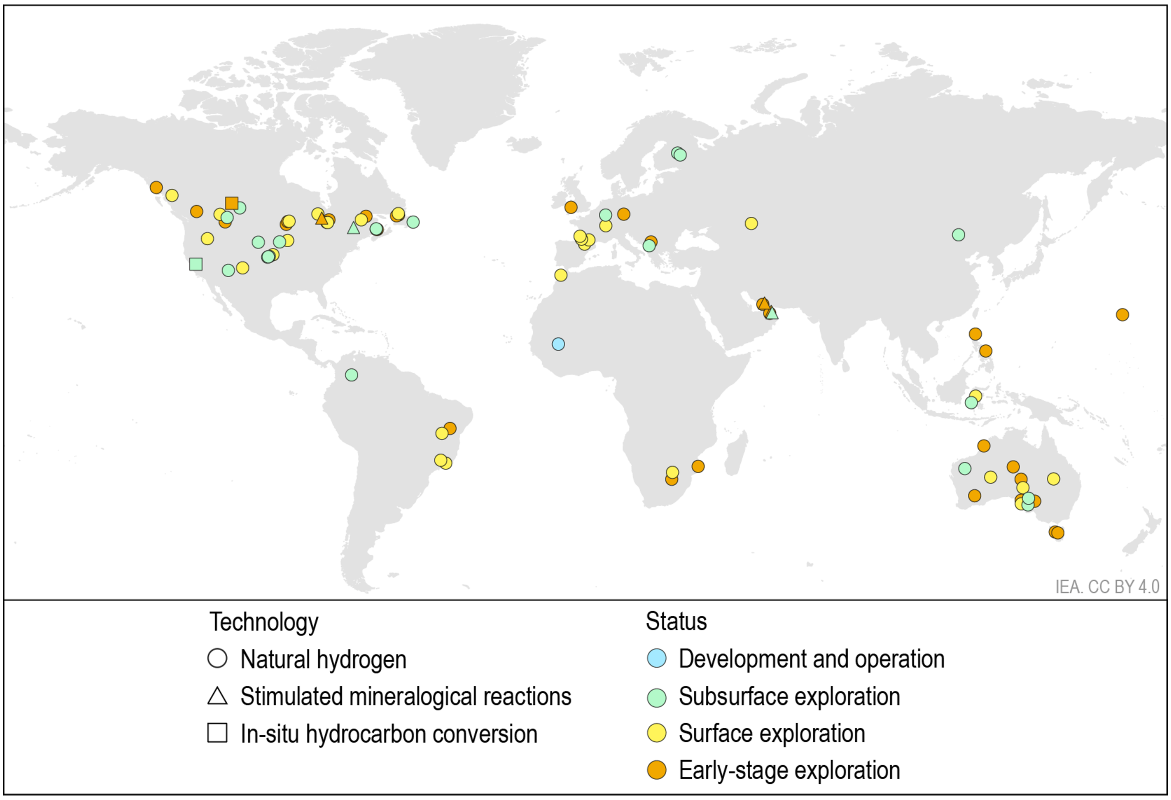
In venture capital (VC), geological hydrogen start-ups have raised nearly USD 0.5 billion since 2023, accounting for around 15% of VC for hydrogen production technologies. While overall VC for hydrogen is declining, investment in geological hydrogen has increased. Funding remains highly concentrated, however, with US-based Koloma attracting nearly 90% of this funding for natural hydrogen, meaning that early technological learning is closely tied to the progress of a small number of companies. Recent fundraising by other start-ups nevertheless points to a gradually broadening innovation landscape, including France-based Mantle8, which announced a USD 36 million fundraising round in May 2026, and US-based Vema, which raised USD 13 million for stimulated geologic hydrogen in 2025.

Strong interest is now driving a growing pipeline of exploration projects, led by a mix of start-ups and small upstream oil and gas firms, and mining companies (Figure 1.10). Large companies are mostly participating through corporate VC, including BP, Fortescue, Mitsubishi Gas Chemical, Mitsubishi Heavy Industries, Osaka Gas, Rio Tinto and Toyota. Geological hydrogen exploration projects can be expected to follow a pathway that is broadly similar to upstream natural gas projects, although activity today remains concentrated in the early discovery phases, mainly at the surface and subsurface exploration stages:

- **Early-stage exploration**: licence or leasing agreement granted, but no significant exploration activity yet.
- **Surface exploration**: geological studies, geophysical surveys and soil gas sampling under way.
- **Subsurface exploration**: initial drilling to confirm hydrogen presence and assess basic subsurface characteristics.
- **Appraisal**: further drilling and reservoir studies to assess flow rates, reservoir behaviour, resource size and project feasibility.
- **Development and operation**: engineering, design, construction, commissioning and production, eventually followed by decommissioning.[11]

[11] The extent to which some natural hydrogen reservoirs may be replenished during production remains unknown.

Figure 1.10 Geological hydrogen projects by development stage, 2026



Source: IEA (2026) IEA Hydrogen Production Projects Database (June 2026).

Geological hydrogen exploration spans almost 30 countries, but remains at an early stage, with only one operating well in Mali and first projects moving to subsurface exploration.

National and sub-national jurisdictions are now moving at different speeds in developing frameworks for natural hydrogen, or geological hydrogen more broadly, and countries can be grouped by their most advanced exploration activity and regulatory readiness. Where frameworks have been updated, they generally adapt existing hydrocarbon and/or mining laws; elsewhere, regulatory uncertainty can slow subsurface exploration.

- **Multiple exploration wells drilled**. The United States accounts for the most exploration drilling, with the first dedicated natural hydrogen well drilled in Nebraska in 2019. Activity has since been concentrated along the Midcontinent Rift, with ongoing drilling in Nebraska, Kansas and Iowa, alongside further activity in Arizona and Idaho. Unlike in many countries where subsurface resources are state-owned, subsurface rights are often privately held, enabling direct leasing arrangements with landowners. There is no dedicated federal framework, and regulation is emerging at the state level: in April 2026, Iowa became the first state to pass dedicated legislation, covering operator obligations and a severance tax.[12] In Australia, drilling began in South Australia in 2023, with four wells drilled to depths of up to 855 m. Natural hydrogen was incorporated into South Australia's Petroleum and Geothermal Energy Act in 2021, with Western Australia introducing similar provisions in 2024. In Canada, a first exploration well was drilled in Saskatchewan in November 2025, followed by a 900 m well in Nova Scotia in April 2026. Saskatchewan has accommodated natural hydrogen within existing permits for helium and associated gases, reflecting its established helium sector, while Nova Scotia passed dedicated subsurface energy legislation in April 2026 that covers natural hydrogen among other resources.

- **First exploration wells drilled or planned**. A small number of countries have moved from surface exploration to drilling. In France, natural hydrogen was included in the Mining Code in 2022, and in March 2026, a 3 665 m well was drilled, the deepest globally for natural hydrogen. China drilled its first natural hydrogen well (800 m) in Inner Mongolia in 2025. Colombia updated its framework in 2023 to incorporate natural hydrogen and conducted exploratory drilling in 2025. Further wells are planned. In Oman, interest focuses on the Semail Ophiolite, where several international companies have signed agreements with Omani partners and a research pilot well has tested stimulated hydrogen production, building on the subsurface characterisation of the Oman Drilling Project. In the United Arab Emirates, a national oil company is targeting first drilling in 2026 in the Semail Ophiolite, in collaboration with international partners. The Philippines held a government-run auction in 2024 and has since awarded several exploration contracts. In Spain, a 4 000 m appraisal well is planned for H2 2026, but regulatory uncertainty has delayed progress.
- **Surface prospecting and soil gas surveys**. Other countries remain at earlier stages of exploration, focused on field studies, surface prospecting and soil gas surveys. Brazil established a legal basis for natural hydrogen exploration in 2024, with implementing regulation still under development, and surface exploration was launched in 2026. In South Africa, exploration licences followed field studies, and public institutions in Morocco and researchers in Kazakhstan have published results from soil gas surveys. Belgium has approved funding for a national scientific exploration programme for natural hydrogen.
- **Upstream regulatory frameworks updated, but limited or no exploration activity yet.** Poland amended its mining law in 2023 to include natural hydrogen, and Germany's Hydrogen Accelerator Act of 2026 enables the use of standard mining permitting procedures.

Downstream regulatory frameworks have not yet integrated geological hydrogen, creating uncertainty over eligibility for low-emissions hydrogen support schemes even where upstream regulation is advancing. In most jurisdictions, eligibility

[12] A severance tax is a levy applied by governments on the extraction of natural resources.

depends on GHG emissions accounting for defined production pathways, which do not currently include geological hydrogen. Colombia has taken a step in this direction by classifying geological hydrogen as a non-conventional renewable resource. In the European Union, geological hydrogen is not covered as a renewable fuel of non-biological origin (RFNBO) under RED III, nor is it covered by the 2025 low-carbon fuels GHG methodology. In the United States, it is not included in the 45VH2-GREET model for the 45V tax credit for clean hydrogen production, although producers can petition for a Provisional Emissions Rate. Australia and Canada's support schemes for hydrogen, similarly, do not cover geological hydrogen.

Technological innovation could help reduce exploration risk, cut costs and shorten development timelines for geological hydrogen. Extraction may draw on established subsurface drilling practices, but these still need validation for hydrogen reservoirs. Dedicated exploration workflows are emerging that combine geology, geochemistry and geophysics with 3D/4D subsurface imaging and AI-based data analytics to identify prospective hydrogen accumulations and help target drilling. Innovation is also advancing in in-situ hydrogen separation, including ongoing technology testing in France. Stimulated geological hydrogen approaches are progressing as well, with Vema drilling first pilot wells and signing a conditional offtake agreement with Verne, a provider of off-grid power for data centres. Public research support is also increasing, including projects in the United States supported by the Advanced Research Projects Agency-Energy (ARPA-E) and Japan's Frontier Development Program on geological hydrogen.

Some projects are increasingly linking natural hydrogen and helium exploration, as the two can co-occur, with some companies now exploring both, including Gold Hydrogen's Ramsay project in Australia and HyTerra's Nemaha project in the United States. Helium can improve project economics because it commands a higher market value than hydrogen, and demand is growing across applications including semiconductors, such as high-performance chips for AI, and in healthcare. At the same time, supply remains concentrated, with most helium produced from natural gas processing, and Qatar accounting for one-third of global supply in 2025. With helium prices doubling in the first month following the start of the Middle East conflict, joint exploration could offer an alternative supply route and additional revenue streams. Some projects are also assessing natural hydrogen, helium and deep geothermal resources within integrated exploration programmes, such as Swiss Geo Energy's Jorat project in Switzerland and Tellus Energy Solutions' Kairos project in Germany, which reflects growing interest in the ability of geothermal energy to provide reliable around-the-clock power.

In the absence of large-scale geological hydrogen production, upstream oil and gas development provides a useful, albeit imperfect, reference for timelines. In oil and gas projects that started production after 2010, the period between early exploration to discovery has averaged around 5 years, followed by a variable period to FID, and typically less than 5 years from FID to commissioning. However, this comparison may represent an optimistic benchmark, as oil and gas development in the 2010s benefited from decades of resource characterisation, reservoir knowledge and established development practices. Geological hydrogen is at an earlier stage. If the industry is closer to where unconventional oil and gas was in the 1990s and 2000s, substantial production volumes could require a further 10-20 years of technology, resource and project development. First production from smaller onshore wells could emerge in the early to mid-2030s, but larger-scale contributions are unlikely before the 2040s. Timelines could be shorter for projects near existing infrastructure or demand centres, or where standardised approaches can be replicated across similar geological settings. This may be relevant for stimulated geological hydrogen, drawing on lessons from shale developments, where drilling times declined as techniques matured.

Confirmed discoveries in Mali and Albania have demonstrated hydrogen flows, but have not yet validated resource potential, and no other projects have advanced to appraisal stage. Current growth in market capitalisation and VC activity therefore reflects expectations rather than demonstrated resource potential. Until subsurface explorations and appraisal drillings confirm sustained flow rates and economically viable concentrations, geological hydrogen warrants continued assessment, but its near-term role is likely to remain limited. Realising its potential will require upstream and downstream regulatory frameworks that explicitly integrate geological hydrogen, and technological innovation to reduce drilling risk.

Chapter 2. Hydrogen demand

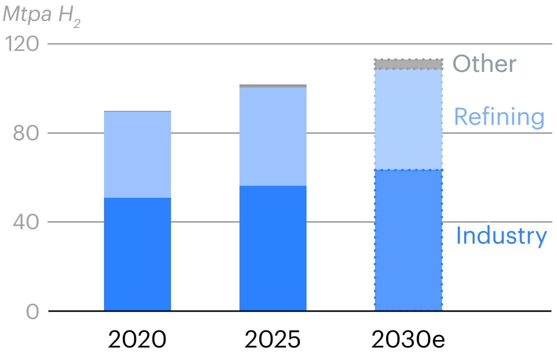
Highlights

- Global hydrogen demand grew almost 3% in 2025 to surpass 100 Mt, concentrated in traditional uses in industry and refining. The impacts of the conflict in the Middle East render the near-term outlook for current hydrogen applications uncertain, particularly for fertiliser production and trade.
- Demand for low-emissions hydrogen grew by 20% in 2025, reaching close to 1 Mt. However, sluggish and uncertain policy implementation is failing to address the major barriers to adoption and preventing faster uptake.
- New offtake agreements for low-emissions hydrogen reached 1.7 Mtpa in 2025, as in 2024. One-fifth of all new agreements were firm offtakes, concentrated in power generation, industry and refining. Trade-oriented agreements were higher than agreements for domestic use for the first time.
- Volumes for low-emissions hydrogen included in procurement tenders grew marginally in 2025, to reach more than 1 Mtpa. More than 0.3 Mtpa have been contracted as of Q1 2026, with progress occurring mostly in refining and fertilisers thanks to supportive policies and regulations in Europe and India.
- Refining and industry remain the main sectors in which low-emissions hydrogen adoption is taking place. Based on projects that have at least reached a final investment decision (FID), 2.5 Mt is expected to be produced and consumed in refineries and industrial facilities by 2030.
- Fuel cell electric vehicle (FCEV) stock grew 20% in 2025, to almost 130 000, due to truck sales in China and a rebound of car sales in Korea. Policies in these countries are the main driver behind a projected tripling of stock by 2030, with trucks and buses accounting for around 60% and 30% of hydrogen use.
- In shipping, uncertainties around the implementation of the International Maritime Organization (IMO) Net-Zero Framework have given a key role to European regulations as a driver for short-term adoption of hydrogen-based fuels, but in most cases, they are insufficient to enable fuel switching.
- In aviation, Europe's mandates remain the only policy driver for adoption, with limited impact on ticket prices expected this decade. However, investment in new production capacity is lagging as firm offtake agreements remain scarce.
- In the power sector, progress remains slow and concentrated in Japan and Korea. In Japan, policy support has helped projects to reach investment decisions, whereas changing policy priorities in Korea have led to a more cautious outlook than in previous years.

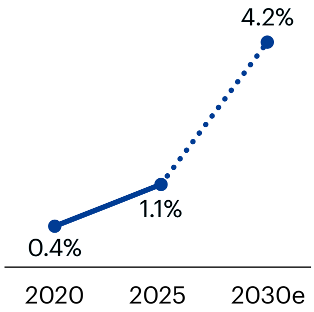
Hydrogen demand

Global hydrogen demand surpassed 100 Mt for the first time in 2025, concentrated in refining and industry, but the short-term outlook is uncertain due to the conflict in the Middle East

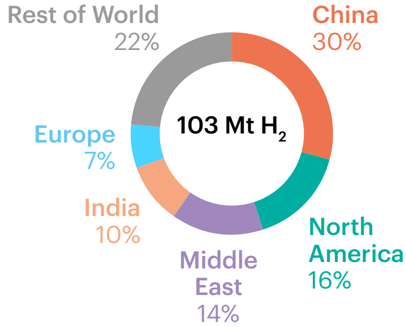
Hydrogen use by sector



Share of new hydrogen applications

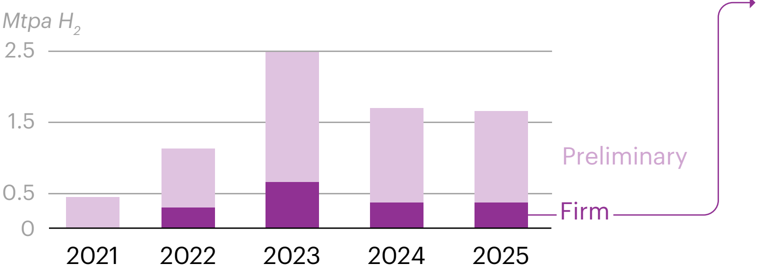


Hydrogen use by region, 2025

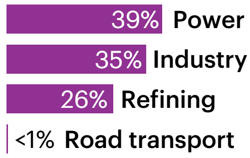


New offtake agreements in 2025 remained at the same level as in 2024, with refining, power generation and industrial applications making up almost all new firm agreements

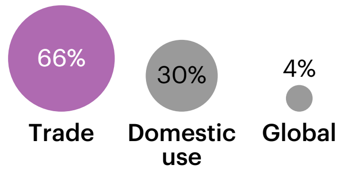
Annual new offtake agreements



Firm offtakes in 2025 have unlocked investment in production

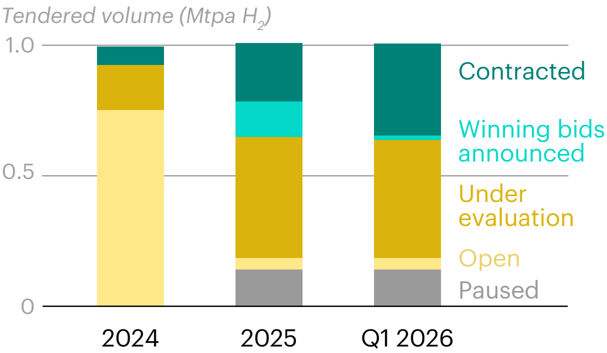


Policies in **Europe** and **Japan** have enabled firm offtakes linked to **international trade**

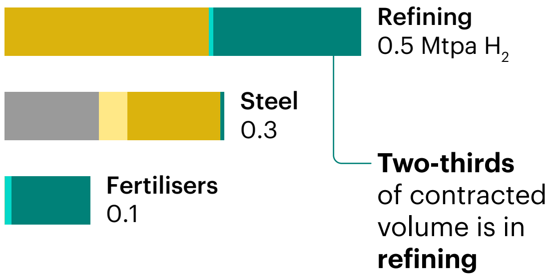


Tenders for low-emissions hydrogen procurement grew marginally in 2025, but 35% of tendered volumes have already been contracted, leading to FIDs on production projects

Progress of hydrogen tenders

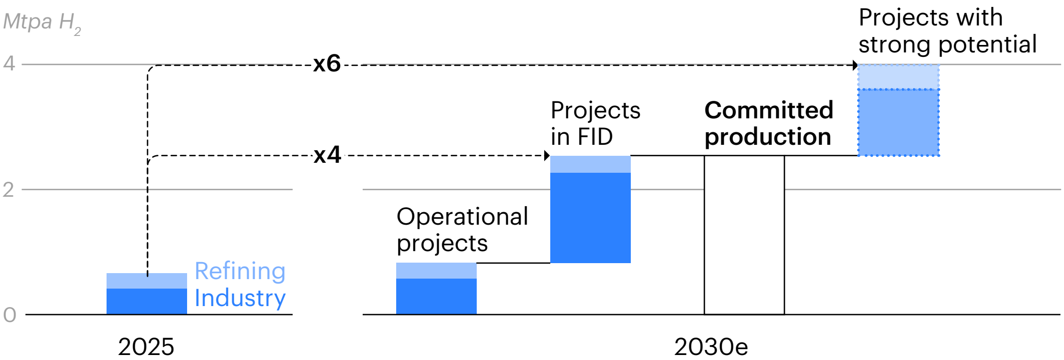


Status of hydrogen tenders by sector Q1 2026



Europe and **India** are home to **100%** of launched tenders

Refining and the chemical sector lead the adoption of low-emissions hydrogen, with committed projects accounting for 2.5 Mt of production for self-consumption by 2030



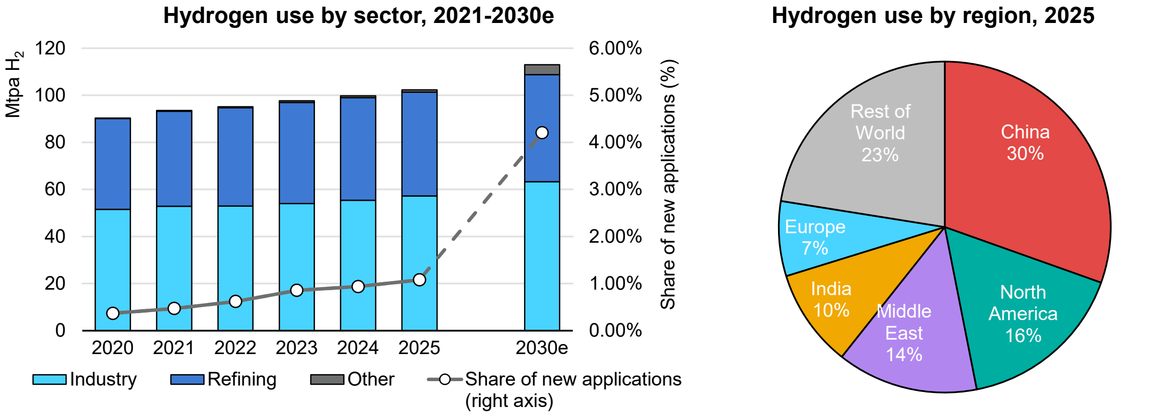
China is driving growth in **industry**, and **Europe**, in **refining**

50% of committed projects in **industry** target **ammonia** production

Overview

Global hydrogen demand grew almost 3% in 2025 to surpass 100 Mt for the first time (Figure 2.1). The People's Republic of China (hereafter, "China") remains the largest hydrogen user, with almost 30% of global demand, followed by North America (16%) and the Middle East (15%). All major markets saw an increase in demand in 2025, with the exception of Europe, where demand remained almost constant compared with 2024. India (+4%) and the Middle East (+3%) saw the largest growth, with both refining and industrial demand growing evenly in both regions.

Figure 2.1 Hydrogen demand by sector and region, 2021-2030e



Note: "Other" includes transport, power generation, production of hydrogen-based fuels, buildings and biofuels upgrading.
Sources: IEA analysis based on data from Argus Media Group, All rights reserved; International Fertilizer Association and World Steel Association.

Global hydrogen demand exceeded 100 Mt in 2025, concentrated in traditional applications in refining and industry.

This growth trajectory is expected to continue in 2026, prolonging a decades-long trend only interrupted in 2020 due to the Covid-19 pandemic. However, the conflict in the Middle East that began on 28 February 2026 could have a significant impact on this trend. The region is a large producer and exporter of ammonia, methanol and refined oil products. Moreover, countries in the Middle East are also major suppliers of natural gas to China, India and Europe, where natural gas-based hydrogen production meets a large share of domestic hydrogen demand.

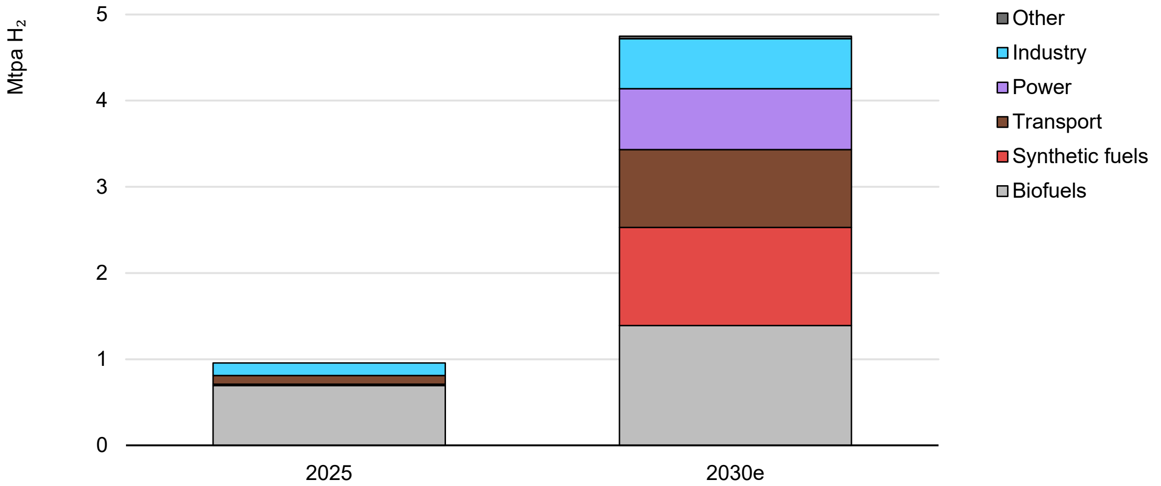
Traditional hydrogen uses in the chemical and steel industry and refining accounted for almost all hydrogen demand in 2025.[13] New applications such as biofuels production, transport, power generation or new industrial uses surpassed 1% of global demand for the first time. The demand growth in these applications

[13] See the Annex for details on how demand is reported in the Global Hydrogen Review.

was pushed mainly by hydrogen use in biofuels production and, to a lesser extent, growing demand in transport, particularly for heavy-duty trucks in China.

The achievement of government goals to stimulate demand for hydrogen and hydrogen-based fuels in these new applications remains uncertain due to slow policy implementation. However, policies already implemented can make an impact in the short term. By 2030, global hydrogen demand could reach more than 110 Mt, with new applications accounting for one-third of the growth until the end of the decade. By 2030, these applications could be responsible for more than 4% of global demand (Figure 2.2). The main driver of growth is the use of hydrogen in biofuels production, but production of hydrogen-based fuels for their use in power generation, shipping and aviation also contribute significantly.

Figure 2.2 Hydrogen demand for new applications in 2025 and 2030e



Hydrogen demand in new applications remains low, but it is expected to grow significantly thanks to both use of hydrogen as a fuel and an increased use of hydrogen-based fuels.

Demand creation for low-emissions hydrogen

Demand for low-emissions hydrogen[14] grew by 20% in 2025 to reach close to 1 Mt. An increase in the use of renewable hydrogen in existing industrial processes, particularly in North America and China, accounted for most of this growth. Low-emissions hydrogen demand has grown by 60% since 2020, but it still represents less than 1% of total hydrogen demand. Existing policies are expected to stimulate a certain amount of growth, potentially reaching over 5 Mt by 2030. However, this is still far from the targets that governments announced in early 2020s. Sluggish and uncertain policy implementation is failing to address the main barriers to

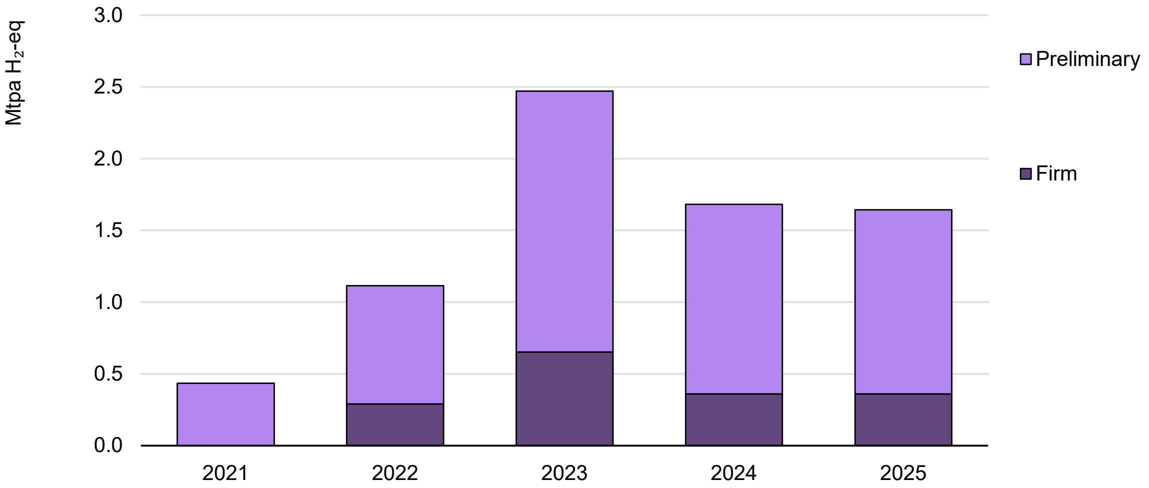
[14] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

uptake – the high cost gap with incumbent technologies (see Chapter 4) and uncertainty among stakeholders about the future marketplace for low-emissions hydrogen – and preventing faster demand growth.

Offtake agreements for low-emissions hydrogen

Newly signed offtake agreements for low-emissions hydrogen and hydrogen-based fuels and products in 2025 remained at around 1.7 Mtpa, practically the same value as in 2024 but 0.8 Mtpa lower than the 2023 peak (Figure 2.3).[15] This brought the cumulative volume of hydrogen covered by offtake agreements signed since 2020 to more than 7.5 Mtpa at the end of 2025. However, only around one-fifth of the volume included in new agreements in 2025 is covered by firm offtake agreements. Firm offtakes that include binding contractual conditions between supplier and off-taker can create certainty for suppliers to secure investment in production projects. By contrast, preliminary offtakes are more uncertain; since 2020, 0.8 Mtpa of low-emissions hydrogen has been included in preliminary offtakes that were later cancelled.

Figure 2.3 Annual offtake agreements signed for low-emissions hydrogen, 2021-2025



Notes: Only offtake agreements disclosing the amount agreed are included. Firm offtake agreements are classed by the year in which they became firm, and preliminary agreements that become firm in later years are only included in the year in which they became firm. Cancelled agreements have been excluded. Announcements for hydrogen production and self-consumption are not included.

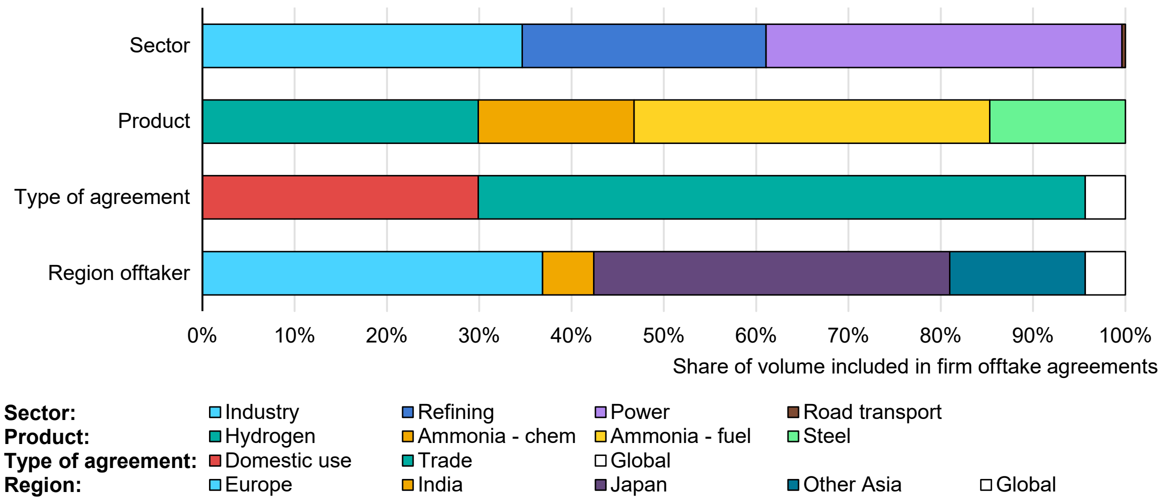
Sources: IEA analysis based on announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved; BloombergNEF and S&P Global.

New offtake agreements in 2025 remained at the same level as in 2024, with cumulative agreements since 2020 growing to 7.5 Mtpa.

[15] Analysis only includes offtake agreements disclosing the amount agreed.

In 2025, firm offtake agreements accounted for 360 ktpa of low-emissions hydrogen, practically all for refining, power generation and industry applications (Figure 2.4). Almost 80% of firm offtake agreements in refining originated in Europe, and the remainder in India. This suggests that progress on transposing into national legislation the transport targets of the EU Renewable Energy Directive (RED) is triggering offtakes in this sector, in a similar way to FIDs on production projects for self-consumption in refineries (see Refining). The only two offtakes for power generation were made by JERA and Mitsui & Co., for importing into Japan ammonia produced in the United States (through a joint venture with CF Industries). These offtakes have been facilitated by support received through the Contracts for Difference (CfD) scheme of the Japanese government, and both JERA and Mitsui & Co. have received preferential loans from the Japan Bank for International Cooperation. On the industry side, the two major firm offtake agreements were linked to production projects in India (ammonia production)[16] and Oman (iron production).

Figure 2.4 New firm offtake agreements by sector, product, type of agreement and region, 2025



Notes: Only offtake agreements disclosing the amount agreed have been included. 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, All rights reserved; BloombergNEF and S&P Global.

New firm offtake agreements in 2025 were in power generation, industry and refining, with trade-oriented agreements overtaking agreements for domestic use for the first time.

Two-thirds of firm offtakes in 2025 were trade-oriented. This was the first year in which trade-oriented offtakes accounted for a larger share of firm offtakes than projects for domestic use. Almost 80% of the contracted volumes were to export ammonia (for power generation in Japan and fertiliser production in Europe) and

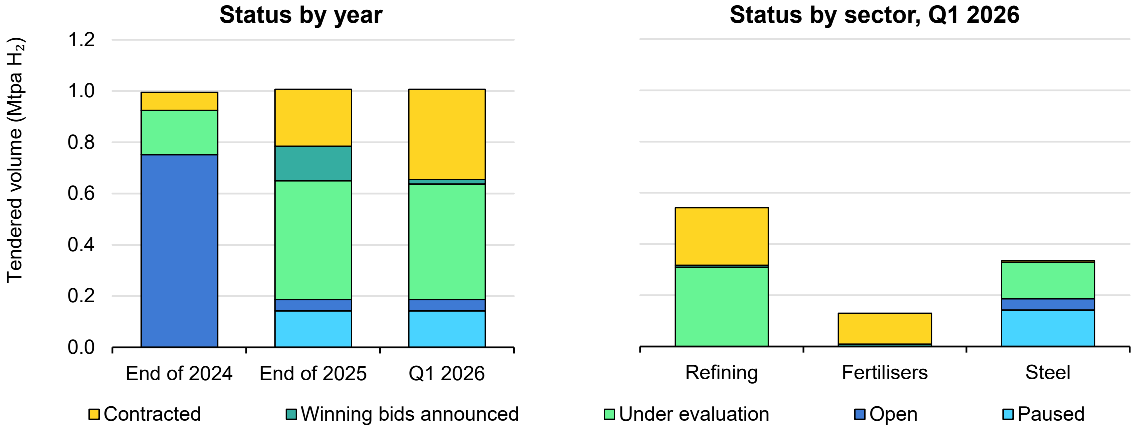
[16] Yara inks renewable ammonia offtake agreements with Indian producers at less than USD 680/mt: sources, Platts Hydrogen Daily, 4 June 2025.

the remainder was linked to the Oman project, aiming to export hot briquetted iron to Viet Nam for the production of steel, targeting exports to Europe. Overall, the global market for low-emissions hydrogen and hydrogen-based products is developing slowly, but policies in Japan (CfDs for supply chains) and Europe (the Carbon Border Adjustment Mechanism [CBAM], along with gradual phase-out of free allowances in the EU Emissions Trading System [ETS]) are starting to generate activity.

Tenders

Private tenders for procuring low-emissions hydrogen and hydrogen-based products advanced slowly in 2025, although significant milestones were achieved in some sectors (Figure 2.5). The total volume that private companies are aiming to procure through this mechanism increased marginally last year (by only 1% more than in 2024), reaching just above 1 Mtpa H_2-eq. However, the contracted volumes reached more than 200 ktpa by the end of 2025, tripling the quantities that were already contracted at the end of 2024. An additional 130 ktpa were contracted in the first quarter of 2026 (Q1 2026). In addition, even if they did not move to the final contracting stage, most of the tenders opened in 2024 did progress in 2025, reaching at least the evaluation phase. Winning bids for 140 ktpa have already been announced.

Figure 2.5 Total volume of tenders for the procurement of low-emissions hydrogen by status and sector, 2024- Q1 2026



Note: In the sectoral breakdown, a tender for the use of hydrogen in construction sites, already contracted, has been excluded due to its small size (1.2 ktpa).

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

Tenders for low-emissions hydrogen procurement grew only marginally in 2025, but 35% of tendered volumes had already been contracted by the end of Q1 2026.

More than 90% of the contracted volumes at the end of 2025 were in refining, mostly due to the progress in the 500 ktpa tender of TotalEnergies, which signed contracts for 200 ktpa of the tendered volume and aims to finalise the agreements for the remaining 300 ktpa in 2026. Three smaller tenders, accounting for 25 ktpa, have already been contracted in India. The signing of these supply contracts has led to FIDs in production projects in both Europe and India.

In the fertiliser sector, between July and August 2025 the Solar Energy Corporation of India (SECI) announced the winning bids[17] for its dual-phase tender to supply 724 ktpa of renewable ammonia (equivalent to 130 ktpa of hydrogen) to 13 fertiliser plants. It also began planning a second tender following talks with fertiliser companies.[18] The prices of the winning bids spanned in the range of INR 49.75-64.74/kg ammonia (NH_3) (Indian rupees) (~USD 570-750/t NH_3). This represents a significant premium compared with typical ammonia import prices in the country (USD 330-525/t NH_3 in 2025), which translates into premium of 10-130% and an abatement cost of USD 20-205/t CO_2. The deals with the fertiliser producers (the final step to contract the volumes) were expected to be finalised by the end of 2025,[19] but the first deals were delayed to 2026.[20] In March 2026, the government announced that 11 fertiliser companies have signed deals for more than 90% of the tendered volume and 2 companies had withdrawn since they were no longer able to take the supply.[21] However, there is still uncertainty about whether all the deals will move forward. Some of the bids were low, counting on regional incentives which may not materialise; if SECI has to cover the whole premium, the original budget for the tender would be exceeded.

Steel is the sector in which tenders are facing the most difficulties in progressing to the contracting phase. Only one deal has been signed, in September 2025, accounting for less than 2% of the tendered volume. In addition, the largest tender launched in 2024 was suspended in March 2025 since the offers received were above the acceptable threshold of the procuring company. The low conversion of tenders into contracts in the steel sector compared with in refining and fertilisers suggests that the current cost premium of low-emissions hydrogen is far more difficult to absorb in the steel industry than in the case of existing uses of hydrogen.

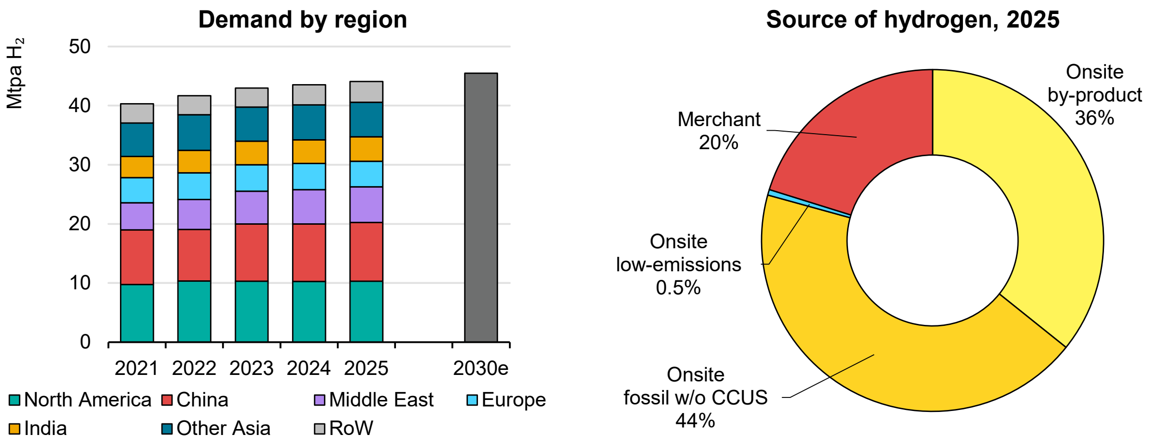
[17] Suryam succeeds in India's final green ammonia auction, Argus Media Group. All rights reserved (29 August 2025).
[18] India starts planning for second green NH3 tender, Argus Media Group. All rights reserved (15 September 2025).
[19] India's Madras Fertilizer may exit green NH3 tender, Argus Media Group. All rights reserved (12 November 2025).
[20] India finalises green NH3 supply, purchase agreements, Argus Media Group. All rights reserved (30 March 2026).
[21] Two Indian green ammonia tender buyers withdraw, Argus Media Group. All rights reserved (13 April 2026).

Refining and biofuels

Refining

Global hydrogen demand in refining reached 44 Mt in 2025, growing just slightly more than 1% compared with 2024 demand (Figure 2.6). As in 2024, hydrogen demand in refineries grew more slowly than its historical average. North America, with more than 10 Mt, and China with close to 10 Mt, remain the regions with the largest demand for refining. Most hydrogen demand was met with dedicated production onsite in refineries using unabated fossil fuels (44%), and hydrogen obtained as a by-product in processes (36%) such as catalytic naphtha reforming. The procurement of merchant hydrogen (also predominantly from unabated fossil fuels) made up the remaining 20%.

Figure 2.6 Hydrogen use for refining by region and source of hydrogen, 2021-2030e



IEA. CC BY 4.0

Notes: fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; RoW = Rest of World. “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 increased in 2025 to reach 44 Mt, but short-term growth is uncertain due to the consequences of the conflict in the Middle East.

The short-term development of the sector, and therefore of hydrogen demand, is uncertain due to the conflict in the Middle East, which is likely to impact the refining sector in the region and beyond.

Box 2.1 Potential impacts of the conflict in the Middle East on the refining sector

The conflict in the Middle East that began on 28 February 2026 has disrupted oil markets and, consequently, the refining sector. The Middle East exported 16-18 mbpd of crude oil between 2020 and 2025 – equivalent to the combined exports from the Americas, Africa and Eurasia. In addition, the region is a major refining hub, with close to 12 mbpd of refining capacity (more than 10% of global capacity), around one-third of which is export-oriented. As a consequence, the Middle East is one of the largest consumers of hydrogen for refining, with 6 Mt of demand in 2025.

The closure of the Strait of Hormuz and associated losses of crude exports is impacting refining activity globally, although regional impacts are uneven. While OECD countries in the Americas are net exporters and imported less than 0.5 mbpd of crude from the Middle East in 2025, OECD countries in Europe imported 1.3 mbpd in 2025, and OECD countries in Asia-Oceania imported 4.6 mbpd. By comparison, China imported 5 mbpd of Middle Eastern crude last year. Governments and refineries' concern about supply disruptions have led to precautionary run cuts, particularly in Asia. While existing crude stocks can help in maintaining activity, long-term runs will be subject to refineries securing additional crude supplies.

The conflict is affecting refining activity in the Middle East. The closure of the Strait has prevented export-oriented refineries from securing vessels to load cargoes, forcing a reduction in processing rates due to the limited product storage capacity. In addition, several refineries have been the target of attacks, including the Ruwais refinery in the United Arab Emirates (the largest refinery in the Middle East, with a refining capacity of 820 kbpd), Ras Tanura refinery in Saudi Arabia (550 kbpd) and Sitra refinery in Bahrain (400 kbpd). In addition, several refineries have been forced to stop operations due to disruptions in supplies of crude, natural gas or power. Restarting operations and reaching pre-conflict activity levels will take several weeks and even months in the case of damaged refineries.

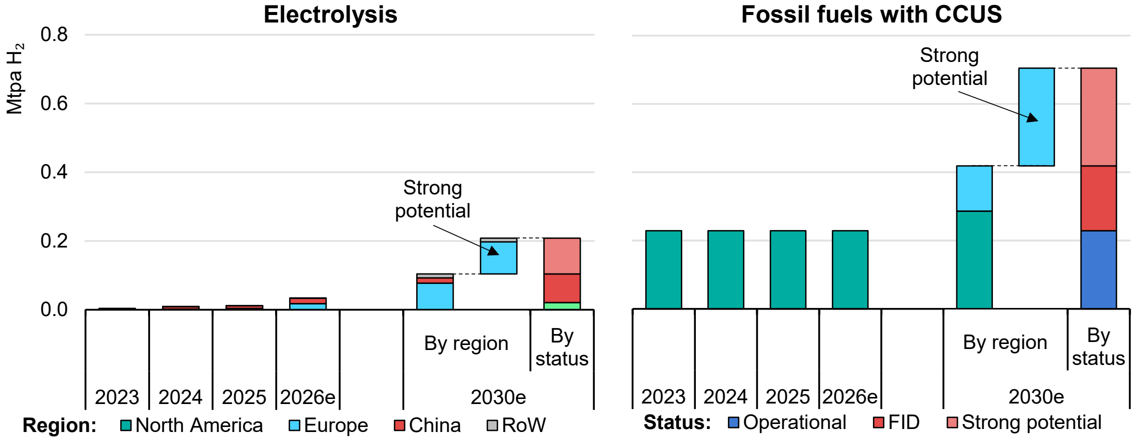
Global refining capacity is not fully utilised and there could be some spare capacity to reallocate operations and partially fill the gap left by the damaged infrastructure. However, the availability of spare capacity remains at question. A significant fraction of the spare capacity is in China, which banned exports of refined products in March. In addition, if there are constraints to crude supply because there are no exports from the Gulf, there will be no feedstock available to run that spare capacity. Refineries would also need to adapt operations to different crude oil qualities, which can have implications for their operations and the slate of products obtained. For example, some Asian refineries shifting from Middle East heavy sour crudes to US light sweet crude are already considering purchases of secondary feedstocks.* The use of lighter crudes reduces the availability of these intermediate, heavier products, which would typically be processed in upgrading units, thereby impacting downstream operations. In addition, using alternative supplies can have price implications, since the Middle East is typically a very low-cost source of supply globally.

* Asian refineries to run less efficiently on crude shift, Argus Media Group, All rights reserved (15 April 2026).

Adoption of low-emissions hydrogen in refineries

Low-emissions hydrogen use in refineries met less than 1% of total demand in refining in 2025, remaining under 250 kt, almost the same value as in 2024 (Figure 2.7). Only a handful of small electrolysis projects, accounting for less than 40 MW and around 1.5 kt of production output, started operation in 2025.

Figure 2.7 Onsite production of low-emissions hydrogen for refining from announced projects by technology and region, 2023-2030e



Notes: CCUS = carbon capture, utilisation and storage; RoW = Rest of World; FID = final investment decision; 2026e = estimate for 2026; 2030e = estimate for 2030. The estimated values for 2026 and 2030 are based on projects that had reached FID by May 2026 with a target commercial operational date in 2026 and 2027-2030, respectively. "Strong potential" refers to projects without FID that have strong potential to become operational by 2030 according to the methodology developed in the GHR-25, updated for this report.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Low-emissions hydrogen use in refineries was under 0.25 Mt in 2025 but is expected to more than double by 2030; it could quadruple if projects with strong potential are realised.

However, short-term prospects are positive, particularly in Europe. 375 MW of electrolysis capacity is under construction in refineries in Greece, the Netherlands, Portugal and Spain and aiming to start operating in 2026. In the case of hydrogen from fossil fuels with CCUS, three large projects under construction in the Netherlands, targeting the supply of hydrogen to refineries in the port of Rotterdam, were expected to start operating this year. However, they have been postponed until the second half of 2027 due to delays with the shared CO_2 infrastructure. If projects still targeting operation in 2026 are realised on time, global low-emissions hydrogen use in refineries could grow by nearly 10% in 2026 compared with 2025. Production would grow 30% year-on-year in 2027 once production sites starting operation in 2026 reach full utilisation (since large-scale projects require several months to ramp up production) and new projects come into operation in 2027.

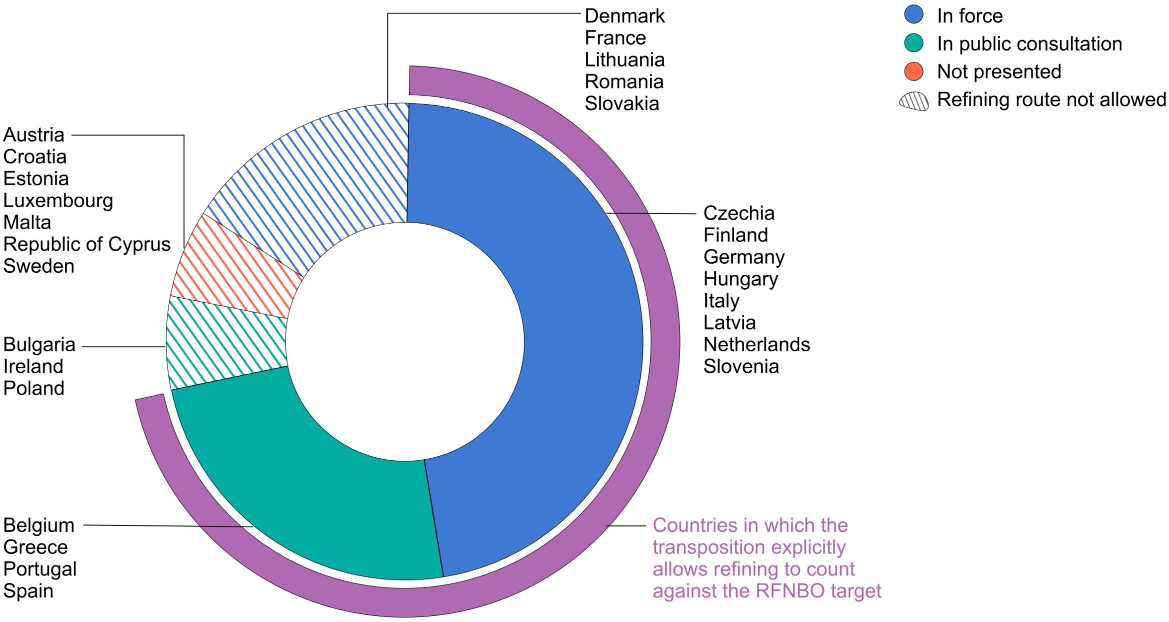
The uptick in projects reaching operation in Europe is the result of the first wave of large-scale support schemes for low-emissions hydrogen production projects, such as the EU Important Projects of Common European Interest (IPCEI) programme and the SDE++ scheme of the Dutch government. In addition, several EU member states are progressing with transposing RED targets for the use of renewable fuels of non-biological origin (RFNBO) in transport into national legislation. As much as 70% of the European Union's refining capacity is in countries that allow the use of renewable hydrogen in refining to count against that target in their transposition of the RED, although less than 50% is in countries that have fully transposed the legislation. The remaining almost 25% is in countries where it is still under consultation (Figure 2.8). Moreover, Belgium, France,[22] Germany[23] and Spain have proposed long-term targets beyond 2030. This provides refineries with a clear regulatory demand signal to speed up the adoption of low-emissions hydrogen.

Looking at 2030, and considering only projects that are operational, under construction or that have reached FID, global low-emissions hydrogen production and use in refineries can reach more than 500 kt. North America currently accounts for 95% of low-emissions hydrogen use in refining globally. However, this share is expected to drop to 55% by 2030 due to momentum in Europe, which could increase its share from around 1% today to 40%. Around one-third of the expected production in Europe is from electrolysis projects (around 70 kt), which would be equivalent to 8% of the required demand for hydrogen to meet the RED target for RFNBO use in transport. In India, developments began later than in Europe and North America, but there was a lot of activity in 2025 thanks to successful tenders launched by refineries in the form of Build-Own-Operate procurements for renewable hydrogen plants. Three of those (for an annual production of 25 kt) have already been contracted at prices between INR 279 /kg H_2[24] and INR 397/kg H_2 (~USD 3.0-4.6/kg H_2), and one has already led to an FID. Compared with the cost of producing hydrogen from unabated natural gas in India (USD 1.6-2.3/kg H_2 in the past 5 years), the results of these tenders represent a cost premium of 30-185% and abatement costs in the range of USD 65-295/t CO_2.

[22] French parliament partially adopts RED III, Argus Media Group. All rights reserved (18 February 2026).
[23] German Bundesrat votes for higher green H2 quotas, Argus Media Group. All rights reserved (2 February 2026).
[24] India's NeuEN confirms NRL green H2 tender win, Argus Media Group. All rights reserved (24 March 2026).

Beyond committed projects, close to 400 kt of potential production in refineries has strong potential to come online by 2030 (see Chapter 3), mostly in Europe, where the regulatory framework is very advanced and is supportive. If these projects materialise, by 2030 close to 15% of hydrogen use in EU refineries could be met by low-emissions hydrogen, and renewable hydrogen could meet more than 15% of the hydrogen demand required to meet the RED target. These figures could be higher when considering the additional supply that refineries could obtain from merchant projects under development. We estimate that projects under construction or that have reached FID could supply an additional 200 kt of low-emissions hydrogen to refineries globally by 2030.

Figure 2.8 Refining capacity in the European Union and status of the transposition into national legislation of the Renewable Energy Directive target for renewable fuels of non-biological origin use in transport, May 2026



Notes: RFNBO = renewable fuels of non-biological origin use in transport. The information in this document with reference to “Cyprus” relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the “Cyprus issue”. The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Source: IEA analysis based on data from Fuels Europe.

70% of EU refining capacity is in countries that allow renewable hydrogen in refining to count against the RED target for RFNBO use in transport, creating regulatory certainty.

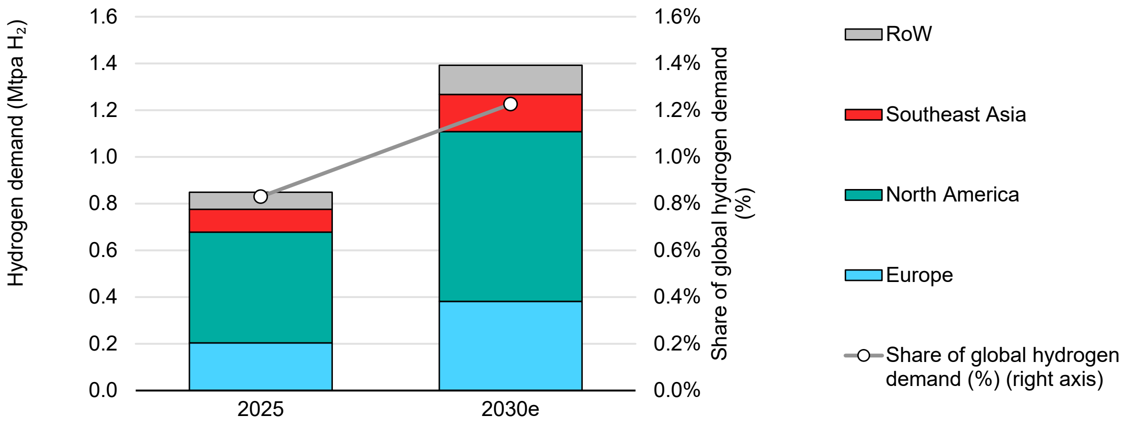
Biofuels

Demand for liquid biofuels is growing strongly, mostly in transport, where they currently meet 4% of energy demand. In 2025, global demand for liquid biofuels reached 5.2 EJ, 30% higher than before the Covid-19 pandemic, and they are projected to surpass 6 EJ by 2030.

Roughly 15% of biofuels demand is met with hydrotreated vegetable oils (HVO) and hydroprocessed esters and fatty acids (HEFA), which require hydrogen in their production processes. The production of 1 tonne of these fuels requires around 45-55 kg H_2. Moreover, the processing of biological feedstock is more hydrogen-intensive than production from fossil hydrocarbons, requiring 5-15 times more hydrogen per unit of processed feedstock. Consequently, the demand for hydrogen in biofuels production has grown steadily in recent years, reaching more than 800 kt in 2025, almost totally from hydrogen produced from unabated fossil fuels. Biofuels production accounts for almost three-quarters of global demand for new hydrogen applications, and this demand is expected to keep growing. Hydrogen demand for biofuels production could reach 1.4 Mt by 2030, double the demand registered in 2024. Although its share of demand for new applications decreases to around 30% by 2030 in this scenario, biofuels production still represents the largest demand among new applications, followed closely by transport.

There are only three small projects currently using low-emissions hydrogen for the production of biofuels. However, a growing number of biofuels producers are considering the use of low-emissions hydrogen as a potential input for the process, mostly in Europe but also in China and North America. The use of low-emissions hydrogen allows for the reduction of the carbon intensity of hydrotreated vegetable oils (HVO)/hydroprocessed esters and fatty acids (HEFA) production to comply with certain regulations, such as low-carbon fuel standards and the Carbon Offsetting and Reduction Scheme for International Aviation of the International Civil Aviation Organization, which will enter its mandatory phase in January 2027.

Figure 2.9 Hydrogen demand for biofuels production, 2025 and 2030e



Note: RoW = Rest of World.

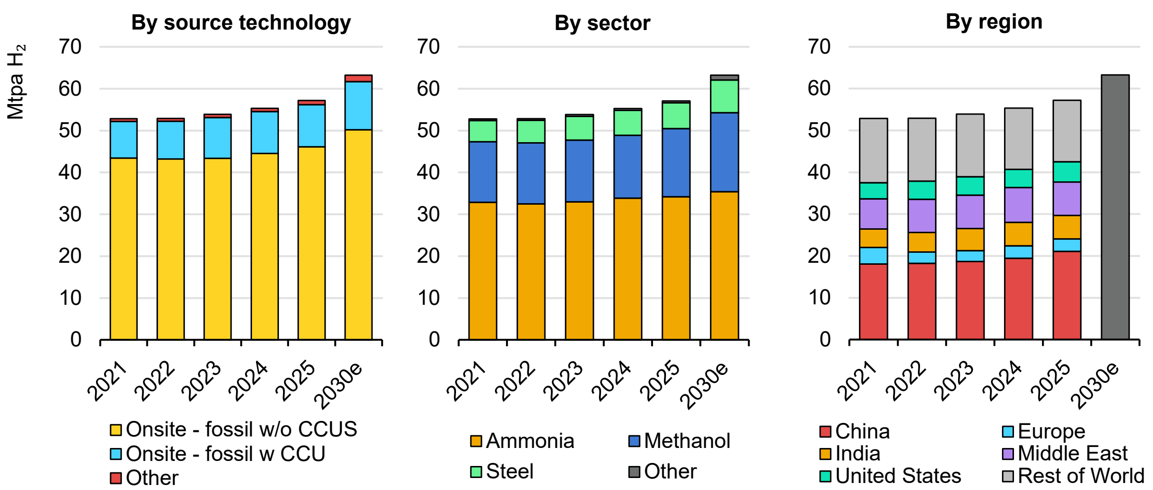
Growing demand for hydrogenated biofuels can push associated hydrogen demand to 1.4 Mt by 2030.

Industry

Global hydrogen demand in industry reached 57 Mt in 2025, an increase of 3% year-on-year, double the average growth rate of the past 5 years (Figure 2.10). About 60% of this demand was for ammonia production, 30% for methanol and 10% to produce direct reduced iron (DRI) in the steel sector. Hydrogen use for methanol had the highest growth at 8%, followed by steel (4%) and ammonia (1%).

Most of the hydrogen used in industry applications is produced within the same facility, mostly from unabated fossil fuels. Carbon capture is a common practice in certain industries, although most of the 155 Mtpa of CO_2 captured is used for other industrial applications, such as urea production, and ends up being released to the atmosphere. As a result, hydrogen production in industry was responsible for around 740 Mt of direct CO_2 emissions in 2025, up 5% from 2024, and approximately equal to the total GHG emissions of Canada.

Figure 2.10 Hydrogen use in industry by source technology, sector and region, 2021-2030e



Notes: Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; Fossil w CCU = fossil fuels with carbon capture and use. In production by source technology, "Other" includes onsite production with bioenergy, carbon capture and storage or electricity, and merchant hydrogen. In demand by sector, "Other" includes dedicated hydrogen production for high-temperature heat applications.

Sources: IEA analysis based on data from Argus Media Group, All rights reserved; International Fertilizer Association and World Steel Association.

Industrial hydrogen demand grew 3% year-on-year, driven by methanol production.

China remains the largest hydrogen user, with 37% of global industrial use, followed by the Middle East (14%), India (10%) and the United States (8%). In

China, a large portion of olefins are produced from methanol, and rapid growth in demand from the plastics industry led to an increase in methanol production. As a result, the country's industrial hydrogen demand grew over 10% in 2025. By contrast, in Europe, there was a 2% decline in industrial hydrogen demand compared to 2024. This was mainly due to a decline in methanol production caused by structural issues in the European chemical industry linked to high energy costs, leading to lower methanol demand and plant closures. On the other hand, the United States saw a 10% increase in industrial hydrogen demand, with growing outputs in both the ammonia and methanol industries thanks to abundant natural gas.

Future hydrogen demand in industry depends on industrial activity and is expected to maintain a growing trend in general. However, the short-term outlook is uncertain due to the conflict in the Middle East and its impact on the production and trade of hydrogen-based products, such as ammonia and methanol.

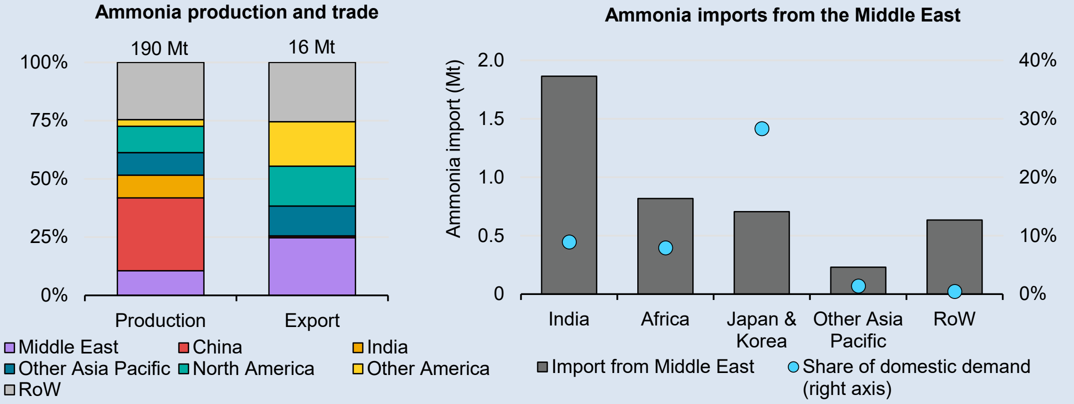
Box 2.2 Impact of the conflict in the Middle East on hydrogen-based industrial products

The Middle East is home to 10% of global production of ammonia and 15% of methanol. As a result, the region consumes 14% of hydrogen used for industry applications globally. Furthermore, the Middle East has more recently been one of the regions with the fastest growth in hydrogen use in industry applications, particularly driven by the construction of large methanol facilities in Iran.

The conflict in the Middle East could have a significant impact on the supply chains of these hydrogen-based products. For example, global ammonia production is around 190 Mtpa, and around 10% is globally traded. The Middle East is the largest exporter of ammonia, accounting for 25% of internationally traded ammonia, with around 70% of exports passing through the Strait of Hormuz. The conflict could have knock-on effects on fertiliser production (the main application of ammonia) and, therefore, food security, since around 25% of nitrogen fertilisers traded worldwide are exported from the region. Moreover, this is on top of the market tensions created by Russia's full-scale invasion of Ukraine.

The supply from Gulf countries has been affected by the closure of the Strait of Hormuz, and major producers have announced reductions in their operations since the first few days of the closure. Supply from outside the Gulf has also been affected, as Oman had to close the port of Salalah (based in the Arabian Sea and which OQ Trading uses to export ammonia) after a drone strike on 11 March.

Production and trade of ammonia per region, 2024



Note: RoW = Rest of World.
Sources: IEA analysis based on data from International Fertilizer Association and CEPII.

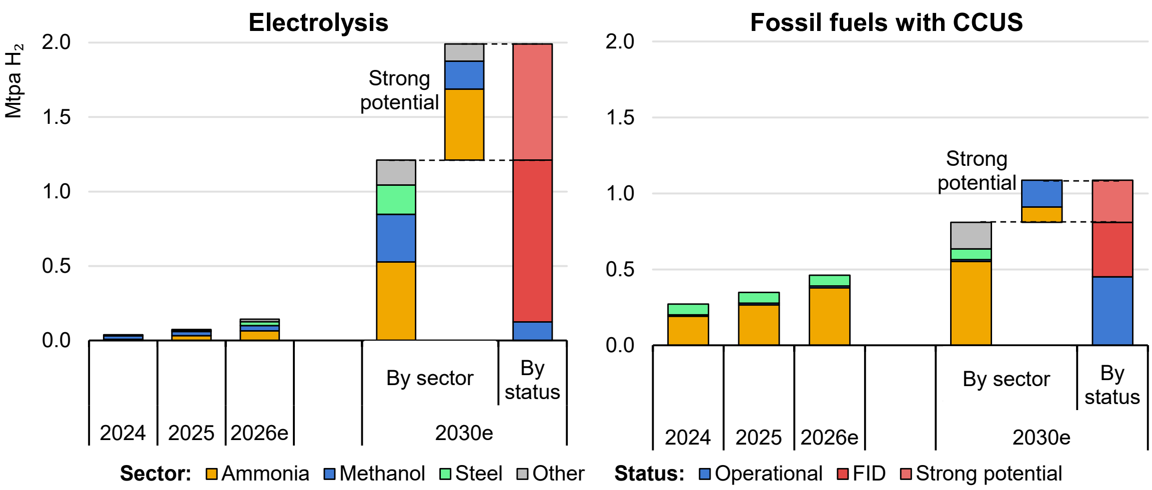
The impact will not be evenly distributed, since some countries are more dependent on supply from the Middle East than others. India was the largest importer of ammonia from the Gulf in 2025, accounting for almost half of the ammonia exported from the region. However, these imports accounted only for around 10% of India's ammonia demand. Countries like Japan and Korea could be more affected: although they only account for around 15% of ammonia exported from the Middle East, this supply accounts for 30% of their ammonia demand. However, the impact of the conflict is expected to be global and to impact regions that are less dependent on Middle East supply as well. For example, the increase in oil and gas prices, along with the reduced supply of ammonia from the region, is pushing up fertiliser prices. The price of ammonia in Europe increased by 30% during the month of March 2026, and the price of granular urea in Brazil by 60%. Supply disruptions may have wider implications since the high gas prices are already forcing fertiliser producers to cut production. This effect has been particularly felt in India, where fertiliser plants had to downscale to 70% of their normal levels, and in Bangladesh, where four out of five state-operated plants have suffered several temporary shutdowns since the beginning of the conflict. Concern about fertiliser supply has led some countries to take measures, such as China, which expanded its restrictions on fertiliser exports in March.

Tightness in global markets may be even higher in the case of methanol. A larger fraction of global methanol production is traded (30% in 2025, compared with around 10% in the case of ammonia), with the Middle East being responsible for around 45% of global methanol trade. China alone was absorbing half of these exports from the Middle East, accounting for 10% of its domestic methanol demand.

Spare production capacity can partially alleviate the situation. Global ammonia production capacity stands above 240 Mtpa, much larger than global ammonia production in 2025 (around 190 Mt). This means that there is theoretically enough spare capacity to meet demand even if all production capacity in the Middle East (20 Mtpa) remains idle. The situation is similar for methanol, with 30 Mtpa of production capacity at risk of being stranded in the Middle East, but with global production capacity theoretically being much larger than annual demand (200 Mtpa of capacity versus 125 Mt of global demand in 2025). The situation is more precarious for urea, as the production capacity outside the Gulf is almost equal to global demand. Increasing the utilisation of this existing capacity will strongly depend on the extent to which producers can operate profitably, which is unlikely to happen under the current high price volatility and without the supply of oil and gas from the Middle East.

Low-emissions hydrogen production and use in industrial plants reached almost 420 kt in 2025, a 35% increase compared to the previous year (Figure 2.11). Most of this growth came from the commissioning in the United States by CF Industries of a carbon capture and storage (CCS) unit at its Donaldsonville complex that produces ammonia and fertilisers. Half of the low-emission hydrogen production in industry is located in North America and one-quarter in China, with CCS accounting for 80% of the production.

Figure 2.11 Onsite production of low-emissions hydrogen for industry applications by sector and by status, 2024-2030e



IEA. CC BY 4.0.

Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; 2026e = estimate for 2026. 2030e = estimate for 2030. The estimated values for 2026 and 2030 are based on projects that had reached FID by May 2026 with a target commercial operational date in 2026 and in 2027-2030, respectively. “Strong potential” refers to projects without FID that have strong potential to become operational by 2030 according to the methodology developed in the GHR-25, updated for this report. Only projects that are operational, under construction, or that reached FID are included.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

By the end of 2026, low-emissions hydrogen production for industry is expected to be double what it was in 2024.

In 2026, low-emissions hydrogen production for industry is expected to reach almost 600 kt, 40% more than in 2025. The United States alone accounts for half of this growth, driven by the ramp-up of the Donaldsonville complex. Europe accounts for 15% of production growth, including two very large projects: the commissioning of Stegra's H_2-DRI steel plant in Sweden, and Yara's Sluiskil CCUS-based fertiliser plant in the Netherlands. However, both projects are expected to produce small amounts of low-emissions hydrogen this year, ramping-up production in 2027. In China, on the other hand, growth is spread across dozens of electrolysis projects of significant size, such as the 90 ktpa electrolytic-based hydrogen plant by Jizhong Energy in Inner Mongolia.

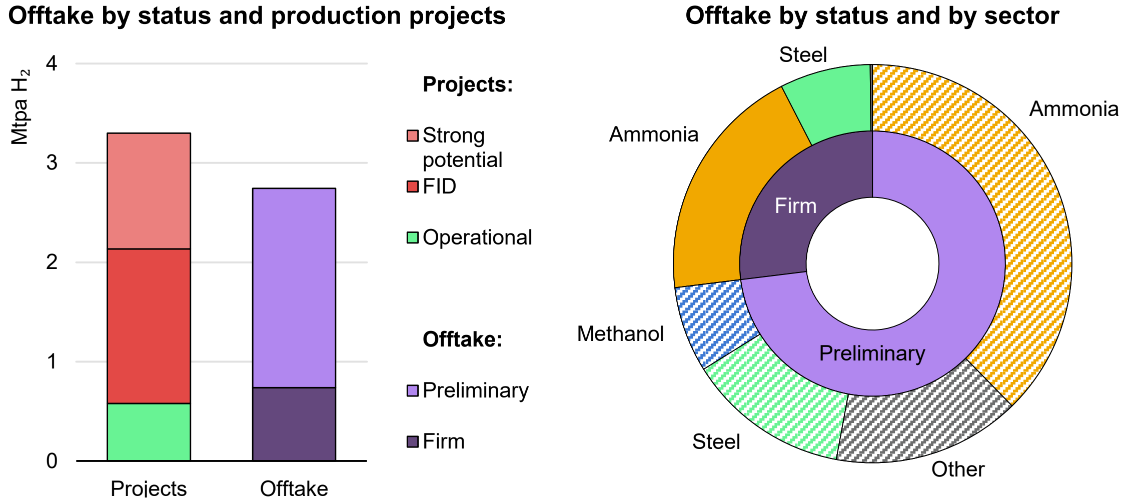
Considering projects that are already operational, under construction or that have reached FID, low-emissions hydrogen production and use in industry could reach 2.0 Mt by 2030. This represents an average annual increase in production of about 350 ktpa, equivalent to 80% of the low-emissions production in 2025. 75% of this additional production is based on electrolysis, and 45% is aimed at ammonia production. Over half of this committed low-emissions industrial hydrogen production is located in China, 20% in North America, 15% in Europe, 5% in India and 2% in the Middle East. The vast majority of projects in North America and the Middle East are CCUS-based, taking advantage of access to low-cost fossil fuels in those regions. In contrast, announced projects in China and Europe rely mainly on electrolysis to produce low-emissions hydrogen. This focus on electrolysis technology is driven by policy objectives in both regions (see Chapter 7) and higher cost of imported natural gas, although in the case of China, faster growth is also influenced by the lower production-cost gap compared with fossil-based routes (see Chapter 3). In Europe, a combination of public support measures (such as the EU IPCEI scheme and domestic programmes such as the carbon contracts for difference (CCfD) scheme in Germany) with regulation (such as the EU ETS and the gradual phase-out of free allowances in certain sectors as CBAM is implemented) have supported a few projects to reach a cost level that is considered acceptable with incumbent technologies (see Chapter 4) and move forward with investments. However, development in the sector has not yet gained the speed required to meet government objectives. This is mostly due to the lack of regulatory clarity regarding renewable hydrogen use in industry arising from the slow transposition into national legislation of the RED targets for RFNBO use in industry, and to the high cost of electricity.

There is an additional 1.1 Mt of potential low-emissions hydrogen production in announced projects with strong potential to be operational by 2030 (see Chapter 3). If those projects were realised, low-emissions hydrogen production could reach 3.1 Mt by 2030.

One of the major factors helping projects to reach FID is the ability to secure long-term offtake agreements that can provide security to investors. At the end of 2025, offtake agreements covered the equivalent of 2.7 Mtpa of industrial hydrogen, be it directly in the form of hydrogen or of products made with hydrogen, like ammonia, methanol or steel (Figure 2.12). Only one-quarter of those offtakes are firm, a volume equivalent to one-third of committed production. However, several production projects targeting industrial use are projects for self-consumption in already existing facilities. These projects typically do not require an offtake agreement with a third party for the hydrogen that they produce in order to reach FID.

Ammonia (70%) and steel (25%) represent the majority of firm offtake agreements. Global ammonia and fertiliser producers (such as Yara or OCI) are better-placed to strike offtake deals, since they have already established international supply chains that can be optimised to reach lowest cost. The interest in low-emissions steel comes in large part from car manufacturers like Mercedes and Volkswagen, driven by customer pressure as well as regulation, such as the proposal to use low-emissions steel to offset the emissions of internal combustion engine vehicles in the European Union.

Figure 2.12 Offtake agreements for hydrogen in industry by status and by sector compared with announced production projects, 2030



Notes: FID = final investment decision. Only offtake agreements disclosing the amount agreed have been included. Announcements for hydrogen production and self-consumption are not included. Hatching indicates preliminary offtake.

Sources: IEA analysis based on IEA (2026),Hydrogen Production Projects Database (June 2026); announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved; BloombergNEF and S&P Global.

Offtake agreements cover 2.7 Mtpa of hydrogen equivalent, mostly near-zero emissions ammonia and steel.

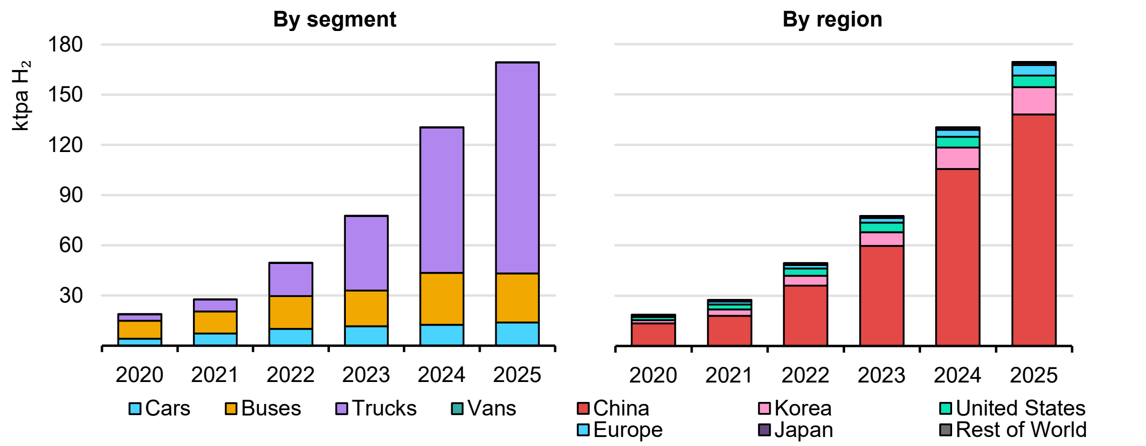
Road transport

Hydrogen use in road transport

In 2025, hydrogen demand for road transport grew almost 30% year-on-year to reach around 170 kt, although growth was slower than in the previous year. Despite this significant increase, the road transport sector remains only a minor and emerging contributor to global hydrogen demand, accounting for roughly 0.2% of total hydrogen consumption.

This increase in 2025 was primarily driven by growth in demand for fuel cell trucks, particularly in China. Although trucks made up less than 30% of the global stock of hydrogen-fuelled vehicles in 2025, they accounted for nearly three-quarters of hydrogen consumption in the sector, as they cover greater distances and consume more energy per kilometre than other road passenger vehicle segments.

Figure 2.13 Hydrogen demand in road transport by vehicle mode and region, 2020-2025



Notes: Total hydrogen consumption in road transport is calculated by multiplying vehicle stock, annual mileage and hydrogen consumption per kilometre for each vehicle segment and region. Annual mileage assumptions come from the IEA Global Energy and Climate modelling framework and fuel economy values are derived from a range of studies and research papers.

The large Chinese fleet and higher per-vehicle energy consumption of fuel cell trucks meant they accounted for 70% of the road sector's hydrogen demand globally in 2025.

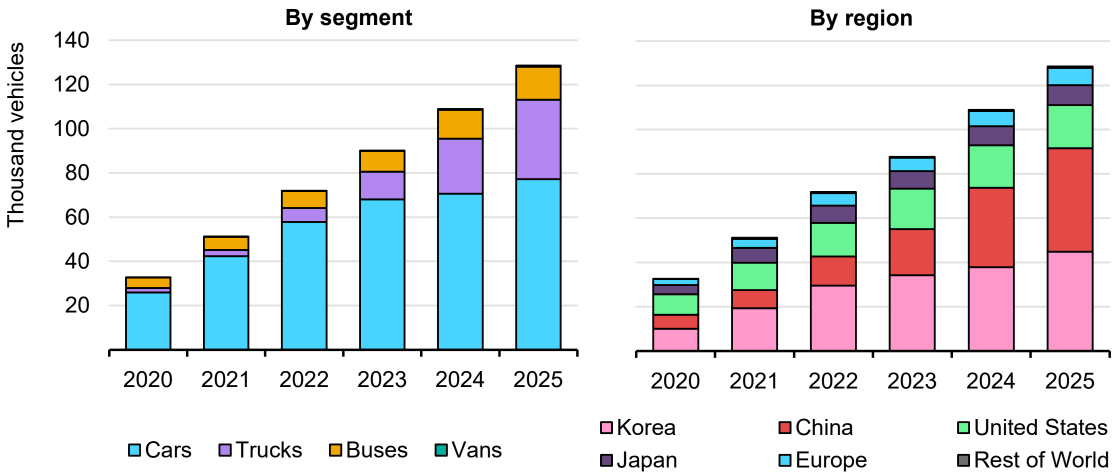
Fuel cell electric vehicle market developments

Fuel cell car sales rebounded 45% in 2025 after 3 years of decline, to exceed 7 000 worldwide. Growth was primarily located in Korea, where sales more than doubled year-on-year after Hyundai released the second generation of its flagship fuel cell car model, the Nexo. In all other major fuel cell car markets, such as North America, Europe and Japan, however, fuel cell car sales continued to decline in 2025 as they were largely outsold by lower-cost battery electric and plug-in hybrid electric cars.

The global stock of fuel cell trucks kept increasing in 2025 to reach more than 35 000 vehicles, over 5 times as many as at the end of 2022. The largest stock increase occurred in China, which was home to more than 95% of the world's fuel cell trucks in 2025. However, they are still vastly outnumbered by alternative powertrain technologies: in 2025, for example, there were more than 25 times as many battery electric trucks operating in the country.

Although they have higher operating costs than battery equivalents, fuel cell truck uptake in China has been driven by policy support. This takes the form of incentives provided to hydrogen corridors and pilot city clusters that are required to reach vehicle deployment, charging infrastructure and hydrogen price benchmarks in order to qualify for vehicle purchase subsidies and support with refuelling infrastructure roll-out. A third subsidy round for FCEV demonstration projects was announced in April 2025. In March 2026, a new city-cluster policy was released, aimed at stimulating demand across multiple applications, while retaining the performance-reward structure of the previous scheme and its focus on heavy-duty FCEVs and corridor applications. The programme, with a maximum budget of up to CNY 8 billion (Yuan renminbi) (about USD 1.1 billion), introduces a target of 100 000 FCEVs by 2030 (from the approximately 47 000 units seen in 2025) and aims to cut the average end-user price of hydrogen to less than CNY 25 (USD 3.5) per kg, with certain focus regions aiming for a target price of CNY 15 (about USD 2.1) per kg.

Figure 2.14 Fuel cell electric vehicle stock by segment and region, 2020-2025



Sources: IEA analysis based on data from the Advanced Fuel Cells Technology Collaboration Programme, CATARC, AIRIA, EV Volumes, Toyota, California Fuel Cell Partnership.

Most early fuel cell vehicles were cars, but uptake is now shifting to trucks and buses.

Fuel cell buses also gained traction in 2025, driven by deployment in Korea, China and Europe, bringing the global fleet to 15 000 vehicles, double the stock recorded 3 years earlier. Of this, about 70% are in China, and nearly 20% in Korea, where the stock saw the largest increase globally in 2025, growing to nearly 3 000 buses and meeting about 10% of Korea's 2030 deployment target.

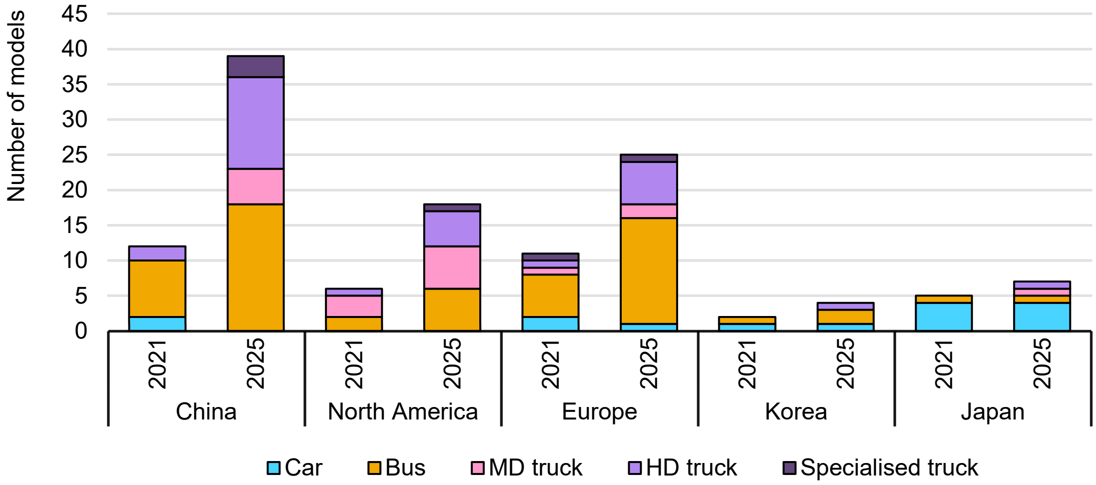
Momentum in Korea's fuel cell vehicle uptake is expected to continue, backed by strong policy support. In early 2026, the Korean government launched a USD 390 million subsidy programme to support the deployment of about 8 000 fuel cell vehicles, including 1 800 buses and 6 000 passenger cars. In China, fuel cell buses fall under the scope of the FCEV city-cluster programme and may consequently be eligible for purchase subsidies, similarly to their truck counterparts. However, their deployment is closely linked to continuous policy support, as fuel cell buses usually underperform their battery electric rivals on economics due to lower energy efficiency, higher fuel costs and higher vehicle purchase prices.[25] In Europe, several fuel cell bus pilot projects faced operational and financial challenges. In the United Kingdom, refuelling station reliability concerns prompted the city of Aberdeen to sell its hydrogen bus fleet and move to electric buses instead. The hydrogen bus programme was also abandoned in Liverpool for similar reasons. Likewise, in France, the city of Dijon dropped hydrogen buses, pointing to hydrogen supplier failures. In Poland, Arthur Bus, a fuel cell bus start-up, filed for bankruptcy in early 2026, before its first-ever customer delivery. Despite these setbacks, the stock of fuel cell buses in Europe grew to about 850 vehicles in 2025, representing just over 5% of the global total. Germany was the largest fuel cell bus market in Europe in 2025, accounting for more than two-thirds of new registrations. Strong policy support and government funding have historically supported the deployment of fuel cell buses in the country. This is set to continue in 2026 with the German Federal Ministry of Transport procuring over 50 fuel cell buses for the Ruhr region.

FCEV model availability and manufacturers' strategies

Over 90 fuel cell vehicle models were available worldwide in 2025, about 15 times fewer than battery electric models. Of these, about half were truck models, up from around one-quarter in 2021. Fuel cell bus models represented most of the remaining models, with cars making up only a minor share.

Figure 2.15 Fuel cell electric vehicle models by original equipment manufacturer origin and vehicle segment, 2021-2025

[25] In applications involving long driving distances, strict refuelling time requirements, and sustained cabin heating demand – particularly intercity coach operations – fuel cell powertrains may offer operational advantages over battery electric alternatives despite less favourable economics.



Notes: MD = medium-duty; HD = heavy-duty. This figure is based on a continually updated inventory and may not be fully comprehensive due to new model announcements and small manufacturers not yet captured in the database. "MD truck" includes 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 that have a GVW of less than 3.5 t are excluded from this analysis.

Sources: IEA analysis based on the Global Drive to Zero ZETI tool database and EV Volumes.

More than 90% of available FCEV models in 2025 were trucks and buses, with heavy-duty trucks representing a growing share of the total.

Toyota, the world's largest manufacturer of fuel cell cars, is increasingly shifting its strategy to include heavier vehicle segments. The carmaker recently announced plans to launch a fuel cell bus together with Isuzu, and a fuel cell truck with Hino. In March 2026, Toyota, Daimler Truck and Volvo signed an agreement to co-operate in the joint venture cellcentric to develop, produce and commercialise fuel cell systems for heavy-duty applications. Other major carmakers are similarly focusing on heavy-duty applications. In January 2026, the joint venture between Honda and General Motors decided to discontinue fuel cell system production in the United States, pointing to a likely phase-out of Honda's only fuel cell car model. At the same time, Honda unveiled plans to develop its next-generation fuel cell system modules, set to be mass-produced in 2027 and to fit heavy-duty applications.

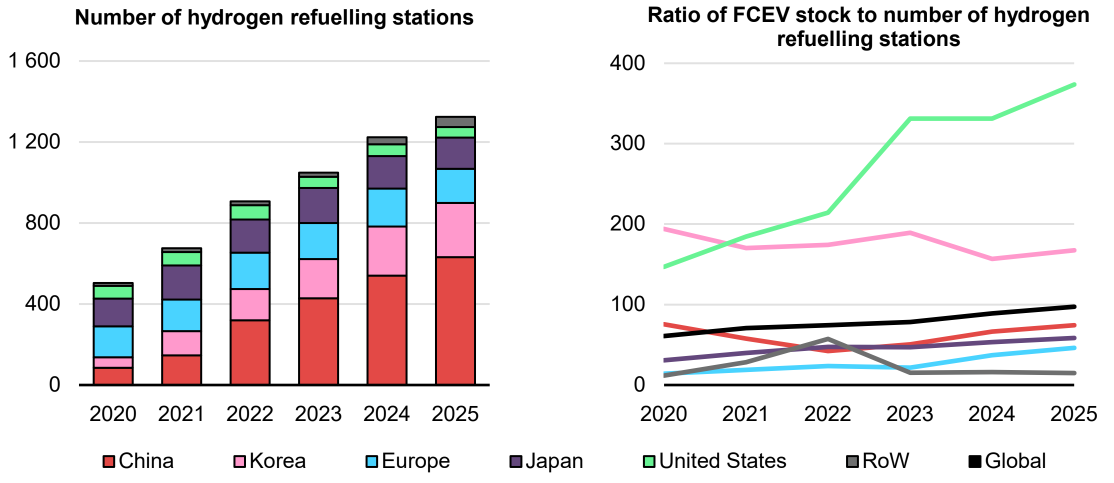
Truck manufacturers are also expanding their fuel cell vehicle portfolios. European original equipment manufacturer Daimler announced it would move its fuel cell heavy-duty truck to mass production in early 2026. At the same time, MAN delivered 15 hydrogen-fuelled combustion trucks to a Dutch fleet operator. Chinese manufacturers remain the most active in the fuel cell truck segment, supported by the scale of the domestic market, with both established truck-makers and new entrants adding fuel cell models to their line-ups.

Despite weak sales outside Korea over the past 4 years, a handful of carmakers maintained plans to add new fuel cell car models to their line-ups. In China, the carmaker Changan announced the release of its new fuel cell SUV in early 2026, even though China's fuel cell car sales plummeted to just five units in 2025. Similarly, BMW unveiled a fuel cell SUV model, the X5, which is planned for 2028, and Toyota announced plans to release its fuel cell HiLux passenger pickup truck the same year.

Hydrogen refuelling infrastructure

At the end of 2025, there were more than 1 300 hydrogen refuelling stations (HRSs) in operation worldwide, reaching around 10% yearly growth. The biggest increases were recorded in China and Korea, where about 90 and 25 new stations were added, respectively. In China, the world's largest HRS broke ground in late 2025, capable of dispensing 10 tonnes of hydrogen and serving up to 300 trucks per day. In 2026, Korea's government launched a USD 130 million subsidy programme to increase the cumulative number of hydrogen refuelling points to over 660 by 2030, up from around 450 dispensers installed across fewer than 270 HRSs in 2025. In Europe, the number of HRSs declined in 2025, falling to below 170 after multiple closures across the region. Under the Alternative Fuel Infrastructure Regulation (AFIR), the European Union has set binding deployment targets, requiring stations every 200 km along the TEN-T core road network and in all major urban nodes. Hydrogen Europe estimated that meeting these targets would require between 400 and 500 stations, more than double the HRS count in late 2025. These targets were initially based on an assumption of over 300 000 fuel cell vehicles in Europe by 2030. However, recent market developments suggest that this level of deployment is unlikely. In March 2026, the European Commission launched a call for evidence, offering the opportunity to gather inputs ahead of the planned AFIR 2026 review, which is likely to amend the distance-based HRS deployment targets.

Figure 2.16 Number of hydrogen refuelling stations by region and ratio of fuel cell electric vehicle stock to number of stations, 2020-2025



Note: FCEV = fuel cell electric vehicle; RoW = Rest of World.

Sources: IEA analysis based on data from the Advanced Fuel Cells Technology Collaboration Programme; EAFO; US Alternative Fuels Data Center; Korea, Ministry of Climate, Energy and Environment.

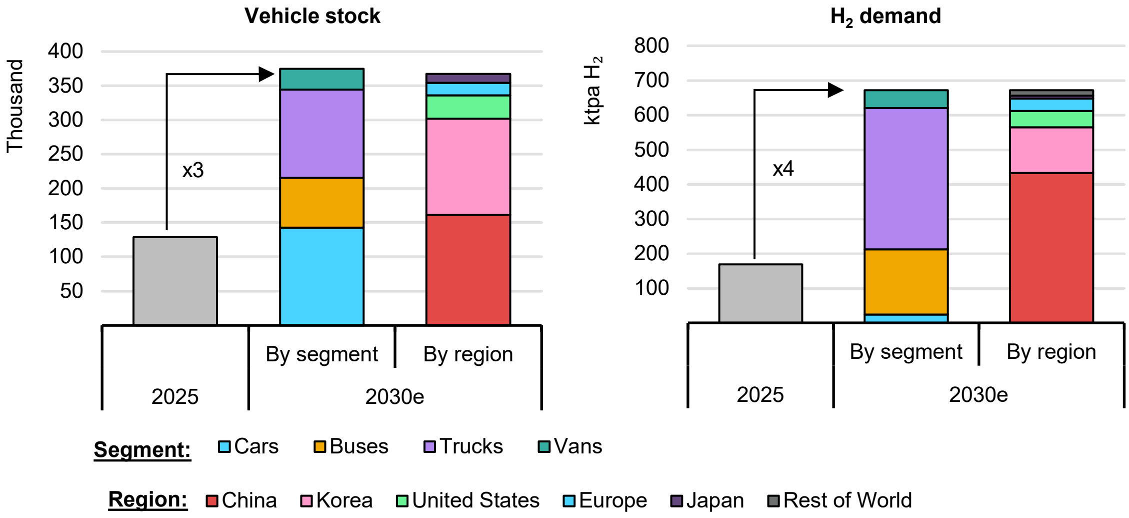
China leads the global roll-out of hydrogen refuelling stations, whereas station availability has declined in the United States, due to reliability and hydrogen supply issues.

Refuelling infrastructure reliability and supply shortages have emerged as a major constraint in some regions, particularly in Europe and North America. Nearly 60% of hydrogen stations in California were reported unavailable because of a supply shortage beginning in February 2026. In Germany, station closures and limited network coverage disrupted operations for fuel cell electric vehicles. Similarly, most of the challenges faced by fuel cell bus fleet operators across Europe mentioned above involved refuelling infrastructure reliability and shortages concerns.

Outlook for hydrogen demand in road transport

Strong policy support in China and Korea is expected to drive increased uptake of fuel cell vehicles, particularly in the truck and bus segments. Based on existing policies, the global FCEV stock is projected to almost triple by 2030, with trucks and buses accounting for around 35% and 20% of the total, respectively. As a result, the share of passenger cars is expected to decline to less than 40% of global FCEV fleet.

Figure 2.17 Global fuel cell electric vehicle stock and hydrogen used in transport by vehicle segment and region, 2025-2030e



By 2030, hydrogen use in road transport could grow fourfold from 2025 levels, primarily driven by trucks and buses.

The expansion of the FCEV fleet, combined with the growing share of heavy-duty vehicles, could drive a fourfold increase in hydrogen demand in road transport by 2030. Fuel cell trucks are expected to account for over 60% of total hydrogen use in the sector, with buses representing most of the remainder. Driven by its 100 000 FCEV stock target for 2030, China is expected to host the majority of fuel cell trucks. By 2030, China could capture nearly two-thirds of global hydrogen demand in road transport, while the remaining demand is expected to be dominated by fuel cell buses and fuel cell cars in Korea.

Shipping and aviation

Shipping

Heavy fuel oil remains the dominant fuel used in shipping today, but national net zero targets and the FuelEU Maritime regulation in the European Union are driving a shift toward low- and zero-emissions alternatives such as hydrogen and hydrogen-based fuels. Shipping will play a key role as an early source of demand for these alternatives and as an enabler of international fuel trade.

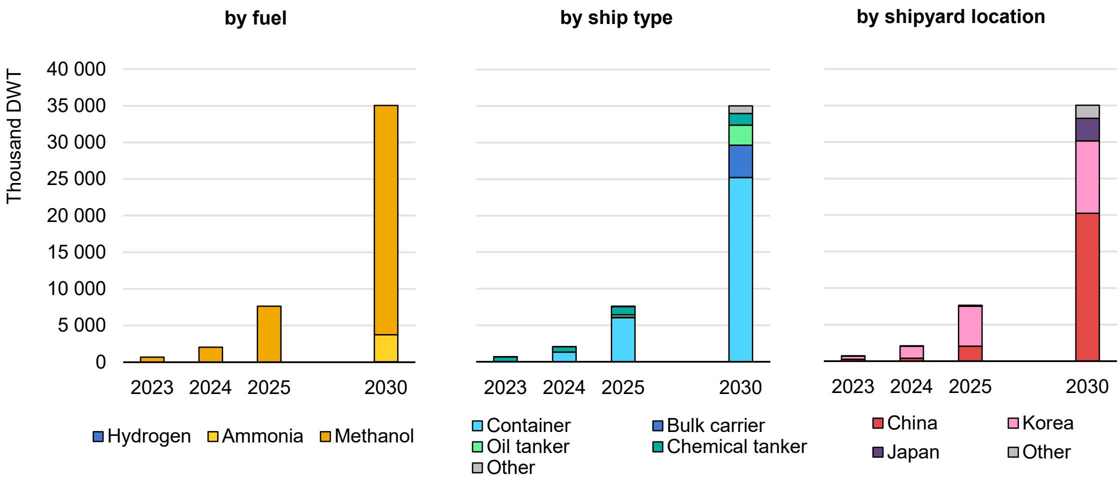
In 2025, there were over 100 ships on the water with dual-fuel engines,[26] an increase of nearly 70% compared with 2024. More than 95% of these ships could burn methanol (Figure 2.18). However, today these ships still run mostly on fossil fuels, and collectively account for less than 0.5% of the total deadweight tonnage

[26] Dual-fuel refers to methanol and ammonia capable ships only, and excludes liquefied natural gas (LNG).

(DWT) of in-service ships. Container ships made up more than half of the fleet by number of vessels, and almost 40% were chemical tankers, often used for transporting methanol. In terms of DWT, however, container ships account for almost 80% of the total.

Looking at the order books to 2030, methanol and ammonia dual-fuel vessels represent around 5% and 1%, respectively, of the total DWT on order – with conventional fuels making up the remainder – and reaching just over 1% of the total DWT on the water. However, annual orders decrease from over 7% in 2027 to less than 3% in 2029, which could indicate a slowdown in momentum. Most new orders are for container ships, which could represent nearly 70% of the total DWT by 2030.

Figure 2.18 Total deadweight tonnage of ships historically and based on order books by low-emissions fuel, by ship type and by shipyard location



Note: The value for each year refers to the cumulative deadweight tonnage (DWT) deployed by that year.
Source: IEA analysis based on orderbooks retrieved from the Ship Register accessed through the UN Global platform.

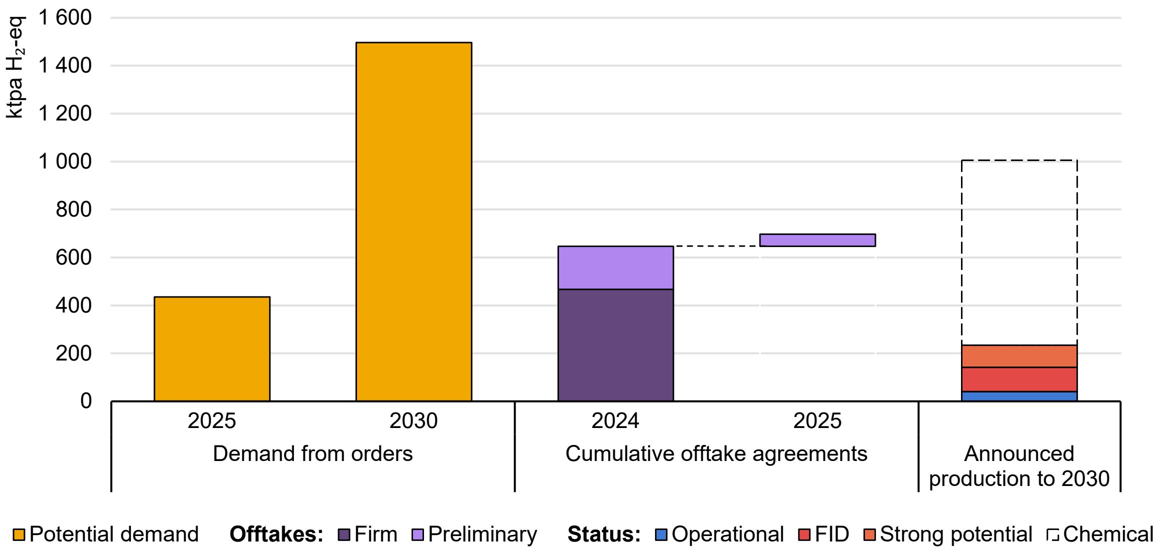
Based on orders, methanol remains the preferred choice for low-emissions ships, across an increasing number of ship types, and as China's share of ship-building increases.

A shift in ship-building locations is also expected. While Korea currently accounts for more than 70% of the cumulative DWT deployed for methanol and ammonia dual-fuel vessels, its share is projected to fall to about 30% by 2030 based on orderbooks, whereas China's share is set to rise to around 60%. This trend is being driven by lower costs for ship-building in China (which is 5-15% cheaper than in Korea) and supportive industrial policies, such as the Action Plan for Green Development in the Shipbuilding Industry (2024-2030), launched in 2023, which targets a market share of more than 50% in LNG and methanol ships.

The potential demand for methanol from shipping is already around 45 PJ per year (Figure 2.19), although this remains only a potential, as most of the dual-fuel engine ships currently in operation run primarily on fossil fuels. Based only on the ships on order to 2030, potential methanol demand could grow to at least around 160 PJ per year, which could be met both by synthetic methanol and biomethanol.

In 2025, the cumulative offtake agreements for hydrogen-based fuels in the shipping sector amounted to over 800 ktpa H_2-eq, an increase of 7% compared with 2024. More than 85% of these volumes were associated with methanol (the remainder was linked to ammonia), accounting for slightly less than 700 ktpa H_2-eq (73 PJ). Two-thirds of these offtakes are firm and would be able to meet around 30% of the potential demand from the fleet in 2030.

Figure 2.19 Total potential methanol demand from ships on order books, cumulative offtake agreements and announced production, 2024-2030



Notes: FID = final investment decision; "Strong potential" refers to projects without FID that have strong potential to become operational by 2030 according to the methodology developed in the GHR-25, updated for this report. "Chemical" refers to the potential production from announced projects targeting the production of methanol for chemical applications.

Sources: IEA analysis based on the UN Global platform; IEA (2026), IEA Hydrogen Production Projects Database (June 2026); and announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved; BloombergNEF and S&P Global.

Announced methanol production remains low compared to offtake agreements and potential demand.

At the same time, announced projects for the production of low-emissions methanol for use as a fuel account for around 1 300 kt H_2-eq (135 PJ) by 2030. However, only around 9% – or 140 kt H_2-eq (15 PJ) – have a committed investment. This could increase to 230 kt H_2-eq (24 PJ) considering projects that have a strong potential to reach operation by 2030. These projects could therefore supply around one-sixth of the potential demand from the dual-fuel ready vessels on order and expected to be on the water in 2030. However, there is an additional 770 kt H_2-eq (81 PJ) of announced production in projects targeting methanol for chemical applications with strong potential to be in operation by 2030. Part of this production could be available for shipping as some project developers are open to targeting both sectors.

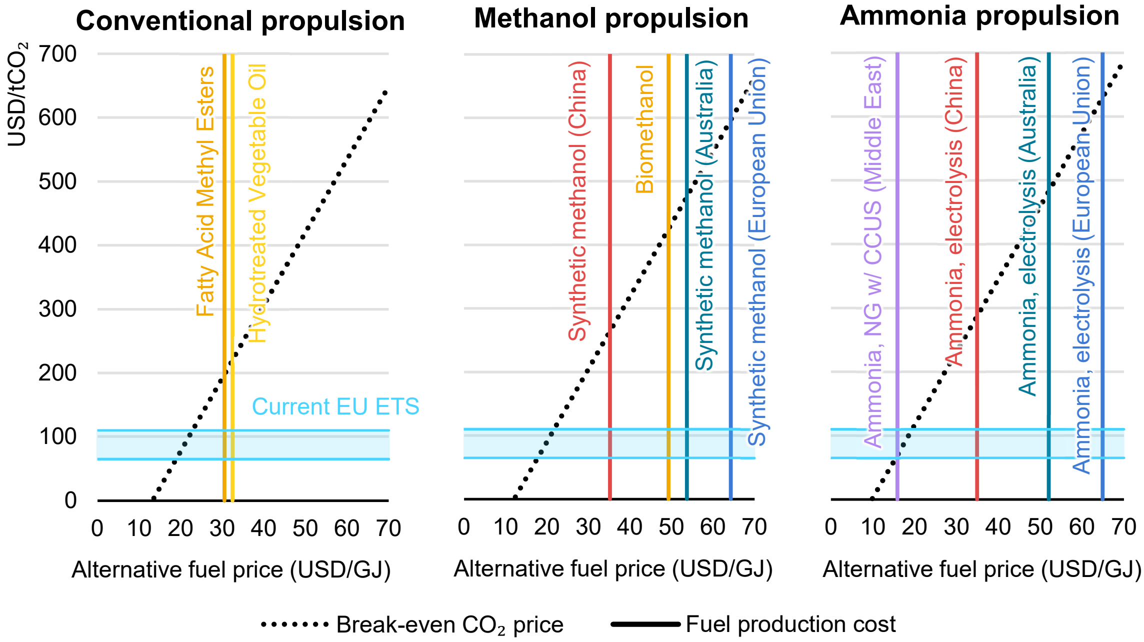
The future regulatory environment for alternative shipping fuels remains somewhat uncertain at the global level. The International Maritime Organization (IMO) 2023 GHG strategy is still in effect, but its implementation through the Net-Zero Framework has been delayed, as the decision on its adoption originally planned for October 2025 has been postponed to December 2026. This means that national or regional regulations are the main drivers of uptake in the short term.

In the European Union, several regulations are in place. In particular, the integration of the shipping sector in the EU ETS will come into full effect for emissions reported in 2026, meaning that companies will be required to purchase allowances covering these emissions in full. An initial assessment of the implementation of this measure in 2024 suggested that compliance levels were satisfactory, with no evidence of evasive behaviours (such as trans-shipment outside the European Union or re-routing). It found that freight rates increased between 1% and 5% for deep sea container services. In order to reduce the impact of the measure on costs, shipping companies can implement energy-saving measures, such as slow steaming, in the first instance, but a subsequent switch to low-emissions fuels is expected to be incentivised.

Considering the total cost of ownership for ships makes it possible to derive the level of carbon pricing that would be needed to make alternatively powered large ocean-going ships competitive with their conventional counterparts powered by heavy fuel oil. The appropriate level will depend on the type of propulsion, as both the difference in fuel unit price and the difference in the ship capital expenditure (CAPEX) would need to be offset. Ammonia from natural gas with CCS can be produced at a relatively low cost, so the level of carbon pricing necessary to make it competitive can be within the current ETS price range of USD 65-110/t CO_2 (see Figure 2.20). By contrast, to make drop-in fuels like biodiesels competitive, the carbon price would need to be increased from the current levels. For synthetic methanol or ammonia from electrolytic hydrogen, the production costs are significantly higher, and the level of carbon pricing needed to make them competitive would therefore appear to be outside the realistic range of the ETS carbon price.

Other elements of EU regulation, such as the standard on fuel unit emissions in the FuelEU Maritime, and the specific incentives for RFNBO penetration, may have a greater impact on the deployment of alternative fuels. In addition, following the recently issued EU Industrial Maritime Strategy and Port Strategy, a mechanism to support the uptake of sustainable fuels and clean propulsion technologies, based on revenues from the ETS, will be discussed in July 2026.

Figure 2.20 Break-even carbon pricing for alternative fuels



Notes: ETS = Emissions Trading System; NG w/ CCUS = natural gas with carbon capture, utilisation and storage. Reference fuel (Heavy Fuel Oil) price USD 500/t (USD 11/GJ). Fuel production costs in optimum conditions for renewable electricity cost. Hydrotreated Vegetable Oil and Fatty Acid Methyl Esters are biodiesels that can be used with conventional propulsion. The alternative fuels mentioned are expected to be zero-rated, as per the EU ETS directive.

Current EU ETS carbon prices are too low to make most low-emission fuels cost-competitive with the reference fossil fuel.

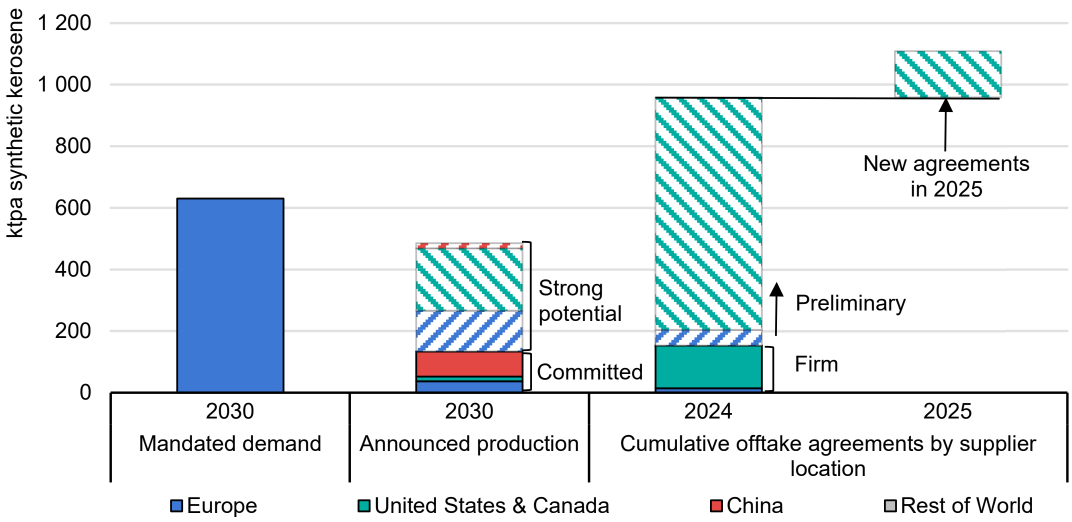
Aviation

In the aviation sector, mandates for hydrogen-based synthetic kerosene (e-SAF)[27] will take effect in Europe within the next 5 years. In the European Union, fuel suppliers must ensure an average share of 1.2% of e-SAF in jet fuel reaching airports across 2030 and 2031. In the United Kingdom, a similar obligation starts in 2028 at 0.2%, rising to 0.6% in 2030. These mandates are set to create demand for more than 630 kt of e-SAF by 2030, while current global production for such fuels is less than 10 kt (Figure 2.21). Plants already at FID are expected to add around 130 kt, and projects with strong potential to become operational by 2030 could provide a further 350 kt. Meeting the upcoming mandates remains

[27] Here, SAF includes both hydrogen-based synthetic fuels which are produced from low-emissions hydrogen and a carbon source from biogenic origin or from direct air capture and biofuels. When referring exclusively to hydrogen-based synthetic fuels, the acronym e-SAF is used.

technically feasible, but only if several early-stage projects reach FID within the next 2 years — an increasingly tight timeline.

Figure 2.21 Mandated demand, announced production and offtake of synthetic kerosene, 2024-2030



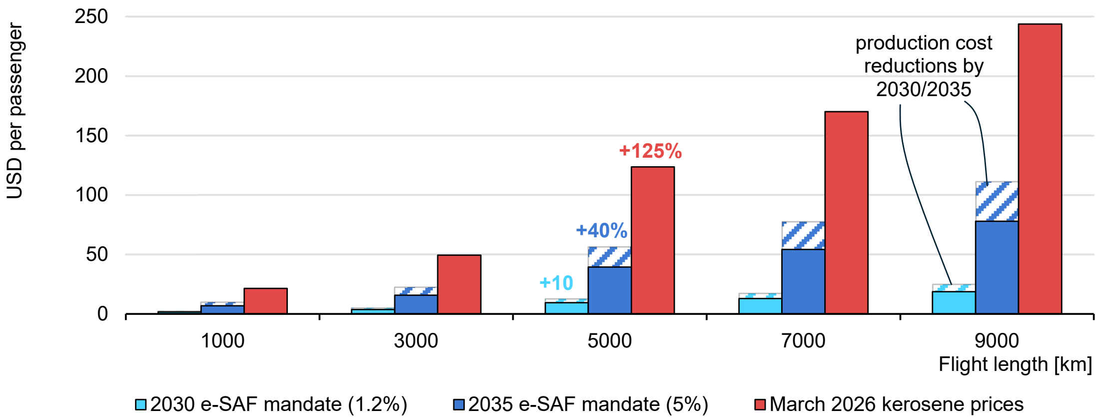
Note: Mandated demand is due to EU and UK regulations setting minimum shares for e-SAF in aviation fuel.
Source: IEA analysis based on IEA (2026), IEA Hydrogen Production Projects Database (June 2026); and announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved; BloombergNEF and S&P Global.

Strong demand signals for e-SAF in Europe have not yet translated into production capacity.

While Europe is currently generating the strongest demand signals for e-SAF, other regions are closer to scaling up supply. The world's largest e-SAF facility is under construction in China, and North American fuel suppliers currently hold the largest share of offtake agreements – many of which are with European airlines. The United States and Europe currently lead the pipeline of projects with a high potential to be operational by 2030, which combined add up to around 330 kt. Meanwhile, offtake agreements announced in 2025 have been limited, with around 150 ktpa, primarily in North America. Given this geographical mismatch between demand and near-term supply, trade is likely to play a central role, especially as transport costs for e-SAF are typically negligible compared to production costs. For example, tanker rates between the United States, where e-SAF can currently be produced at around 25% lower cost, and European Union have averaged around USD 35/t over the past 5 years, compared with current European e-SAF production costs of over USD 8 000/t.

European airlines have raised concerns about competitive disadvantages and the risk that passengers may shift to non-EU hubs. However, despite high price premiums for early e-SAF production, the impact of blending mandates on ticket prices is expected to remain relatively modest this decade (Figure 2.22). Current e-SAF production costs are up to ten times those of fossil kerosene, but the 2030 EU mandate would add less than USD 5 per passenger on short-haul flights and less than USD 30 on long-haul flights.[28] Under the 2035 mandate and with cost reductions compared to first-of-a-kind projects today, the increase could reach around USD 90 for the longest routes. These cost increases are small compared with the fuel price volatility seen in 2026 after the closure of the Strait of Hormuz.

Figure 2.22 Fuel cost increase per passenger compared to 2025 for flights departing from airports in the European Union, 2030-2035



Notes: Fuel cost assumptions: Fossil kerosene 2025: USD 710/t; March 2026: USD 1 600/t; e-SAF 2025: USD 8 300/t; 2030: USD 6 400/t; 2035: USD 5 200/t. The e-SAF costs represent averaged production costs across the European Union. The ReFuelEU mandates 6% and 20% total SAF shares in 2030 and 2035, respectively. The rest is assumed to be covered by bio-kerosene and will lead to a further cost increase. According to IATA, fuel costs accounted for 27% of airline operational costs in 2025 on average.

Sources: IEA analysis based on kerosene prices from IATA; fuel consumption per passenger calculated with AIM (UCL).

Fuel cost increases due to e-SAF mandates over the next decade are small compared to the fossil kerosene price spike in 2026.

Developing e-SAF plants is highly capital-intensive: a first-of-a-kind commercial facility in Europe with 80 ktpa capacity is expected to cost around USD 2 billion to build. Securing FIDs therefore requires policy stability, long-term revenue certainty and strong industrial partnerships. Ten-year (or longer) offtake agreements with airlines or fuel suppliers are central to project financing, but these depend on confidence in future policy frameworks. However, the ReFuelEU regulation's built-in 2027 review has created some uncertainty, despite the European Commission clarifying that the mandates themselves will not be reconsidered. Instead, the review may introduce flexibility mechanisms such as simplified anti-tankering rules and book-and-claim systems in place of airport-specific blending.

Public support to close the cost gap with fossil kerosene is important to enable early e-SAF deployment. Governments have recently started to put schemes in

[28] Considering short-haul flights those up to 1 500 km and long-haul flights those up to 10 000 km.

place, but the support varies by region. In the United States, producers can still access production tax credits that were first introduced under the Inflation Reduction Act in 2023. China has offered substantial capital subsidies for SAF production since the end of 2025. The United Kingdom is preparing the introduction of a SAF revenue certainty mechanism in 2026. The European Union has channelled revenues from the ETS through the Innovation Fund since 2020 and provided free ETS allowances to airlines to cover part of the SAF price gap since 2024. In 2025, the European Union announced the Sustainable Transport Investment Plan (STIP), aimed at mobilising USD 3 billion for low-emissions fuels in aviation and shipping until the end of 2027. One key mechanism under STIP will be double-sided auctions, which were pioneered for other hydrogen-based fuels by H2Global. The first such auction in 2026 is supported by up to USD 2 billion in public financing provided by Germany.

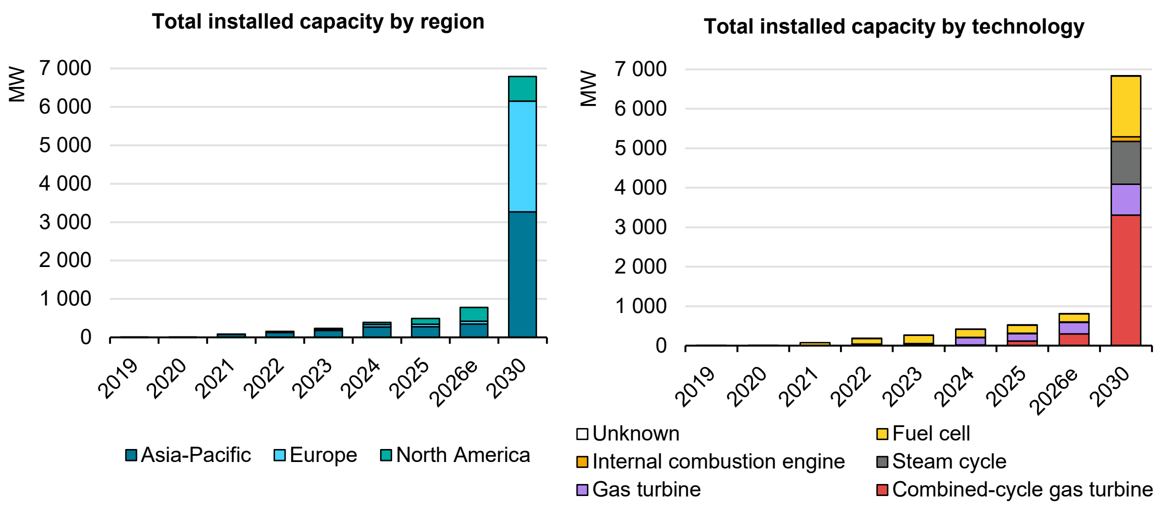
Availability of jet fuels has recently been the centre of attention as a result of the conflict in the Middle East. Moving forward, such energy security concerns have the potential to unlock new funding streams and applications for synthetic kerosene. In response to the conflict, the European Union has outlined an action plan that includes strengthening support for e-SAF, notably through a review of production criteria, increased investment, and a potential extension of the ETS-based SAF support mechanism. At the same time, the defence sector is showing renewed interest in synthetic kerosene. For example, Rheinmetall and Ineratec are developing distributed power-to-liquid plants to enhance military energy security and fuel logistics. Such initiatives could catalyse additional investment in e-fuel production, with capacity potentially serving both military needs and civil aviation demand in peacetime.

Electricity generation

Hydrogen and ammonia can provide valuable low-emissions flexibility for electricity systems and are among the few viable options for large-scale, seasonal electricity storage, especially where renewable generation is high and other long-term storage options are limited. The global installed power capacity using hydrogen and ammonia reached 520 MW at the end of 2025, which represents an increase of 25% compared to 2024, but accounts for less than 0.01% of global installed power capacity. The capacity increase is mainly due to the commissioning of the 840-MW Intermountain Power Project in the United States, which plans to co-fire 11% of hydrogen (in energy terms, 30% in volume terms) with natural gas, though hydrogen co-firing is foreseen to only start in 2026. In addition, a 100% hydrogen-fired 30-MW gas turbine commenced operation in China in 2025. In the United States, a 75-MW gas turbine also running to 100% on hydrogen was commissioned in January 2026. In Singapore, construction started in 2026 on a 20-MW fuel cell power plant that will run on renewable hydrogen and provide electricity for a data centre (Box 2.3).

Based on announced projects, the power capacity using hydrogen and ammonia could reach 6 800 MW by 2030 (2 000 MW based on operating plants and projects under construction or having reached FID), a decline of 10% compared to the assessment in the GHR-25 (Figure 2.23). This downward revision is mainly caused by a reassessment of some projects, for which no progress has been reported after their initial announcement. The Asia-Pacific region accounts for half of the announced capacity by 2030, followed by Europe with 40% and North America with 10%.

Figure 2.23 Power generation capacity using hydrogen and ammonia by region, historical and from announced projects, 2019-2030



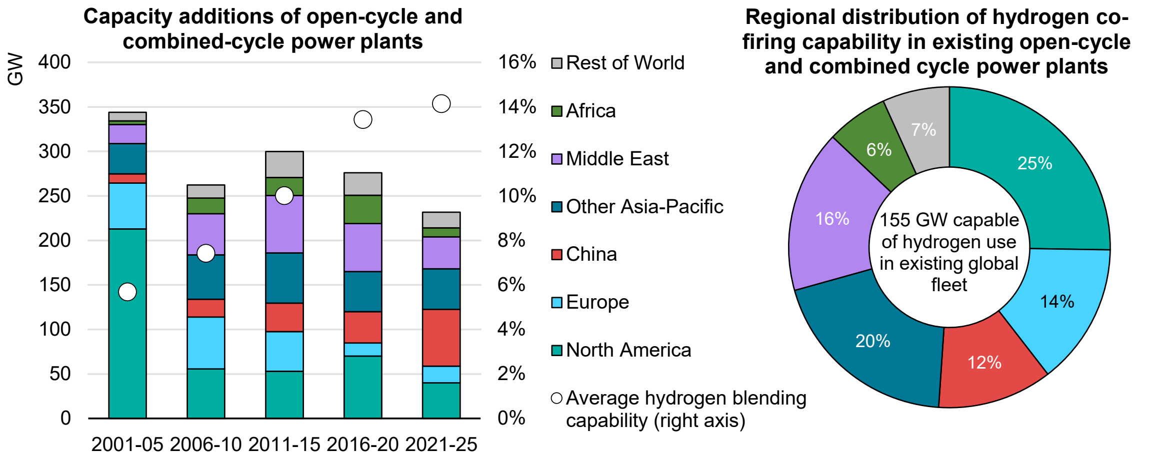
Note: Values for 2026 are estimates, assuming plants with an announced start date in 2025 that are under construction or have reached FID will start operation in 2026.
Sources: IEA analysis based on announcements from industrial stakeholders; ERM for fuel cells up to 2023.

Based on existing plants and announced projects, hydrogen and ammonia-fired power capacity could reach 6 800 MW by 2030, less than 0.1% of today's global power capacity.

Most of the announced projects plan to use hydrogen in open-cycle or combined-cycle gas turbine power plants. Hydrogen co-firing is already possible in existing gas turbine designs. Some existing gas turbines, which use diffusion combustion and steam or water injection as a measure to reduce nitrogen oxide (NOx) emissions, can run completely on hydrogen, but they suffer from efficiency penalties compared to modern gas turbine designs using dry low-NOx combustion systems. The use of 100% hydrogen with dry low-NOx systems has already been demonstrated, and manufacturers are planning to make such turbines commercially available by 2030. Within the existing global gas-fired capacity of around 1 700 GW, around 1 100 GW are capable of co-firing hydrogen, though the co-firing share depends on the gas turbine design and the capability of other equipment as pipes. Overall, a capacity corresponding to around 155 GW could run on hydrogen within the existing fleet of open-cycle and combined-cycle gas turbine power plants (Figure 2.24).[29]

Projects planning to co-fire ammonia in coal power plants or to directly use ammonia in gas turbines are also being pursued. In Japan and Korea, seven projects are under development to co-fire ammonia in coal power plants, benefiting from government support programmes. In Singapore, a consortium was selected in October 2025 to conduct a front-end engineering and design study for a 55-65 MW ammonia power plant, as well as terminal and bunkering infrastructure. Progress has been made in the direct use of ammonia in gas turbines. In March 2026, 100% ammonia combustion was demonstrated by GE Vernova and IHI in an F-class gas turbine. With the smallest F-class turbine having a capacity of 50 MW, this would represent a significant scale-up following IHI's demonstration of 100% ammonia firing in a 2-MW gas turbine in 2022. The companies plan the commercial deployment of ammonia-capable gas turbines by 2030. Mitsubishi Power also plans to demonstrate 100% ammonia firing in its H-25 gas turbine.

Figure 2.24 Capability of hydrogen co-firing in existing gas-fired power plants, 2001-2025



Source: IEA analysis based on data from Global Energy Monitor.

The average capability of hydrogen in new gas-fired power plants has almost tripled since 2001. As a result, around 9% of existing gas-fired capacity could run on hydrogen.

Policy support schemes for the use of low-emissions hydrogen and ammonia in the power sector have been implemented, with activities being mainly concentrated in Japan and Korea (Figure 2.25). In Japan, JERA and Mitsui & Co.

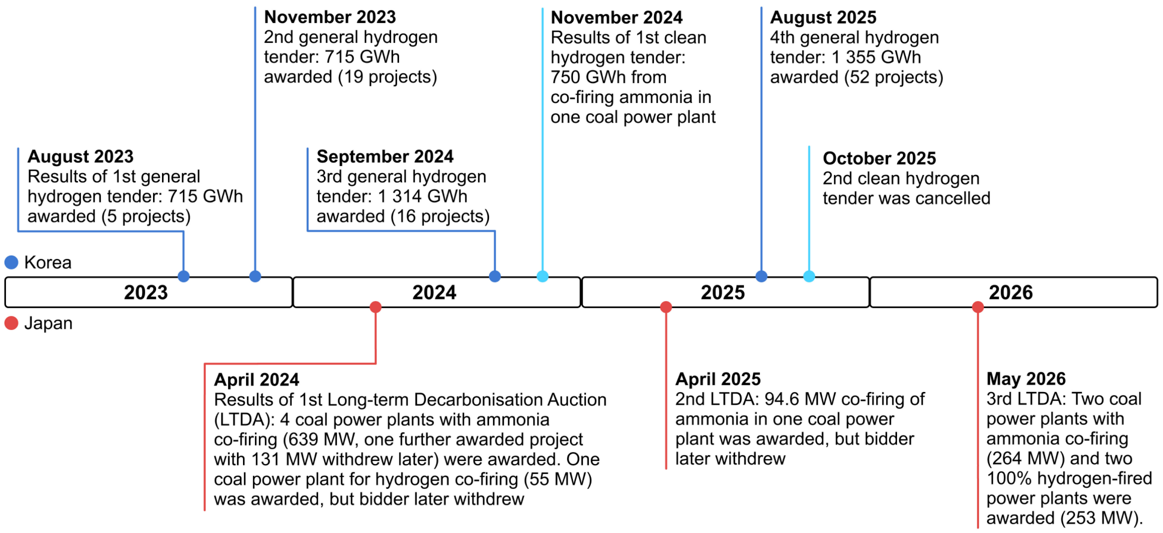
[29] Derived by taking the maximum hydrogen co-firing shares of gas turbine designs multiplied by the total capacity for individual plants.

were selected in December 2025 for the government's 15-year support scheme for hydrogen and ammonia contracts for difference (CfD) scheme.[30] Both projects aim to import low-emissions ammonia from the Blue Point facility in the United States, which plans to start ammonia production from natural gas in combination with CCS in 2029. The ammonia imported by JERA and Mitsui & Co. will be largely co-fired in JERA's 1 000-MW Hekinan coal power plant and Hokkaido Electric's 700-MW Tomato-Atsuma coal power plant. Both power plants also receive capital cost support from Japan's first Long-Term Decarbonized Capacity Auction (LTDA).[31] The winners of the third LTDA were announced in May 2026.[32] Compared to the first two LTDAs, the third auction also includes support for 100% firing of hydrogen and ammonia as well as a fuel cost support component, covering the price gap to fossil fuels based on a 40% utilisation rate. Two 100% hydrogen-fired units with a combined capacity of 253 MW were awarded, consisting of the retrofit of an existing coal-fired unit to hydrogen and a new hydrogen-fired power plant. Two existing coal-fired units received funding for conversion to ammonia co-firing with a combined capacity of 264 MW. Hokkaido Electric's Tomato-Atsuma unit 4 was already awarded in the first LTDA, and there are plans to increase the ammonia co-firing share from 20% to 40%. Kobelco was awarded 131 MW for a 20% ammonia co-firing at unit 1 of its Kobe power station. The company was already awarded in the first LTDA, but later withdrew. The fourth LTDA is in preparation, and the introduction of an electricity intensity threshold is under discussion.

In Korea, the second tender for clean hydrogen power generation from May 2025 was cancelled in October 2025.[33] The tender aimed to provide support to an annual electricity generation from hydrogen and ammonia of 3 TWh over a period of 15 years. The Korean government is now considering stopping funding ammonia co-firing in coal power plants.[34] In a first tender in 2024, 750 GWh were awarded to a project planning to co-fire ammonia in a coal power plant, far below the intended volume of 6 500 GWh. Besides supporting clean hydrogen and ammonia, which requires an emission intensity below 4 kg CO_2-eq/kg H_2,[35] Korea also supports the use of general hydrogen in the power sector, without any emissions limits. In the four general tenders so far, an annual generation of 4 100 GWh was awarded.

Figure 2.25 Auctions for hydrogen and ammonia use in the power sector in Japan and Korea, 2023-2026

[30] Japan's Meti picks two more NH3 projects for subsidy, Argus Media Group. All rights reserved (19 December 2025).
[31] Japan's clean power auction sees slow start for NH3, H2, Argus Media Group. All rights reserved (1 May 2024).
[32] Japan funds two H2-fired power units: Correction, Argus Media Group. All rights reserved (18 May 2026).
[33] South Korea cancels clean H2 power tender, Argus Media Group. All rights reserved (17 October 2025).
[34] South Korea mulls end to ammonia co-firing plans, Argus Media Group. All rights reserved (29 October 2025).
[35] South Korea H2 power auction excludes some NH3 projects, Argus Media Group. All rights reserved (30 May 2024).



Sources: Various news articles and government announcements.

In Japan, 1 200 MW using low-emissions ammonia or hydrogen were awarded in three auctions, while in Korea an annual generation of 750 GWh was awarded.

Germany revised its power plant strategy and now intends to tender 12 GW of dispatchable capacity in 2026 as part of this. Germany's agreement with the European Union foresees that all of these new power plants must be capable of running on hydrogen, but they may decide to pursue other technologies to decarbonise by 2045. The government plans to set incentives to convert 2 GW of capacity to hydrogen by 2040, and a further 2 GW by 2043. All these measures still need to be formulated in a legal act, which would then require final approval under state aid rules from the European Commission.

In November 2025, the UK government finalised decarbonisation readiness guidance, requiring new and substantially refurbished combustion power plants in England to demonstrate that they can be converted to low-emissions hydrogen or can be retrofitted to capture 90% of the generated CO_2.

Box 2.3 Data centres – an opportunity for hydrogen?

The data centres now emerging are growing consumers of electricity. As their electricity consumption is large and concentrated, the deployment of data centres can create challenges, in particular for electricity infrastructure. While the construction of a data centre takes around 1 to 2 years, the wait times for a grid connection can be much longer, ranging from 2 to 10 years in the European Union, for example. Some AI companies are therefore turning towards onsite generation. In the United States, some data centres are starting to use electricity from onsite gas turbines, but tight supply chains for gas turbines, with lead times of 5 to 7 years, are also becoming a bottleneck.

Onsite electricity generation from low-emissions hydrogen or hydrogen-based fuels using fuel cells or internal combustion engines can be an alternative. Several data centres are already using fuel cells as a backup power option, with an estimated installed capacity of around 400 MW. However, almost all of these fuel cells run on natural gas, not hydrogen. Only a few data centres use hydrogen as a fuel to date. In the Netherlands, in 2022 NorthC Datacenters installed a 500-kW fuel cell running on renewable hydrogen for backup power. The same company installed six 1-MW gas engines with renewable hydrogen as the main fuel at another site a year later. In Korea, a 900-MW fuel cell power plant*, providing electricity to a data centre and running on clean hydrogen, is planned for 2030. Hydrogen-based fuels can be another option. The companies Rolls-Royce and Ineratec plan to develop backup power solutions for data centres using synthetic diesel being produced from renewable hydrogen and CO_2. In Singapore, the company Amogy and the public R&D agency A*Star announced a plan to demonstrate an ammonia-fuelled power system for data centres, which includes an onsite ammonia cracker and a fuel cell or gas engine for electricity generation.

However, the use of hydrogen in data centres also faces challenges. When used as a backup power option, hydrogen storage tanks are needed. For continuous operation, hydrogen supply infrastructure is needed, such as connection to a hydrogen pipeline or integration into a hydrogen hub. Depending on the availability and costs of other low-emissions electricity generation options, the use of hydrogen may be limited to backup power services, and be too expensive for continuous electricity generation. Ammonia or synthetic hydrogen-based fuels can be alternatives, but also face challenges, such as ensuring safe handling in the case of ammonia or higher costs in the case of synthetic hydrocarbon fuels.

* S Korea province plans 900MW H2 fuel cell power plant, Argus Media Group, All rights reserved (26 November 2024).

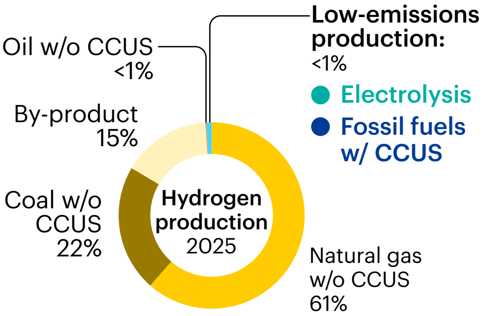
Chapter 3. Hydrogen production

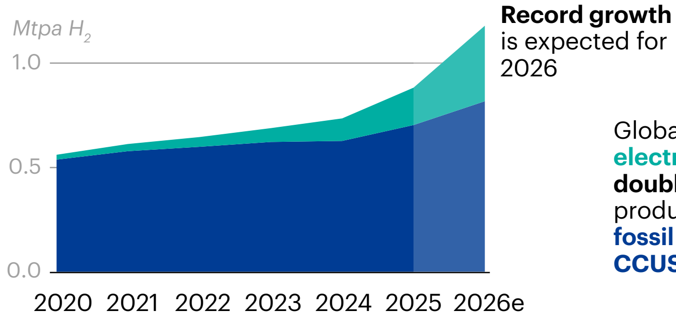
Highlights

- Global hydrogen production remains dominated by unabated fossil fuels. Low-emissions hydrogen production reached almost 1 Mt in 2025 and is expected to register record growth in 2026, accounting for more than 1% of global production, strongly concentrated in China, Europe and North America.
- Installed electrolysis capacity doubled in 2025 to surpass 4 GW, thanks to the commissioning of several large-scale projects in China. More than 2.5 GW are under construction, targeting operation in 2026. Growth is expected mostly in Europe, with 2 GW, but is highly concentrated in a small number of big projects.
- One large project for production from fossil fuels with carbon capture, utilisation and storage (CCUS) started operation in 2025. Two smaller projects are expected for 2026, but several have been postponed due to delays in CCUS infrastructure.
- Investment momentum slowed in 2025. New final investment decisions (FIDs) dropped below 0.8 Mtpa after two consecutive years at around 1 Mtpa. Recent policy developments in China can reinvigorate investment, but lack of demand and regulatory barriers lead to an uncertain outlook in the rest of the world.
- Committed production grew by 3%, reaching 4.3 Mt by 2030, which could increase to more than 6 Mt if projects with strong potential to be operational by 2030 reach FID in 2026 or 2027. However, the project pipeline shrunk by 10 Mt to 27 Mt by 2030, driven by delays expected after 2030, projects temporarily paused and cancellations. More than 100 GW of announced electrolysis capacity could lose any chance of being in operation by 2030 if investment decisions are not taken before the end of 2027.
- Electrolyser manufacturing is entering a consolidation phase, due to slow market development. China leads electrolysis manufacturing thanks to low costs and experience with large projects, but some signs of consolidation are also arising there, due to unsustainable domestic competition driven by excess capacity and offers below manufacturing costs. As a response, many manufacturers are looking to expand markets outside of China.
- In the near term, fossil-based production will remain less costly than renewable hydrogen in most parts of the world. Fossil price volatility can significantly reduce the cost gap during some periods, but this will not be enough to unlock FIDs and support policies will remain necessary for the near future.

Hydrogen production

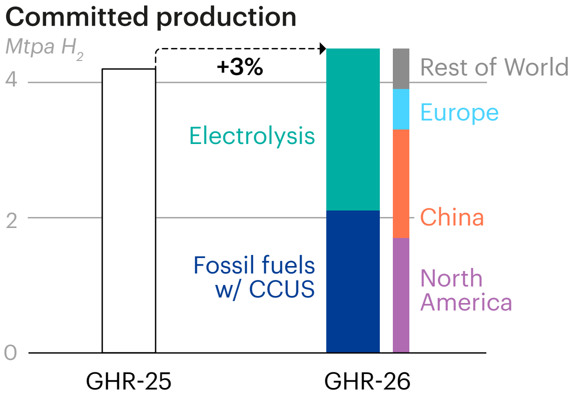
The hydrogen production mix remains dominated by unabated fossil fuels, but low-emissions hydrogen is growing and could exceed 1% of global production in 2026

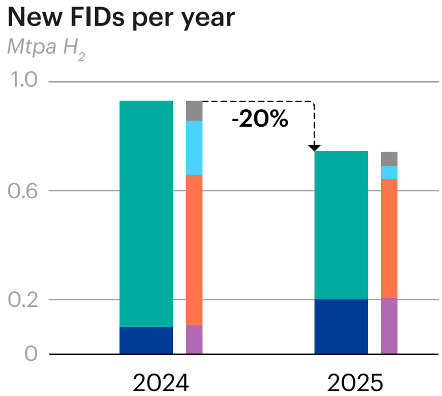




Global installed **electrolysis** capacity **doubled** in 2025; production from **fossil fuels with CCUS** increased **10%**

Committed production of low-emissions hydrogen has grown just 3% since GHR-25 and new FIDs decreased, resulting in an outlook that is positive in China but uncertain elsewhere

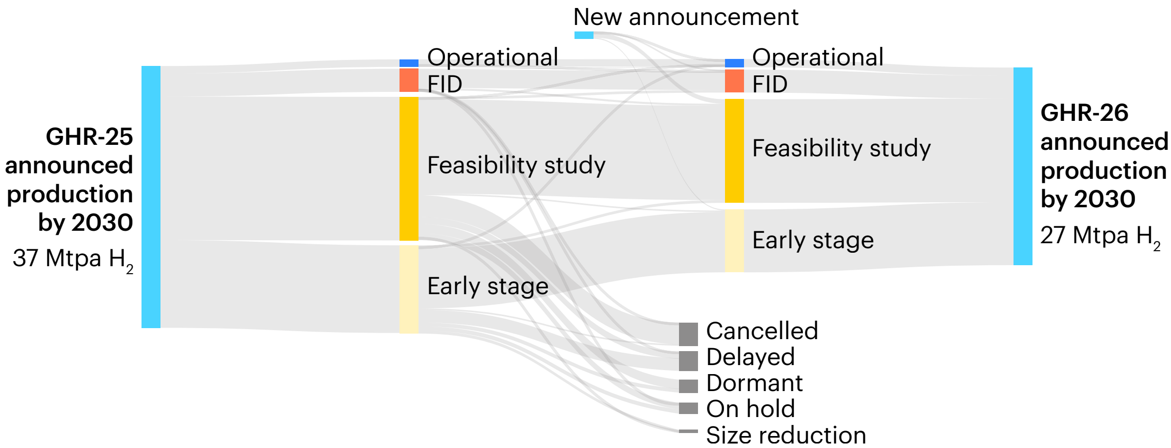




New policies in China to stimulate the hydrogen market

- 15th Five-Year Plan (2026–2030)
- CAPEX subsidies for electrolysis
- Large-scale demonstration programmes
- USD 1.15 billion to stimulate demand

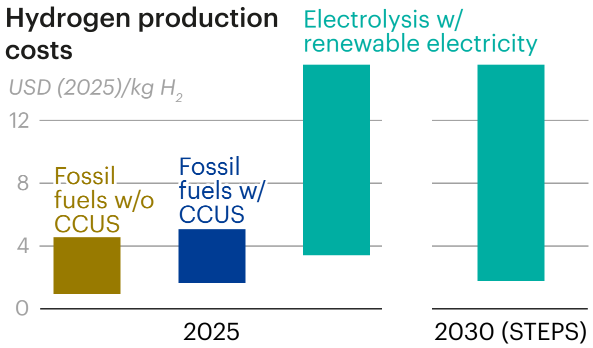
The project pipeline by 2030 has been reduced to 27 Mt and further reductions are expected, but targeted support can unlock investment in more advanced projects

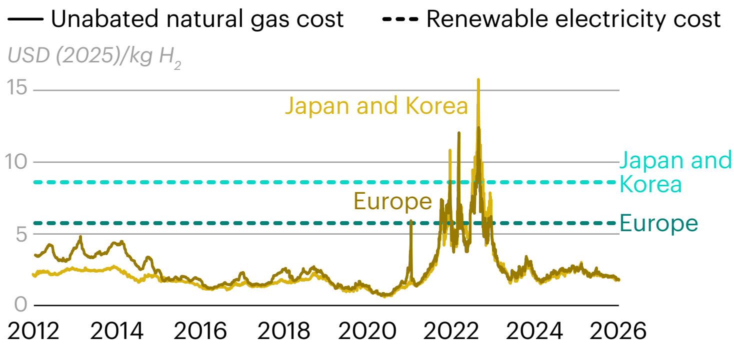


Most cited reasons to cancel or delay projects

- High cost and access to public support
- Permitting issues
- Lack of offtake
- Regulatory barriers

Renewable hydrogen costs more than fossil-based production; volatile fossil fuel prices can narrow the cost gap, but support schemes will remain necessary in the near term

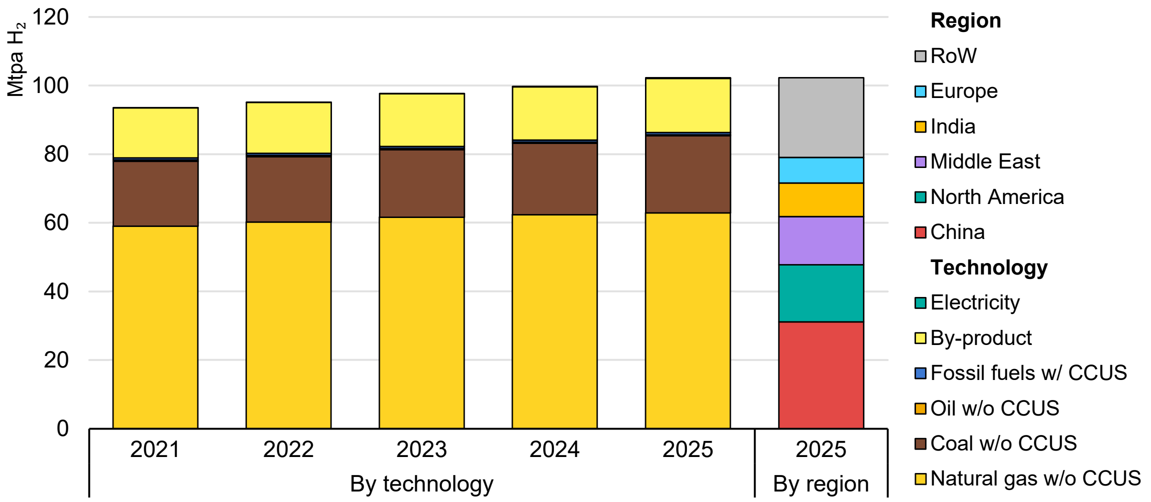




Overview and outlook

Global hydrogen production remains overwhelmingly based on unabated fossil fuels, mostly natural gas (accounting for roughly 60% of output) and coal, primarily in the People's Republic of China (hereafter, "China") (Figure 3.1). As a result, hydrogen production generated around 1 000 Mt of CO_2 in 2025[36] — exceeding the combined emissions of Indonesia and France. Low-emissions hydrogen[37] still represents less than 1% of total production. However, it grew by 20% in 2025, approaching 1 Mt, driven by both electrolysis capacity additions and new CCUS-enabled facilities (Figure 3.2).

Figure 3.1 Hydrogen production by technology and region, 2021-2025



Notes: CCUS = carbon capture, utilisation and storage; RoW = Rest of World. By-product hydrogen includes hydrogen production in catalytic naphtha crackers and steam crackers which is subsequently used in refining.

Hydrogen production remains dominated by unabated fossil fuels, leading to emissions of around 1 000 Mt of CO_2 in 2025.

Production from electrolysis grew by two-thirds in 2025. China played a central role, bringing several large-scale projects online, including the world's largest electrolysis project (500 MW) in Chifeng. In parallel, CCUS-based hydrogen also expanded due to a single large-scale project in the United States, which was sufficient to almost match the increase observed in production via electrolysis.

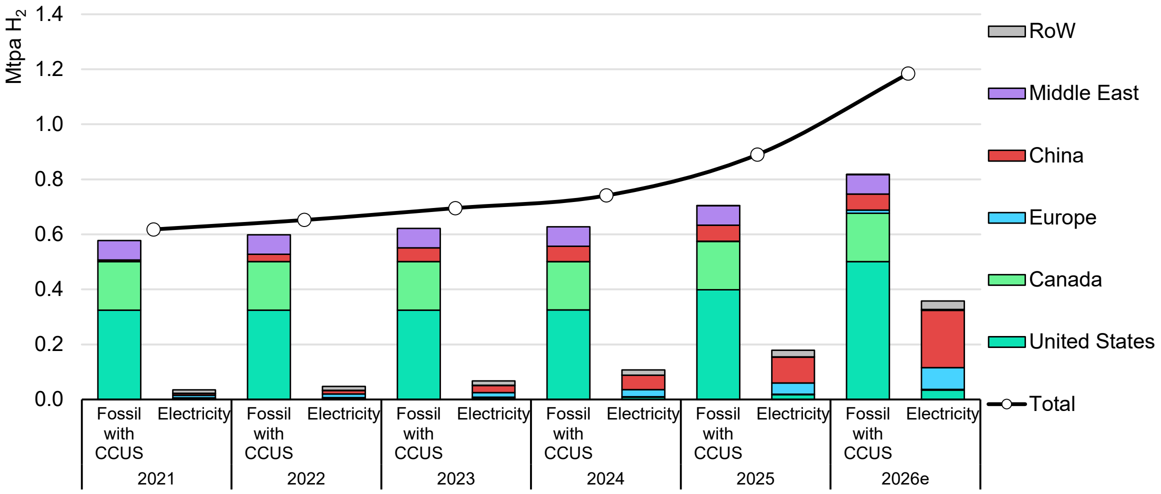
[36] Assuming 0 kg CO_2/kg H_2 for hydrogen produced as a by-product in naphtha crackers and steam crackers. If a maximum of 10 kg CO_2/kg H_2 is assumed, emissions would increase to close to 1 200 Mt CO_2. This includes direct emissions from hydrogen production and more than 300 Mt of CO_2 used in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply.

[37] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Growth is expected to accelerate further in 2026. Low-emissions hydrogen production could increase by 30%, reaching close to 1.2 Mt. This expansion remains geographically concentrated, with China, Europe and the United States leading developments, albeit through different technological and policy pathways.

The United States is expected to account for the largest increase in production, linked to the ramp-up of production in projects commissioned in previous years. China's production is expected to grow almost as much as the United States', driven entirely by electrolysis, as continued cost reductions in electrolysers, low financing costs and sustained industrial policies have created favourable conditions for rapid deployment. In Europe, the commissioning of the first wave of large-scale electrolysis projects supported under the Important Projects of Common European Interest (IPCEI) scheme is anticipated, along with the first large-scale CCUS-linked project in the region. However, several CCUS projects in Europe and the United States[38] have been pushed beyond 2026 due to delays in commissioning the enabling infrastructure.

Figure 3.2 Low-emissions hydrogen production by technology and region, 2020-2026e



IEA. CC BY 4.0

Notes: CCUS = carbon capture, utilisation and storage; RoW = Rest of World. 2026e = estimate for 2026, based on projects planned to start operations in 2026 that have at least reached FID. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Low-emissions hydrogen production reached close to 1 Mt in 2025 and is expected to see record growth in 2026.

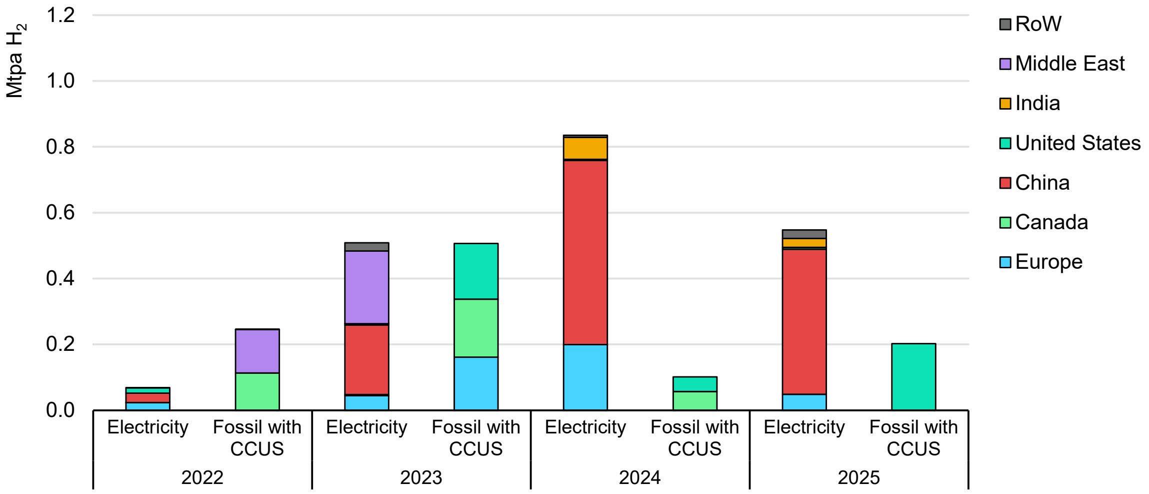
Despite strong growth in operational projects, investment momentum slowed in 2025. New FIDs declined to less than 0.8 Mtpa after two consecutive years in

[38] Woodside delays Texas blue ammonia on H2 supply slip, Argus Hydrogen and Future Fuels Issue 26-11.

which they reached around 1 Mtpa (Figure 3.3). This decline was most pronounced in China's electrolysis sector, although recent policy measures introduced in late 2025 and early 2026 are expected to reinvigorate investment activity.

In Europe, FIDs also dropped sharply following a surge in 2023 and 2024 linked to IPCEI projects. A key constraint is demand uncertainty: The slow transposition into national legislation of the EU Renewable Energy Directive (RED) targets for Renewable Fuels of Non-Biological Origin (RFNBO) use in transport and industry has delayed the clarity on future hydrogen demand requirements needed to spark investment. As a result, project developers have faced difficulties securing offtake, in some cases leading to the return of previously awarded public funding. In addition, challenges in complying with the strict RFNBO criteria, leading to higher production costs, have also been cited by project developers as a reason for slow deployment. The European Commission announced in April 2026 that it will propose a targeted review of these rules, starting in June 2026. Fragmentation across national and EU-level support schemes (such as the European Hydrogen Bank) has further delayed deployment, with some projects opting out of European funding mechanisms in favour of more favourable domestic support that is not compatible with EU-level funding.

Figure 3.3 Low-emissions hydrogen production to reach final investment decision, 2022-2025



Notes: CCUS = carbon capture, utilisation and storage; RoW = Rest of World. The figure includes projects that reached a final investment decision (FID) in the stated year, some of which have already reached operation. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

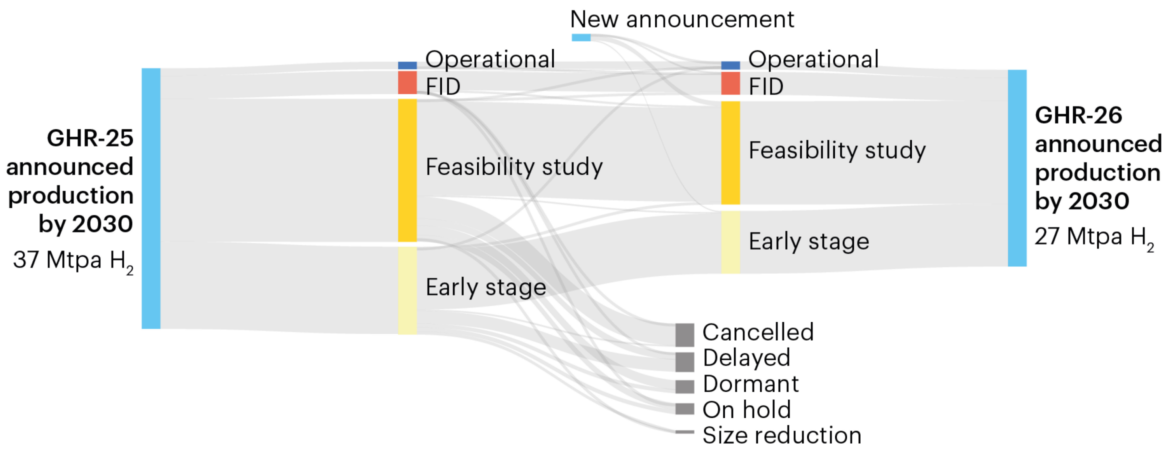
FIDs in low-emissions hydrogen production decreased by 20% in 2025 after two consecutive years reaching around 1 Mtpa.

In the United States, FIDs increased primarily thanks to one large CCUS project for ammonia production for export markets, mostly Japan. More broadly, uncertainty regarding long-term policy support has slowed project development across both electrolysis and CCUS pathways. Even with clearer incentives for CCUS than for electrolysis, such as the 45Q tax credits, investment has been constrained by concerns over future demand, especially in key export markets such as Europe.

The global project pipeline dynamics reflect these challenges (Figure 3.4). Based on announced projects, low-emissions hydrogen production could reach 27 Mt by 2030 – 10 Mt lower than the assessment in the Global Hydrogen Review 2025 (GHR-25). This downward revision is driven by a combination of cancellations (30% of the decrease), project delays post 2030 (25%), projects temporarily paused (15%) and the exclusion from this estimate of projects that have not reported progress in more than 3 years ("dormant" projects). Around half of the decrease comes from gigawatt-scale electrolysis projects targeting exports from both advanced and emerging economies.

The most common reasons for projects to be delayed, cancelled or put on hold are persistently high technology costs in combination with insufficient public support or challenges in meeting criteria for public funding to close the cost gap. These are combined with barriers for permitting (mostly issues with access to the power grid in Europe) and lack of offtake, particularly due to uncertain regulatory frameworks that could otherwise stimulate demand and provide long-term visibility of the hydrogen marketplace.

Figure 3.4 Changes in the project pipeline between the 2025 and 2026 Global Hydrogen Review editions



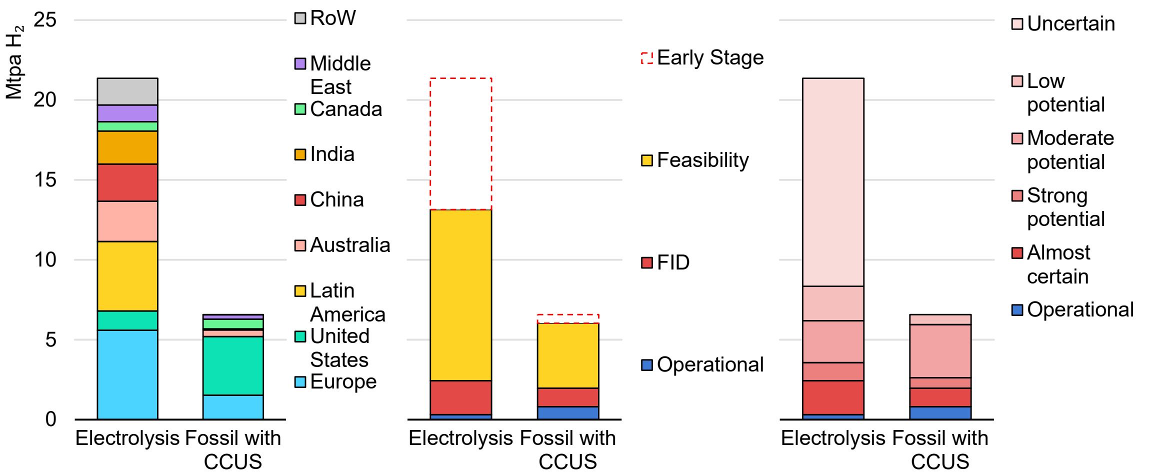
Notes: FID = final investment decision. "Dormant" includes announced projects that have not reported any progress for at least 3 years.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

The project pipeline has shrunk by 10 Mtpa since the GHR-25 due to delays and cancellations, with committed production growing only marginally.

At the same time, production from projects under construction or that have reached FID remained at 3.2 Mtpa. There have been new FIDs, particularly in large electrolysis projects in China and Spain (associated with the use of hydrogen in refineries) and one large-scale CCUS project in the United States. However, a significant share of capacity has entered operation since the GHR-25 (mostly in China) and several electrolysis projects in China that were considered at FID in the GHR-25 have been reclassified as undergoing feasibility study.[39] In addition, some projects at advanced stages have been cancelled – due to financial restructuring, bankruptcy of project partners or operational challenges – although they represent less than 25 kt of potential production by 2030, compared with around 330 kt of new FIDs. As a result, there has been no net increase in the production by 2030 from projects under construction or having reached FID. This production accounts for 12% of the total announced project pipeline.

Committed production (defined as projects that are operational, under construction or have reached FID) by 2030 reached 4.3 Mt, only 3% higher than the estimate in GHR-25. Still, this means that low-emissions hydrogen production could grow from less than 1% of global hydrogen production in 2025 to around 4% in 2030. This is comparable to the case of solar PV one decade ago, which grew from 1% of global electricity production in 2015 to more than 3% in 2020.

Figure 3.5 Low-emissions hydrogen production based on announced projects by technology, region, status and likelihood of operation by 2030



IEA. CC BY 4.0

Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision. RoW = Rest of World. Only planned projects with a disclosed operational start year are included. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Announced projects for low-emissions hydrogen production by 2030 account for 27 Mt, but only 4.3 Mt have committed investment.

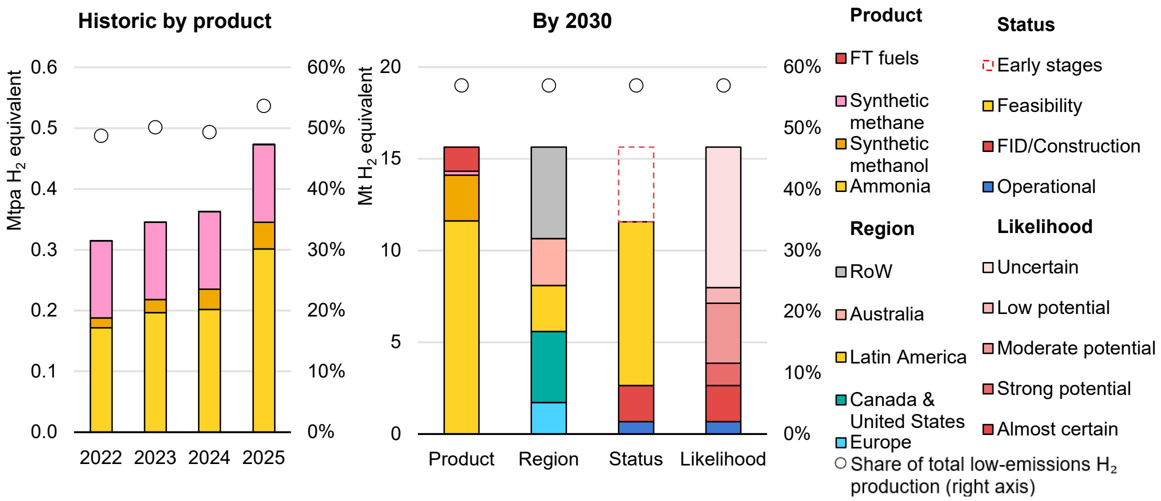
[39] These projects had launched tenders for the purchase of electrolysers or had started with civil engineering works, but after 1 year there has been limited progress or the tenders have been suspended, suggesting that some of these projects were not really at FID yet.

Including projects with strong potential to be operational by 2030, potential production of low-emissions hydrogen by 2030 could increase to more than 6 Mt (Figure 3.5). This is significantly lower than the estimate of the GHR-25, reflecting delays in several large-scale projects that would have required near-term investment decisions to be operational by 2030 and policy uncertainty in some key markets, notably the United States. These trends underscore the importance of strengthening enabling frameworks to accelerate project execution and bridge the gap between announced ambitions and realised capacity.

Hydrogen-based fuels and feedstocks

Hydrogen-based fuels and feedstocks – including ammonia, methanol, synthetic methane and synthetic liquid fuels – accounted for more than half of low-emissions hydrogen production in 2025, mostly to produce ammonia to be used as feedstock in the chemical industry (Figure 3.6).

Figure 3.6 Projects for hydrogen-based fuels and feedstocks, 2022-2025, and announced projects by product, region, status and likelihood of operation by 2030



Notes: FID = final investment decision; FT = Fischer–Tropsch; RoW = Rest of World. 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 (2026), IEA Hydrogen Production Projects Database (June 2026).

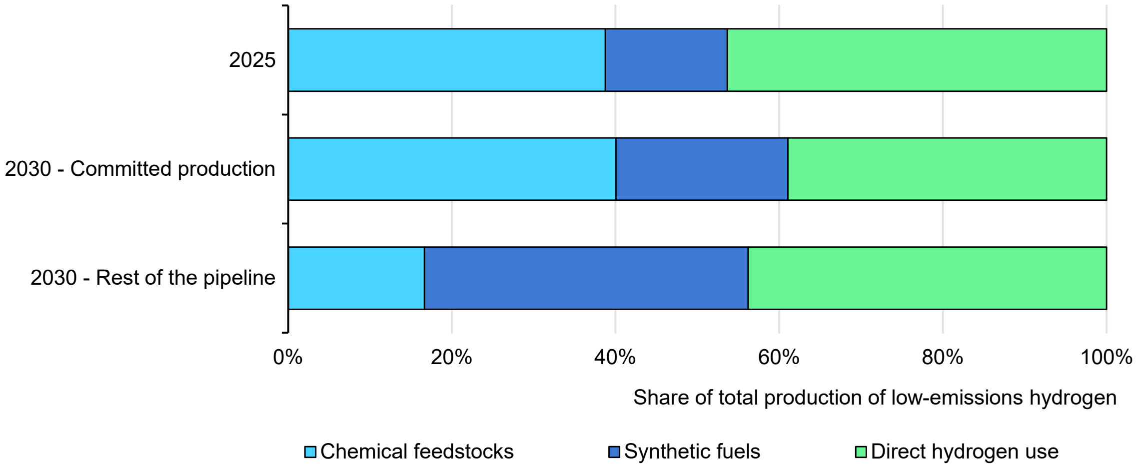
The production of low-emissions hydrogen fuels and feedstock, particularly ammonia, accounts for more than half of the project pipeline.

Based on announced projects, these products are expected to remain extremely important in the hydrogen sector. Almost 60% of announced low-emissions hydrogen production by 2030 is directed towards these fuels and feedstocks. There is also a growing share of announced production targeting fuel applications in sectors like power generation, transport and to be used as hydrogen carriers

(Figure 3.7). This reflects growing interest in new applications such as co-firing of ammonia in power generation (particularly in Japan, Korea and, more recently, China) and the maritime sector, with notable project development activity in China despite ongoing uncertainty around international regulatory frameworks. This indicates a gradual diversification of hydrogen end-uses, driven by both policy support and industry-led initiatives.

This trend is also visible in committed projects, although this is less marked than for the whole of announced production. While the production of ammonia and methanol for chemical feedstocks still accounts for close to 40% of total committed production by 2030 (1.7 Mt), the share of projects targeting fuel applications increases to around 20% (0.9 Mt). The rest of committed production targets the direct use of hydrogen, mostly in refining, steel production and other industrial applications (such as chemicals, ceramics and high-temperature heating).

Figure 3.7 Share of existing and announced low-emissions hydrogen projects targeting the production of chemical feedstocks, synthetic fuels and direct use of hydrogen, 2025 and 2030



Notes: "Chemical feedstocks" include ammonia and methanol production for their use in chemical industry applications; "Synthetic fuels" include synthetic liquid fuels, synthetic methane and the use of ammonia and methanol in fuel applications. "Direct hydrogen use" includes the direct use of hydrogen in refining, industry, mobility, power generation, domestic applications and biofuels production, as well as undisclosed uses.

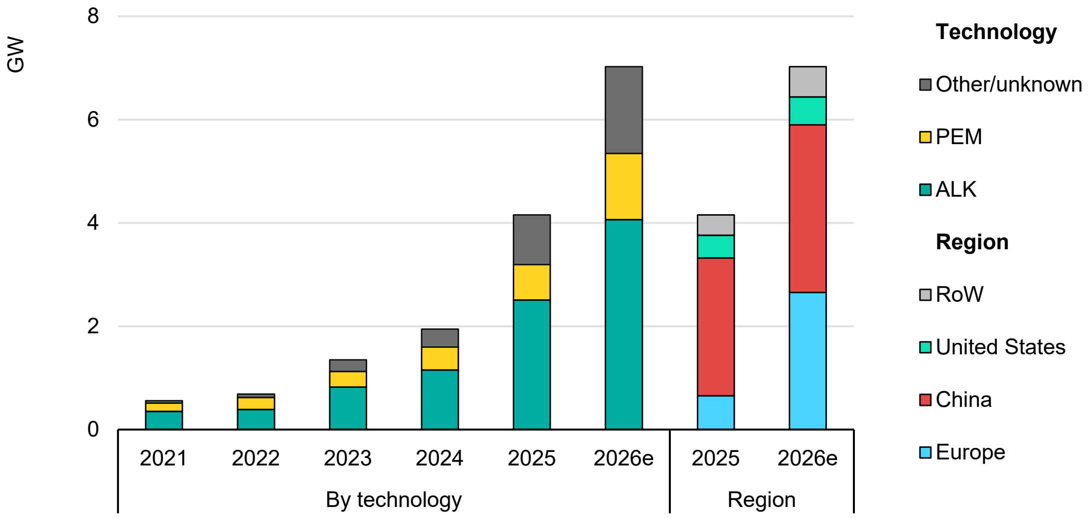
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

The production of synthetic fuels is gaining attention, but the production of chemical feedstocks is expected to remain larger based on committed projects.

Electrolysis deployment

Global electrolysis capacity expanded rapidly in 2025, with installed capacity doubling to exceed 4 GW (Figure 3.8). This is 700 MW lower than the estimate made in GHR-25, mostly due to project delays in China and Europe and a small number of cancellations (around 130 MW).

Figure 3.8 Installed electrolyser capacity by technology and region, 2021-2026e



Notes: ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers; RoW = Rest of World. "Other/unknown" technology includes solid oxide electrolysis, anion exchange membrane electrolysis, other novel designs, projects considering combining different technologies and projects for which the technology used is not known. The unit is GW of electrical input. 2026e = estimate for 2026 capacity, based on projects planning to start operations in 2026 and that have at least reached FID. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Installed electrolyser capacity doubled in 2025, and 2026 is expected to be another year of record growth, driven by China and the first wave of 100+ MW projects in Europe.

Following a temporary slowdown in 2024, the upward trend in annual deployment resumed in 2025. The capacity added last year was three times higher than the previous record set in 2023. This growth was heavily concentrated in China, which accounted for nearly three-quarters of new installations. Europe and the United States each contributed just over 10% of annual additions each, reflecting a more gradual pace of deployment. As a result, China has consolidated its position as the largest market for electrolysis. By the end of 2025, it accounted for around two-thirds of global installed capacity – four times the level observed in Europe, the second-largest market. Outside of the three major markets, some significant innovative projects have also started operation in India (25 MW, for iron production),[40] Uzbekistan (20 MW, for fertiliser production), Japan (16 MW, for heat generation in a distillery) and Namibia (12 MW for iron production). This suggests that, despite being at earlier stages than the three major markets and still more in an experimental phase, electrolysis technologies are also gaining traction in new markets that can contribute strongly to deployment in years to come.

Looking ahead, 2026 is expected to be another record year for electrolysis deployment. At the time of writing, more than 2.5 GW of capacity is under construction worldwide targeting operation in 2026, 90% of which is located in China and Europe. This suggests that the global market will continue to expand rapidly, albeit with a high degree of regional concentration.

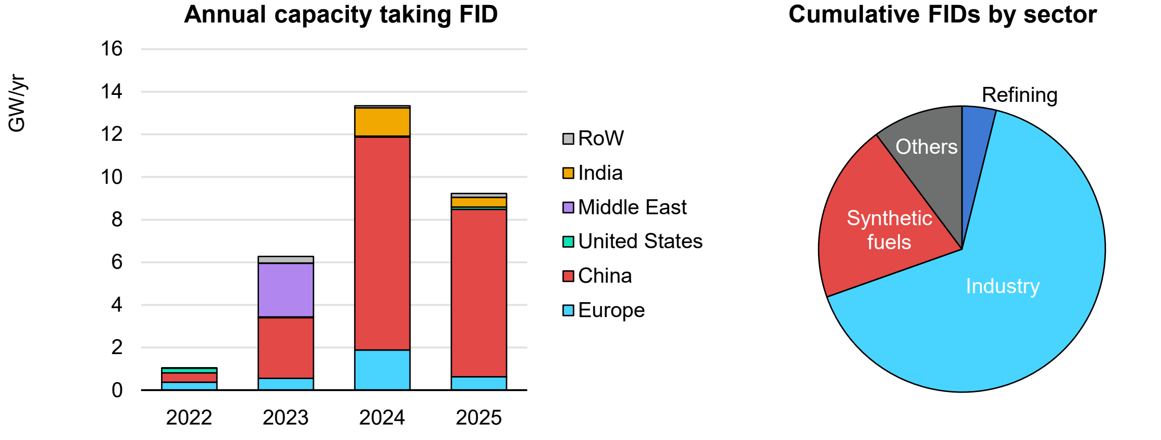
Europe is expected to lead growth this year, with close to 2 GW under construction and scheduled to come online in 2026. The region could see its installed capacity quadruple. In the European Union, installed capacity could reach 2.4 GW by the end of 2026. This is an important scale-up, although it would still represent only around 6% of the 40 GW ambition for 2030 established in the EU Hydrogen Strategy from 2020, which is currently being revised. Much of this progress is linked to projects in the IPCEI programme, which has supported the development of large-scale electrolysis projects, including several installations exceeding 100 MW that are now approaching commissioning.

However, Europe's near-term outlook is partly dependent on the timely delivery of a limited number of large projects. More than one-third of the capacity expected for 2026 is associated with a single project (Stegra) of more than 700 MW. Any delay in its commissioning would shift a substantial portion of capacity additions into subsequent years.

In contrast to the strong growth in installed capacity, investment momentum weakened in 2025 (Figure 3.9). The electrolysis capacity reaching FID declined by around 30% compared with 2024. This decrease was most pronounced in China but was also observed in Europe and India. Underlying causes differ across regions, but the slowdown highlights persistent uncertainties affecting project development.

[40] India's JSW Steel commissions 25-MW renewable hydrogen plant, Platts Hydrogen Daily, 21 October 2025.

Figure 3.9 Capacity reaching final investment decision by region and cumulative capacity with final investment decision by sector, 2022-2025



Notes: FID = final investment decision; RoW = Rest of World. The left figure includes projects that reached FID in the stated year, some of which have already begun operation. The unit is GW of electrical input. "Synthetic fuels" include synthetic hydrocarbon liquid fuels, synthetic methane, as well as ammonia and methanol for energy uses. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Investment momentum weakened in 2025 across all regions, with two-thirds of FIDs targeting industrial uses.

In China, the decline appears to be temporary. The initial wave of FIDs in recent years was driven by the policy framework established under the 14th Five-Year Plan and the Hydrogen Industry Development Plan (2021–35), which focused on building technological capabilities and establishing early supply chains, with a strong focus on fuel cell electric vehicles (FCEVs). Since the second half of 2025, the policy landscape has evolved further, with new measures including CAPEX subsidies, large city-scale demonstration programmes and the designation of hydrogen as a strategic industry in the 15th Five-Year Plan (2026–30), which are expected to stimulate investment in the near term. Importantly, policy priorities are also broadening beyond FCEVs. Renewable hydrogen and hydrogen-based fuels are increasingly seen as key contributors to energy security, particularly in reducing reliance on fossil fuel imports in industrial sectors. In March 2026, the central government launched a CNY 8 billion (Yuan renminbi) (USD 1.1 billion) programme aimed at stimulating demand across multiple applications, including ammonia and methanol production, steelmaking, industrial heating and heavy-duty transport. These developments are expected to support a renewed increase in investment activity in the near term.

In Europe and India, however, the investment outlook remains more uncertain, particularly due to limited visibility on demand. The slow transposition of the RED targets for RFNBOs has created uncertainty for project developers in Europe, especially those targeting industrial applications. Projects aimed at industrial use have struggled to progress to FID and several such projects have been cancelled due to the lack of clarity on future demand. On the other hand, 70% of the capacity reaching FID in 2025 was associated with refining, particularly in countries where the use of renewable hydrogen in refining can count against the RFNBO target for transport, for which transposition into national legislation is much more advanced.

In India, initial progress has been made through the results of the government tender for renewable ammonia supply to fertiliser plants. In March 2026, 11 of the 13 supply contracts awarded in the auction were signed, with the other 2 contracts being cancelled since the off-takers pulled out.[41] However, challenges in terms of public funding to cover the cost gap with unabated fossil-based routes still persist (see Chapter 2). Outside these markets, activity remains limited, and no significant developments beyond demonstration projects are expected in the near term.

The global project pipeline for electrolysis stands close to 320 GW by 2030, approximately 30% lower than in GHR-25 (Figure 3.10). This reduction is largely attributable to delays and cancellations in large-scale, trade-oriented projects announced in the early 2020s. Most of these projects have been postponed or cancelled due to slower-than-expected development of international markets for hydrogen and its derivatives. Further downward revisions are likely, given that around 240 GW of capacity (75% of the global pipeline) is considered to have low likelihood or uncertain prospects of being operational by 2030.

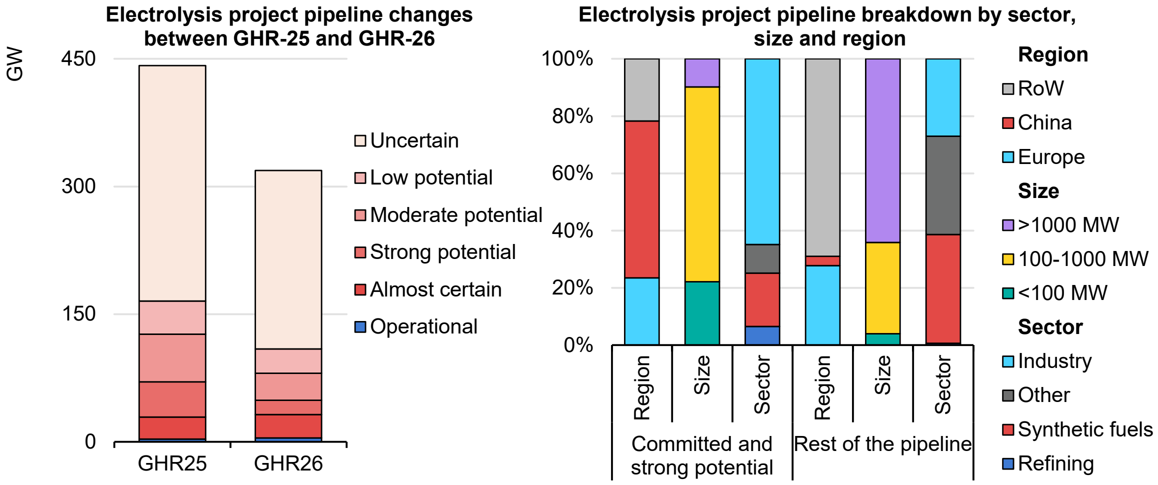
Project lead times represent an additional constraint. The time required from FID to operation typically ranges from 1 to 4 years, depending on project size, technology and location. This implies that most projects above 1 GW (60% of the announced capacity by 2030) that have not yet reached FID are unlikely to be operational before 2030. By comparison, for the assessment in the GHR-25, some of these projects were considered to have moderate potential to be operational by 2030. In the short term, further reductions in the pipeline can be expected if projects do not reach FIDs quickly. There is more than 100 GW of capacity in announced projects with sizes between 100 MW and 1 GW that could lose all chances of being in operation by 2030 if investment decisions are not taken in 2026 or 2027.

Despite these challenges, there are positive signs. Almost 28 GW of capacity has already reached FID (7% higher than in the GHR-25) and is targeting operation by 2030. An additional 17 GW has strong potential to become operational within this timeframe, provided adequate policy support to close the cost gap with unabated fossil-based production is in place and demand creation policies are implemented. The implementation of demand-side policies targeting sectors that are more ready to adopt low-emissions hydrogen and hydrogen-based fuels in the near term will be

[41] Two Indian green ammonia tender buyers withdraw, Argus Media group. All rights reserved.

particularly important. Refining, industry and the production of hydrogen-based fuels accounts for 85% of committed capacity and almost 100% of the announced capacity with strong potential to be operational by 2030.

Figure 3.10 Changes in the electrolysis project pipeline between the 2025 and 2026 editions of the Global Hydrogen Review and capacity breakdown by sector, size and region



Notes: RoW = Rest of World. "Committed and strong potential" includes projects that are operational, under construction, that have reached final investment decision (FID), and the projects without FID that have strong potential to become operational by 2030. "Synthetic fuels" include synthetic hydrocarbon liquid fuels and synthetic methane, as well as ammonia and methanol for energy uses. The unit is GW of electrical input. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Announced electrolysis capacity by 2030 decreased by 30% compared to in the GHR-25, but 50 GW have strong potential to be operational by 2030 – 10 times more than today.

Electrolysis manufacturing and cost

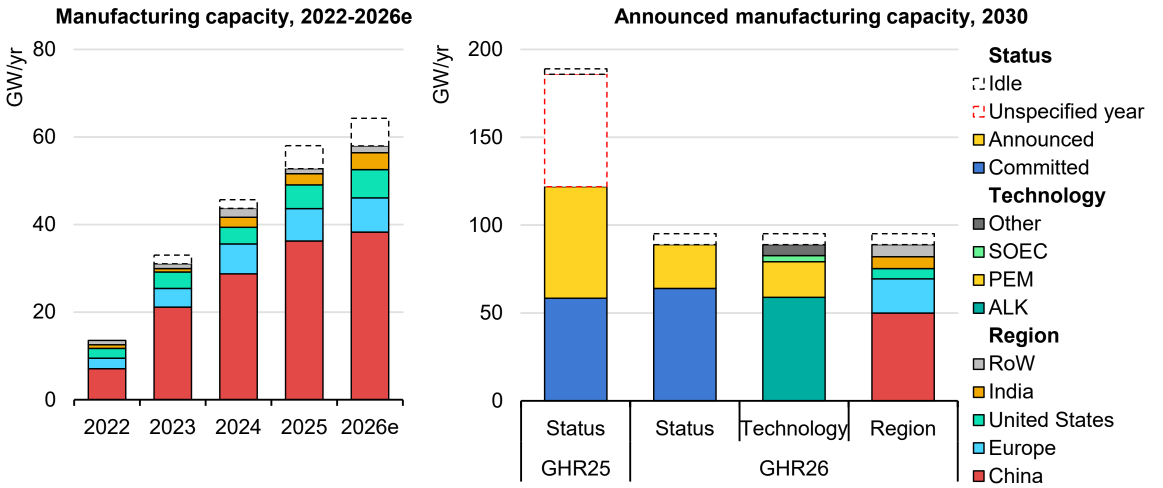
Manufacturing

After years of rapid expansion, electrolyser manufacturing is now entering a consolidation phase. Global manufacturing capacity increased from 46 GW/yr in 2024 to nearly 58 GW/yr in 2025 (Figure 3.11), but growth is expected to slow in the coming years, with capacity additions largely resulting from the gradual build-out of facilities announced earlier in the decade. This reflects slower than anticipated market development, which has resulted in considerable overcapacity, with an estimated output of less than 5 GW in 2025.[42] This trend is likely to persist towards 2030, as the available manufacturing capacity exceeds the expected annual

[42] This estimation includes manufacturing of electrolysers for the chlor-alkali industry, which has been traditionally the core market for electrolysers, as well as electrolysers manufactured for dedicated production of hydrogen, which is now the largest market for electrolysers.

electrolyser deployment, estimated at an average of 9 GW based on projects that have reached FID or show strong potential to be realised. China accounts for 60% of the global manufacturing capacity, followed by Europe (20%), and the United States (10%). India's capacity is expanding quickly, driven by ambitions to develop a domestic manufacturing ecosystem, though it still heavily relies on imports of key components such as membranes, catalysts and bipolar plates.

Figure 3.11 Electrolyser manufacturing capacity by region, 2022-2026e, and announced capacity additions by region, technology and status, 2030



Notes: ALK = alkaline electrolyser; PEM = proton exchange membrane; SOEC = solid oxide electrolysis cell; ROW = Rest of World; GHR = Global Hydrogen Review; 2026e = estimate for 2026 based on projects already under construction that target commencing operations in 2026. "Committed" refers to capacity that is operational, under construction or with final investment decision (FID).

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

Electrolyser manufacturing capacity is entering a period of consolidation, as overcapacity, weak demand and financial strain cause a rethink.

Headwinds from projects struggling to reach FID in 2025 pushed the industry into a delicate phase, testing the resilience of electrolyser original equipment manufacturers (OEMs). Liquidity constraints have become increasingly critical, with many OEMs reporting widening losses as revenues lagged upfront investments in manufacturing capacity. Well-capitalised firms – often with diversified revenue streams – are better positioned to navigate these fluctuations. Early signs of this dynamic can be seen in the acquisition of assets from bankrupt firms, which may contribute to a gradual consolidation of the industry around a smaller number of financially robust players. By contrast, financially constrained players may be forced to scale back or exit the market. Of the 58 GW/yr of available manufacturing capacity, about 64% is held by large firms with diversified business lines, while the remaining 36% belongs to companies specialised in the hydrogen sector, which face higher exposure to market volatility. The financial distress faced by these OEMs also poses a risk to cost-reduction trajectories, as the exit of firms during this stage of market development could weaken the industry's innovation pipeline.

Some OEMs have responded to the current market headwinds by reassessing their business strategies. Notably, Cummins Inc. has announced a halt to electrolyser sales after fulfilling existing orders. By contrast, signs of possible renewed momentum began to emerge towards the end of 2025, supported by strengthening demand in Asia. For example, membrane producer Agfa-Gevaert N.V. reported a 22.1% increase in fourth-quarter 2025 sales compared with the same period in 2024, largely driven by Asian markets, contributing to a 3.7% annual increase.

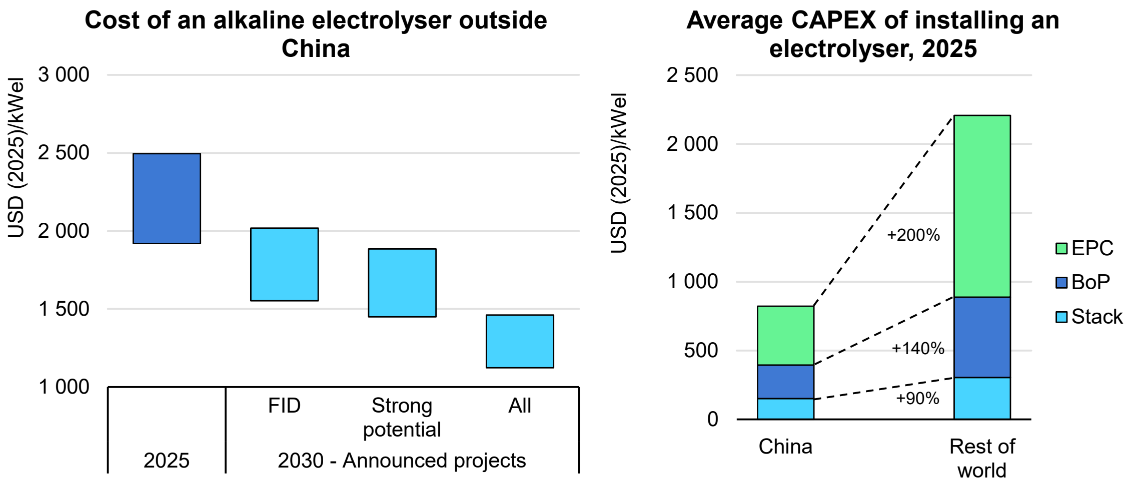
In the European Union, the ongoing transposition of the RED III mandates into national legislation (see Chapter 7) is an important step towards creating more predictable revenue conditions for OEMs. The proposed Industrial Accelerator Act (IAA) signals the European Union's intention to strengthen domestic manufacturing, requiring projects receiving EU support to use electrolysers of "Union origin". However, the definition of "Union origin" extends beyond the European internal market, including, for auctions, products from third countries with which the European Union has established a free trade area or a customs agreement, and, for procurements, countries that are parties to the Agreement on Government Procurement as well. Mandating higher-cost European equipment introduces a trade-off between supporting domestic manufacturing and hydrogen production costs, potentially slowing project deployment. However, the overall impact on the levelised cost of hydrogen is likely to remain limited, as electricity and engineering, procurement and construction (EPC) costs (which are largely driven by domestic factors) typically outweigh electrolyser CAPEX. In parallel to the IAA, several EU member states have announced support for electrolyser manufacturing under the Clean Industrial Deal State Aid Framework.

Based on announced expansion plans, global electrolysis manufacturing capacity could reach nearly 95 GW/yr by 2030. This estimate excludes announced expansions without a specified commissioning year or location, which are considered unlikely to be realised by 2030 given slow market development. As a result, the projected capacity is approximately 90 GW/yr lower than in GHR-25. The committed capacity (i.e. under construction or having reached FID) totals 64 GW/yr, although capacity additions largely reflect investment decisions made earlier in the decade. The committed capacity would be sufficient to meet demand from the entire project pipeline, corresponding to an average annual deployment of approximately 60 GW, although this would require significantly higher factory utilisation rates than observed today. When considering only projects that have reached FID or show strong potential to be realised, the average annual deployment falls to 9 GW, resulting in a continuing trend of manufacturing overcapacity. More than half of the announced capacity is expected to be in China, although this remains a smaller share than for other clean technologies such as solar PV and batteries. Alkaline systems are expected to remain the leading technology, being the preferred option among Chinese OEMs. Proton exchange membrane (PEM) manufacturing is set to nearly double by 2030, led by Europe, though manufacturing volumes remain far lower than those of alkaline systems.

Cost of electrolysers

Electrolysis is a very capital expenditure (CAPEX)-intensive technology, and a reduction in the cost of the equipment will be essential in order to facilitate widespread deployment. In the early 2020s, the strong momentum around hydrogen brought hopes for fast deployment and scale-up that could enable rapid cost reductions of the technology, as has been seen for other clean energy technologies in recent years. However, this has been the case only in China, while in the rest of the world, slower-than-expected electrolyser deployment is limiting the anticipated cost reductions towards 2030.

Figure 3.12 Cost of electrolysers manufactured outside of China in 2025 and 2030 based on the level of deployment and breakdown of capital expenditure on electrolysers manufactured in China and rest of the world, 2025



Notes: "EPC" = engineering, procurement and construction; "BoP" = balance of plant; "FID" refers to the capacity deployed according to announced projects that have at least reached final investment decision (FID), which is 32 GW by 2030. "Strong potential" refers to the capacity deployed according to announced projects that have at least reached FID and the projects without FID that have strong potential to become operational by 2030, which is 50 GW by 2030. "All" refers to the capacity deployed according to all announced projects, which is 320 GW by 2030. The learning rate for the electrolyser stack is assumed at 13%, while for the other components of the balance of plant it is 2-5%. For the EPC costs, a learning rate of 8% has been assumed.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers; data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved; IEA (2026), IEA Hydrogen Production Projects Database (June 2026); IEA (2024), Advancing Clean Technology Manufacturing.

Lower-than-expected deployment is preventing cost reductions, apart from in China, where large-scale manufacturing and project development have driven down CAPEX.

In 2025, the cost of installing an electrolyser made in the West (including the equipment, gas treatment, plant balancing, and EPC cost, and contingencies) outside China remained broadly in line with the cost in 2024, ranging between USD 1 900/kW and USD 2 500/kW (Figure 3.12). This remains significantly higher than the cost of installing a Chinese electrolyser in China, which ranged between USD 500/kW and USD 1 100/kW, while the cost difference is far smaller for Chinese electrolysers installed outside of China, given that EPC and contingency costs make up a large share of costs.

This difference is based on the lower cost of manufacturing the stacks and components in China, largely due to access to cheaper materials, economies of scale and optimised supply chains, but also due to the experience and learnings gained through the deployment of large-scale projects, which has led to lower costs for the balance of plant and for EPC. Chinese electrolysers have traditionally suffered from lower efficiencies and more performance issues than electrolysers manufactured outside China, but both government and OEMs in China have taken action to solve these issues. In March 2026, the Chinese government set a performance target for mass-manufactured electrolysers and is planning to implement mandatory national standards for energy efficiency in electrolysers.[43] In parallel, OEMs are announcing a new wave of more efficient products that are able to meet international standards.

However, the large overcapacity in China has stimulated fierce competition, with numerous manufacturers offering prices below the cost of manufacturing of the stack and the balance of plant, sacrificing profits to gain market share (see section on China). This suggests that, although still large, the cost gap between electrolysers made in China and those made elsewhere is likely to be smaller than it first appears. In addition, several western electrolyser manufacturers have made claims that their next wave of products, coming to market after important innovation efforts along with scale-up and full utilisation of giga-scale manufacturing sites, can deliver significant cost reductions and even make them competitive against Chinese competitors. For example, Electric Hydrogen (EH2) has developed the HYPRPlant modular plant, based on proprietary PEM electrolyser technology, targeting CAPEX around USD 1 000/kW in the Infinium Roadrunner project, currently under construction in the United States and targeting operation in 2027. ITM Power has launched the new 50 MW PEM electrolysis system Alpha 50, with a cost of around USD 1 200/kW. Sunfire has announced the new 50 MW pressurised alkaline electrolyser system HyLink® Alkaline 23, claiming up to 50% reductions in the total installed costs. Nel ASA has presented its next-generation pressurised alkaline electrolysis systems, with estimated CAPEX below USD 1 450/kW for a 25 MW plant. Stiesdal Hydrogen has introduced a new 6.5 MW HydroGen Electrolyser, targeting CAPEX at roughly

[43] China sets H_2 electrolyser efficiency targets for 2028, Argus Media Group, All rights reserved (20 March 2026).

half the current European market average. Nevertheless, these figures remain based on company announcements and have yet to be demonstrated at scale in commercial deployment.

Realising this potential cost reduction hinges on an increase in orders for electrolysers to enable high utilisation factors of the available manufacturing capacity, learning through experience in the development or larger projects, and sustained innovation efforts. However, electrolyser projects are still struggling to secure FIDs and orders, and therefore deployment is still lagging.

Based on the deployment that can be achieved with projects that have already reached FID and those that have a strong potential to be online by 2030, we estimate that the cost of manufacturing and installing an electrolyser outside China could fall to a range of USD 1 500-1 900/kW by 2030, approaching China's 2025 cost range. If all announced projects materialise, this could drop further to USD 1 100-1 500/kW, although achieving this level of deployment seems unlikely (see Electrolysis deployment). If slower deployment limits the scale-up needed to deliver cost reductions, costs would fall less than expected, further weakening project economics in a self-reinforcing dynamic.

In addition, the fallouts of the ongoing energy crisis may affect the decline in electrolyser costs. The inflationary trends following Russia's full-scale invasion of Ukraine significantly increased the CAPEX of manufacturing and installing electrolysers, due to severe increases in the cost of materials, services and labour, which reduced the speed at which the technology was adopted. The conflict in the Middle East could have similar consequences. Although the situation remains highly uncertain, central banks, including the European Central Bank and the Federal Reserve, have highlighted that geopolitical tensions in the Middle East can increase inflation risks. Inflation could limit, or potentially even prevent, further reductions in the cost of electrolysers in the short term. The impact of inflation on future cost reductions would not be limited to electrolysers. However, other clean energy technologies that have already reached cost-competitiveness with fossil-based alternatives in several markets, such as solar PV and batteries, can more easily absorb cost inflation with a more moderate impact on deployment. By contrast, in the case of renewable hydrogen, which remains more expensive than unabated fossil fuel-based production, inflation can significantly increase the investment barrier and reduce the speed of deployment.

China's expanding electrolysis landscape

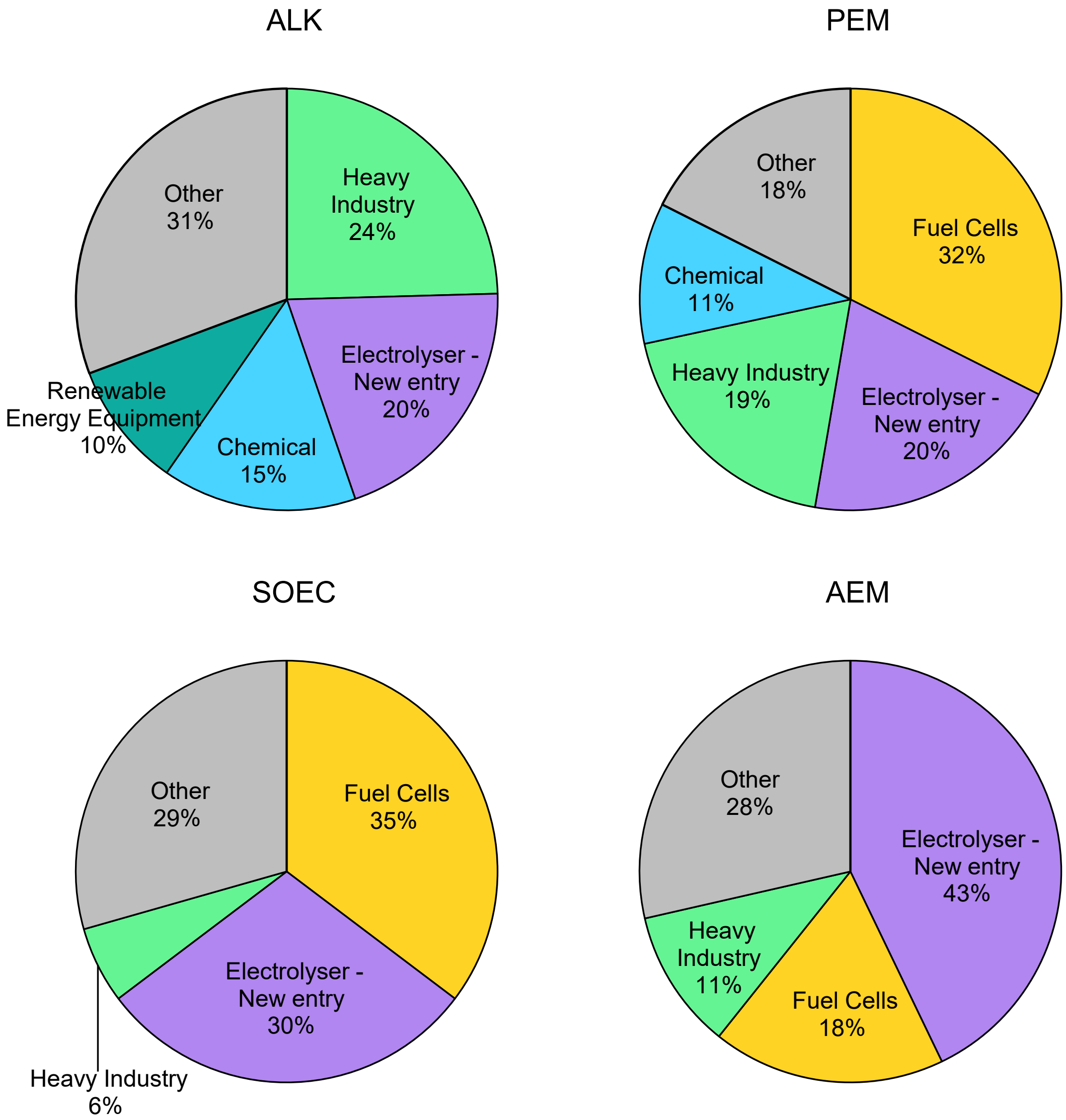
As the world's largest manufacturing base for electrolyser systems, with capacity of more than 35 GW/yr, China is now widely seen as the main driver of cost reductions in electrolysers globally. Nonetheless, Chinese players are increasingly vulnerable to unsustainable internal competition, known in China as "involution", as detailed below.

China's electrolyser industry has been growing since 2021 – when the 14th Five-Year Plan (2021-2025) and the subsequent Hydrogen Industry Development Plan (2021-2035) cemented hydrogen as a frontier area for focused advancement. While national deployment targets were relatively moderate, setting renewable hydrogen production at 100-200 kt by 2025, ambitious provinces such as Inner Mongolia accelerated hydrogen initiatives and crafted a pilot-project-driven demand base for electrolysers. Policy momentum has ushered in a surge in the number of electrolyser manufacturers over a short period of time. To date, nearly 200 companies, at least, claim electrolyser manufacturing capability. Technologies range across alkaline, PEM, solid oxide electrolysis cell (SOEC) and anion exchange membrane (AEM) – and are primarily alkaline, which has a combined capacity of over 32 GW/yr, and for which nearly half of manufacturers were founded after 2021. The newer technologies remain much smaller: PEM stands about at 2.5 GW/yr, compared to SOEC with 0.1 GW/yr and AEM at less than 0.1 GW/yr at the end of 2025.

Market composition

The influx into alkaline technologies comes from heavy industrial equipment manufacturers, with strengths in large-scale plant engineering (Figure 3.13). These players alone account for 40% of existing alkaline capacity. Renewable energy equipment providers, though fewer in number, contribute nearly one-third of total capacity, making these two groups dominant in installed capacity. Independent electrolyser makers are also present, mostly focused exclusively on alkaline electrolysers; some offer integrated systems with balance-of-plant components rather than stacks alone. In contrast, the largest group of new PEM entrants are from the fuel cell sector, building on their expertise in membrane technologies to expand both upstream and downstream in the hydrogen value chain, particularly as FCEV deployment in China has fallen short of its target as of 2025. Entry into SOEC manufacturing is likewise led by firms from the fuel cell industry, and most remain highly concentrated in SOEC, rather than diversifying into alkaline, PEM or AEM. Compared with the other technologies, AEM has the highest share of dedicated entrants, predominantly composed of start-ups founded after 2021, with some already transitioning from component-level R&D stage towards early commercialisation.

Figure 3.13 Industry origin of electrolyser manufacturers in China, by company count, 2025



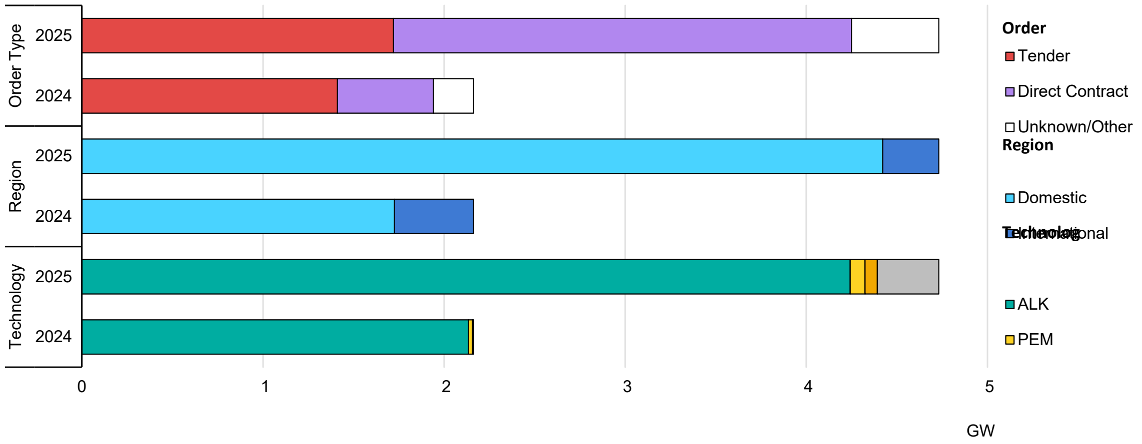
Note: AEM = anion exchange membrane electrolysers; ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers; SOEC = solid oxide electrolyser cell. Industry origin categories are defined based on the companies' primary business activities. Electrolyser - New entry denotes companies established in the 2020s with no identifiable prior industrial base (e.g. independent start-ups). Companies affiliated with existing industrial groups are classified according to the primary business of the parent group.

Sources: IEA analysis based on data from Energy Iceberg, and publicly available company information.

Industry origin patterns of electrolyser manufacturers show distinct entry pathways.

Despite there being nearly 200 companies in the market, electrolyser orders are heavily concentrated. In 2025, China's electrolyser manufacturers secured orders of 4.7 GW, with over 90% (4.4 GW) driven by domestic demand and the remainder for export (Figure 3.14). Aggregated confirmed orders show that the top ten companies by received orders account for approximately 70% of total volumes, while more than two-thirds of manufacturers secured no single order (Figure 3.15). Market share heavily depends on winning large-scale projects, which are not always awarded through tenders. Last year saw a pronounced rise in direct contracting, typically for large alkaline projects, such as the 1 GW-scale deployment of electrolysers through a bilateral strategic partnership. This contrasts with 2024, when tender-based orders represented 70% of secured volumes (if excluding cases with undefined routes).

Figure 3.14 Electrolyser orders secured by Chinese manufacturers by technology, region and order type, 2024-2025



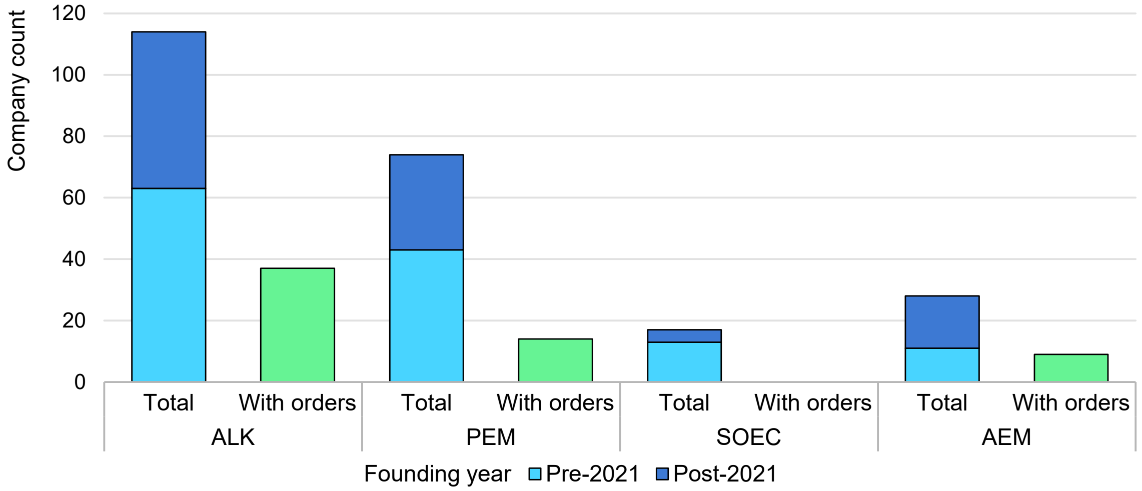
Notes: AEM = anion exchange membrane electrolysers; ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers. “Unspecified/Mixed” refers to orders for which the technology type is not reported or hybrid configurations (e.g. ALK/PEM) where the breakdown by technology is not disclosed. “Domestic” refers to orders supplying demand within China; “International” refers to orders exporting outside China.

Sources: IEA analysis based on data from Energy Iceberg, announcements of tender results and orders.

China secured 4.7 GW of electrolyser orders in 2025, mainly for domestic delivery and for alkaline technologies.

Notably, tenders enabled broader participation, with more than 30 winning manufacturers in 2025, roughly twice as many as through direct contracts (including e.g. strategic partnerships). Yet the latter pathway accounts for much larger total volumes, resulting in market concentration shaped more by a few mega projects than by manufacturers. If these large-scale direct contracts stay dominant in the market, OEMs that currently have no orders are at high risk of exiting. Fewer tender opportunities may lead to natural market consolidation around established players.

Figure 3.15 Number of Chinese electrolyser manufacturers by founding year and companies with secured orders, 2025



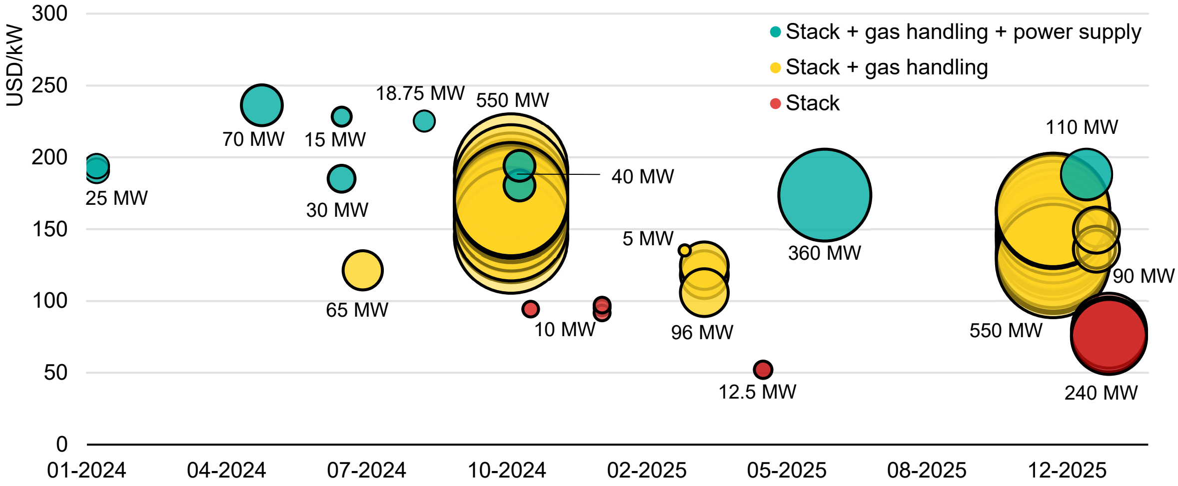
Notes: AEM = anion exchange membrane electrolysers; ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers; SOEC = solid oxide electrolyser cell. "Company count" includes double counting of OEMs across alkaline, PEM and AEM technologies. No confirmed orders for solid oxide electrolysers were reported by Chinese electrolyser manufacturers in 2025.

Sources: IEA analysis based on data from Energy Iceberg, announcements from individual companies and order records.

China's electrolyser market has gained many new entrants since 2021 yet fewer than one-third succeeded in winning orders in 2025.

Nevertheless, the significant imbalance between manufacturing capacity (more than 35 GW/yr) and booked demand (4.7 GW in 2025), has driven price erosion in China's electrolyser landscape. Based primarily on tender results, alkaline electrolyser unit price continued declining through to the end of 2025, pushing stack-only bids below USD 80/kW, equivalent to one-quarter of the reference price range (USD 290-380/kW) outside of China, while full-package systems sit around USD 170-200/kW and stack-with-gas-handling to USD 100-170/kW range (Figure 3.16). These structural pressures are becoming visible, such as in the case of GuofuHee, an electrolyser supplier with 3.5 GW/year of manufacturing capacity. In March 2026, the company raised discounted equity after loss alerts due to weaker hydrogen demand, primarily to strengthen working capital and repay credit facilities. This suggests that price cutting is beginning to weigh on equipment suppliers, especially for standalone manufacturers, compared to entrants with larger financial buffers.

Figure 3.16 Alkaline electrolyser unit price in China, 2024-2025



Notes: The x-axis indicates the date of award or order announcement. Values are expressed in nominal dollars. All data points are from tender results, except for the 360 MW entry. Colours indicate the scope of electrolyser supply. Circle size represents the capacity (MW).

Sources: IEA analysis based on announcements of tender results and orders in China.

Prices for alkaline electrolysers in China continue to fall steadily due to overcapacity.

Dynamics beyond involution

Amid fierce domestic price competition, leading manufacturers are broadening international engagements, despite exports representing less than 7% (just over 300 MW) of total orders in 2025. In January 2026, LONGi hydrogen, the subsidiary of a global solar module manufacturer, delivered its first 5 MW alkaline system to Europe, fully compliant with Europe's safety and pressure equipment regulations. Sungrow Hydrogen, an arm of China's PV-inverter group, delivered 160 MW for a renewable ammonia project in Oman, and signed an 80 MW electrolyser contract in Kenya. PERIC, part of a state-owned heavy industrial group, has entered an exclusive OEM licence agreement allowing Metacon to manufacture its alkaline electrolysers in Europe. GuofuHee launched an electrolyser plant in April 2026 through a German joint venture.

At the same time, the industry has begun to take collective action. In November 2025, 40 electrolyser manufacturers jointly signed the "China Electrolyser Industry Healthy Development Initiative", with commitments to pivot from a volume-driven growth strategy to high-quality development and to stabilise both domestic and international markets. As a first step, the initiative has called for an end to below-cost bidding, which drains the long-term foundations of R&D. Also critical is the commitment to eliminate overstating performance, in cases where units fail to meet efficiency and output targets under actual operating conditions, typically in off-grid renewable projects, such as the Sinopec Kuqa project.

Meanwhile, policy signals for the hydrogen sector remain strong under the 15th Five-Year Plan (2026-2030), in which hydrogen is presented as a future industry to drive economic growth. This was followed by the city-cluster demonstration programme launched in March 2026. This new framework has a dual emphasis – not only on expanding demand applications through incentives, but also on raising technical standards. For instance, technical criteria for renewable ammonia/methanol production projects include both stack-level energy efficiency requirements for electrolysers and project-level operational flexibility under renewable power, suggesting a shift towards scale-up with improved equipment standards. Other policies from China also point to a broader focus on performance. The first list of key pilot-scale testing platforms for clean hydrogen, issued in June 2025, features MW-scale pre-commercial electrolysis testbeds for performance validation and long-term operational data collection. This was followed by the release of GB/T 46104-2025, which standardises testing metrics and methodologies for the adaptability of Alkaline and PEM electrolysers under fluctuating power. In March 2026, four authorities, including the Ministry of Industry and Information Technology, issued a plan that not only sets an efficiency target for electrolysers to meet by 2028 but also aims for greater adaptability under actual variable load conditions.

Industry practice has already moved in the same direction. In December 2025, a project for the production of renewable ammonia and methanol began operation in Songyuan, using ALK-PEM hybrid systems to absorb renewable intermittency. This project was recognised by the National Energy Administration among the technological achievements of the year, paving the way for flexible system integration as deployment scales. There is also a wave of PEM upscaling toward the 500 Nm^3/h size, as exemplified by state-owned manufacturer Dongfang Electric, which claimed in March 2026 to have developed a PEM stack with an energy efficiency of 4.2 kWh/Nm^3 at 3 A/cm^2.

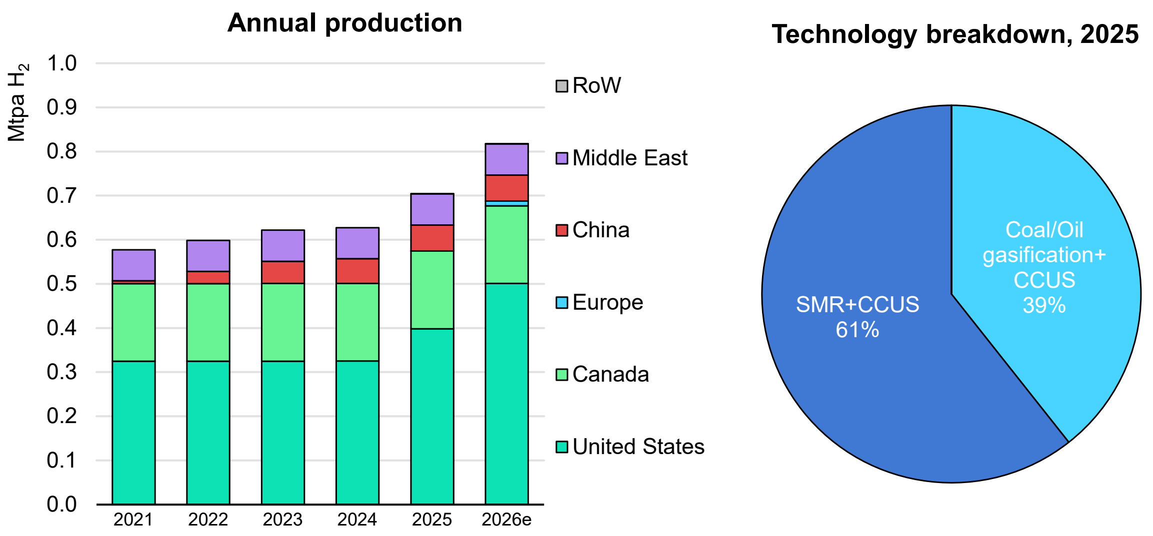
Taken together, these developments show that China's electrolyser sector is moving into a new phase where price alone no longer defines competitiveness. Increasingly rigorous actual-performance oriented requirements, coupled with testing platforms, should lay a foundation for credible performance assessment and clearer differentiation among technologies and suppliers based on their diverse technical origins. As project-driven demand begins to reflect these expectations, electrolyser manufacturers will be better positioned to compete on demonstrated efficiency, durability and system integration capability rather than on margin-eroding price alone.

Fossil fuels with CCUS

Low-emissions hydrogen production from fossil fuels combined with CCUS expanded in 2025. Growth was driven primarily by the commissioning by CF Industries of a carbon capture plant to retrofit its large-scale ammonia and fertiliser production facility in the United States. This will allow to capture and permanently store up to 2 Mtpa of CO_2.

As a result, global production of low-emissions hydrogen from fossil-based pathways reached 0.7 Mt in 2025 (Figure 3.17). Around 60% of this output was produced via natural gas reforming, while the remainder originated from coal and oil gasification. In total, installed CO_2 capture capacity across these facilities reaches close to 13 Mtpa, equally divided between facilities running on natural gas and those running on coal and oil. Although gasification routes contribute a smaller share of hydrogen production, these facilities typically capture larger quantities of CO_2 due to the higher carbon intensity of the underlying processes.

Figure 3.17 Production of low-emissions hydrogen from fossil fuels with carbon capture, utilisation and storage, 2021-2026e



Notes: CCUS = carbon capture, utilisation and storage; SMR = steam methane reforming; RoW = Rest of World. 2026e = estimate for 2026, based on projects planned to start operations in 2026 that have at least reached FID. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Low-emissions hydrogen production from fossil fuels grew more than 10% in 2025, driven by a single new large-scale project starting operations in the United States.

Deployment is expected to grow further in 2026, driven by the ramp-up of production in the CF Industries project that began operation in 2025 and two new facilities coming online in France and the Netherlands. Deployment had previously been expected to accelerate further this year, but delays in five projects in the United States,[44] Europe and the Middle East has pushed back this growth at least until 2027. However, even with this delay, the deployment of hydrogen production from fossil fuels with CCUS is expected to significantly accelerate in 2026 and 2027 compared with historical trends. Between 2013 and 2025, a total of 16 projects with a combined capacity of approximately 600 ktpa entered operation. In contrast, more than 500 ktpa of capacity could be added between 2026 and 2027 alone by just seven projects, reflecting both increasing project scale and improved deployment momentum.

The United States is expected to remain the largest producer of low-emissions hydrogen from fossil fuels with CCUS in 2026, supported by the ramp-up of the CF Industries project. However, project execution challenges continue to affect timelines. For instance, an ammonia facility that began operations in 2025 has faced delays in integrating low-emissions hydrogen from a neighbouring autothermal reforming unit due to construction and operational issues. As a result, its operation is now expected to occur after 2026.

At the same time, production is beginning to diversify geographically. Europe is poised to host its first large-scale facility, which has been realised through a combination of regulation, common infrastructure developments and policy support. The Yara Sluiskil project is expected to start operating at the end of this year in the Netherlands, following a retrofit to an ammonia production facility. The CO_2 captured in the plant will be stored in the Northern Lights CCS project in Norway (which received direct support from the Norwegian government in 2022). Regulatory drivers, like the decision to gradually phase-out free allowances for fertilisers in the EU Emissions Trading Scheme (ETS) as the Carbon Border Adjustment Mechanism (CBAM) entered into force, also helped this project to reach FID back in 2023. Three other projects were previously expected to start operating in the Netherlands this year, all of them linked to the use of hydrogen in refineries (another sector within the scope of the EU ETS). All three are linked to the Porthos CO_2 transport and storage infrastructure in the Port of Rotterdam, and have secured long-term carbon contracts for difference provided by the Dutch government though the SDE+ programme, which has reduced revenue uncertainty and facilitated investment decisions. However, the start-up of the Porthos infrastructure has been delayed until the second half of 2027.

Looking ahead to 2030, prospects remain moderately positive. Based on committed projects, hydrogen production from fossil fuels with CCUS is expected to more than double, reaching close to 2 Mt by 2030 (Figure 3.18). This additional

[44] Woodside delays Texas blue ammonia on H2 supply slip, Argus Hydrogen and Future Fuels Issue 26-11.

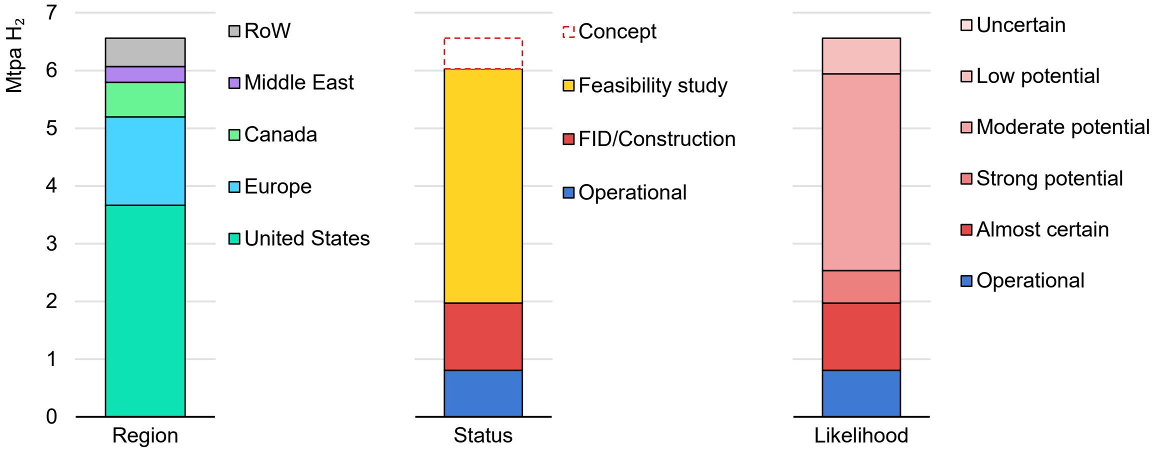
capacity is concentrated in North America, where the availability of tax incentives for carbon capture has strengthened project economics and facilitated access to financing.

However, the commercial viability of most projects depends on export markets, particularly for ammonia. Several projects in the United States and Canada are targeting supply to international markets, particularly Japan and Europe. These projects rely on the creation of markets for low-emissions products, which is occurring through policy instruments such as the contracts for difference (CfD) scheme in Japan and the CBAM in the European Union to support competitiveness. The CfD scheme in Japan has been fundamental in enabling the world's only FID in 2025 for a CCUS-enabled project: the Blue Point Project. This is a joint venture between CF Industries, JERA and Mitsui & Co., and both Japanese companies have been awarded CfDs, along with preferential loans to finance the project (see Chapter 2).

In the case of the CBAM, recent policy discussions have introduced uncertainty about its potential to support low-emissions hydrogen projects. After agriculture ministers raised concerns over food price inflation, in December 2025 the European Commission proposed an emergency mechanism that would allow the temporary suspension of CBAM coverage for specific goods such as fertilisers in the event of severe market disruption. The Commission also clarified that such a suspension could apply retroactively if adopted. The provision requires approval by the European Parliament (which in April 2026 presented a proposal to push back on the temporary suspension, which still needs to be voted) and the Council. Meanwhile, the Commission has proposed other measures, such as a temporary suspension of tariffs for imported fertilisers, which does not impact the business case of these projects. While the temporary suspension may eventually not be adopted, it has created uncertainty, not only for export-oriented projects targeting exports to Europe but also for domestic developments, which can lead to delayed investments. This illustrates the sensitivity of investment decisions to evolving trade and climate policy frameworks.

Beyond committed projects, close to 0.6 Mt of additional production capacity has a strong potential of becoming operational by 2030. In addition to North America, there are emerging opportunities in the United Kingdom, where the government has supported CCUS industrial clusters. Despite some delays, Hynet and the East Coast Cluster started construction in 2025. This could enable low-emissions hydrogen projects to progress towards FIDs.

Figure 3.18 Low-emissions hydrogen production from fossil fuels with carbon capture, utilisation and storage based on announced projects by region, status and likelihood of operation by 2030



Notes: FID = final investment decision; RoW = Rest of World. More details about announced projects for low-emissions hydrogen production can be found in the IEA Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

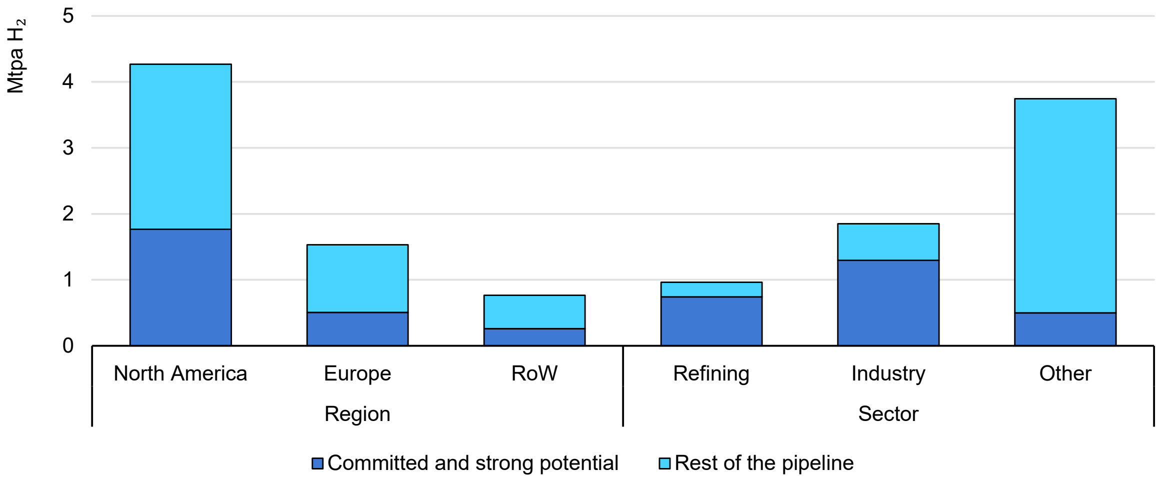
Production of low-emissions hydrogen from fossil fuels with CCUS is projected to reach 2 Mt by 2030 based on committed projects.

In the European Union, there is some production capacity with strong potential to be operational by 2030. Regulatory clarity has improved with the adoption of the delegated act on low-carbon hydrogen, which sets the methodology for assessing GHG emissions savings from low-carbon fuels. However, significant gaps remain in the policy framework. Financial support mechanisms are still limited, and demand-side measures to stimulate offtake are not yet sufficiently developed. Without stronger incentives to close the cost gap with unabated fossil-based production, these projects are likely to face challenges in achieving bankability and progressing to implementation.

The large majority of committed projects, and those that have strong potential to be in operation by 2030, are targeting established industrial applications, particularly ammonia production for the fertiliser sector and, to a lesser extent, refining (Figure 3.19). A smaller share of projects is focused on the production of hydrogen-based fuels, particularly ammonia for power generation, targeting exports to Japan and Korea.

On the other hand, 4 Mt of announced production is considered to have moderate or low potential of becoming operational by 2030. Many of these projects are based in the United States and Europe, where the conditions are favourable. However, many of these projects were announced in the early 2020s under the expectation of an increase in demand that has not yet materialised. Consequently, they have not yet defined clear end-use applications, meaning that they are unlikely to establish the necessary links to secure offtake agreements in the near term, and therefore limiting their ability to reach FID in time to reach operation by 2030. A minor share of projects are located in regions where regulatory frameworks, infrastructure and technical expertise are still under development, suggesting that their deployment may be delayed beyond the current decade.

Figure 3.19 Distribution of announced production of low-emissions hydrogen from fossil fuels with carbon capture, utilisation and storage by region, sector and likelihood of operation by 2030



Notes: RoW = Rest of World. "Other" includes the direct use of hydrogen in transport, power generation, grid injection, biofuels production, the production of hydrogen-based fuels such as ammonia and methanol for energy uses and projects without disclosed use of hydrogen.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

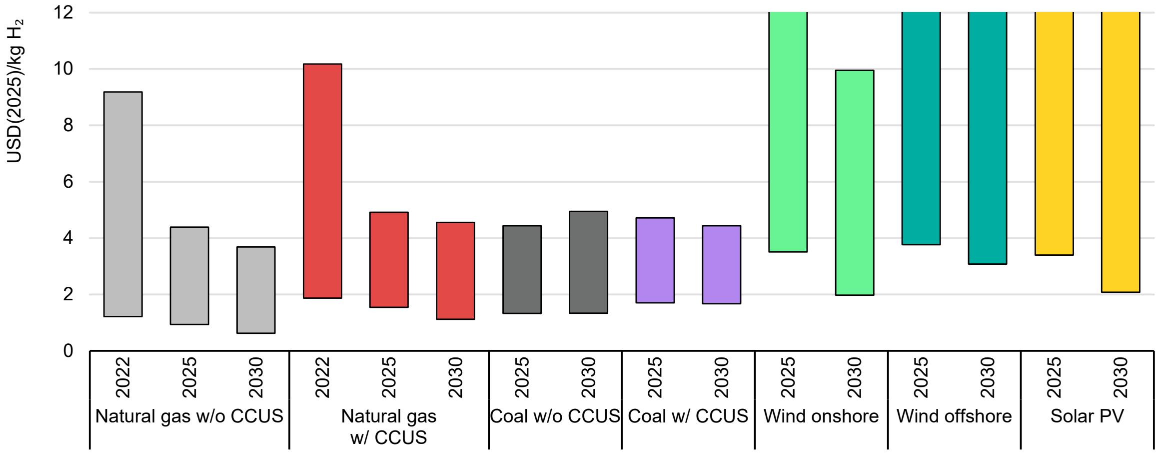
Projects that are already committed or have a strong likelihood of being operational by 2030 are concentrated in the refining and industrial sectors.

Cost of different routes and products

Low-emissions hydrogen production costs remain higher than unabated fossil-based routes. Rapid cost reductions were expected this decade, particularly in the case of electrolysis-based production, but these have not materialised due to slower-than-expected deployment, limited advancements in scale, and high inflation in 2022-23 that increased materials and labour costs.

Hydrogen production cost using unabated fossil fuel-based routes ranged between less than USD 1/kg H_2 and more than USD 4/kg H_2 in 2025, depending on the cost of the feedstock, which varies across regions (Figure 3.20). The lowest costs occurred in North America and the Middle East. Adding CCUS to fossil-based processes increases costs from USD 0.4/kg H_2 to more than USD 1/kg H_2.

Figure 3.20 Hydrogen production cost by pathway and in the Stated Policies Scenario, 2022-2030



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 capital expenditure (CAPEX) and operating expenditure (OPEX) as well as cost of capital. Natural gas price is USD 5.2-54/MBtu for 2022, USD 3.4-23/MBtu for 2025 and USD 1.4-22/MBtu in the Stated Policies Scenario (STEPS) in 2030. Coal price is USD 43-200/t for 2025 and USD 35-190/t for the STEPS in 2030. CO_2 price is USD 0-90/t CO_2 for 2022, USD 0-80/t CO_2 for 2025 and USD 0-110/t CO_2 for the STEPS in 2030. The levelised production cost of solar PV electricity is USD 23-110/MWh for 2025 and USD 18-89/MWh for the STEPS in 2030, with a capacity factor of 11-35%. The levelised production cost of onshore wind electricity is USD 30-120/MWh for 2025, USD 29-110/MWh for the STEPS in 2030, with a capacity factor of 23-53%. The offshore wind electricity levelised production cost is USD 43-270/MWh for 2025 and USD 36-210/MWh for the STEPS in 2030, with a capacity factor of 30-67%. For China, electrolyser CAPEX is USD 820/kW in 2025 and USD 680/kW for the STEPS in 2030, whereas for the rest of the world, it is USD 2 200/kW in 2025 and USD 1 700/kW for the STEPS in 2030. Electrolyser CAPEX includes the electrolyser system, balance of plant, engineering, procurement and construction (EPC) and contingencies; electrolyser capacity factor is assumed to be the same as the renewable power plant. The cost of capital is 5-20%. Figure capped at USD 12/kg H_2, although some production routes reach higher values. Water cost is not included. More details on the cost of producing low-emissions hydrogen using different technologies and in different regions can be found in the IEA Hydrogen Tracker.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF; Argus Media Group, All rights reserved; Lewis, E. et al. (2022), Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies; IEAGHG (2017), Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

In the short term, low-emissions hydrogen will remain more costly than unabated fossil-based production, although some regions are on the brink of reaching cost parity.

In the case of renewable-based electrolysis, the range of production cost is much larger, from over USD 3/kg H_2 to values that can reach well above USD 10/kg H_2. The cost of producing hydrogen via electrolysis is driven primarily by the price of electricity, the cost of installing electrolysers and the cost of capital for the development of the project. Only China can achieve the lower end of the range, thanks to low electricity prices (coming from low CAPEX and cost of capital for renewables), today’s lowest CAPEX for electrolysis, balance of plant and EPC, and a low cost of capital for renewable hydrogen projects. Although Chinese electrolysers often experience issues related to underperformance (a situation that has improved lately, as explained in the electrolysis section), they can still achieve the lowest production costs. Other regions with favourable cost conditions today, albeit still far from being competitive with fossil-based routes, include the Middle East, Chile, Australia and North America.

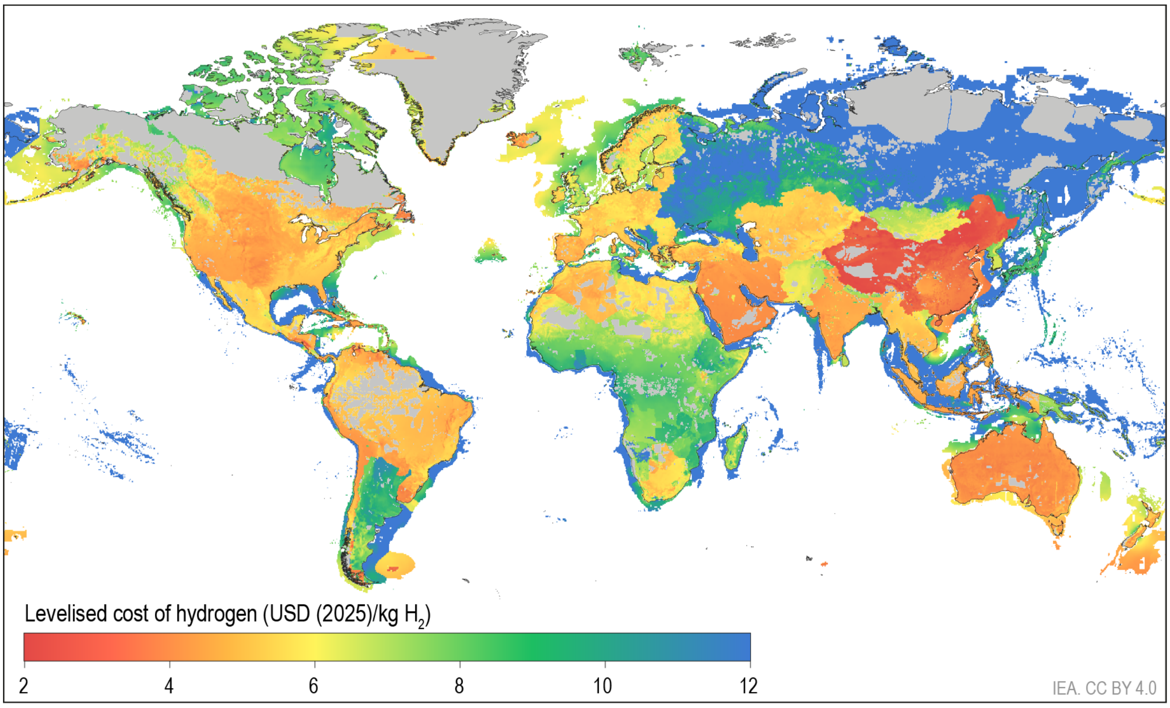
However, some regions are well-positioned to significantly reduce the cost of producing hydrogen from renewables in the near term. In the IEA's Stated Policies Scenario (STEPS),[45] project configurations that optimise combinations of solar PV and wind resources can achieve production costs for renewable hydrogen below USD 2/kg H_2 by 2030 in several regions in northern China (Figure 3.21). Australia and some regions in the United States similarly benefit from a low cost of capital and strong renewable potential, while the Middle East, India and Chile also have strong renewable potential, enabling production costs to fall to just above USD 3/kg H_2 and below USD 4/kg H_2. These reductions are driven mainly by declining electrolyser CAPEX (responsible for up to 60% of the cost reductions outside China), alongside falling renewable electricity costs (responsible for up to 40%). In the case of China, where electrolyser CAPEX is already low, the cost reduction from electrolyser CAPEX and renewable electricity have a similar impact on the reduction of the cost of producing renewable hydrogen. Other aspects, such as improvement in electrolyser efficiency, can provide additional contributions by 2030, but they are relatively minor compared with the cost of electrolysers and renewable electricity.

Australia, the United States and the Middle East are all gas-producing regions which typically benefit from low natural gas prices. Given the limited technology learning to 2030, the cost of natural gas will remain the main cost component of the production of hydrogen in gas-based routes. This means that hydrogen from natural gas with CCUS is likely to be the most cost-competitive option to produce low-emissions hydrogen in these regions. However, this will strongly depend on the evolution of gas prices, which currently are highly volatile and uncertain (see next section).

In regions that depend on imported gas, such as Europe and Southeast Asia, the cost gap between renewable hydrogen and hydrogen from unabated natural gas is expected to narrow. However, these regions do not benefit from the technology and cost of capital advantages of China, meaning the cost gap will remain and it will depend on the evolution of gas prices. In the STEPS, the cost of producing renewable hydrogen in some locations in Europe could fall to USD 3.5/kg H_2, equivalent to producing hydrogen from unabated natural gas at a price of around USD 60/MWh. This is 45% higher than the average European wholesale price in 2025,[46] but less than 20% of the peak price observed during the energy crisis in 2022, and 15% lower than the prices observed in March 2026.

[45] See the Annex for details on the use of IEA scenarios in the Global Hydrogen Review.
[46] Price at Dutch Title Transfer Facility (TTF) virtual trading point.

Figure 3.21 Hydrogen production cost from electrolysis using hybrid solar PV and onshore wind, and from offshore wind, in the Stated Policies 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 370-1 430/kW, Onshore Wind CAPEX is USD 820-2 760/kW, Offshore Wind CAPEX is USD 1 220-5 440/kW. The cost of capital is assumed to be between 5-20% across different locations in this map. Water cost is not included. More details on the cost of producing low-emissions hydrogen using different technologies and in different regions can be found in the IEA Hydrogen Tracker.

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

Renewable hydrogen production cost in China could fall to less than USD 2/kg H_2 thanks to the combination of strong renewable potential, low CAPEX and low cost of capital.

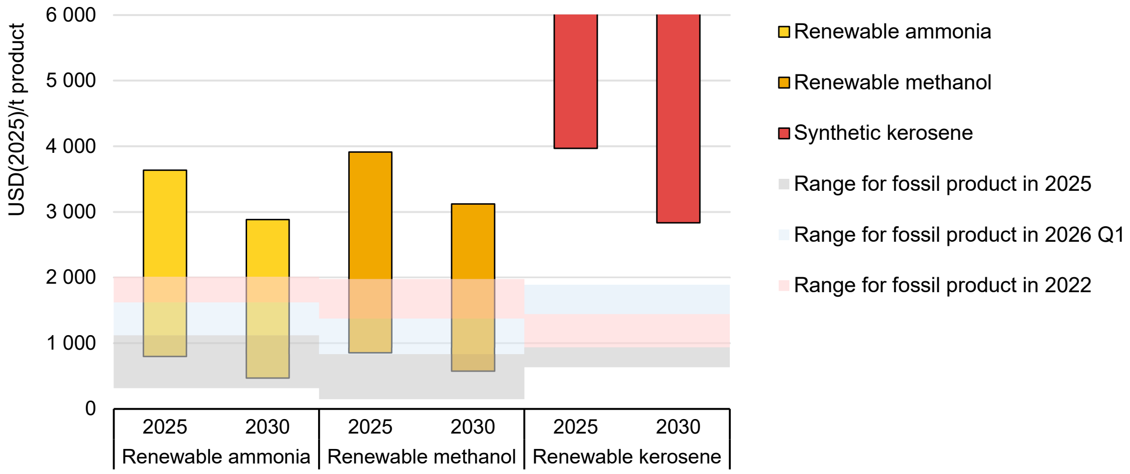
High energy prices can further reduce the cost gap for renewable hydrogen and hydrogen-based products

Hydrogen from unabated fossil fuel routes is expected to remain cheaper than renewable hydrogen in the short term. However, volatility in oil and gas prices due to geopolitical instability can increase the competitiveness of renewable hydrogen relative to hydrogen from unabated fossil fuels, at least for some time. In 2022, Russia’s full-scale invasion of Ukraine steeply increased the prices of fossil fuels, particularly natural gas. The levelised cost of hydrogen (LCOH) production from unabated natural gas increased significantly in natural gas-importing countries in Asia and, particularly, in Europe, where LCOH reached above USD 9/kg H_2 as an annual average, with peak values of close to USD 16/kg H_2 at certain moments of the year. The conflict in the Middle East that began on 28 February 2026 is also severely tightening the market. The Japan/Korea Marker benchmark price for spot liquefied natural gas (LNG) cargos in Asia and the Dutch TTF benchmark for

Europe rose to reach USD 85/MWh and EUR 70/MWh at the end of March 2026, significantly above their annual averages in 2025. Such prices would increase hydrogen production costs from unabated natural gas by 50% in Europe and 80% in the Asia-Pacific region, such as in Korea and Japan.

The prices of fossil-based ammonia (NH_3), methanol and jet fuel have also increased strongly. For example, the Cost and Freight Northwest Europe ammonia price reached around USD 910/t NH_3 at the end of April 2026, compared with USD 440-700/t NH_3 in 2025. In comparison, in 2025, the cost of producing renewable ammonia ranged from USD 800 to USD 3 600/t NH_3 (Figure 3.22).

Figure 3.22 Production cost of renewable ammonia, methanol and synthetic kerosene in the Stated Policies Scenario, 2025 and 2030, compared with cost ranges of fossil-based equivalents in 2022, 2025 and Q1 2026



Notes: Ranges for fossil-based ammonia and methanol are determined by natural gas prices. Natural gas prices for industrial users are assumed at USD 2.1-23/MBtu in 2025, with upper-bound values of 43/MBtu in 2026 Q1 and 54/MBtu in 2022. Ranges for renewable ammonia, methanol and kerosene are based on dedicated renewables supply in locations with strong renewable resource in each region. Minimum renewable ammonia, methanol and kerosene production costs in 2030 STEPS assume optimal oversizing of the renewable plant in each location, based on a hybrid configuration of onshore wind and solar PV from analysis from Forschungszentrum Jülich. CAPEX for Haber-Bosch and air separation is USD 560-980/t ammonia; for methanol synthesis and distillation USD 220/t methanol; and for Fischer–Tropsch synthesis and refining USD 2 400-2 770/t liquid hydrocarbons. A 70% kerosene product slate is assumed, with the remainder as naphtha, sold at their fossil-equivalent prices in each region. Renewable methanol and kerosene are assumed to use biogenic CO_2 as the carbon source.

Sources: IEA analysis based on Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite; EPC companies and project developers; data from McKinsey & Company and the Hydrogen Council; BloombergNEF; Argus Media Group, All rights reserved; Lewis, E. et al. (2022), Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies; IEAGHG (2017), Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

Some low-emissions hydrogen-based products could become cost-competitive in the near term, helping to reduce fossil fuel dependency and hedge against price shocks.

Economies of scale and learning-by-doing are expected to significantly reduce the costs of producing these products from renewable electricity in the near term. More than half of committed electrolysis projects for renewable ammonia and methanol production are sized larger than 100 MW of electrolysis capacity, and two ammonia projects under construction have more than 1 GW (see electrolysis section). In the STEPS in 2030, the cost of producing renewable ammonia and methanol in Australia, China, the Middle East and some regions in the United States falls to USD 470-1 700 and USD 570-1 900/t, respectively.[47] In the case of Europe, the cost ranges are USD 820-2700/t for ammonia and USD 940-2900/t for methanol. Producing ammonia and methanol at the same cost using unabated natural gas, would require gas prices in the range of USD 60 and USD 300/MWh, with the lower range reflecting around 15% of the peak of the European gas prices observed in 2022, or around 70% of the Asia prices seen in March 2026.

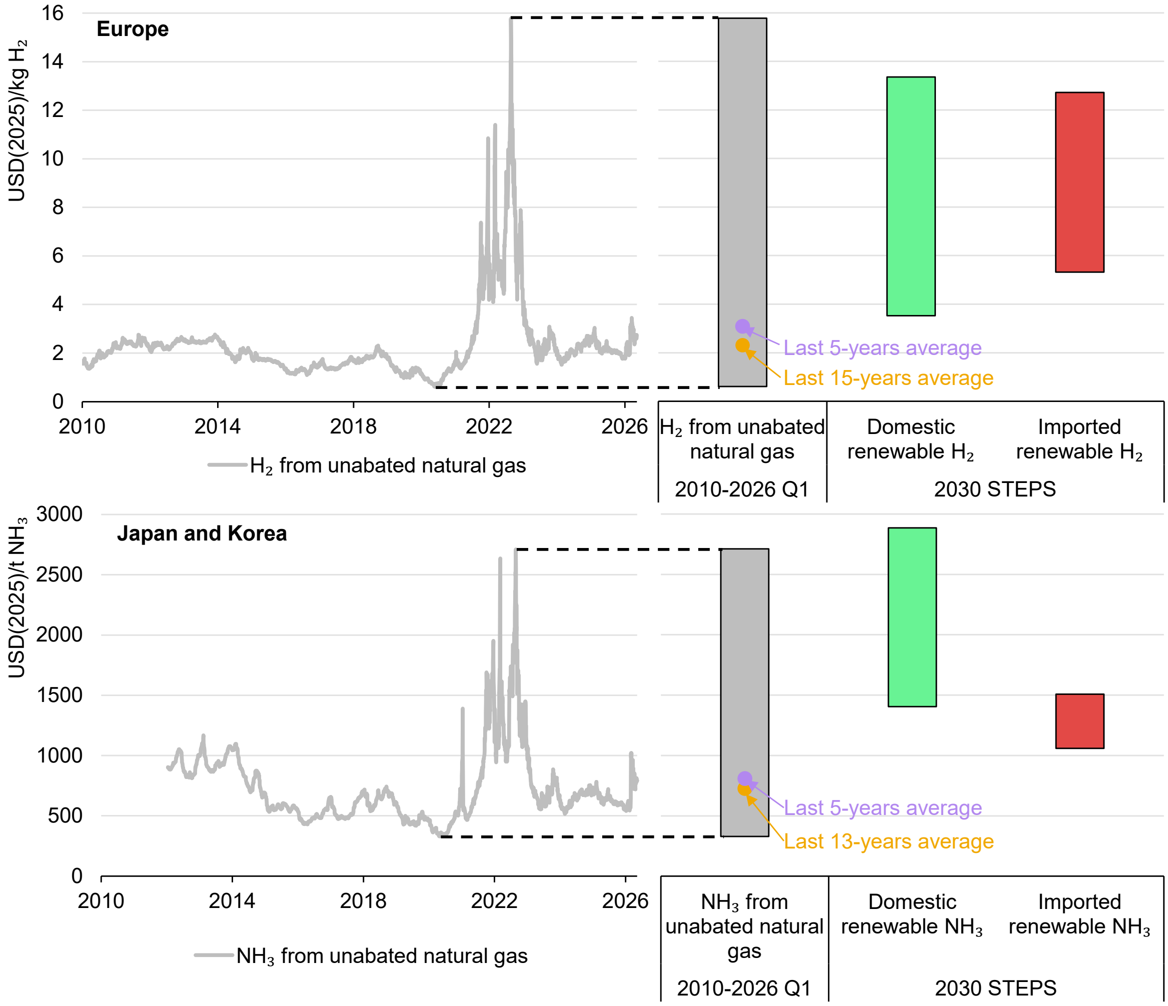
In the case of synthetic kerosene, the cost gap is much larger. In 2025, the lower end of the range for the cost of producing synthetic kerosene from renewable electricity was around USD 510/bbl, compared with USD 80-110/bbl for the price of fossil-based jet fuel observed that year. In the STEPS, synthetic kerosene production costs fall to USD 360/bbl by 2030, i.e. they are still very high. Early investments in innovative technologies to produce synthetic kerosene are necessary to reduce this gap further by creating scale and learning effects.

However, the fact that renewable hydrogen and hydrogen-based fuels can reach lower cost than fossil-based production at certain moments of stress in fossil fuel markets is unlikely to be enough to stimulate investment. Investment decisions are not taken on a single year basis, but on the expected evolution of costs over the lifetime of the project. The LCOH from unabated natural gas in Europe between the end of 2021 and early 2023 was well above USD 3/kg H_2 (Figure 3.23). This is higher than the LCOH that could be achieved by 2030 in some locations in Europe with good conditions for renewable hydrogen production. Even averaging the LCOH from unabated natural gas over the last 5 years (USD 3/kg H_2), the production of renewable hydrogen would be only slightly more expensive (USD 3.5 kg H_2). However, when averaged over the last 15 years, the LCOH from unabated natural gas is USD 2.3/kg H_2 and the production of renewable hydrogen would represent a cost premium of slightly above 50%.

Similarly, several times between 2021 and 2023, the cost of producing ammonia from unabated natural gas in Japan and Korea has reached values above the production cost that could be achieved by 2030 by producing it from domestic renewable sources. However, averaging the production cost of ammonia from unabated natural gas over the last 13 years, the production from domestic renewable energy would represent a cost premium of more than 90%. Given the limited renewable resources in these countries, an alternative could be to import ammonia from other regions with high renewable potential and significantly lower production costs. In the case of importing renewable ammonia from India, the cost premium compared with production from unabated natural gas would fall below 50%.

[47] Assuming that, in the case of methanol, carbon is sourced from bioenergy facilities, which represent the lowest cost for sourcing the carbon needed to produce methanol and synthetic kerosene in combination with electrolytic hydrogen.

Figure 3.23 Cost of producing hydrogen in Europe and ammonia in Northwest Asia from unabated natural gas, 2010-Q1 2026, compared with the cost of renewable-based production in the Stated Policies Scenario, 2030



Notes: NH_3 = ammonia. STEPS = Stated Policies Scenario. Europe unabated hydrogen production costs are derived based on natural gas prices from the Dutch TTF benchmark. Northwest unabated ammonia production costs are derived based on daily prices from East Asia LNG price assessment (EAX). “Last 5-years average”: Q1 2020 to Q1 2026 (quarter-end basis); “Last 15-years average”: Q1 2010 to Q1 2026; “Last 13-years average”: Q1 2012 to Q1 2026. Minimum renewable hydrogen and ammonia production costs in 2030 STEPS set by assuming optimal oversizing of the renewable plant in each location, based on a hybrid configuration of onshore wind and solar PV from analysis from Forschungszentrum Jülich. The upper range for renewable hydrogen and ammonia are based on dedicated renewables in areas with good renewable resource in each region. For ammonia, Haber-Bosch and air separation unit CAPEX is USD 560-980/t ammonia. “Imported renewable H_2” refers to hydrogen imported into Europe from North Africa by pipeline; “Imported renewable NH_3” refers to ammonia imported into Japan and Korea shipped from India. Ammonia shipping distance from India to Northwest Asia assumed to be 7 900 km, and pipeline hydrogen import distance into Europe from North Africa assumed to be 3 300 km.

Sources: IEA analysis based on data from ICIS, Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite, and data collected through a survey to original equipment manufacturers, EPC companies and project developers; data from McKinsey & Company and the Hydrogen Council; BloombergNEF; Argus Media Group, All rights reserved; Lewis, E. et al. (2022), Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies; IEAGHG (2017), Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

Low-emissions hydrogen can compete with unabated fossil-based hydrogen at periods of high fossil fuel prices, but investment decisions require longer-term competitiveness.

Despite the potential reduction in the cost gap between renewable hydrogen and hydrogen-based products and the incumbent fuels that they could replace, persistent high costs, along with uncertainty about the ongoing situation, may slow down the necessary investment. Supportive policies for renewable hydrogen and hydrogen-based products will remain necessary to achieve cost reductions through economies of scale and innovation in order to tap into the long-term public benefits that these products can provide, beyond decarbonisation alone. Such benefits include the diversification of fuels as well as lower energy price volatility, since renewable hydrogen projects can sign long-term power purchase agreements that secure a stable price from which off-takers can benefit. In addition, in the case of synthetic kerosene, sourcing jet fuel domestically can reduce risks of supply chain disruptions and enhance security.

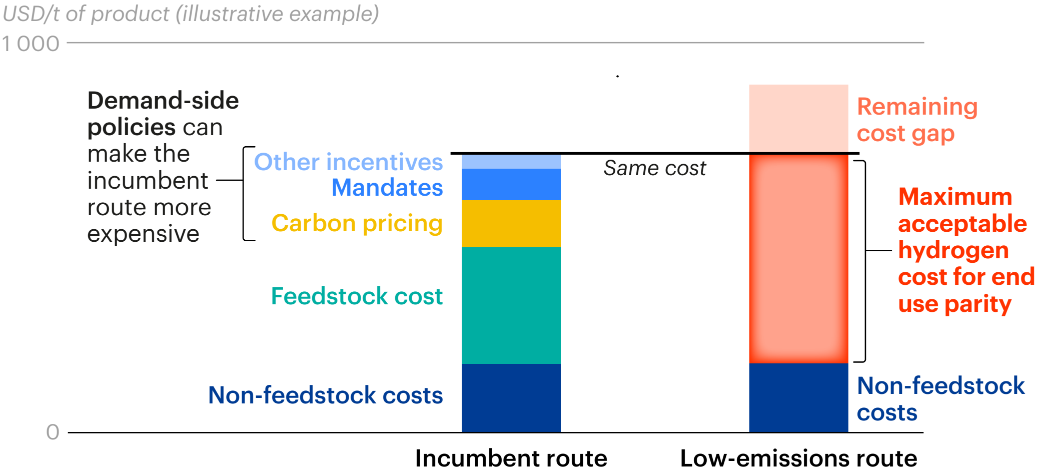
Chapter 4. Cost acceptability

Highlights

- Analysis of the costs of hydrogen in different end-uses enables identification of the maximum acceptable costs for hydrogen users, i.e. the maximum amount that can be spent on the hydrogen feedstock within a low-emissions pathway while maintaining the same total levelised cost of production as the incumbent pathway to produce the same commodity.
- This can enable policy makers and investors to identify sectors with both high maximum acceptable hydrogen costs and high potential volumes that can serve as lead markets for low-emissions hydrogen. Cost acceptability can be influenced by policies and depends on technologies, fuels and cost structure.
- The factors with the most influence on the maximum acceptable hydrogen cost are energy and carbon prices. Applications where energy has a larger weight in total product cost, like refining and ammonia, in regions with high energy prices, like the European Union, have the highest maximum acceptable hydrogen costs. Steel has high specific emissions and a low share of energy costs, making it the sector most affected by carbon pricing.
- In the absence of policy support, the maximum acceptable hydrogen cost is below USD 2/kg for most combinations of sectors and regions. For steel production, the hydrogen cost must be negative (i.e. would require incentives) to reach parity with the incumbent route.
- Carbon pricing can increase the maximum acceptable hydrogen cost across regions and sectors with high impact on demand. Quotas can create demand certainty but are not widely used. Even with policy incentives, the cost gap is not closed in most regions and applications. Only China would come close, and only if sufficiently high carbon pricing were to be implemented across all sectors.
- The cost gap can also be closed by front-running companies and consumers who are willing to pay a premium for low-emissions products. This willingness is largest for steel and aviation. Co-ordination among stakeholders in the value chain can help to distribute the cost premium to those actors most willing to pay.
- About 45% of the low-emissions hydrogen demand in the Net Zero Emissions by 2050 Scenario could be achieved with an abatement cost of less than USD 250/t CO_2 by 2035. Nearly two-thirds of this demand is in China, mostly in the industrial sector, due to low hydrogen production costs. Europe also has low abatement costs, due to high costs for both incumbent and the low-emissions routes.

Maximum acceptable hydrogen cost

The maximum acceptable hydrogen cost represents what a hydrogen user could pay for low-emissions hydrogen, based on current costs and demand-side incentives

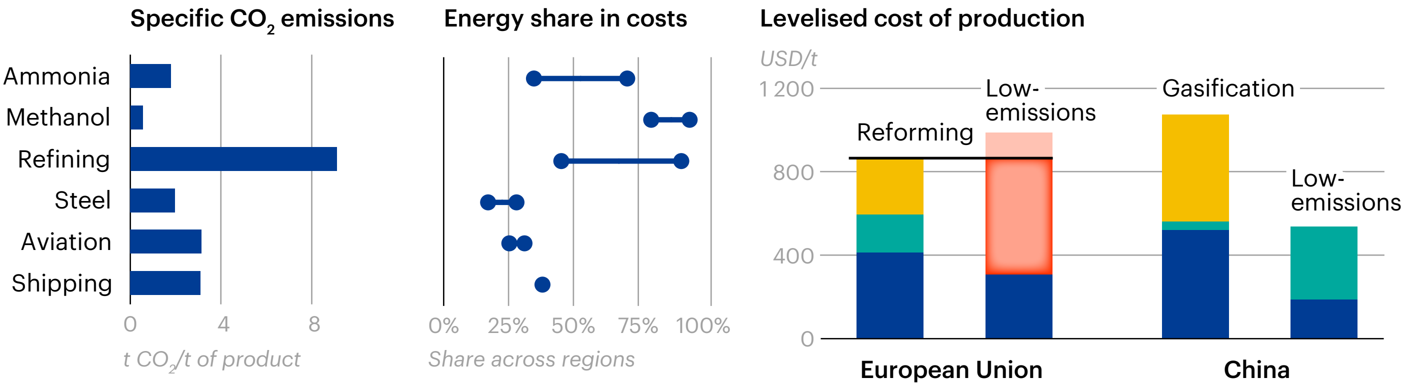


Analysis focuses on the hydrogen cost that makes the hydrogen-based route have the same cost as the incumbent one.

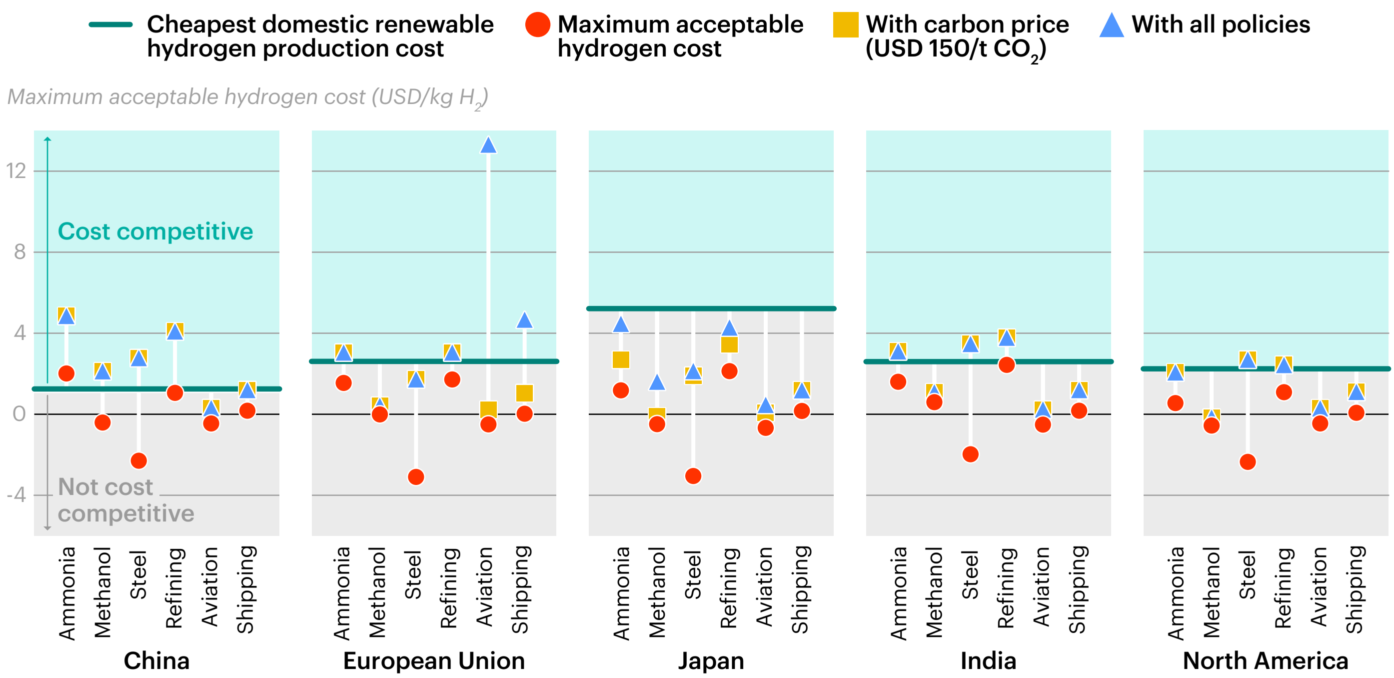
Analysis covers:

5 regions	**6 sectors**
China	Ammonia
European Union	Methanol
Japan	Refining
India	Steel
North America	Shipping
	Aviation

Energy costs and specific CO_2 emissions explain most of the difference in maximum acceptable hydrogen cost across sectors and regions



The gap between the maximum acceptable hydrogen cost and the supply cost is smallest in China; further policy support would be needed to fully close it



Cost acceptability analysis

One of the main barriers to scaling low-emissions hydrogen[48] is the absence of large consumers who can absorb today's higher costs for low-emissions hydrogen at sufficient volumes to unlock economies of scale. Without anchor demand, project developers cannot secure the firm offtake agreements required to reach a final investment decision (FID). The lack of established indices for low-emissions hydrogen prices, due to the nascency of the sector, makes it difficult to form such agreements. This makes it essential to identify the level at which low-emissions hydrogen costs become competitive with incumbent technologies – and thus acceptable to hydrogen users – across different applications and regions. This analysis could enable policy makers and investors to identify applications in which the maximum cost that would be acceptable to users is relatively high, and that have high potential volumes. These sectors could potentially serve as lead markets where low-emissions hydrogen can scale first. At the same time, these values will vary over time as policies expire and will be defined by the evolution of the energy system. This chapter aims to answer four questions:

- What is the maximum acceptable cost for low-emissions hydrogen in each of its applications?
- Which regions and sectors could have the largest uptake of low-emissions hydrogen in the coming decade?
- How does policy affect the costs that would be acceptable to users?
- How do these values compare with the production costs?

The analysis focuses on five regions: the People's Republic of China (hereafter, "China"), the European Union, India, Japan and North America. These regions represent the bulk of hydrogen demand today (63%) and most of the low-emissions hydrogen project pipeline (59%), as well as having the strongest policy support for the development of low-emissions hydrogen. Sectors covered are those where hydrogen is used as a feedstock or where electrification is the most difficult today. There is some evidence that road transport has the highest acceptable hydrogen cost in order to reach parity with the incumbent route (mostly due to high fuel taxes making the incumbent pathway more expensive). However, electrification is becoming cost-competitive, even for heavy-duty vehicles, so this sector is excluded from the analysis. The emphasis is on the next 10 years given the uncertainty associated with longer time horizons, both because of hydrogen-related aspects like technology innovation, cost trends and market developments, as well as the wider energy system transformation.

[48] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Methodology

The maximum acceptable hydrogen cost is derived from a comparison of total levelised costs between an incumbent pathway and the low-emissions hydrogen-based pathway to produce the same commodity. It represents the maximum amount that can be spent on the hydrogen feedstock within a low-emissions pathway in order for the total levelised cost of production to equal that of the incumbent pathway to produce the same commodity, and thus to be acceptable to users (Figure 4.1). For instance, in ammonia production, where hydrogen is already used today, low-emissions hydrogen would need to have the same cost as hydrogen produced from fossil fuels, since the other costs (e.g. synthesis unit, compression, air separation unit) remain the same for both routes. In contrast, for shipping, the maximum acceptable cost for low-emissions hydrogen would need to be lower than the cost of heavy fuel oil, since other cost elements like bunkering, storage and the ship's engine are more expensive for hydrogen-derived fuels. These higher other costs would need to be offset by a lower hydrogen cost in order to have the same total levelised cost.

Estimating the maximum acceptable hydrogen cost requires calculating the levelised cost of production for low-emissions hydrogen use in each application, as well as for the incumbent pathway (Table 4.1). The maximum acceptable hydrogen cost is assessed at the end-use level after conversion and use, rather than at the level of hydrogen production.

Table 1.1 Incumbent pathways substituted by the use of low-emissions hydrogen

Hydrogen application	Technology/fuel substituted
Chemicals and refining	Coal gasification (China), steam methane reforming of natural gas (rest of the world)
Steel	Blast furnace with basic oxygen furnace and electric arc furnace
Shipping	Heavy fuel oil with established oil infrastructure
Aviation	Fossil jet fuel

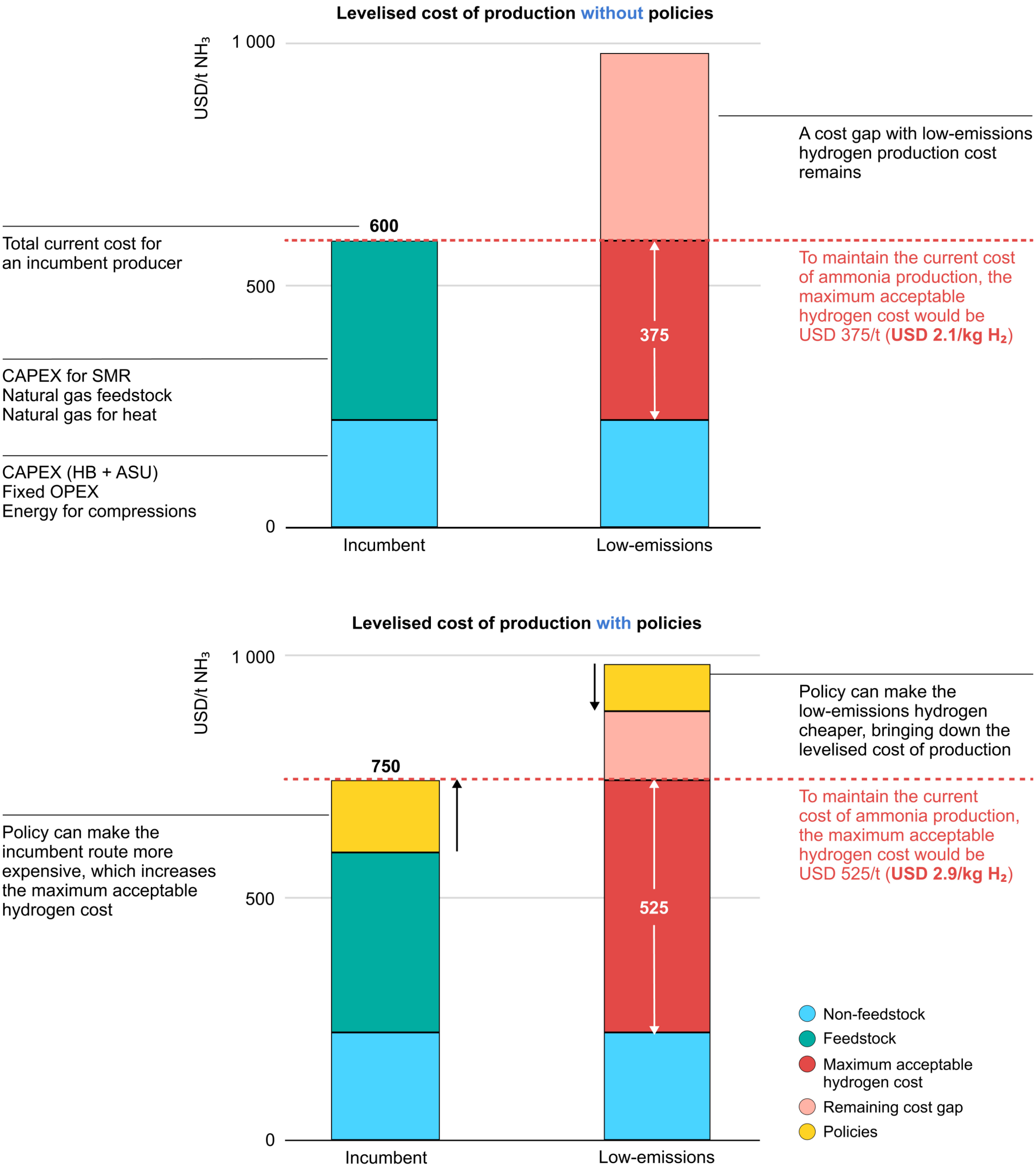
Note: The technology substituted is chosen based on the technology with the largest market share today.

The maximum acceptable hydrogen cost is influenced by policy measures that make the incumbent route more expensive, such as carbon pricing and quotas coupled with non-compliance penalties. Carbon pricing depends on the type of economy and year, which means the maximum acceptable hydrogen cost at which end-use parity with the incumbent route is achieved changes over time. Quotas are in place in the European Union for industry,[49] aviation and shipping. The maximum acceptable cost can also be influenced by policy measures to make the low-emissions route cheaper, such as demand-side incentives like tax breaks,[50]

[49] The European Union has set targets for 2030 and 2035, but member states can decide what instrument to use to achieve those targets.
[50] This assumes that hydrogen would be taxed at a lower level than incumbent options, which would have direct negative fiscal implications in the short-term and as such may be used only for early stages of the market.

grants, loans (guarantees) and operational expenditure (OPEX) support, although in the examples discussed below these measures are insufficient to affect the maximum acceptable hydrogen cost.

Figure 4.1 Illustrative example of maximum acceptable hydrogen cost and remaining cost gap for ammonia production, with and without policy measures

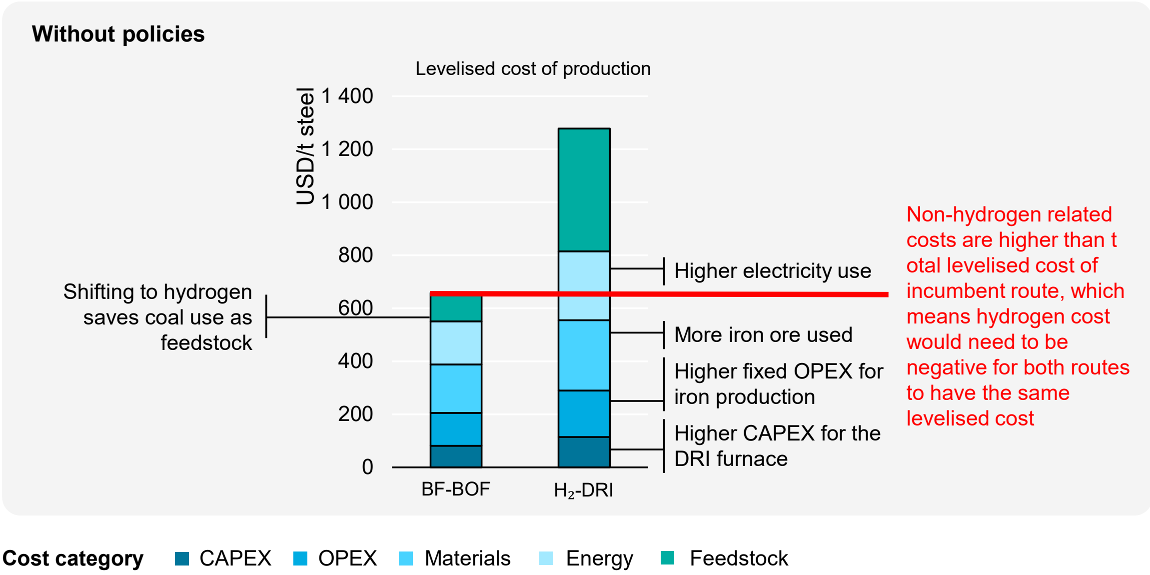


Note: CAPEX = capital expenditure; SMR = steam methane reforming; ASU = air separation unit; HB = Haber Bosch (ammonia synthesis unit).

Maximum acceptable hydrogen cost is what can be spent on the hydrogen feedstock in a low-emissions pathway without exceeding the levelised cost of the incumbent pathway.

Applications that already use hydrogen today are the simplest to compare in terms of cost structure, because all the other cost components not related to the hydrogen supply remain the same. For new applications, the comparison is complicated by the fact that other factors beyond the hydrogen supply also change when considering the low-emissions route. For instance, a shaft furnace for direct reduction of iron (DRI) is more expensive than a blast furnace. This also means that the fixed operating cost (usually estimated as a fraction of the capital expenditure [CAPEX]) is also higher. The electricity consumption for H_2-DRI is higher than for a blast furnace, but the H_2-DRI route does not use coal, which can account for 14-21% of the total levelised cost. However, when switching to the low-emissions pathway, H_2-DRI, the increase in the non-feedstock costs is higher than the savings made by avoiding the coal feedstock. As such, even if the hydrogen had no cost, the low-emissions route would still cost more than the incumbent route (Figure 4.2).

Figure 4.2 Levelised cost of production for steel production in the European Union, 2024



Note: BF-BOF = blast furnace-basic oxygen furnace; CAPEX = capital expenditure; DRI = direct reduced iron; OPEX = operational expenditure.

For H_2-DRI, the hydrogen cost would need to be negative to reach levelised cost of production parity with the incumbent route, as other costs are also higher.

The maximum acceptable hydrogen cost for the hydrogen end-use (related to hydrogen demand) differs from the cost gap between low-emissions hydrogen and incumbent hydrogen production from unabated fossil fuels (related to hydrogen supply). The concept of maximum acceptable hydrogen cost applies to the demand side (or end-use), and the maximum acceptable hydrogen cost is the cost at which the low-emissions route is cost-competitive with the incumbent route for the same final product. The cost gap refers to the part of the low-emissions hydrogen costs that exceeds the maximum acceptable hydrogen cost in each application. Policy incentives targeting supply, such as tax credits for production, CAPEX grants, fixed premium and contracts for difference help close the cost gap but do not influence the maximum acceptable hydrogen cost and are therefore excluded from this analysis. Additionally, the analysis only covers direct costs; externalities like air pollution, price stability, energy security (see related question in Chapter 1), industrial competitiveness, water and land use and any impact beyond GHG are not included. Consideration of these externalities would tend to favour the renewable route, across applications, and mean that this route could still be attractive from the societal perspective even when the economic perspective is less attractive.

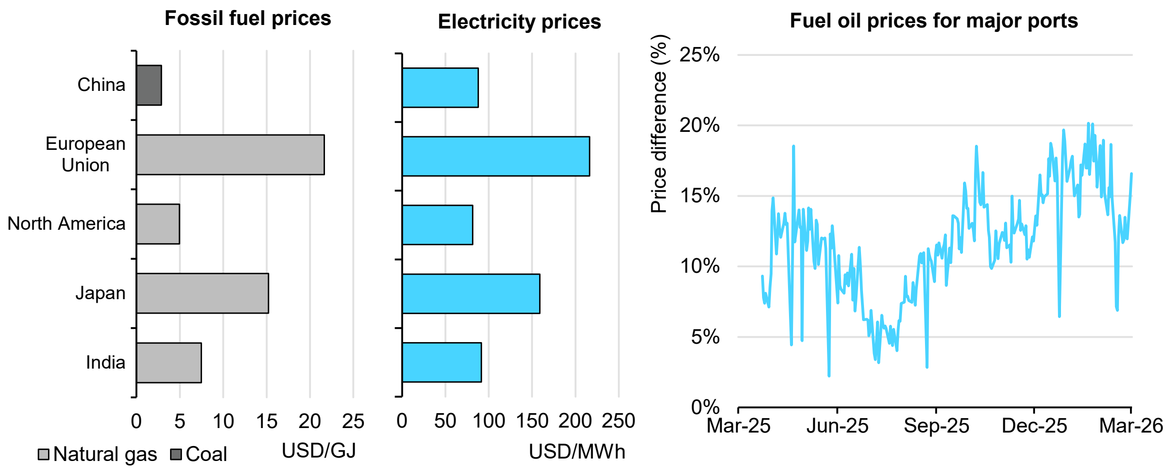
The rest of this chapter discusses the factors that explain the differences in the maximum acceptable hydrogen cost across regions and sectors, followed by a comparison with the production cost. Then, potential demand volumes for 2035 are used to understand the combinations of regions and sectors that have the smallest cost gap and the largest volumes. The last section discusses an additional green premium that certain actors might be willing to pay and which could also help to close the cost gap.

Regional differences

The parameters with the largest influence on the hydrogen cost parity, which also cause variation across regions, are the energy and carbon prices. For ammonia, energy and feedstock costs can represent 35-70% of the levelised cost of production. This means that regions with high energy prices, such as Europe and Japan, have a higher production cost for the incumbent route, which translates into a higher maximum acceptable hydrogen cost. In addition, these two regions have the highest carbon pricing, which further increases the acceptable cost.

High energy prices in these two regions affect both the incumbent and the low-emissions route. They increase the maximum acceptable hydrogen cost, since the incumbent route is more expensive, but also affect the cost gap, since the production costs for the low-emissions pathway are also the highest in these regions (Figure 4.3). This means that despite a high maximum acceptable hydrogen cost, the cost gap is also larger. In contrast, regions with cheaper energy and low carbon prices, such as North America, have the lowest production cost for the incumbent route, resulting in the lowest maximum acceptable hydrogen cost. The contributing factors are different in China, which uses coal gasification as an incumbent technology, resulting in higher CAPEX than steam reforming, but benefiting from lower energy prices thanks to the use of coal. Despite not having a high carbon price or other supporting policies that increase the maximum acceptable cost of hydrogen, China benefits from low production costs for the low-emissions route, which means the cost gap can be closed in the coming decade.

Figure 4.3 Regional energy price differences, 2025

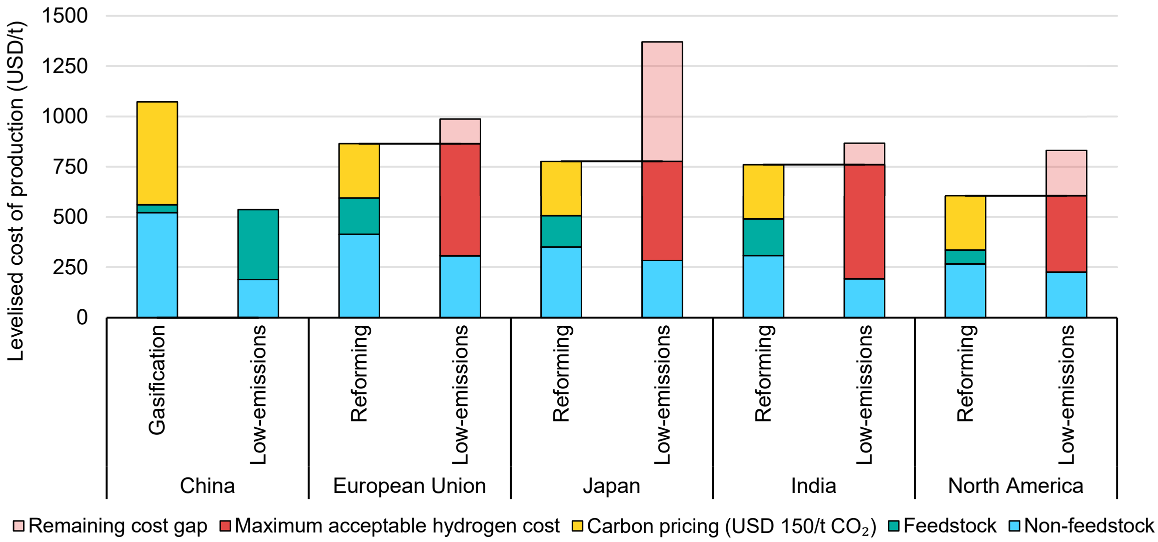


Notes: Electricity prices are for industrial facilities connected to the electricity grid. Fuel oil price differential between minimum and maximum price for major bunkering ports: Zhoushan (China), Rotterdam (the Netherlands), Singapore, Fujairah (United Arab Emirates), Gulf Coast (United States).

Energy costs vary significantly across regions and affect each application differently.

The factors affecting the maximum acceptable hydrogen cost over time are the cost reduction for low-emissions pathways based on innovation and learning effects, and the change in fossil fuel demand that affects fossil fuel prices (and therefore costs for the incumbent route). For example, in a future with lower emissions, natural gas demand would be lower, which would push natural gas prices down. This would decrease the levelised cost of the incumbent option for ammonia, methanol and refining, which would therefore decrease the maximum acceptable amount that can be spent on hydrogen (Figure 4.4). Carbon pricing alone might not be enough to offset such a decrease, since it would need to reach a very high level. Other policies, such as quotas coupled with penalties, are therefore needed to maintain the same maximum acceptable hydrogen cost as today. In the European Union, this highlights the importance of finalising the transposition of the Renewable Energy Directive.

Figure 4.4 Acceptable low-emissions hydrogen cost for end-use parity in ammonia production by region, 2035



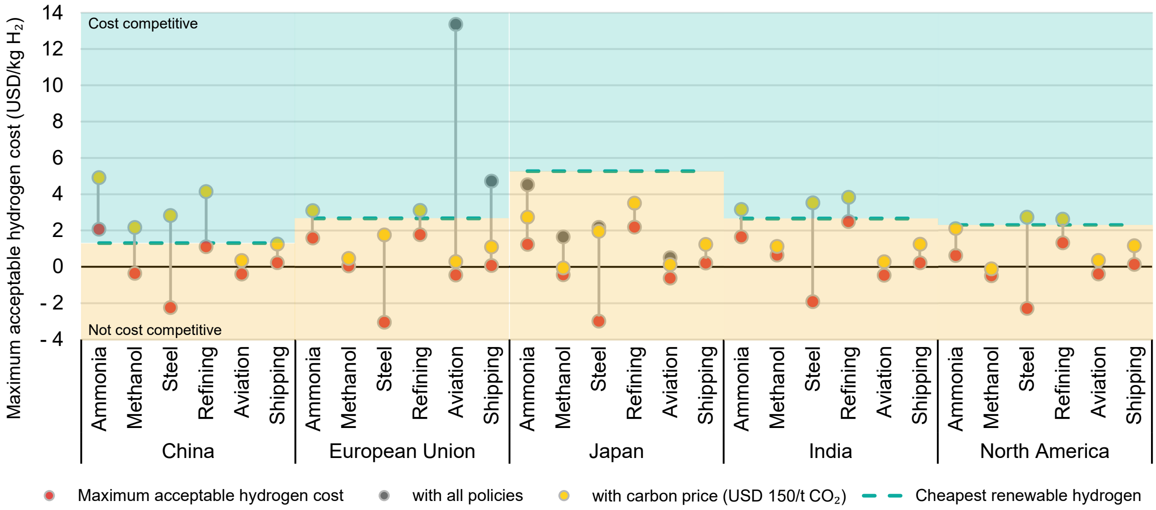
Notes: Carbon pricing assumption of USD 150/t CO_2 used as a reference to show the effect across sectors. This is not a prediction or expectation of the carbon price level in 2035. Carbon price effect (yellow bars) is directly proportional to the carbon price. Feedstock refers to the hydrogen feedstock for low-emissions and natural gas and coal respectively for reforming and gasification. Non-feedstock cost includes Haber Bosch synthesis, air separation unit and fixed electricity consumption for compression in the synthesis loop. The low-emissions route for China is cheaper than the incumbent route so there is no cost gap and the cost parity is higher than the feedstock cost expected for 2035.

Energy costs are the main driver behind differences in maximum acceptable hydrogen cost in ammonia production across regions.

Shipping is different from industrial applications since the incumbent commodity is an oil derivative, which is more globally traded than gas and electricity, so the variation in heavy fuel oil prices across regions is generally much smaller than other commodities, in the order of 5-20% in 2025. Similarly, vessels and associated equipment such as tanks, as well as bunkering infrastructure, are largely commoditised items. Almost 80% of global energy demand for shipping is for international voyages, which are overseen by the International Maritime Organization (IMO) and therefore any IMO policy is applicable to all regions. Only the European Union has a specific policy for the use of hydrogen-based fuels in shipping, the FuelEU Maritime, which will introduce a 2% quota for renewable fuels of non-biological origin (RFNBO) in 2034 if the RFNBO share by 2031 is less than 1%. However, since EU demand is relatively small, this quota would only be enough to trigger demand for 180-210 ktpa of low-emissions hydrogen (depending on the fuel) based on existing policies. As a reference, this represents about a third of the production capacity that could come online by 2030 from projects in the region that have taken FID (which mostly target industry rather than shipping).

Aviation, like shipping, uses oil products for the incumbent pathway, which means regional differences are small and only driven by the combination of different refinery margins and transport costs, which are much smaller. For aviation, the European Union and Japan have policies in place that affect the maximum acceptable hydrogen cost (Figure 4.5). In the European Union, ReFuel EU introduces quotas from 2030 (1.2%) to 2050 (35%), combined with penalties which are twice the difference between the RFNBO and fossil jet fuel prices. In Japan, there is a tax credit of JPY 30/L (USD 240/t) for 10 years. For reference, supporting 100 kt of synthetic jet fuel with this incentive, which is 3% of current Japanese demand, would require a total funding of USD 240 million.

Figure 4.5 Maximum acceptable low-emissions hydrogen cost across regions and applications, 2035



Notes: Carbon pricing assumption of USD 150/t CO_2 used as a reference to show the effect across sectors. This is not a prediction or expectation of the carbon price level in 2035. Carbon price effect (yellow dots) is directly proportional to the carbon price. Policy impact for aviation in the European Union is based on the non-compliance penalties of ReFuelEU. Where the value for “with all policies” is not visible, there are no other policies in that combination of region and sector.

The gap between the maximum acceptable hydrogen cost and the supply cost is smallest in China; further policy support would be needed to fully close it.

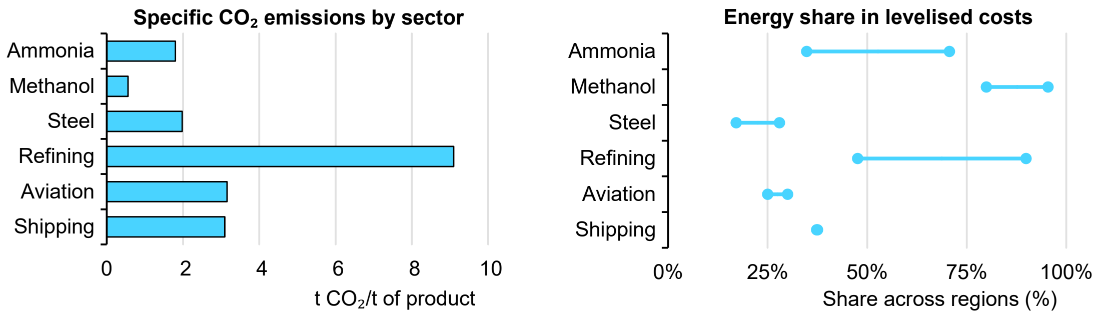
Without policy support, the maximum acceptable hydrogen cost is below USD 2/kg H_2 for most combinations of regions and applications (red markers in Figure 4.5). This cost level could only potentially be achieved in China, which means a cost gap remains in other regions. This is consistent with reality today, where multiple projects have been cancelled due to the cost gap being larger than available public support. Examples include projects from the European Hydrogen Bank (see Chapter 7), where competition drove bids below the cost gap, from India, where two buyers withdrew from the ammonia tender, and from the United Kingdom, where one project withdrew from the process of the Hydrogen Allocation Round.

The maximum acceptable hydrogen cost is largely dependent on fossil fuel prices which are subject to volatility and may differ from the assumed values at specific points in time. In the European Union, carbon pricing, which has been around EUR 65-90/t CO_2 in early 2026, could help to close the cost gap. In addition, the CO_2 reduction targets for the next phase of the EU ETS will be defined as part of the 2040 climate strategy, which will likely lead to higher prices as the overall GHG reduction target is tightened to 90% by 2040 (relative to 1990). In other regions, supply side incentives like the contract for difference (CfD) scheme in Japan, the SIGHT programme and associated tenders in India and tax incentives in the United States and Canada could help close the cost gap.

Sectoral differences

The main differences between sectors relate to the cost structure, more specifically the share of the energy input cost, and the effect of carbon pricing through the specific sectoral emissions (Figure 4.6). In terms of cost structure, at one extreme there is methanol, which has relatively low non-feedstock-related costs for the synthesis unit. This means most of the cost difference with the incumbent pathway relates to the cost of the low-emissions hydrogen. In contrast, for steel, the fixed non-energy costs (such as the direct reduction furnace) are significant and higher for the hydrogen route. This means that on a purely economic basis, the hydrogen cost would need to be negative in order to be acceptable, since the hydrogen route would be more expensive even with free fuel. The maximum acceptable hydrogen cost becomes positive only when policy support through carbon pricing is considered.

Figure 4.6 Specific CO_2 emissions and share of energy costs by sector, 2035

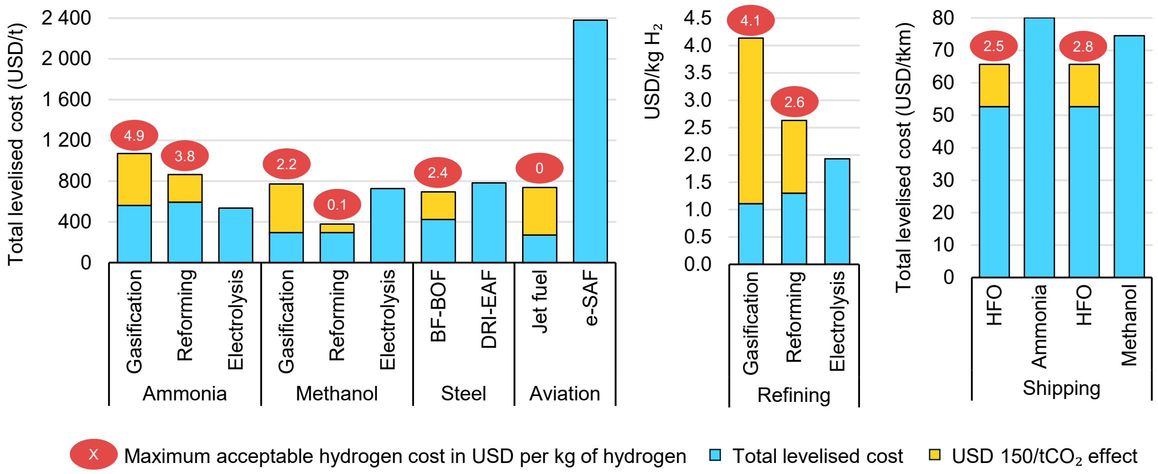


Notes: Specific emissions based on best available technology. Aviation is based on jet fuel and shipping based on heavy fuel oil. Share of energy costs in China, the European Union, India, Japan and North America.

Sectoral differences in maximum acceptable hydrogen cost are driven by different specific emissions and different shares of energy costs.

Carbon pricing can have a large impact on the maximum acceptable cost for low-emissions hydrogen. In 2025, there were 80 carbon pricing schemes implemented around the world, covering 28% of global GHG emissions with an emissions-weighted average price of USD 19/t CO_2 (with a range from nearly zero to USD 160/t CO_2). The effect of carbon pricing is defined by the specific CO_2 emissions per tonne of product and the share of fuel and feedstock costs. Considering both, carbon pricing has the most impact in industrial applications and more specifically for steel (Figure 4.7). Quotas combined with penalties ensure a specific market penetration and do not have a negative fiscal impact, which are the two main advantages over subsidies. For shipping and aviation, both sectors are exposed to international regulation, which means an intervention at the international level can enable a level playing field with minimal market distortion. Quotas work well because these sectors have a large cost gap that is not expected to close with innovation or carbon pricing, meaning that an instrument like subsidies would not be economically sustainable over time, would leave a cost gap once phased out, and would require a large amount of funding per tonne of product. As such, an alternative approach would be to co-ordinate stakeholders along the value chain and pass on the costs to the end consumers, where the cost premium is the smallest.

Figure 4.7 Effect of carbon pricing on total levelised cost of different hydrogen derivatives produced in China, 2035



Notes: BF-BOF = blast furnace-basic oxygen furnace; DRI = direct reduced iron; EAF = electric arc furnace; e-SAF = hydrogen-based aviation fuel; HFO = heavy fuel oil. Hydrogen cost parity is not proportional to the total levelised cost differential because each application has a different hydrogen consumption. USD 150/t CO_2 carbon price is taken as a reference to show the effect across sectors. This is not a prediction or expectation of the carbon price level in 2035. Carbon price effect (yellow bars) is directly proportional to the carbon price.

Carbon pricing can have a widespread impact on the maximum acceptable cost of low-emissions hydrogen, especially in steel and refining.

Sectors are also differently impacted over time by the evolution of fuel and carbon prices. High carbon pricing increases the maximum acceptable cost of hydrogen, in the same way as high fossil fuel prices. However, if carbon pricing increases over time, then there would be less demand for fossil fuels, which in turn would lead to lower fossil fuel prices, all other things being equal. The net effect on the maximum acceptable cost is also affected by the specific emissions of each sector. For ammonia, steel, shipping and jet fuel, which have high specific emissions, the carbon pricing effect is likely to dominate costs even at relatively low prices, and the maximum acceptable hydrogen cost would increase over time.

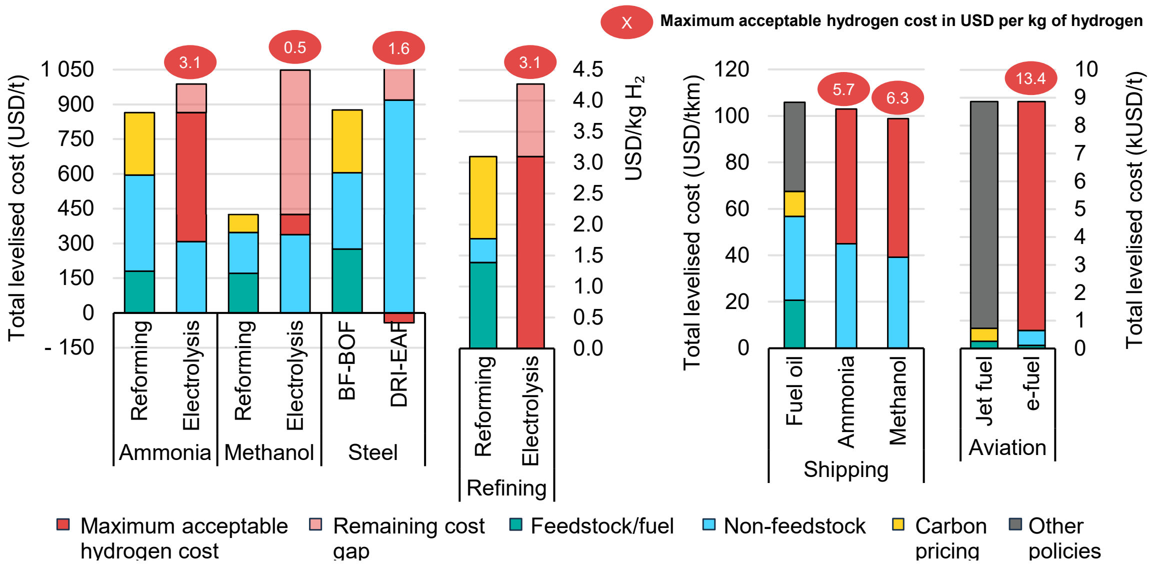
The effect of learning over time as technologies are deployed depends on the CAPEX share and maturity for each technology. For example, for refining, the incumbent technology is steam reforming, which is a mature technology with limited learning over time. In contrast, a hydrogen-related technology like Fischer–Tropsch for synthetic kerosene production, for example, is a commercial technology but has been deployed to a more limited extent, with more room for learning. There has therefore been some cost decrease over time, although its impact is small due to the CAPEX share in the cost structure. Across sectors, technology learning over time plays a limited role in maximum acceptable hydrogen cost.[51]

For aviation, the maximum acceptable hydrogen cost is less than USD 0.5/kg H_2 for most combinations of regions and years (Figure 4.5). The factors that drive the maximum acceptable cost above this threshold are carbon pricing (which would require introducing this sector in the scope of the carbon pricing scheme for regions other than the European Union) and specific policies such as ReFuelEU aviation, or the tax credits in Japan. ReFuelEU alone can increase the hydrogen cost parity to USD 13.5/kg H_2 in 2035 since non-compliance is twice the price differential between RFNBO and fossil jet fuel, so by design it provides a larger incentive than needed to close the cost gap. In aviation and shipping, the incumbent technology is based on fuels that have low transport costs and are globally traded (jet fuel and heavy fuel oil), with smaller regional differences than industry and power, where the role of domestic energy sources is larger. However, there are still differences due to refinery margins and supply mix. For example, for shipping, the price difference between major ports was 5-20% in 2025, while for jet fuel it can be around 10%.

For shipping, the decision on the introduction of the IMO Net Zero Framework was adjourned by a year in 2025, creating uncertainty around the timing and outcome of its adoption process (see Chapter 2). Only the penalties for fossil fuels are known (USD 100/t CO_2 and USD 380/t CO_2 depending on the GHG emissions threshold, which varies over time). Since the reward system for (near-)zero emission fuels has not been fully defined and the policy is not yet in force, it is excluded from the cost parity analysis. The effect of the carbon price depends on the type of ship, which affects fuel consumption and therefore the fuel share in the overall costs. A price of USD 100/t CO_2 would be enough to close about 10-45% of the cost gap, depending on the region. If implemented, this policy could change the hydrogen cost parity by USD 0.8-1.8/kg H_2 depending on the type of ship.

[51] Technology learning can still play a role in closing the cost gap with low-emissions hydrogen production (e.g. learning for electrolysers).

Figure 4.8 Maximum acceptable cost for low-emissions hydrogen for end-use parity across applications in the European Union, 2035



Notes: Carbon pricing assumption of USD 150/t CO_2 used as a reference to show the effect across sectors. This is not a prediction or expectation of the carbon price level in 2035. Carbon price effect (yellow bars) is directly proportional to the carbon price. Tonnes in the total levelised cost refer to tonnes of product.

Ammonia and refining have the highest maximum acceptable hydrogen cost in the European Union based on energy costs and emissions.

The production cost for energy-intensive industries more closely follows the energy cost trends across regions. As such, the highest maximum acceptable hydrogen cost today among the regions assessed is in the European Union and the lowest is in North America. Over time, this cost closely follows the energy prices by scenario. In the short term, gas prices could decrease in the European Union, Japan and China, driven by lower demand (European Union) and cheaper liquefied natural gas (LNG) imports, while prices increase for North America and India, driven by an increase in LNG exports and increased demand (India).

The maximum acceptable hydrogen cost for hydrogen and ammonia use in the power sector follows a similar trend to in energy-intensive industries, with the difference that fuel shifting is easier, since the system is designed with overcapacity. For example, in the case of high gas prices, there could be a shift towards more coal generation, which could enable a higher volume of ammonia co-firing (most relevant for Japan and India). This would lead to lower conversion efficiencies since gasification plants have lower efficiencies than gas turbines, which decrease the maximum acceptable hydrogen cost. This cost is less than USD 2/kg H_2 in most cases and only higher in Japan due to the CfD scheme. The scheme has earmarked funding of USD 20 billion. Considering that the OPEX support is provided for 15 years and there is an average price differential of USD 5/kg, this budget would be enough to support about 265 ktpa of low-emissions hydrogen, which is roughly more than one-quarter of the additional 1 Mtpa of low-emissions hydrogen that Japan aims to introduce through the Green Transformation CfD scheme.

Cost-volume demand curves

Hydrogen is a versatile energy carrier that can help governments to potentially achieve multiple policy objectives. This includes energy security, displacement of fossil fuel imports, higher economic growth through investment along the value chain, and abatement of emissions in those applications where electrification or other technologies might be difficult or too expensive. With regards to energy security, hydrogen's contribution goes beyond a higher share of domestic energy production. Hydrogen can also be converted to other energy carriers and improve the resilience of the system by providing more alternatives that can be used in the case of a supply disruption, infrastructure damage or any other unforeseen event.

The extent to which low-emissions hydrogen is deployed in the future will depend on how these different drivers play out considering the context of each country. By 2035, low-emissions hydrogen demand could range from 12 Mt in a scenario with policies that have been adopted or put forward, to more than 110 Mt in a scenario where the different factors outlined above align to drive demand uptake. This section uses the upper bound of demand as an upside potential, which is also associated with lower fossil fuel prices (see technical annex) and lower maximum acceptable hydrogen costs overall.

Cost demand curves help to understand the cost implications of reaching certain hydrogen demand levels (see Figure 4.9), depending on the policy objectives. For this, the maximum acceptable hydrogen cost from previous sections can be combined with the sectoral and regional demand to construct the demand curves for low-emissions hydrogen. For example, for Japan in 2035, maximum acceptable hydrogen cost is less than USD 2.2/kg H_2 or even negative for all sectors. This could be significantly raised by carbon pricing and other policies, but in most cases, it might not be enough to close the cost gap. Only in the case of power generation does Japan's contract for difference scheme close the full cost gap with the renewable hydrogen route, which is what the policy instrument is meant to achieve. This indicates that either additional policy incentives or voluntary willingness to pay are needed to close the remaining gap.

The same approach can be used across regions to estimate the global cost demand curve and determine the sector-region combinations with the highest maximum acceptable hydrogen cost. By 2035, import-oriented regions such as the European Union and Japan represent just over 10% of global demand for low-emissions hydrogen, adding up to 1.3 Mt in the Stated Policies Scenario (STEPS).[52] These are the regions with the highest maximum hydrogen acceptable costs due to

[52] See the Annex for details on the use of IEA scenarios in the Global Hydrogen Review.

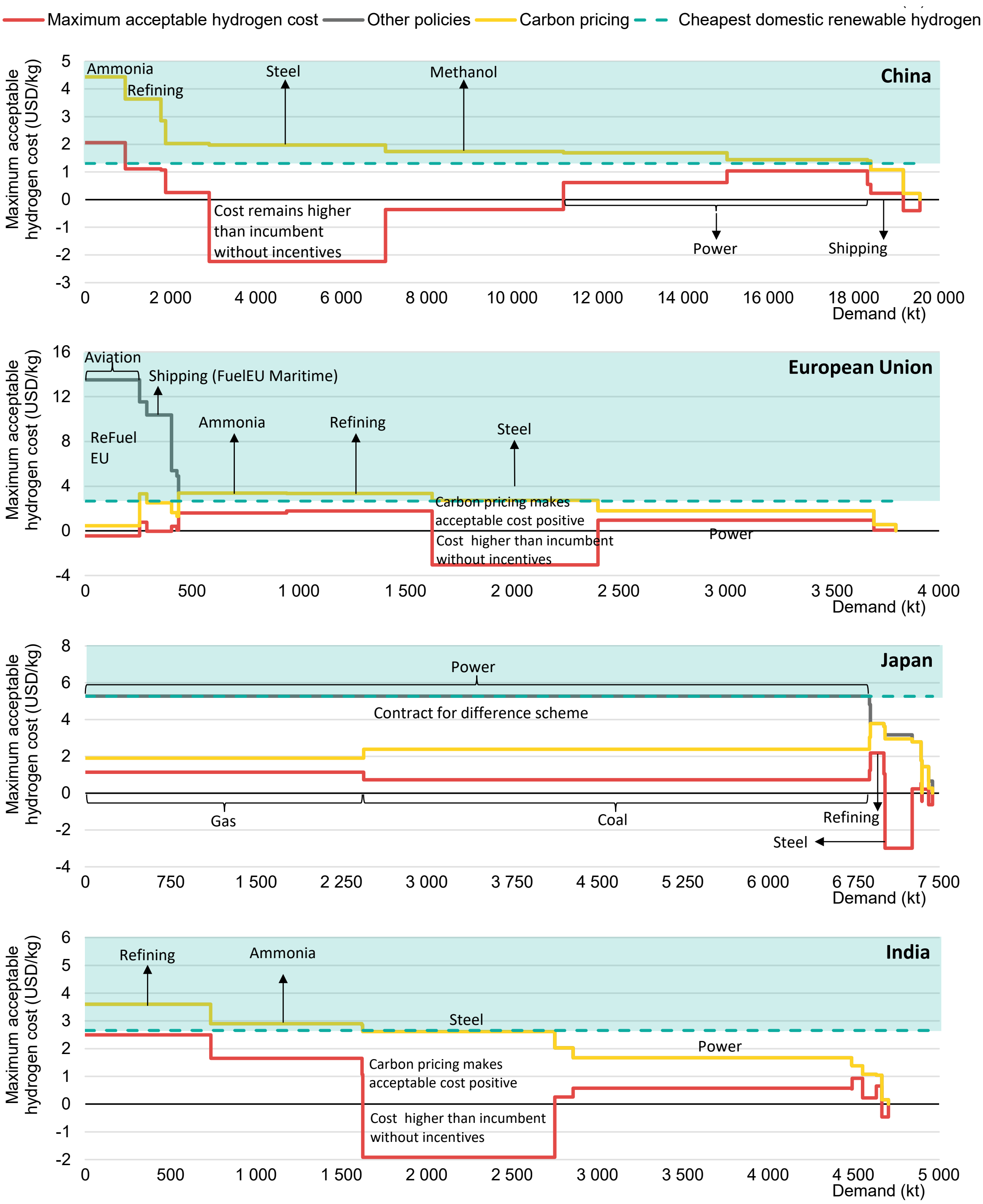
their high energy costs. Only a share of that would be satisfied with imports, which highlights the slow development of global hydrogen trade in this scenario. In the European Union, ReFuelEU provides the strongest support by using a penalty of double the differential with fossil jet fuel. However, to satisfy the 5% quota of synthetic fuels, about 665 ktpa of low-emissions hydrogen would be needed. Similarly, Japan introduced tax incentives for capital investment for steel, chemicals and sustainable aviation fuel (SAF) production in 2025, which will be available over a 10-year period. For chemicals, the tax incentive is about USD 335/t, which is equivalent to about two-thirds of the production cost by 2035 (without carbon pricing). The corresponding demand targeted by these tax incentives is also relatively small, with an additional 280 ktpa.

Most of the industrial sector across regions has a maximum acceptable hydrogen cost of USD 1-4/kg H_2, largely driven by carbon pricing. If it were not for carbon pricing, the maximum acceptable hydrogen cost for steel would be negative across all regions. This is because the cost increase in CAPEX, OPEX and energy consumption already put the hydrogen route at a disadvantage. For other industrial sectors, while the maximum acceptable hydrogen cost is positive without carbon pricing, it can still make a big difference. For example, a carbon price of USD 150/t CO_2 is equivalent to USD 1.5/kg H_2 when hydrogen is used for ammonia production, USD 0.38/kg H_2 when used for methanol, and USD 1.4/kg H_2 when used for refining. In refining in the European Union, an additional factor that increases the maximum acceptable hydrogen cost are the penalties from quotas introduced in the Renewable Energy Directive (see Chapter 7). By early June 2026, member states representing nearly half of the transport energy demand in the European Union had transposed the Directive. However, non-compliance penalties have a wide range (from no penalty to EUR 14.4/kg), only some countries allow for the refinery route[53] and many of these are still under discussion which make their inclusion in the analysis difficult and are therefore excluded.

In long-distance transport, the maximum acceptable hydrogen cost in aviation is mostly driven by carbon pricing, with USD 150/t CO_2-eq equivalent to an oil price of about USD 70/bbl. Even then, maximum acceptable cost is relatively low, at less than USD 0.5/kg H_2 across regions. Shipping is not favoured by the cost structure where the non-fuel costs are more than double the costs for heavy fuel oil. In both the ammonia and methanol pathways the other cost components not related to the fuel are higher than in the incumbent pathway due to higher engine, storage and bunkering costs, which makes the largest cost contributor even larger, leaving less room for the acceptable hydrogen cost. Even with the lower bound being considered in the IMO Net Zero Framework of USD 100/t CO_2, the maximum acceptable hydrogen cost for ammonia and methanol used in shipping would be below USD 0.5/kg H_2.

[53] The refinery route refers to being able to count the hydrogen used in refineries for hydrocracking towards the 1% RFNBO target in transport by 2030 under the logic that the energy contained in the hydrogen ends up in the refined fuels. This is seen as a cheaper alternative to meet the target due to the potential to use existing infrastructure.

Figure 4.9 Low-emissions hydrogen cost to meet maximum acceptable hydrogen cost by sector and region in the Net Zero Emissions by 2050 Scenario, 2035



Notes: Carbon pricing assumption of USD 150/t CO_2. Effect on maximum acceptable hydrogen cost is directly proportional to carbon price.

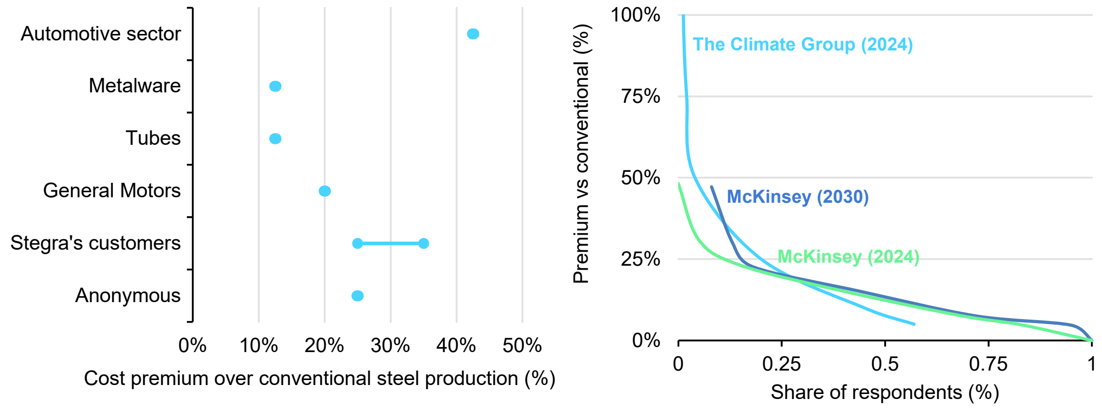
The ammonia and refining sectors have the highest maximum acceptable hydrogen costs, while the power sector has a large demand but a low maximum acceptable hydrogen cost.

Voluntary willingness to pay for low-emissions products

Part of the cost gap can also be closed through willingness to pay (WtP) a premium for low-emissions commodities on the part of pioneering companies. Reasons why companies might be willing to pay more include brand positioning, shareholder interests, emissions reduction targets and financing conditions. This WtP from the private sector can help trigger initial demand for low-emissions hydrogen. There is a higher chance that companies within a specific sector will be willing to pay more when the share of hydrogen cost within the total operating costs is relatively small, and when they have strong pricing power, giving them the ability to pass on the costs to downstream customers. The interaction between policy and WtP is more variable, since policy can change the landscape for investment.

WtP is usually assessed using market surveys, although these have drawbacks: they can be affected by a wide range of parameters, like the sample or the phrasing of the questions, and only provide a snapshot of the time in which they were conducted. Given the voluntary nature of WtP, it may vary over time as companies weigh competing priorities and deal with variable external conditions.

Figure 4.10 Willingness to pay from steel buyers for near-zero and low-emissions steel



Notes: Anonymous steel producer based on IDs 17 and 18 in Table 16 of Björsne and Cederlund (2025). 20% for General Motors is an upper bound.
Sources: IEA analysis based on data from Björsne and Cederlund (2025); Hydrogen Europe (2025); Stegra (2025); Climate Group (2024); McKinsey (2024); SSAB (2023); General Motors (2023).

Both steel producers and buyers have a significant willingness to pay for low-emissions products, which could be used to drive initial demand.

Across the value chains for different products, some stakeholders exhibit higher WtP than others. Collaboration between them is therefore important, to pass on the cost premium to those that are less impacted by it or willing to pay more. For example, in the steel sector (see Figure 4.10), some users from the automotive industry in Europe are willing to pay a cost premium of up to 42.5% compared to the incumbent pathway. The WtP can extend to players downstream the value chain, where the cost premium becomes smaller. For example, in Japan, one survey found that about 25% of the car owners who describe themselves as environmentally conscious are willing to pay a 24% premium on the price of the car. While this cannot be generalised, this is equivalent to more than 240% of the premium for the steel production, which is higher than the 169% cost premium of iron from H_2-DRI in comparison to a blast furnace. The WtP largely depends on the part of the value chain. For example, in ammonia use as fertiliser, both fertiliser companies and farmers are exposed to commodity markets with global competition, making the case for paying an extra premium more difficult (although despite this, there are multiple fertiliser companies driving offtake of low-emissions ammonia). However, final consumers might be willing to pay a sustainability premium for food, but the size of that premium depends strongly on method, label design and product type. There are also many steps in the value chain from ammonia producers to the end consumers of food products, which makes collaboration more difficult.

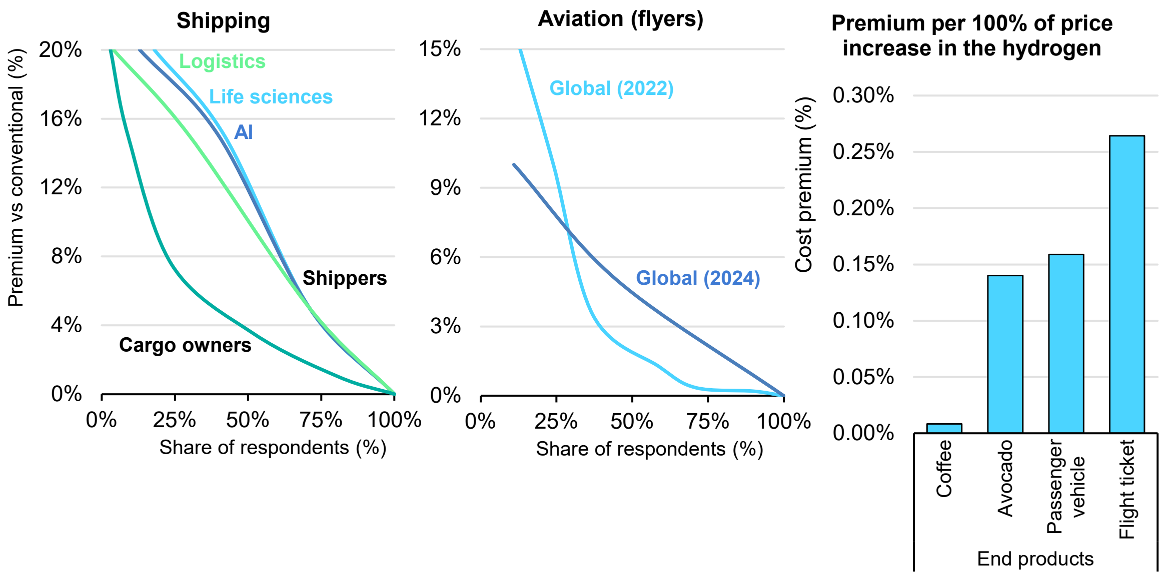
The premium that consumers are willing to pay differs significantly by sector and there are several examples where consumers would be willing to pay more than double the conventional option. Steel has, on average, the highest WtP, with the automotive sector leading among steel users. The amount that consumers are willing to pay differs along the value chain. For example, for steel producers, a small premium can have a larger impact on profit margins, resulting in a smaller WtP. Further downstream, car buyers include a wider range of customer types. In China, one survey found that more than a third of the car buyers that consider themselves most progressive would be willing to pay a 12% markup. This would be equivalent to a premium of 160% if it were all assumed to be used for low-emissions steel in the car, but it would be lower if it had to also cover the costs of decarbonising the other materials used in manufacturing a car. For shipping, Maersk estimates that a carbon price of at least USD 150/t CO_2, which is equivalent to about a 25% cost premium on the fuel, would be needed to cover the cost gap between fossil and renewable fuels in shipping.

Willingness to pay is also associated with the degree of decarbonisation in comparison to the conventional route. For example, in North America, 8% of steel companies[54] would be willing to pay a premium of up to 50% if the CO_2 reduction is at least 90%, whereas this high WtP disappears if the CO_2 reduction is just 50%. A recent survey of steel buyers found that only 10% of the respondents indicated that they would be willing to pay a premium of up to 25% for a product that reduces

[54] This does not mean that 8% of the steel demand would have this WtP, since the fraction of the demand from each company that would be covered by this WtP is unknown. This should only be taken as an indication of maximum WtP.

GHG emissions by at least 25% compared to the conventional route. In contrast, more than half said they would be willing to pay a premium of up to 25% if the emissions reduction exceeds 90%.

Figure 4.11 Willingness to pay for low-emissions products in shipping and aviation and effect of premium on end product price



Notes: Shipping results based on a sample of 125 cargo owners. Aviation results based on global surveys of more than 5 500 air travellers (2022) and nearly 248 (2024). Profit margins are not included. Under "Coffee", average fertiliser use and yield for the United States is assumed, with a conventional ammonia price at USD 380/t and low-emissions ammonia price at USD 1 000/t, and a cup of coffee at USD 4. For "Avocado", assumptions include use of 100% of low-emissions ammonia as shipping fuel; heavy fuel oil price at USD 15/GJ and low-ammonia price at USD 50/GJ; maritime route of 10 500 nautical miles and a speed of 23.9 knots. For "Passenger vehicle", assumptions include steel intensity of 820 kg/vehicle; price USD 40 000/vehicle. For "Aeroplane ticket", assumptions include the 2030 mandate of ReFuelEU for sustainable aviation fuels and e-fuels; fossil kerosene price at USD 28/GJ, bio-jet kerosene price at USD 35/GJ; and synthetic kerosene price at USD 163/GJ; fuel cost assumed to be 25% of the final ticket price.

Sources: Boston Consulting Group (2025); McKinsey (2024); IEA analysis for cost premium in end products based on IEA (2023); The Role of E-fuels in Decarbonising Transport; REFuelEU, and data from UN Food and Agriculture Organization; Haifa; International Fertilizer Association; Bloomberg.

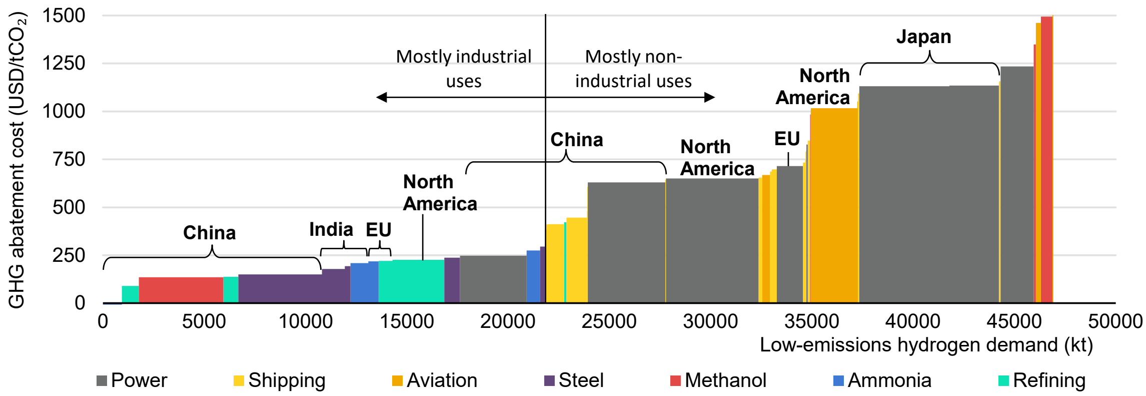
The share of buyers willing to pay a premium falls with higher premiums but the impact on the end product price is small, so the premium could be passed down the value chain.

For aviation, a survey of 23 airlines, logistics service providers and corporate customers found a WtP more than double the price of conventional jet fuel, whereas among final consumers, 13% were willing to pay a 15% premium on ticket prices. Shipping shows the lowest WtP, but it has improved in recent years. From a survey of 125 cargo owners, 24% were willing to pay more than 5% in 2024, more than doubling from 2021, although WtP declined in 2025. In these sectors, WtP could be high enough and have enough volume to create a lead market, highlighting the role of first movers in creating early demand for hydrogen-based products.

Abatement cost curves

The comparison of the maximum acceptable hydrogen cost and the production cost gives an indication of how far an application is from being cost-competitive, and how many incentives it might need. A more universal metric to compare different applications is the abatement cost of emissions. This combines the cost gap for each application with the emissions that can be mitigated with the low-emissions route. The abatement cost reflects one of the key dimensions to consider, together with energy security spillover effects and affordability, when designing energy policies. For applications where hydrogen is used as a feedstock (in refining and chemicals), there are no other technology options and hydrogen will continue to be used, regardless of the abatement cost. A large share of low-emissions hydrogen deployment is expected to be from renewable hydrogen, which could provide full mitigation of emissions.[55]

Figure 4.12 Abatement cost for low-emissions hydrogen by sector in the Net Zero Emissions by 2050 Scenario, 2035



Notes: GHG = Greenhouse gas; EU = European Union. Additional policy incentives like quotas, penalties and tax credits are excluded. Levelised cost for the low-emissions route is based on the best available resource for a single technology for electricity production (i.e. hybrid technologies are excluded). The cheapest technology is dependent on the region. Refer to the technical annex for details on technoeconomic assumptions.

By 2035, about 45% of the low-emissions hydrogen demand could be met with an abatement cost of less than USD 250/t CO_2.

There is a wide range of abatement costs for the use of low-emissions hydrogen (Figure 4.12).[56] Nearly two-thirds of the demand with an abatement cost of less than USD 250/t CO_2 demand is in China, and more specifically in the industrial sector. China benefits from low CAPEX and low cost of capital, which results in the cheapest production of hydrogen derivatives and therefore the smallest need

[55] Excluding emissions associated with the construction of the assets.
[56] This level does not represent a target or forecast, it just reflects a point after which the slope of the curve increases (i.e. the marginal benefit of higher carbon pricing would trigger less demand than previous increases).

for incentives to close the cost gap. The industrial sector in the European Union and India is next in terms of lowest abatement cost, given that both pathways (fossil-based and low-emissions) are expensive due to imports, resulting in an abatement cost that is higher than in China, but lower than in other regions.

Refining and ammonia in India are the applications with the lowest abatement cost thanks to the large contribution of fuel costs in these applications and the high reliance on imports for the fossil-based route (gas), which makes the incumbent route expensive. This, combined with high-quality renewable resources that make the renewable route cheaper, mean that the abatement costs remain low. In North America, the abatement cost is increased due to the low cost of the incumbent route (gas).

For methanol, the cost structure is more skewed towards fuel than for ammonia and steel, which means high fuel costs from low-emissions hydrogen have a larger impact on total production cost. Furthermore, methanol has lower specific emissions than ammonia, steel and refining, which means it would need a higher carbon price to have the same impact on production cost. This results in methanol having the highest abatement cost among industrial sectors; China is the only country in which the abatement cost is lower than USD 135/t CO_2. Steel has relatively high specific emissions, which means its sensitivity to carbon pricing is higher than other sectors and this translates into relatively low abatement costs.

Most of the non-industrial applications like shipping, aviation and power have an abatement cost of more than USD 400/t CO_2 due to the additional conversion steps and associated energy losses, which increase the production cost of derivatives. For these, China also has the lowest abatement costs for the same reasons as in the industry sector.

Low-emissions hydrogen has higher abatement costs than other technologies. For example, renewables are already cost-competitive with fossil fuels in many countries around the world (including storage to make them firm generation), which means they have negative abatement costs. This is also the case for energy efficiency, modal shift in transport and electric vehicles in some countries. Solar and wind could mitigate more than 8 Gt CO_2-eq/yr by 2030 at a cost lower than USD 100/t CO_2. These emissions reduction levers, together with electrification of the end-uses and efficiency, would already be enough to mitigate nearly three-quarters of current energy-related emissions, but hydrogen and other technologies are still needed to decarbonise the other quarter. While a gradual deployment from low to high abatement cost is the ideal optimum, real-world constraints like innovation cycles, infrastructure development, energy security and industrial capacity, among others, mean that pathways with a higher abatement cost need to start being deployed earlier. Similarly, given the high abatement cost for some of the hydrogen pathways, an alternative to consider is the use of carbon dioxide removal (CDR), which could reach lower abatement costs. However, CDR is still in the early stages of development, and the long-term costs are unclear. Furthermore, most countries do not have a policy framework in place to consider the interaction between mitigation and removals, which could lead to removals substituting mitigation instead of being used for those emissions that are harder to abate.

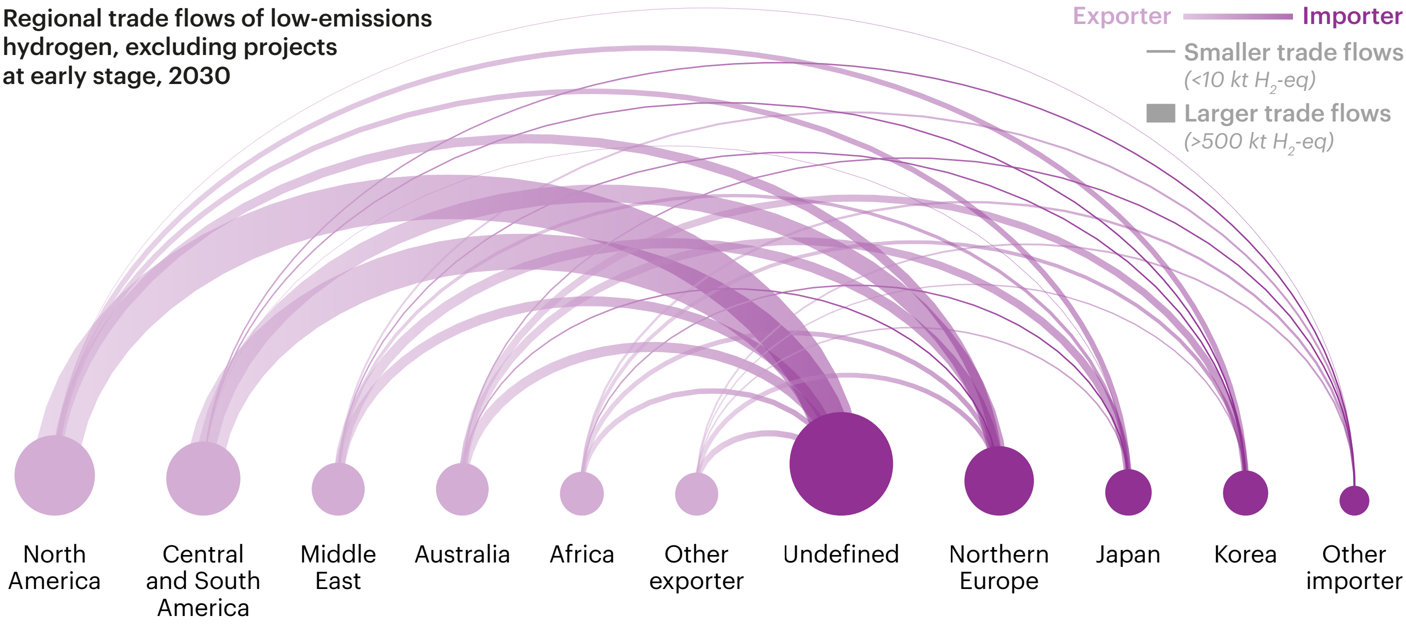
Chapter 5. Hydrogen trade and infrastructure

Highlights

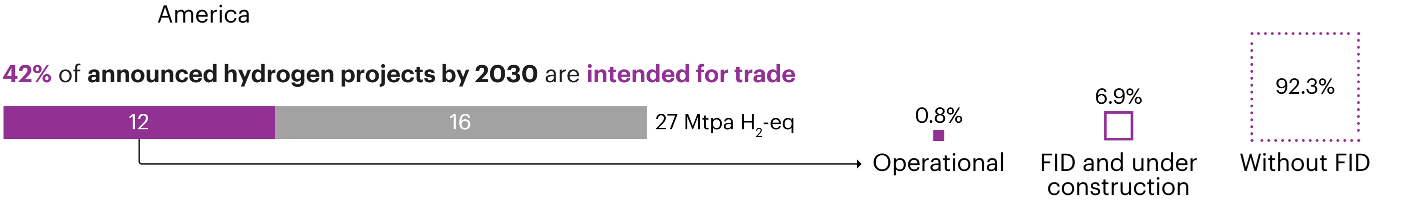
- Trade remains a key driver of low-emissions hydrogen projects, and would underpin over 40% of announced volumes by 2030 if all projects materialise. Less than 8% of this, around 1 Mtpa H_2-eq (hydrogen equivalent), comes from projects that are operational, in construction, or have committed investments, compared with around 16% across the overall project pipeline.
- First shipments of low-emissions hydrogen are taking place, enabling trials of logistics and certification approaches. Long-term bilateral contracts dominate, particularly for ammonia and ammonia-derived fertilisers, while hot briquetted iron (HBI) is gaining prominence.
- Announced hydrogen pipeline projects, including new and repurposed natural gas pipelines, exceed 40 000 km by 2035, but only 9% of this length is operational or has a committed investment. Since GHR-25, operational and committed hydrogen pipeline length has increased by 70%. Activity remains concentrated in Europe and China, which saw major milestones in 2025, as China began construction of the world's longest hydrogen pipeline, and Germany completed the world's longest repurposing of a natural gas pipeline.
- Announced underground hydrogen storage projects could provide 11 TWh of capacity by 2035 (335 kt H_2), but just over 7% has reached final investment decision (FID) or is under construction, equivalent to 0.6% of the estimated throughput from committed low-emissions hydrogen projects. Large-scale salt caverns are in construction in the United States, Germany and China.
- Around 170 ammonia and 130 methanol port terminals are in operation. Ammonia leads among announced projects, but more methanol infrastructure is under construction, mainly linked to bunkering. In Japan, construction has started on the first commercial-scale terminal for liquefied hydrogen imports.
- Pipelines are often the lowest-cost option for pure hydrogen transport where suitable routes are available and high utilisation rates can be achieved, while shipping can provide sourcing flexibility and use certain existing port infrastructure. However, where pure hydrogen is required at the point of use, shipping implies minimum costs of around USD 2/kg H_2 and energy use above 10 kWh/kg H_2, equivalent to over 30% of hydrogen's energy content, due to intensive liquefaction or reconversion steps, such as ammonia cracking.

Hydrogen trade and infrastructure

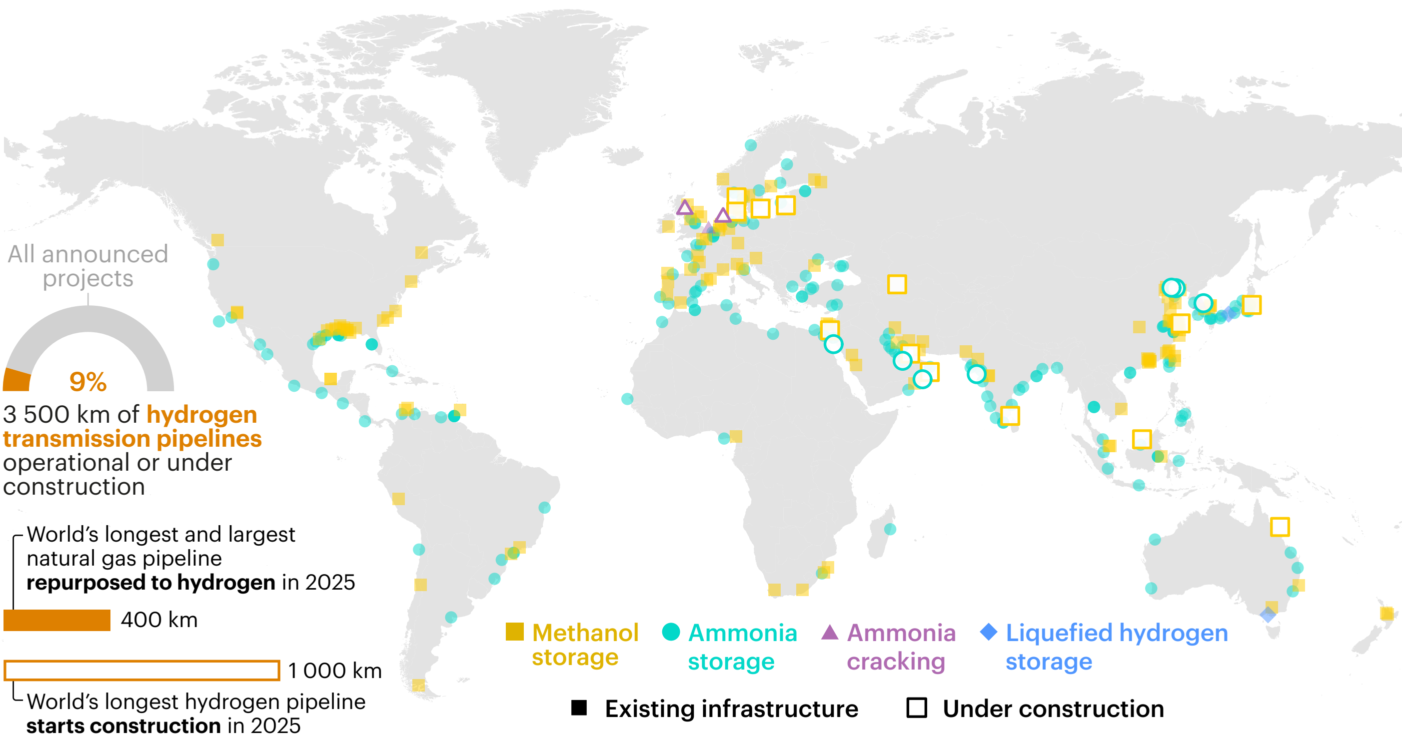
Trade drives low-emissions hydrogen project announcements, but realisation remains uncertain



42% of **announced hydrogen projects by 2030** are **intended for trade**



Many hydrogen infrastructure projects are announced, but few have reached construction, although those that do are often among the largest at scale to date



3 500 km of **hydrogen transmission pipelines** operational or under construction

World's longest and largest natural gas pipeline **repurposed to hydrogen** in 2025

400 km

1 000 km

World's longest hydrogen pipeline **starts construction** in 2025

7%

800 GWh of **underground hydrogen storage** operational or under construction

11 TWh	9 TWh	370 GWh	330 GWh$_e$
Announced underground hydrogen storage projects by 2035	Global installed capacity of pumped hydro storage in 2024	World's **largest salt cavern** for low-emissions hydrogen storage **nearing commissioning**	Global installed capacity of battery storage at utility scale in 2024

Overview and outlook for hydrogen trade

Today, hydrogen is mainly produced and consumed on-site, with only limited volumes transported by truck or pipeline to supply industries or refuelling stations. International trade is mainly limited to ammonia and methanol, which are exchanged primarily as chemical feedstocks rather than as energy carriers, with flows historically shaped by exporting countries' access to low-cost natural gas. Despite the absence of a global market for low-emissions hydrogen-based fuels[57] and continued uncertainty around its pace and scale of development, several notable commercial shipments have taken place in the past year, which can serve as demonstrations of logistics, certifications and regulation:

- In early 2026, Envision delivered the world's first commercial shipment of electrolytic ammonia from its plant in Inner Mongolia, the People's Republic of China (hereafter, "China"), to LOTTE Fine Chemical at the port of Ulsan, Korea, certified under the International Sustainability and Carbon Certification (ISCC) scheme.
- In early 2026, 2.5 million litres of electrolytic methanol (0.4 kt of hydrogen equivalent [H_2-eq]) from the Solar Park Kassø project in Denmark were shipped to Germany, certified under ISCC as Renewable Fuel of Non-Biological Origin (RFNBO).
- In October and November 2025, CF Industries exported low-emissions ammonia (NH_3), produced from natural gas with CCUS from Louisiana, United States, certified under the Verified Ammonia Carbon Intensity programme. These shipments included 23.5 kt NH_3 (4 kt H_2-eq) delivered to the port of Antwerp, Belgium, to be used by Envalior in caprolactam production, and 5 kt NH_3 (1 kt H_2-eq) delivered to the port of Varna, Bulgaria, for Agropolychim's nitrogen fertiliser production.

While the Envision and Solar Park Kassø shipments reflect bilateral arrangements, CF Industries' exports are handled by the trader Trafigura, acting as intermediary and managing logistics and delivery to end-users. As the market is still emerging, long-term bilateral contracts remain the dominant model (Table 5.1), providing revenue certainty that can lower financing costs. As markets mature and volumes scale up, trading companies may play a larger role by aggregating supply and demand, enabling shorter-term transactions, facilitating destination flexibility and supporting price discovery, thereby contributing to greater market liquidity. For example, Chinese trader Ampro has secured around 300 ktpa of electrolytic ammonia from at least four producers in northern China by 2028.

[57] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Table 5.1 Selected projects for low-emissions hydrogen fuels and derived products targeting exports with new or updated offtake agreements, 2025-2026

Project and exporter	Product and intended use	Off-takers and import region	Volume*	Type of agreement and expected year of first shipments
Blue Point, United States	**Ammonia** Co-firing for power. Industrial furnaces	Jera, Mitsui (Japan)	500 ktpa NH_3 (90 ktpa H_2, JERA), 280 ktpa NH_3 (50 ktpa H_2, Mitsui)	Off-takers are shareholders (2030)
AM Green Ammonia Kakinada, India	**Ammonia**	Uniper (Germany)	500 ktpa NH_3 (90 ktpa H_2)	Long-term binding offtake agreement (2028)
Envision Energy's Chifeng facility, China	**Ammonia** Co-firing for power. Bunkering fuel	Lotte Fine Chemical (Korea), Marubeni (Asia-Pacific region)	Undisclosed	Long-term offtake agreement (Q4 2025)
RIL's New Energy platform, India	**Ammonia**	Samsung (Korea, others)	Undisclosed; Valued at over USD 3 billion	15-year binding purchase agreement (2028–2029)
Yanbu green H_2 and ammonia hub, Saudi Arabia	**Ammonia** Ammonia cracking for pipeline injection	EnBW (Germany)	Undisclosed	Memorandum of understanding (MoU)
L&T Energy GreenTech plant at Kandla India	**Ammonia** bunkering	ITOUCHU (bunkering in Singapore)	300 ktpa NH_3 (55 ktpa H_2)	Long-term take-or-pay offtake agreement
ATOME La Villeta, Paraguay	**CAN** Fertiliser	Yara (Global)	260 ktpa of CAN (20 ktpa H_2)	Binding 10-year offtake agreement (2029)
Pacifico Mexinol, Mexico	**Methanol** Chemicals	Mitsubishi Gas Chemical (Japan, other Asia)	1 Mtpa of methanol	Long-term offtake agreement (2029)
Meranti Green Steel's Duqm project, Oman	**HBI** Electric arc furnace	Thyssenkrupp Materials Trading and Interfer (Europe), Meranti (Thailand), Glencore (Global)	2.5 Mtpa HBI (40% Thyssenkrupp, 10% Interfer, 50% Glencore & Meranti)	Firm offtake agreements
ACME Green steel project, Oman	**HBI/DRI** Electric arc furnace	Stavian Industrial Metal (Viet Nam)	800 ktpa HBI/DRI	10-year binding offtake agreement

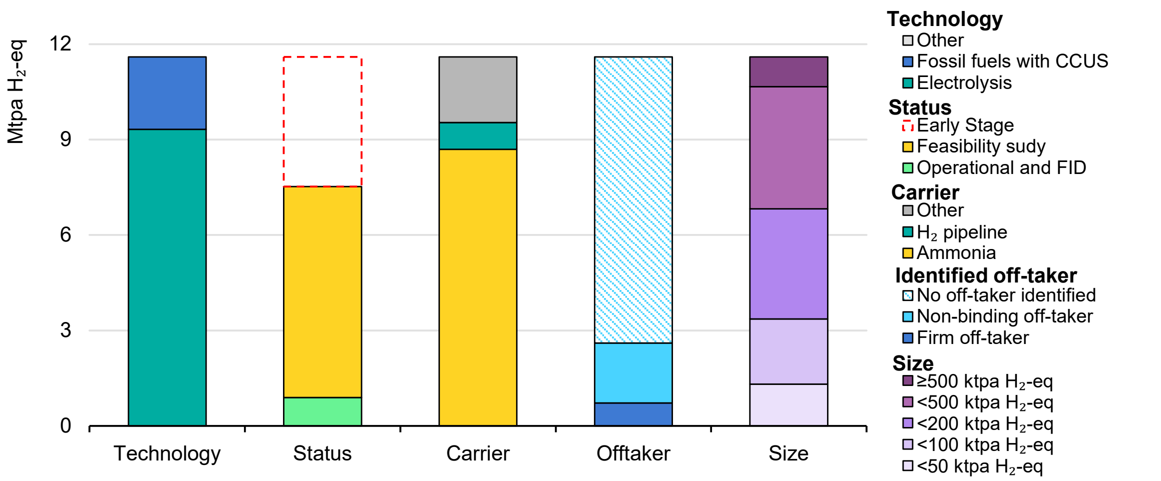
* Where hydrogen consumption figures are not reported, projects may combine natural gas reforming or natural gas-based reducing processes with direct electrolytic hydrogen injection. In such cases, hydrogen-equivalent volumes are not shown because they depend on the share of electrolytic hydrogen in the feedstock or reducing gas mixture, which varies by project and may evolve over time.

Notes: H_2 refers to H_2-eq. CAN = calcium ammonium nitrate; DRI = direct reduced iron; HBI = hot briquetted iron. For projects that have not yet reached FID, binding or firm offtake agreements are considered conditional on the project proceeding to FID.

Trade is a major driver behind many project announcements

Export-oriented projects represent almost 12 Mtpa H_2-eq by 2030, accounting for more than 40% of total potential low-emissions hydrogen production if all announced projects are realised. This illustrates that expectations for the development of an international market are a key driver for project announcements. Electrolysis-based projects are around 30% more likely than CCUS-based projects to target export markets, reflecting uncertainty over the eligibility of CCUS-based imports in Europe. However, progress remains limited: less than 8% of the potentially traded volume – almost 1 Mtpa H_2-eq – comes from projects with committed production, i.e. those that are operational, under construction or that have reached FID. This compares with around 16% across the overall low-emissions hydrogen project pipeline to 2030.

Figure 5.1. Announced projects for low-emissions hydrogen and hydrogen-based fuels intended for exports, 2030

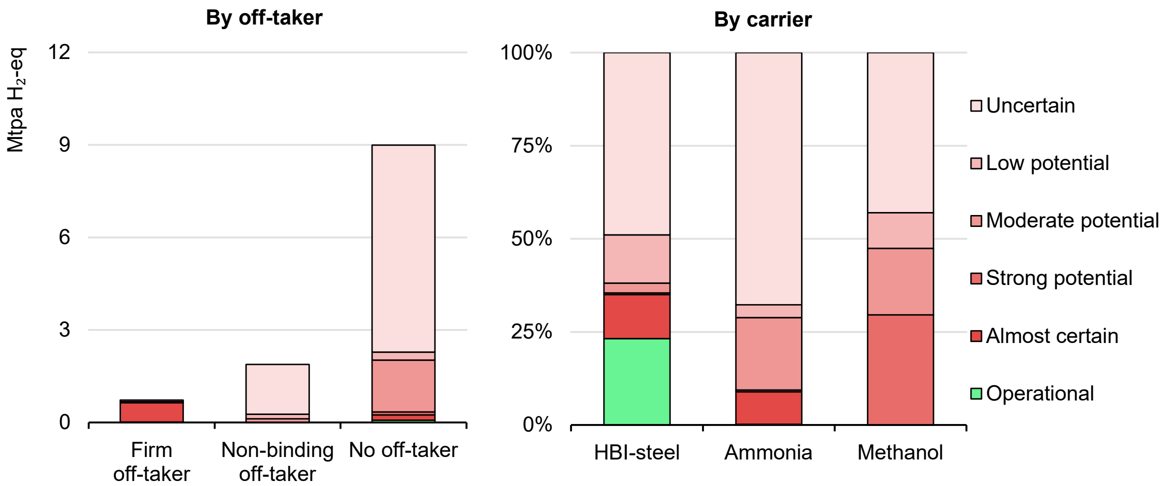


Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision. Size refers to estimated annual throughput, not installed capacity.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Trade expectations underpin more than 40% of announced low-emissions hydrogen volumes by 2030.

Across all project types, committed production amounts to 4.3 Mtpa H_2-eq by 2030, of which export-oriented projects account for around 20%. This is well below their 40% share in announced production, indicating that export-oriented projects are advancing to FID at roughly half the rate of the overall project pipeline. Using our methodology to evaluate how much low-emissions hydrogen production could feasibly be operative by 2030 (see Chapter 3), the additional traded volume with strong potential to materialise by 2030 is estimated at only 0.1 Mtpa H_2-eq, beyond the 1 Mtpa H_2-eq that is already traded or almost certain to be traded.

Figure 5.2. Likelihood of low-emissions hydrogen trade projects by identified off-taker and by carrier, 2030



Note: HBI = hot briquetted iron.
Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Around 1 Mtpa of low-emissions hydrogen could be traded by 2030, but most of the pipeline remains uncertain, notably due to limited offtake.

Several factors underpin the slower progress of export-oriented projects:

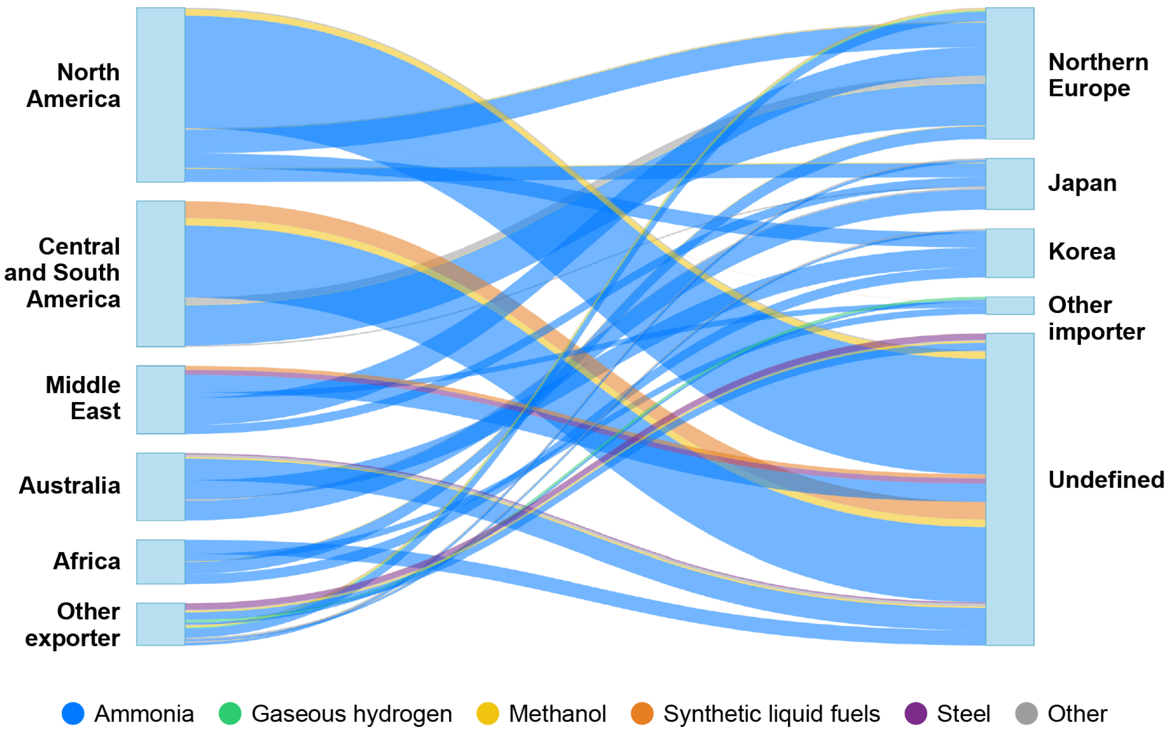
- **Lack of off-takers**. Only around one in five trade-oriented projects has identified a potential off-taker, of which just 30% are firm, with the remainder based on non-binding agreements or memoranda of understanding.
- **Large project scale**. Trade-oriented projects tend to be large, reflecting the scale needed for international trade. Around 70% of the volume comes from projects with estimated annual throughput above 100 ktpa H_2-eq, and 40% from projects above 200 ktpa, compared with 50% and 30%, respectively, across the overall pipeline of projects with committed investments. Given that most trade-oriented projects are electrolysis-based, their estimated annual throughput is well above that of the largest electrolytic plant in operation today, at around 30 ktpa. Only nine committed projects have an estimated throughput above 100 ktpa, and just two of these are electrolytic, while CCUS-based projects are larger. Smaller projects may still participate through certificate-based approaches, such as book-and-claim,[58]

[58] A book-and-claim system allows the environmental attributes of a product to be traded separately from the physical product itself. Under this model, certified low-emissions production generates certificates that can be purchased by a buyer, allowing it to claim the associated environmental attributes without receiving the physical product from the producer that generated them. This can support early markets for low-emissions hydrogen-based products before dedicated infrastructure is developed. A recent example is the low-carbon ammonia attribute agreement between PepsiCo and TalusAg.

rather than dedicated physical flows, particularly when co-located with existing fossil-based trade infrastructure.

- **Infrastructure readiness**. Around three-quarters of the volume is intended to be traded as ammonia, equivalent to nearly 50 Mtpa, while today less than 20 Mtpa are traded globally. With regards to committed projects, targeted investments are now trying to address some infrastructure gaps at ports. However, a significant scale-up of trade would require expanded port handling capacity and ships.
- **High concentration in emerging economies with high financing costs**. Trade-oriented project announcements are strongly concentrated in Latin America, which accounts for the largest share of announced volumes, and in Africa, which also represents a notable share. Excluding projects at a conceptual stage, Latin America ranks second after North America. In these regions, higher financing costs could weaken project competitiveness despite favourable renewable resources.

Figure 5.3. Bilateral trade flows of low-emissions hydrogen by carrier, excluding projects at earlier stages, 2030



Notes: "Undefined" refers to projects for which the import destination has not been identified or disclosed. Earlier-stage projects that are not included are those that remain at the conceptual stage and have not yet progressed to feasibility studies. Total traded volume represented in the diagram corresponds to 7.5 Mtpa H_2-eq by 2030.

Source: IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Compared with today's fossil fuel trade, potential suppliers would be more diverse than importers, but scaling up would require major expansion of infrastructure.

Useful lessons on the conditions needed for projects to make progress can be drawn from those that have reached binding offtake agreements (Table 5.1) and are approaching FID:

- **Competitive supply and export infrastructure**: Blue Point and Pacifico Mexinol benefit from low-cost US natural gas that can be delivered through existing pipelines to Mexico's Pacific coast. Mexinol has secured a long-term natural gas supply agreement and port berth access, allowing dedicated handling infrastructure to be added to existing facilities. Electrolytic projects combine low-cost electricity with high utilisation rates: the ATOME La Villeta project has a power purchase agreement for baseload hydropower from Itaipu, AM Green Ammonia's Kakinada project plans to reach 85% capacity factors with pumped hydro storage, and Envision's Chifeng facility has good renewable resources and low equipment costs. In Oman, projects have cheap gas for direct reduced iron (DRI) production, good renewable resources for low-emissions hydrogen blending and established port infrastructure at Duqm.
- **Demand-side market and policy incentives**: Yara's Climate Choice Fertilisers programme underpins several offtake agreements, including with ATOME, as food companies such as PepsiCo seek to decarbonise their supply chains, starting with potatoes. Meranti Green Steel's off-takers have strong policy incentives, as the EU Carbon Border Adjustment Mechanism (CBAM) enters its definitive phase in 2026, increasing the cost of emissions-intensive iron imports.
- **Access to affordable finance**: ATOME has secured debt commitments from several international public financiers, while Pacifico Mexinol is progressing financing negotiations with prospective public lenders (see Chapter 6). ACME's DRI project in Oman has secured finance from Indian state-owned Power Finance Corporation's REC.

Public support mechanisms are beginning to address one of the main barriers to trade (Table 5.2): the lack of long-term price certainty to de-risk early projects.

Table 5.2 Government-backed mechanisms that supported imports of low-emissions hydrogen and hydrogen-based fuels and progress, Q3 2025 – Q1 2026

Importing country	Product	Supplying regions	Policy type	Status and description
Germany	Methanol compliant with EU RFNBO	Any outside EU/EFTA	H2Global's purchase tender	Tender closed, contracts under negotiation. Budget: increase from EUR 300 million to EUR 438 million.
Germany	Product-open, compliant with EU RFNBO (H_2, NH_3 or methanol)	Africa, Asia, North America and South America & Oceania	H2Global's purchase tender (4 lots)	Tender closed, contracts under negotiation. Budget: increase from EUR 484 million per lot to EUR 580 million per lot.
Germany, Netherlands	Vector-open,* compliant with EU RFNBO	Global, other than Germany or the Netherlands	H2Global's purchase tender	Tender closed, contracts under negotiation. Budget: EUR 567 million of joint funding.

Importing country	Product	Supplying regions	Policy type	Status and description
Germany	Product-open, compliant with EU RFNBO (H_2, NH_3 or methanol)	Canada	H2Global's bilateral purchase tender	State aid approval was granted in January 2026, tender under design Budget: EUR 400 million.
Germany	Compressed hydrogen compliant with EU RFNBO	Denmark	Government subsidy allocated through an AaaS scheme**	State aid approval was granted in May 2026 for direct grants of up to 10-years and three projects awarded (590 MW in total) Budget: EUR 1.3 billion.
Germany	NA	Australia	H2Global's bilateral purchase tender	Public consultation closed; tender expected in H1 2026 Budget: EUR 400 million.
Japan	H_2-based fuels (≤3.4 kg CO_2-eq /kg H_2, ≤0.87 kg CO_2-eq /kg NH_3, well-to-gate)	Global	CfD scheme for hydrogen-based fuels	METI awarded 15-year subsidies for 780 ktpa of ammonia imports to JERA and Mitsui from the Blue Point project in the United States.
Korea	H_2 and NH_3 (≤4 kg CO_2-eq /kg H_2, well-to-gate)	Global	CHPS tender	Tender cancelled in October 2025 by Korea Power Exchange.

* In the vector-open lot, hydrogen must be the final product, but the suppliers are free to choose any transport method (e.g. liquid organic hydrogen carriers [LOHC], ammonia), provided that the carrier is converted back to hydrogen before delivery.

** Allocated through the Auctions-as-a-Service scheme under the European Hydrogen Bank, which enables national funding to support eligible projects that met all criteria in the European Hydrogen Bank auction that closed in 2026 but did not receive EU funding.

Notes: AaaS = Auctions-as-a-Service; CfD = contract for differences; CHPS = Clean Hydrogen Portfolio Standard; EFTA = European Free Trade Association; METI = Ministry of Economy, Trade and Industry (Japan); NH_3 = ammonia; RFNBO = renewable fuel of non-biological origin. Well-to-gate emissions include those generated up to the point hydrogen leaves the production facility, while well-to-wheel emissions also account for transport, storage, and end-use.

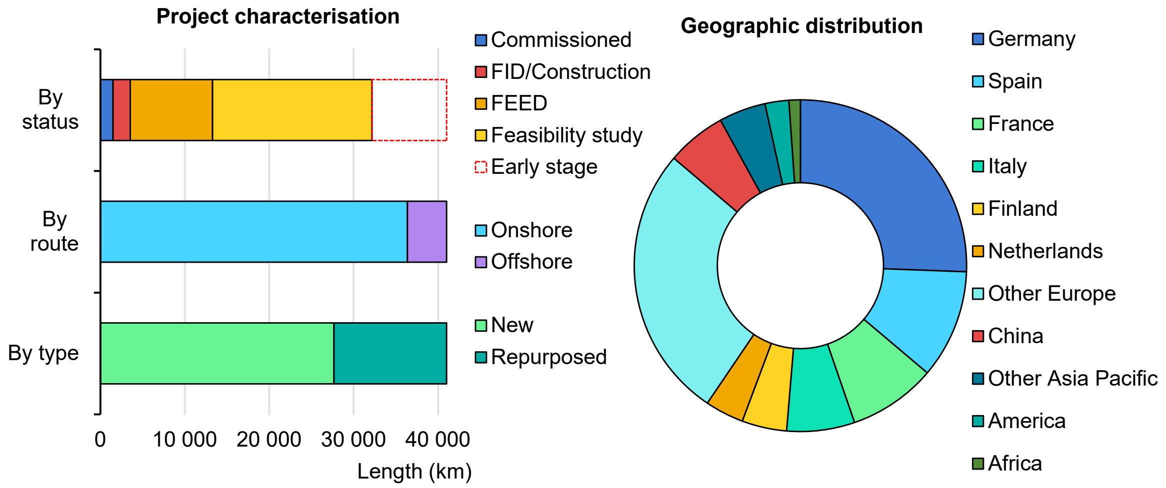
Transmission and underground storage

Transport by pipeline

More than 5 000 km of hydrogen distribution pipelines are in operation worldwide, mainly linking refineries and chemical facilities. These systems differ significantly from natural gas networks: they are typically privately owned, onshore, and designed for short-distance transport using small-diameter pipes operating at low pressure under steady flow conditions. They bear limited resemblance to the future hydrogen transmission networks now being planned, which will require larger diameters, higher pressures, regulated open-access frameworks, and the ability to manage load fluctuations through pressure variation and linepack. This shift is driving updates to global pipeline standards. Hydrogen pipelines are currently often designed under the American Society of Mechanical Engineers (ASME) B31.12 standard, but this is considered conservative for high-pressure transmission. The broader ASME B31.8 standard, widely applied to natural gas transmission and distribution, is now being extended with a dedicated hydrogen exception chapter, expected by late 2026, mirroring the CO_2 exception added in 2025. For offshore hydrogen pipelines, DNV published its first recommended practice in March 2026, DNV-RP-F123, complementing its established submarine pipeline standard, DNV-ST-F101, with specific guidance for transporting hydrogen and hydrogen blends in new and existing pipelines.

Announced hydrogen transmission pipeline projects,[59] including new and repurposed natural gas pipelines, total more than 40 000 km by 2035. However, just 9% of this length has reached FID, is under construction or has been commissioned. Progress has accelerated since the previous edition of the Global Hydrogen Review (GHR-25), with almost 1 500 km added to the total length of operational and under-construction hydrogen pipelines – a 70% increase. While current construction activity appears limited relative to the number of projects, natural gas transmission expanded by around 15 000 km per year over the past four decades. Despite the slower pace of hydrogen pipeline development, the difference in scale is less pronounced than it may appear.

Figure 5.4. Global hydrogen transmission pipeline length based on announced projects by type and region, 2035



Notes: FEED = front-end engineering design; FID = final investment decision. Other Europe includes Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Czechia, Denmark, Estonia, Greece, Hungary, Ireland, Latvia, Lithuania, Poland, Portugal, Serbia, Slovakia, Slovenia, Sweden, Switzerland, Ukraine and the United Kingdom. For each of these countries, the total announced hydrogen transmission pipeline length is below that of the Netherlands, which is the European country with the smallest pipeline length shown separately in the figure. While 2030 is generally used as the reporting year throughout this report, 2035 is used for infrastructure developments to reflect longer lead times required for their planning and construction. More details on announced projects for hydrogen pipelines can be found in the IEA's Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Infrastructure Projects Database (June 2026).

The world's first high-pressure hydrogen pipeline was commissioned in 2025 but only around 9% of the 40 000 km announced by 2035 has committed investments.

[59] A comprehensive list of project announcements related to the construction of new hydrogen transmission pipelines or the repurposing of existing natural gas pipelines can be found in the IEA Hydrogen Infrastructure Database (June 2026).

Projects for pipelines remain geographically concentrated, particularly in Europe and China, with several milestones achieved since the publication of GHR-25.

Relevant progress on new hydrogen pipelines

- In October 2025, China began construction of the world's longest hydrogen pipeline, the 1 038 km Kangbao–Caofeidian pipeline in Hebei (1.55 Mtpa, 72 bar, 0.8 m diameter). Expected to be commissioned at the end of 2026, it will connect the wind-rich Zhangjiakou area (Kangbao) with the industrial hub and port of Caofeidian. Construction also began in September 2025 on the 195 km Huadian pipeline, Dama Banner-Baotou (100 ktpa, 63 bar, 0.5 m diameter), expected to be completed within several months. While more regional in scope, the project is part of Inner Mongolia's planned hydrogen transmission network and links renewable-rich production areas with industrial demand in Baotou. In addition, construction of Sinopec's "West-to-East Hydrogen Transmission" pipeline is expected to start in 2026. This 1 145 km pipeline (100 ktpa), running from Ulanqab in Inner Mongolia to Tianjin via Shanxi, Hebei and Beijing, would become China's first inter-provincial hydrogen pipeline and connect areas with excellent renewable energy resources and land availability for large-scale production to major industrial consumers to the east and south.
- The first 32 km section of the Dutch hydrogen pipeline network around the Port of Rotterdam area, under construction since April 2024, was completed in August 2025, followed by commissioning, including hydrogen filling and pressurisation. The pipeline stretches from the Maasvlakte extension to nearby industrial users, including refineries and chemical plants that today consume around 500 ktpa H_2. In March 2026, the first production project, Shell's 200 MW Holland Hydrogen 1, was weld-connected to the network. Despite delays, the project is expected to start operating in late 2026, supplying Shell's refinery in Pernis. Other developers, including Uniper through its planned 500 MW H2Maasvlakte project, are also studying pipeline connection. The hydrogen pipeline was built alongside the CO_2 pipeline for the Porthos project, with both laid in parallel over a 19 km stretch just 40 cm apart. While this added complexity, it also illustrates the potential for co-ordinated multi-commodity infrastructure development to reduce construction costs relative to separate development.
- While offshore hydrogen pipeline projects remain at an earlier stage, some projects are advancing. In July 2025, a dedicated project company was established by the three gas transmission system operators (TSOs) of France and Spain to develop the BarMar (Barcelona-Marseille) pipeline and support project finance.[60] This was followed in November 2025 by the completion of geophysical studies, confirming the technical feasibility of BarMar. In February 2026, Worley and StreamTec were selected to provide engineering, procurement and construction (EPC) services for the AquaDuctus offshore hydrogen pipeline in the German North Sea.

[60] Project finance allows project risks and financing to be ringfenced from, and not carried on, the sponsors' balance sheets.

Relevant progress on repurposed natural gas pipelines to hydrogen

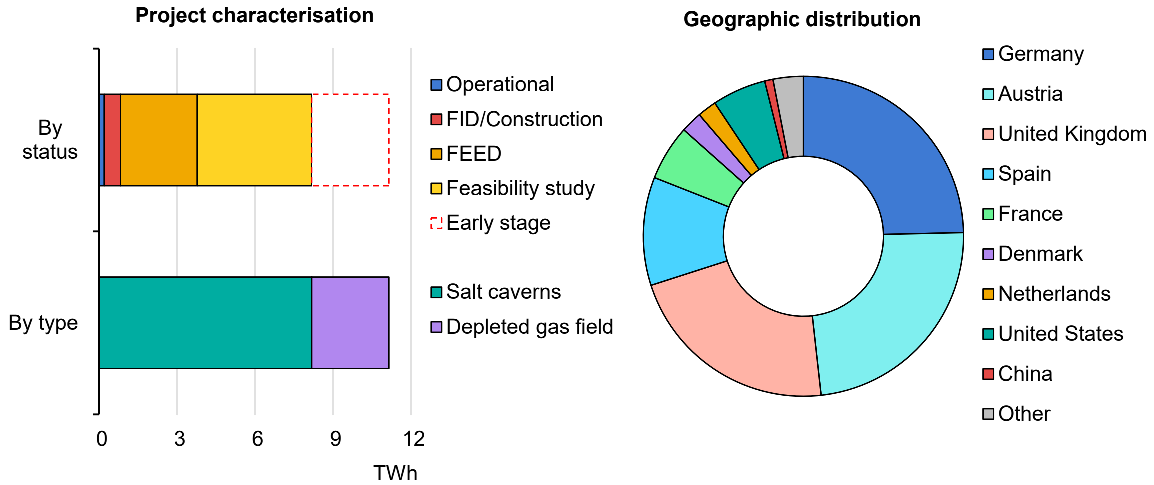
- In December 2025, the repurposing of the first 400 km of the northern section of the Flow–Making Hydrogen Happen project (Lubmin–Saxony/Anhalt) in **Germany** was completed in less than a year. This is the world's largest pipeline repurposing to date, but reflects rather unique circumstances, as the pipeline was originally built to transport natural gas from the Nord Stream landing point on the Baltic Sea to southern Germany and was idle. Binding capacity bookings opened in March 2026 as part of Germany's broader network capacity reservation (see Table 5.3).
- In August 2025, Thyssengas began repurposing the 53 km cross-border pipeline between the Netherlands and Germany, Vlieghuis-Ochtrup, with commissioning expected by 2027. The pipeline is the first physical cross-border link to enable Dutch import capacity from the ports of Amsterdam, Eemshaven and Rotterdam with Germany's GET H2 corridor, as well as with salt cavern storage sites in Zeeland. It will deliver hydrogen to Thyssenkrupp in Duisburg and other chemical sites in the Ruhr region. Binding capacity bookings also opened in March 2026.

Underground gas storage

Underground gas storage is a key component of natural gas systems, providing balancing and flexibility to manage seasonal demand swings and supply disruptions. Global underground gas storage capacity is around 500 bcm, equivalent to roughly 10% of annual gas demand, with almost 90% in porous reservoirs, mainly depleted gas fields. Underground hydrogen storage could deliver similar services, but demand for storage is likely to follow a different pattern. Unlike natural gas, where seasonal heating demand is a major driver, needs for hydrogen storage may be shaped more by industrial operating patterns, variable electrolytic production and the emergence of traded hydrogen and hydrogen-based products. In the near term, underground storage may therefore be most valuable for short-term balancing between variable production and demand. Over time, it could also support energy security by reducing exposure to supply disruptions and price volatility, including those linked to geopolitical risks.

Technological readiness for underground hydrogen storage is progressing across several geological formations, supported by recent demonstration projects (see Chapter 6). However, the transition from demonstration to commercial-scale deployment remains limited. If all announced underground hydrogen storage projects, including new facilities and repurposed natural gas storage sites, are realised by 2035, around 11 TWh of storage capacity (equivalent to 335 kt H_2) would be available. However, just above 7% of this volume has reached FID or is under construction, equivalent to less than 0.6% of the estimated annual production from committed low-emissions hydrogen projects (either operational or with FID). If all announced projects are fully realised, global underground hydrogen storage capacity by 2035 would be equivalent, in energy terms, to around 2% of current natural gas storage capacity in salt caverns and domes.

Figure 5.5. Global underground geological storage capacity for hydrogen based on announced projects by technology, status and region, 2035



Notes: FEED = front-end engineering design; FID = final investment decision. "Salt caverns" covers both underground storage in salt caverns and salt domes. More details of the announced projects for underground hydrogen storage can be found in the IEA's Hydrogen Tracker.
Source: IEA (2026), IEA Hydrogen Infrastructure Projects Database (June 2026).

Few commercial-scale underground hydrogen storage facilities are under construction, and only 7% of more than 11 TWh of announced capacity (335 kt H_2) by 2035 has reached FID.

Relevant progress in the United States and Europe

Currently, there is one commercial-scale hydrogen storage facility under construction in the United States and one in Europe, excluding a few legacy salt caverns for the chemical industry. Most other projects remain at demonstration scale, aimed at validating technologies and building operational experience. Several milestones have been achieved since the publication of GHR-25.

- In the United States, the 11 kt H_2 Delta ACES storage project began commissioning in 2025, including hydrogen cushion gas injection, and completed its first full life-cycle tests in December 2025, being now in the final stages of commissioning. The storage capacity is around 370 GWh across two caverns, which is around 10% larger than the global installed stationary battery storage capacity at utility-scale in 2024. While the world's largest hydrogen salt cavern storage in operation has a similar capacity in a single cavern, Delta ACES will be the first at such scale linked to electrolytic hydrogen.
- In Germany, RWE continued construction of the Epe-H2 project in 2025 (115 GWh, 3.4 kt H_2), with the first cavern expected to be filled from mid-2026. In January 2026, EUR 120 million from the Connecting Europe Facility (CEF) was

allocated to support construction of a second cavern, for which FID is still pending. This marks the first allocation of CEF funding to hydrogen infrastructure construction, as support for hydrogen had previously been limited to studies.

Relevant progress on underground hydrogen storage in China

In China, underground gas storage capacity relative to natural gas demand is lower than in Europe or the United States, particularly for **salt caverns**, as bedded salt formations with thin layers and multiple interlayers are prevalent in the country and constrain the development of salt caverns. These geological conditions, which have also impacted natural gas storage, are also expected to limit the potential for hydrogen storage. Caverns in such formations tend to be flatter and sometimes horizontally developed, making them more complex and costly to construct than the tall, cylindrical caverns typical of salt dome regions in Europe and the United States. Despite this, China has rapidly expanded underground natural gas storage in recent years, with capacity almost doubling between 2020 and 2023. Building on this, several hydrogen storage pilot projects have been launched in the past years to develop solutions adapted to the country's geological context, notably in the provinces leading salt cavern deployment for natural gas.

- China Salt Group and Tsinghua University are developing two large-scale hydrogen salt caverns in Jiangsu Province, with a total capacity of 30 million m³ (2.7 kt H_2), to serve as a testing platform for cyclic hydrogen storage. In September 2025, a tender was issued for design and technical services.
- The Pingmei Shenma salt cavern in Henan Province completed hydrogen storage trials in September 2025 and started operations in 2026 (1.5 million m³, 135 t H_2).

Lined hard rock caverns function as large underground storage tanks, requiring relatively low cushion gas and enabling faster injection and withdrawal rates. They can be developed in a wide range of locations, unlike salt caverns, depleted gas fields or saline aquifers, which are more constrained by geology.

- In December 2024, construction began on the Daye Deep Earth Hydrogen Storage pilot project in Hubei, China's first pilot for hydrogen storage in rock caverns, with progress in 2025 including tunnelling and lining. It consists of a 50 000 Nm³ (4.5 t H_2) horizontal tunnel-type cavern. Once completed, it is expected to be the world's largest hydrogen storage facility in hard rock and the first of its kind, using a horizontal tunnel design and repurposing abandoned mine shafts to reduce construction costs. Further research is supported by the Hubei Deep Earth Energy Storage Technology Innovation Center, established in 2023, with the aim of developing a national hydrogen storage testing platform.

Infrastructure at ports

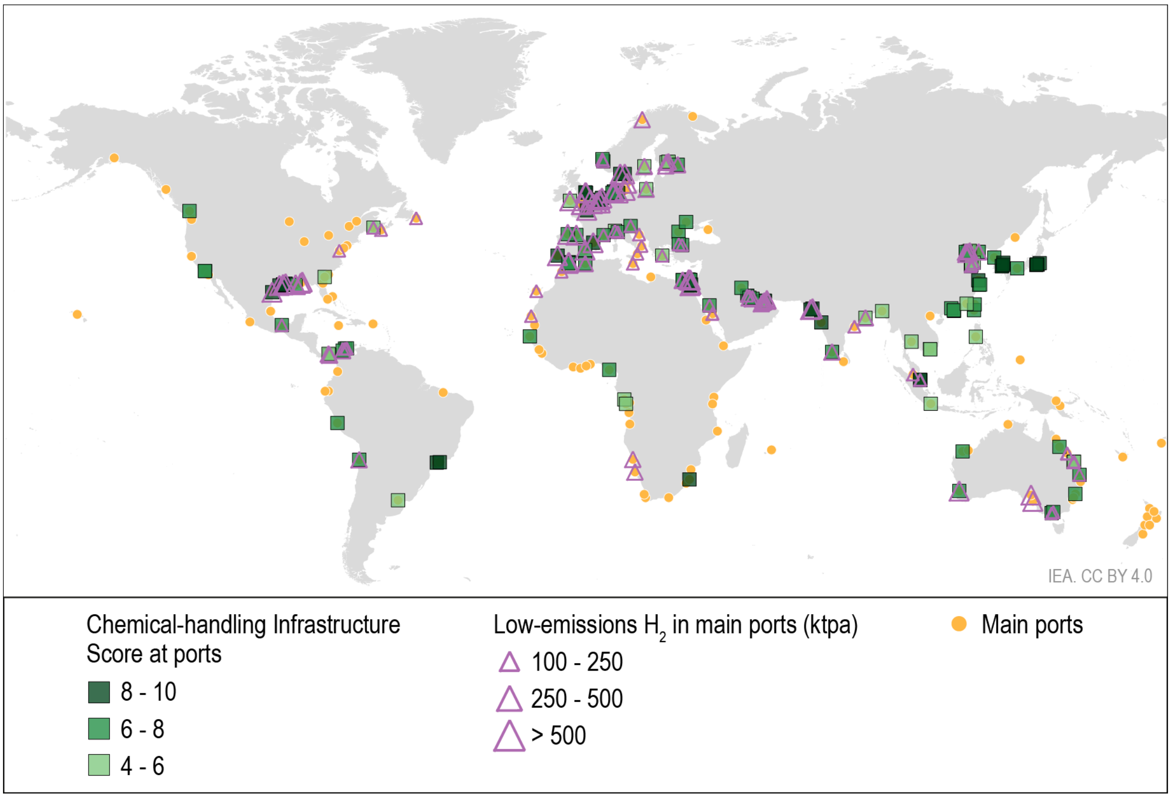
Seaborne trade underpins the global economy and is a key pillar of energy security, enabling diversified supply routes and reducing reliance on fixed infrastructure such as pipelines. Ports also host significant storage capacity, providing a buffer against short-term imbalances in supply and demand. As such, beyond their logistical role, ports act as strategic assets for managing energy stocks, responding to disruptions and supporting market stability. In this context, in March 2026 the European Commission adopted the EU Ports Strategy and the EU Industrial Maritime Strategy, recognising ports as critical for hydrogen import corridors and the supply of alternative fuels for shipping. Notably, in Japan, support for port infrastructure is provided through the Hub Development Support Scheme, launched under the Hydrogen Society Promotion Act, which began accepting applications for hub development front-end engineering design (FEED) support in early 2025. In March 2026, the Hekinan and Tomakomai ammonia import hubs became the first projects approved under the hubs programme.

Trade in low-emissions hydrogen is expected to remain limited by 2030, at less than 12 Mt H_2, even in the unlikely event that all announced projects materialise. However, it is expected to take place on a larger scale than trade in hydrogen derivatives. Ammonia provides an illustrative example, as the preferred carrier for intended exports to date. If all ammonia-oriented trade projects proceed, they could represent more than twice today's ammonia trade, implying a need for substantial additional infrastructure. A more geographically diversified group of potential exporters, compared with today's concentrated ammonia supply base, would further increase these requirements.

More than 50% of announced low-emissions hydrogen production projects expected by 2030 are located within 250 km of a high-traffic port,[61] increasing to almost 70% within 500 km. This indicates that both trade and bunkering could play an important role for these projects. Around 50 high-traffic ports could have access to at least 200 ktpa of hydrogen within 250 km, rising to more than 90 ports within 500 km. This strong spatial alignment highlights the potential synergies between ports and low-emissions hydrogen project development. Despite a 25% reduction in the announced project pipeline compared with announced projects included in GHR-25, the number of ports identified declines by only around 15%. This suggests that the overall picture remains broadly similar, with ports still able to source sizeable volumes of low-emissions hydrogen from nearby projects if they materialise.

[61] A high-traffic port is defined as one of 114 major global ports handling significant volumes of container, dry bulk or tanker traffic, complemented by an additional 128 ports that currently play a significant role in bunkering.

Figure 5.6. Chemical-handling Infrastructure Score at high-traffic ports in 2025 and low-emissions hydrogen-based fuels potentially available close to ports by 2030 based on announced projects



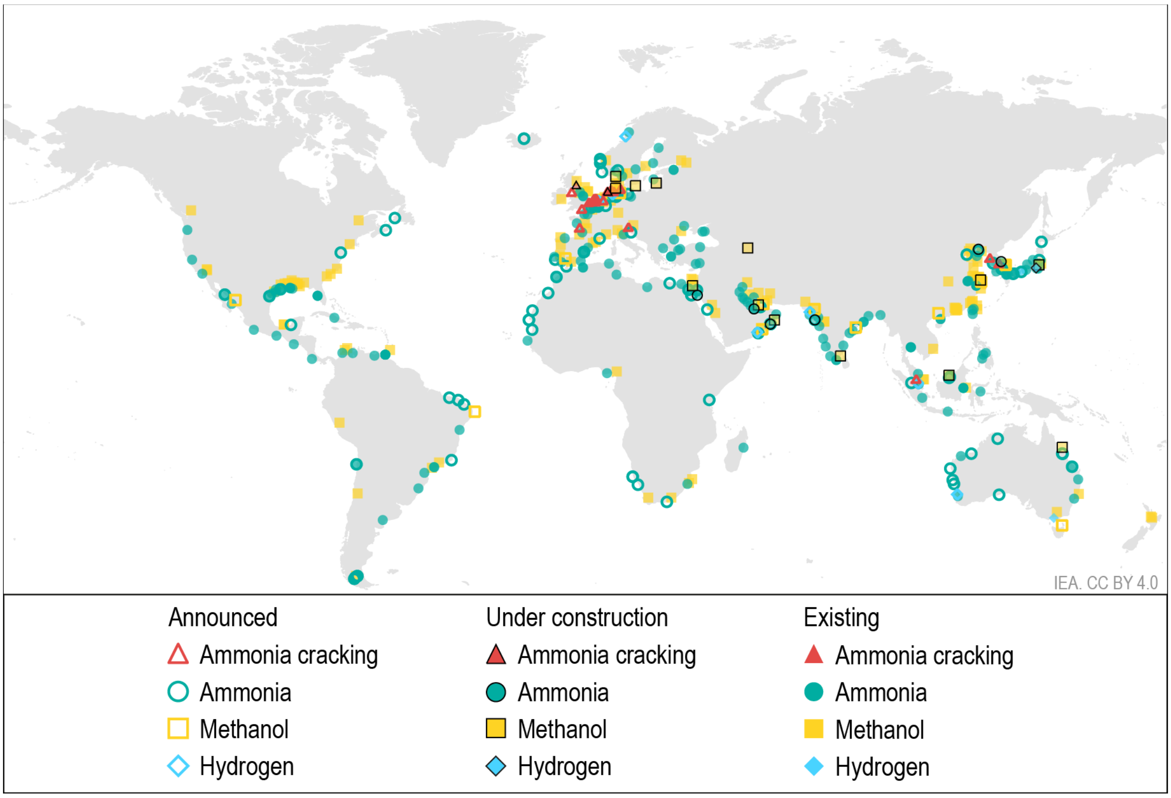
Notes: This figure represents the potential low-emissions hydrogen supply within a 500 km radius of each main port if all announced projects targeting operation by 2030 materialise, regardless of announced end-use. Potential overlaps between nearby ports are not accounted for, so figures represent non-additive, indicative supply per port rather than exclusive or realised volumes. Only those ports whose supply of low-emissions hydrogen would exceed 100 ktpa H_2 are illustrated. The Chemical-handling Infrastructure Score ranges from 0, i.e. no storage infrastructure at all, to 10, i.e. storage infrastructure in place for ammonia, liquefied petroleum gas (LPG), methanol and liquefied natural gas (LNG).

Sources: IEA (2026), IEA Hydrogen Infrastructure Projects Database (June 2026); IEA (2026), IEA Hydrogen Production Projects Database (June 2026).

Nearly 50 ports could have potential access to at least 200 ktpa of hydrogen if all projects are realised, and half of these ports also show high readiness to handle chemicals.

Marine fuels today are mainly liquid oil fuels, while only a small share, around 6%, consists of liquefied natural gas (LNG) and liquefied petroleum gas (LPG), which are gaseous at ambient conditions. A shift to low-emissions fuels, including hydrogen-based fuels, would require adjustments to existing port infrastructure and fuel handling systems, including additional investment, land availability, new construction and permitting. Ports with experience in handling chemicals, supported by established regulatory frameworks, skilled personnel and existing storage assets, are likely to be better placed to support early deployment by scaling up bunkering infrastructure more rapidly. To assess this readiness, in 2025 the IEA developed a Chemical-handling Infrastructure Score,[62] based on existing infrastructure for ammonia (NH_3), LPG, methanol (MeOH) and LNG at ports, which has been applied to the updated project pipeline this year. Nearly 80 ports score above 5 out of 10, indicating a combination of infrastructure and operational capabilities that could facilitate the uptake of low-emissions fuels. This score is similar to in GHR-25, as new port infrastructure has been mostly limited to LNG terminals. Around 25 of these ports could have access to more than 200 ktpa of hydrogen within 250 km, increasing to almost 45 within 500 km, making them early candidates for low-emissions hydrogen-based fuel trade and bunkering.

Figure 5.7. Existing and announced port infrastructure projects for hydrogen and hydrogen-based fuels trade and bunkering



Source: IEA (2026), IEA Hydrogen Infrastructure Projects Database (June 2026).

Around 170 ammonia and 130 methanol terminals already exist, and more methanol port infrastructure is under construction than for ammonia, despite fewer announcements.

Despite these opportunities, investment in port infrastructure remains limited compared to announcements, as many of these announcements are linked to low-emissions hydrogen projects which are yet not moving towards committed

[62] The chemical-handling infrastructure score is calculated as: Score = 3 × NH_3 + 3 × LPG + 3 × MeOH + 1 × LNG, where each variable is binary: 1 if the port has storage infrastructure for that carrier (NH_3, LPG, MeOH, or LNG), and 0 otherwise. Infrastructure score can vary from 0, i.e. no storage infrastructure at all, to the maximum score of 10, i.e. storage infrastructure in place for NH_3, LPG, MeOH and LNG.

investments. A market consultation by the Port of Rotterdam identified demand uncertainty and the lack of hinterland infrastructure, such as pipelines, as key risks, particularly given the high capital costs (which are in the range of hundreds of millions of dollars) and the need for utilisation certainty. Most respondents indicated that terminals are unlikely to be operational before 2030. As one of the main import hubs, this suggests that a large share of the global pipeline for terminals would materialise only after 2030. A study under the German TransHyDE project also highlighted space constraints in European ports, as continued demand for fossil fuel infrastructure limits the availability of land for new low-emissions fuel facilities.

Ammonia infrastructure at ports

Today, more than 170 ammonia terminals are in operation across nearly 60 countries, with a combined storage capacity of around 6.5 Mt of ammonia. Existing infrastructure could accommodate some increase in utilisation, but new terminals are being planned, particularly in potential exporting regions where infrastructure is currently lacking or where higher volumes are expected.

New ammonia terminals have been proposed in 30 countries, including several that currently lack such infrastructure. In many cases, these projects are closely linked to specific trade-oriented low-emissions hydrogen projects. As a result, limited progress towards FIDs for these projects is also slowing the development of associated port infrastructure. However, recent disruptions to fertiliser supply chains linked to the conflict in the Middle East have reopened discussions around strategic nitrogen fertiliser reserves. While nitrogen-related storage presents safety challenges due to the hazardous and potentially explosive nature of some products, renewed interest could support additional investment in ammonia-related storage infrastructure at ports.

Only a limited number of port infrastructure projects are currently under construction. Notable examples include developments in northern China, such as the start of construction on new ammonia terminals in Jinzhou and Panjin ports in Liaoning province, which are expected to handle exports from large-scale projects in nearby inland provinces.

An increase in ammonia trade could drive the development of ammonia cracking infrastructure in locations where final demand is for hydrogen rather than ammonia. In November 2025, Air Liquide commissioned a 30 tonnes per day (tpd) ammonia cracking plant at the Port of Antwerp-Bruges, Belgium, the largest of its kind[63] for low-emissions hydrogen applications. In the same month, Uniper and

[63] Larger ammonia cracking units exist for heavy water production for nuclear applications. These units crack ammonia to extract deuterium rather than to produce hydrogen, and operate under different conditions.

thyssenkrupp Uhde signed an agreement to build up to six large-scale ammonia cracking plants, with a combined capacity of 7 200 tpd of ammonia, including in the planned import terminal in Wilhelmshaven, Germany (Table 5.3).

The Chemical-handling Infrastructure Score indicates where early ammonia bunkering activity may be more likely to emerge, particularly in ports that already handle ammonia. Over the past year, activity has advanced in several high-scoring locations. In Pilbara, Australia, discussions are progressing on ammonia bunkering for bulk carriers under the Pilbara Clean Fuel Bunkering Hub, with companies including MOL and Yara signing MoUs to participate. In Singapore, agreements with Japanese firms, including Itochu and Sumitomo Corporation, are supporting ammonia bunkering development, with Itochu authorised in May 2026 to conduct bunkering trials. Itochu is also studying an ammonia bunkering hub at the Port of Nagoya, Japan. In Europe, OCI and Victrol announced a partnership in October 2025 to develop ammonia bunkering in the Netherlands and Belgium. At the same time, developments are also emerging in locations without existing ammonia infrastructure, such as the ammonia bunkering stations planned by Azane Fuel Solutions in Mongstad, Florø and Risavika, Norway, supported by grant funding from the state-owned enterprise Enova in 2025. These stations are expected to be operational by 2029 and designed with bunkering speeds[64] of more than 100 tonnes of ammonia per hour and around 1.4 kt of storage. By comparison, ammonia storage tanks at major ports today reach capacities of up to 50 kt.

Methanol infrastructure at ports

Today, nearly 130 methanol terminals are in operation across more than 40 countries. The project pipeline for new methanol terminals is smaller than for ammonia. However, as methanol is liquid at ambient conditions and less hazardous to handle, projects tend to progress more quickly, reflecting lower costs, simpler engineering and less stringent handling regulations. Methanol bunkering, rather than methanol trade, is emerging as the main driver of new infrastructure deployment. This includes both new infrastructure at ports that previously lacked methanol storage and the expansion of capacity at major ports in response to growing bunkering demand.

In this regard, the second-largest bunkering port in the world, Rotterdam in the Netherlands, started expanding its methanol and ethanol storage capacity in

[64] Fuel oil bunkering in major ports typically reaches several hundred tonnes per hour. Transfer rates of around 500 t/h are considered an optimal bunkering rate for dry bulk vessels, which are the most likely early users of ammonia. Ammonia also has around half the energy content per tonne of marine fuel oil, implying lower bunkering rates in both mass and energy terms than those typically seen in major ports. Nevertheless, a transfer rate above 100 t/h would allow smaller short-sea dry bulk and offshore service vessels to bunker substantial volumes within typical port turnaround times and to fill their fuel tanks.

March 2026, including the construction of a new jetty. The port of Ulsan, Korea, is also expanding its storage infrastructure to support methanol bunkering, with operations expected in 2026. In China, Shanghai aims to bunker 1 Mtpa of methanol and biofuel by 2030, supported by dedicated port infrastructure developments. In India, Kandla Port is partnering to establish a methanol production and bunkering hub, aiming to supply vessels along the Singapore–Rotterdam corridor as an intermediary refuelling point.

Liquefied hydrogen infrastructure at ports

Shipping hydrogen in its pure, liquefied form has not yet reached commercial maturity, unlike other transport pathways. While hydrogen liquefaction and storage technologies have been deployed since the 1960s, particularly in the space industry, large-scale storage and tankers for shipping liquefied hydrogen (LH_2) remain under development. Momentum towards early commercialisation is building, with the first large-scale terminals and LH_2 carriers under construction. The standard ISO 24132:2024 for LH_2 transport was published in 2024 and a revision is underway.

Over recent years, several announcements have been made on potential LH_2 trade corridors, with more detailed projects emerging in the past few months. In November 2025, Kawasaki Heavy Industries started construction of the world's first commercial-scale LH_2 terminal, in Kawasaki, Japan, with completion expected by 2030. Its 50 000 m³ storage tank, equivalent to around 3.5 kt H_2, would be more than ten times larger than the largest LH_2 tanks in operation today. The size is aligned with plans to have a 40 000 m³ LH_2 carrier in service by the same timeframe. In March 2026, Ecolog selected KBR to carry out the FEED study for a multi-molecule terminal at the Port of Amsterdam, the Netherlands, with a capacity of 200 ktpa LH_2 and 1.8 Mtpa of liquid CO_2. The project could enable cold integration between the two value chains and has already secured equipment supplies with Japanese companies. In addition, new LH_2 trade corridors are being explored, including via the Port of Hamburg, Germany, and from Gen2 Energy's planned projects in Nesbruket and Holandsvika, Norway.

Assessing the market infrastructure needs

Market assessments help address the co-ordination challenge between infrastructure development and demand certainty (Table 5.3). Calls for interest are used to gather input from prospective producers and consumers, covering location, volumes, timing and storage needs. This helps to inform network design and support binding capacity bookings required for projects to reach FID.

Table 5.3 Capacity bookings and market surveys for selected hydrogen transmission and storage projects, Q3 2025 – Q1 2026

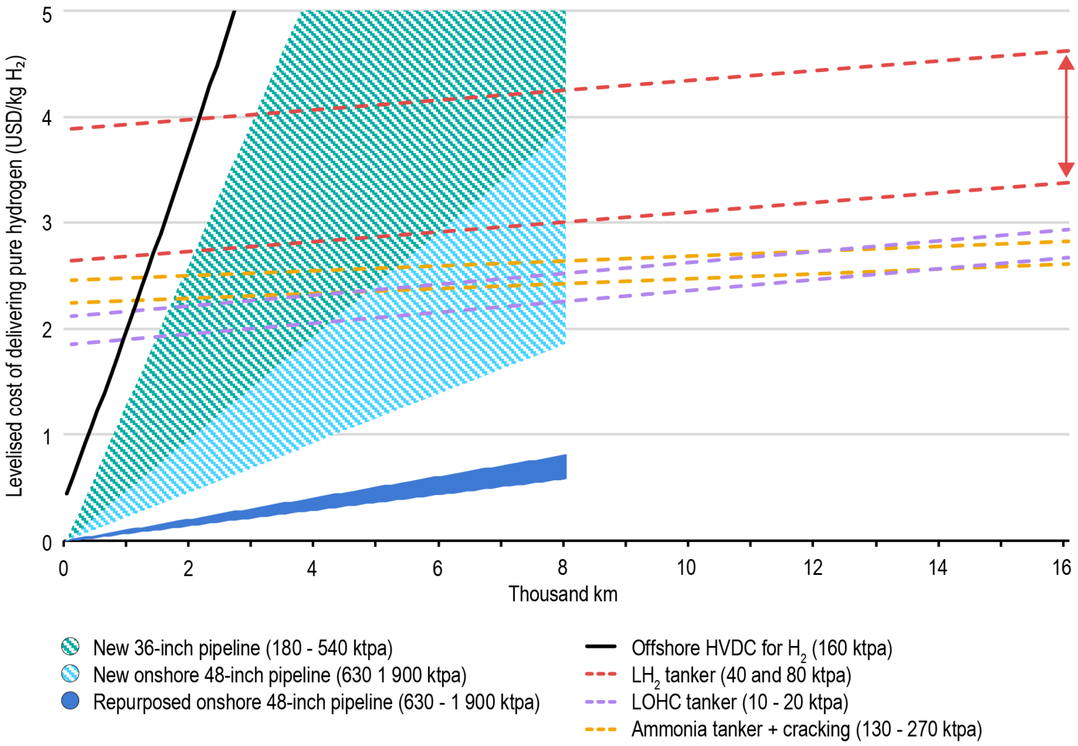
Project & Country	Type	Organisers	Size	Description
Danish Hydrogen Backbone 1 (The Seven) Denmark	Capacity booking - Pipeline	Energinet	133 km Entry and exit capacity: 2.7 GW (10% reserved for short-term products)	Capacity booking opened from January-December 2026 for bookings in 2030-2046. Bookings of at least 0.5 GW at both entry and exit points for 10 years are required for FID. As of April 2026, six companies had signed agreements for up to 3.7 GW over time.
German hydrogen core network Germany	Capacity booking - Pipeline	22 gas TSOs	Exit capacity: 1.7 GW in 2026, 10.8 GW in 2030	Launched in March 2026 for binding reservations for up to 7 years. Requests for 2.9 GW of entry and exist capacities.
Nordic-Baltic Hydrogen Corridor Finland, Estonia, Latvia, Lithuania, Poland, Germany	Market survey - Pipeline	6 gas TSOs	2 500 km	Launched in Q1 2026.
Finnish and Baltic Sea Region Hydrogen Market Value Chains Finland	Market survey - Pipeline	Gasgrid	1 400 km (Nordic Hydrogen Route) 1 250 km (Baltic Sea Hydrogen Collector).	Survey launched in H1 2026.
National Ten-Year Development Plan for Hydrogen Transmission Poland	Market survey - Pipeline	Gaz-System	Infrastructure in Poland and its connection to Europe	Consultation launched with the Polish Energy Regulatory Office in Q1 2026
Spanish Hydrogen Backbone Spain	Call for interest - Pipeline	Enagás	2 600 km	Non-binding consultation launched in Q2 2026
2027 Network Development Plans (NEP) Germany	Market survey – Pipeline & Storage	Hydrogen network operators (WTNB)	Covering all infrastructure in Germany	German WTNB, together with electricity and gas TSOs, conducted a market survey in Q1 2026,
Zuidwending salt cavern Netherlands	Capacity booking - Storage	HyStock	Cavern: 5 kt H_2	Reservation phase planned for Q2-Q4 2026, followed by an agreement phase in Q1-Q3 2027 to finalise contracts before FID.
Hydrogen Import Terminal Wilhelmshaven Germany	Capacity booking – ammonia terminal & cracking	Uniper	Terminal: 2.6 Mtpa ammonia	Non-binding phase launched in Q2 2026

Note: Capacities are illustrated in lower heating value terms.

Hydrogen transport pathways

Hydrogen transport pathways depend on the intended end-use. If hydrogen is to be used as a derivative, such as ammonia, methanol or synthetic liquid fuels, it is more efficient and cost-effective to transport it directly in that form. However, consumers requiring pure hydrogen need it to be converted into higher-density forms, particularly for large-scale or long-distance transport. Transporting compressed hydrogen via pipelines is often the lowest-cost option, but when economies of scale cannot be achieved, including where pipelines must cover very long distances or are not geopolitically feasible, other alternatives are being considered. These include transporting hydrogen by ship in its liquid form (LH_2) or using carriers such as ammonia and liquid organic hydrogen carriers (LOHCs), which then need to be reconverted to pure hydrogen. Large-scale LH_2 shipping and the reconversion stage for ammonia and LOHC pathways have not yet [reached](#) commercial technological readiness.

Figure 5.8. Indicative cost of hydrogen transport by carrier, distance and utilisation rate, 2030



Notes: HVDC = high-voltage direct current; LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier (methylcyclohexane considered). Capacities in brackets are expressed in hydrogen-equivalent ktpa. Costs are levelised costs for delivering gaseous hydrogen and exclude hydrogen production costs unless otherwise stated. Pipeline costs refer to onshore transmission pipelines operating at 25-75% of design capacity for 5 000 full-load hours per year. Offshore HVDC reflects the electricity transmission cost required to produce 1 kg of hydrogen in an electrolyser with 69% efficiency. Shipping ranges reflect port-terminal throughput based on 15 shipments per year at the upper end of the cost range and 30 shipments per year at the lower end, assuming the same vessel size and storage infrastructure. Representative vessel sizes are 40 000 m³ for LH_2, 76 000 m³ for ammonia and 35 000 deadweight tonnes (DWT) for LOHC. LOHC costs are based on methylcyclohexane.

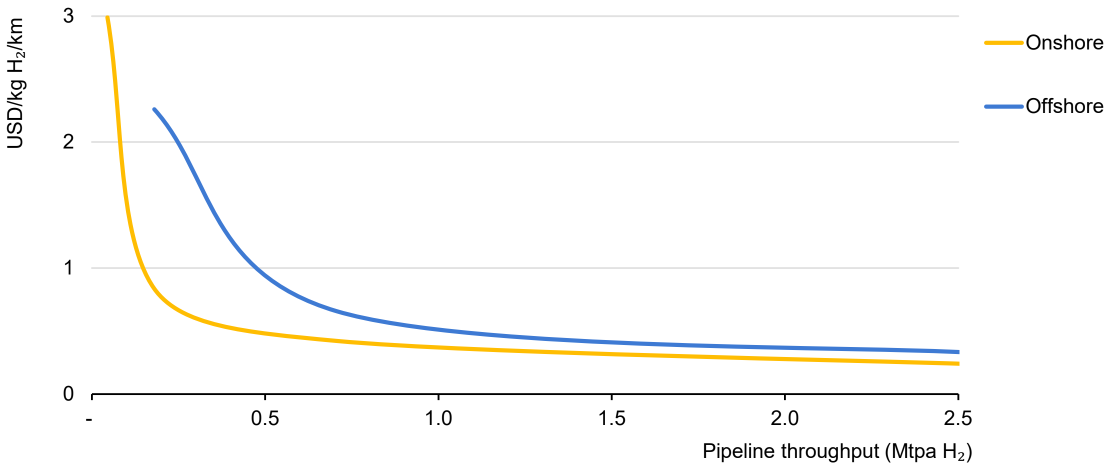
The costs of pipelines increase with distance, while shipping costs depend more on conversion and reconversion costs, with LH_2 most exposed to terminal utilisation rates.

Hydrogen transmission by pipelines

Transport costs for hydrogen pipelines increase broadly in proportion to distance, in contrast to shipping, where costs are largely driven by upfront conversion and reconversion steps that are relatively less dependent on distance. Pipeline transport is capital-intensive and benefits from strong economies of scale, with lower unit costs achieved at higher throughput and utilisation rates, including over long distances.

For example, a new 20-inch diameter pipeline can transport around 1 GW of hydrogen (approximately 135 ktpa), with a levelised cost of around USD 1.0/kg H_2 per 1 000 km when operated at 75% of its design capacity. By comparison, a new 48-inch diameter pipeline can transport up to around 13 GW (around 1.9 Mtpa), with levelised costs falling to approximately USD 0.2/kg H_2 per 1 000 km under similar utilisation assumptions. These economies of scale introduce planning challenges, as future demand for pure hydrogen remains uncertain and infrastructure sizing decisions must be taken with incomplete information. Lower utilisation significantly increases costs: for instance, a 20-inch pipeline operating at 25% of its design capacity (around 45 ktpa) would have a levelised cost of almost USD 3/kg H_2 per 1 000 km. To address this, some countries, such as Germany and Denmark, are introducing inter-temporal cost allocation mechanisms to even out tariffs over time and avoid disproportionately high tariffs in the early years of operation, when users and utilisation may be low. In Denmark, government support is also conditional on a minimum capacity booking requirement of around 20% for 10 years.

Figure 5.9. Indicative investment cost of hydrogen transport by new pipelines, 2030



Notes: For each throughput capacity, the investment cost shown reflects the lowest-cost pipeline option across 20-, 36- and 48-inch diameters, assuming utilisation rates between 25% and 100% and 5 000 full-load hours.

Source: IEA analysis based on Slowinski et al. (2023), European Hydrogen Backbone: Implementation roadmap – cross border projects and costs update.

Hydrogen pipelines can deliver very low costs at scale, but costs are highly sensitive to utilisation, and rise sharply when throughput is limited.

Repurposing existing natural gas pipelines can reduce costs substantially, typically by 40-75%, as the pipeline itself represents the largest share of capital expenditure, even though new compressors and modifications are required. In practice, repurposing depends on asset availability: idle pipelines or systems with multiple parallel strings can enable the conversion of individual lines, whereas pipelines that remain in operation for natural gas transport are not available for repurposing.

Experience from Europe shows that planned hydrogen network costs can change substantially as projects advance, as a result of changes in routing, asset availability, material and equipment costs, regulatory requirements, and so on. In the Netherlands, initial plans for the national hydrogen network relied more heavily on repurposing, but limited availability meant that revisions to the network design were required. This, combined with higher steel prices and other requirements, contributed to an increase in estimated investment costs from EUR 1.5 billion to EUR 3.8 billion for the planned 1 200 km hydrogen pipeline network. In 2022, the government set aside EUR 750 million in direct grants, but in December 2025, the Netherlands Court of Audit warned that this may not be enough to cover start-up losses in the initial years. In Germany, the revised Gas and Hydrogen Network Development Plan 2025 increased the planned hydrogen network length for 2037 by less than 2% compared with 2024 estimates, to 9 206 km, but estimated investment costs rose by almost 30%, to EUR 24.2 billion.

Hydrogen shipping

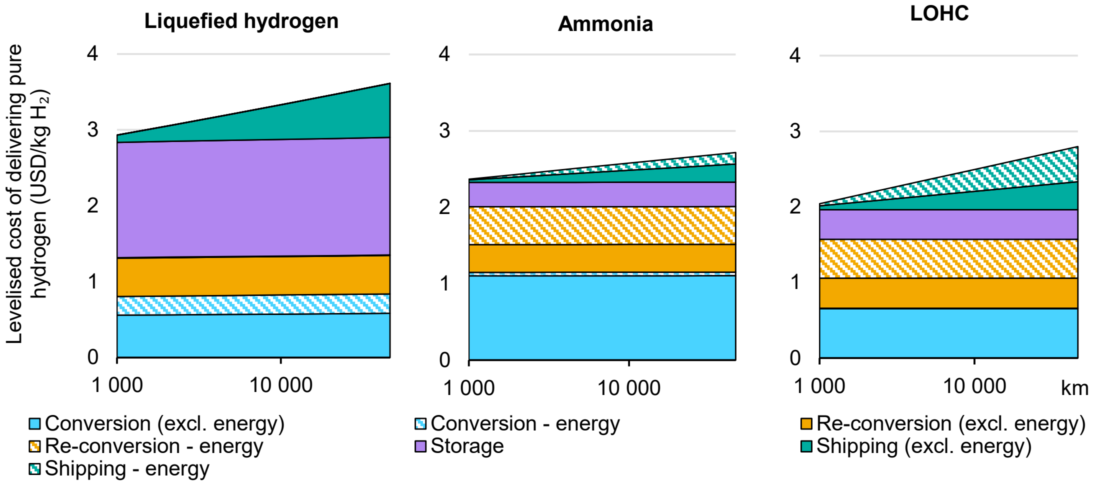
In cases where pure hydrogen is required at the point of consumption, hydrogen transport by ship currently implies minimum costs of around USD 2/kg H_2, but it can offer several advantages compared with pipeline transmission:

- **Use of readily available infrastructure.** Existing infrastructure can be used across much of the value chain, particularly where the hydrogen-based product is transported and used directly without reconversion. Even where reconversion to hydrogen is required, relying on brownfield assets can reduce the need for new infrastructure and shorten development lead times. This makes ammonia the preferred choice for trade-oriented projects, which can draw on existing production, storage, handling and shipping infrastructure to a certain extent.
- **Flexibility**. Shipping enables diversification of supply and demand under a spot market, allowing cargoes to be redirected between suppliers and consumers in response to market conditions or disruptions, including due to geopolitical factors.
- **Moderate economies of scale**. While shipping benefits from economies of scale related to vessel size and port infrastructure utilisation, these are less pronounced than for pipelines, and optimal sizing depends on the carrier used. For ammonia, medium-sized and very large gas carriers (around 40 000-80 000 m³) are

assumed to be the most used, based on the existing fleet and orderbooks. For LH_2, sizing is a more critical parameter, as storage tanks at ports can account for up to 50% of total transport costs, making high utilisation essential. In this context, Kawasaki Heavy Industries initially planned for a 160 000 m³ LH_2 tanker but has recently scaled down designs to around 40 000 m³. The smaller vessel size is intended to support phased supply chain development, improve utilisation of early port infrastructure and enable learning-by-doing before development of the larger 160 000 m³ vessel, although it may imply higher unit capital costs.

- **Distance-related costs**. For long-distance transport, shipping can be more cost-effective than pipelines, as costs are largely driven by conversion and reconversion processes and increase much less with distance. However, the impact of distance varies by carrier: LOHCs are more sensitive to distance, as they transport only around 6% of hydrogen by weight, whereas ammonia tankers carry around 18% of their cargo as deliverable hydrogen.

Figure 5.10. Indicative cost of electrolytic hydrogen transport by carrier and distance, 2030



Notes: LOHC = liquid organic hydrogen carrier. The analysis assumes 25 annual shipments at both exporting and importing ports for liquefied hydrogen, and 20 annual shipments at each port for ammonia and LOHC.

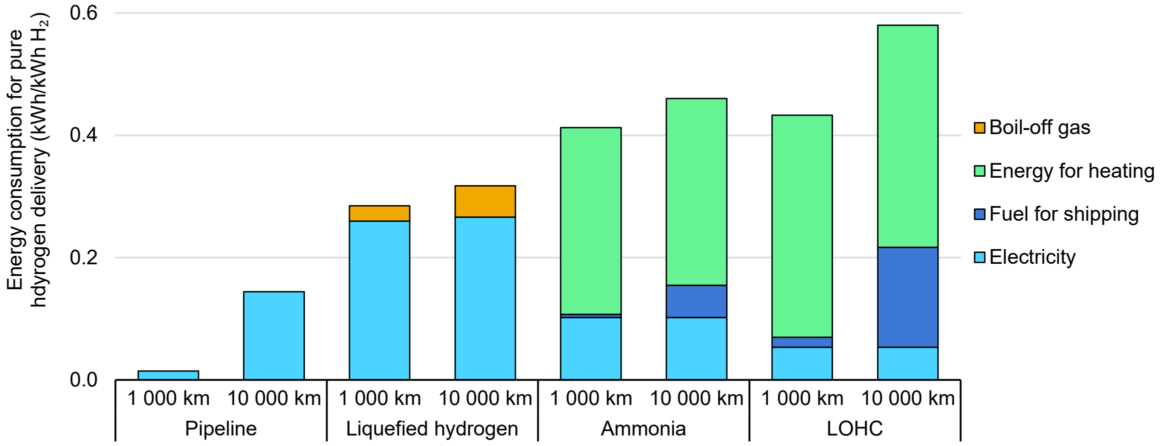
Transport costs for liquefied hydrogen are driven by the cost of cryogenic storage, while those for ammonia and LOHC are dominated by conversion and reconversion steps.

Despite these advantages, hydrogen transport by ship faces three main drawbacks with significant cost implications.

- **Infrastructure requirements**. Transport of hydrogen as LH_2 or ammonia requires access to deep-water port infrastructure. In exporting countries, such investments are more likely to be viable where ports with shared or common-user infrastructure already exist. For LH_2, the main cost driver is the high cost of cryogenic storage tanks. For ammonia, safety requirements and regulatory constraints can limit the development of new terminals, particularly in congested ports. By contrast, LOHCs benefit from greater compatibility with existing infrastructure and simpler handling requirements.

- **High conversion costs**. Conversion requirements vary across carriers and can significantly affect overall transport costs. LH_2 involves high energy consumption during liquefaction, although this is partly offset by relatively lower regasification costs at import. Ammonia synthesis via Haber-Bosch entails higher costs, and its operation is constrained by the need for high temperatures and pressures, which limit flexibility. This is particularly relevant for hydrogen produced via electrolysis from variable renewable energy, as compressed hydrogen storage tanks may be required to avoid frequent ramping and maintain minimum load factors, increasing overall system costs. By contrast, conversion to LOHCs, such as the hydrogenation of toluene to methylcyclohexane, occurs at lower temperatures and pressures, allowing for greater operational flexibility and potentially reducing the need for intermediate hydrogen storage prior to conversion.
- **High energy consumption**. All shipping pathways entail energy requirements of more than 10 kWh/kg H_2, equivalent to over 30% of the energy content of the hydrogen transported (Figure 5.11). The location and form of this energy use vary by carrier. For LH_2, energy is primarily consumed as electricity during liquefaction in the exporting country, which may be relatively low-cost where renewable resources are abundant. By contrast, ammonia cracking and LOHC dehydrogenation require significant heat input at the point of import. While natural gas is often the lowest-cost option, it increases associated emissions and may affect eligibility for support schemes. Alternatives to reduce emissions include using ammonia or recovered hydrogen as fuel, alongside electrification and heat integration with available waste heat, e.g. from power plants or chemical facilities, which may be particularly relevant for LOHC systems given their lower operating temperatures. However, shipping fuel consumption increases with distance for all carriers and is more pronounced for LOHC due to its lower hydrogen content per unit of cargo mass, leading to higher emissions when conventional marine fuels are used.

Figure 5.11. Indicative energy consumption for pure hydrogen delivery, 2030



Notes: LOHC = liquid organic hydrogen carrier. Part of the boil-off gas during liquefied hydrogen shipping is used for propulsion of the ship. Potential electrification of the heat supply for dehydrogenation is not included.

Pipelines have the lowest energy requirements, while all shipping pathways require more than 10 kWh/kg H_2, equivalent to over 30% of the hydrogen's energy content.

Box 5.1 How much hydrogen is leaking and how can it be measured?

Hydrogen itself is not a GHG, as it does not absorb infrared radiation, but when released into the atmosphere it can indirectly affect the climate through chemical reactions that alter the concentrations of certain GHGs. The magnitude of this effect remains uncertain and depends on two factors: hydrogen emissions across the supply chain, including fugitive and operational losses, and their impacts on atmospheric chemistry. Most recent atmospheric modelling studies estimate that hydrogen may have a global warming potential of around 11 ± 4 over a 100-year time horizon (GWP-100)*, although no formal value has been assigned by the Intergovernmental Panel on Climate Change (IPCC).

Assuming a GWP-100 value at the upper end of this uncertainty range, leakage rates above 13% could result in emissions intensities exceeding 2 kg CO_2-eq/kg H_2. Given the cost of low-emissions hydrogen, such high leakage rates would also undermine project economics, providing a strong incentive to minimise losses across the supply chain. Hydrogen's small molecular size, high diffusivity and low resistance to flow may make it particularly prone to leakage. Empirical evidence remains limited, however, and most estimates rely on theoretical modelling or extrapolations from natural gas systems, which may not accurately reflect hydrogen behaviour and have yet to be validated through field measurements. Several initiatives are working to develop methodologies for quantifying hydrogen emissions and advancing precise fastsensing technologies capable of detecting low concentrations, at the parts-per-billion level. Where field measurements exist, further work is needed to harmonise methodologies and integrate results into a consistent inventory, as no standard framework currently exists. This lack of direct and comparable measurements makes it difficult to identify losses along the supply chain and to design effective mitigation strategies.

- Since March 2025, an international research initiative involving industry, research institutions and the US Environmental Defense Fund has been conducting facility- and component-level field measurements of hydrogen emissions in North America and Europe. For the first time, downwind plume measurement techniques are being applied to hydrogen, using an analyser that can measure very low hydrogen concentrations and quantify facility-level emissions.
- The EU-funded NHyRA project aims to develop methodologies for hydrogen leak detection and to create an open-access inventory of hydrogen releases. In 2025, a dedicated testing campaign at the Enagás Fugitive Emissions Test Bench in Spain evaluated different hydrogen leak quantification methods under controlled conditions. Results suggest that bagging methods** provide the most reliable quantification of hydrogen leaks, while acoustic cameras are better suited to leak detection than to precise measurement, as their accuracy varies widely.
- In the EU-funded HYDRA project, a hydrogen leakage detection system is currently undergoing wind tunnel testing.

* The global warming potential over 100 years (GWP-100) measures the warming effect of a GHG relative to carbon dioxide (CO_2) over a 100-year time horizon, accounting for both its ability to absorb heat and its atmospheric lifetime. By definition, the GWP-100 of CO_2 is 1, while methane has a GWP-100 of 29.8, meaning that 1 kg of methane has 29.8 times the warming effect of 1 kg of CO_2 over 100 years, as defined in the IPCC Sixth Assessment Report.

** Bagging methods enclose the leak source and use a controlled carrier gas flow to quantify the leak rate. Acoustic cameras visualise the sound generated by escaping gas and estimate volumetric flow from sound levels.

Chapter 6. Investment and innovation

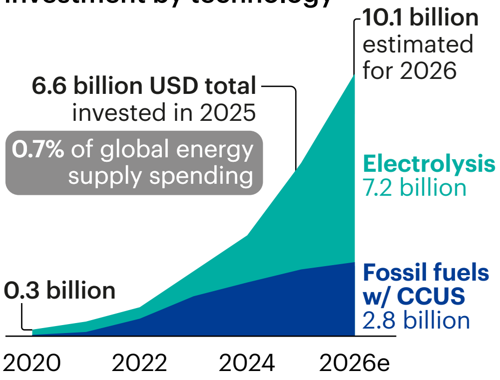
Highlights

- Capital spending on low-emissions hydrogen projects reached nearly USD 7 billion in 2025, nearly double the 2024 level and equal to 0.7% of global investment in energy supply. Investment in electrolysis overtook investment in carbon capture, utilisation and storage (CCUS)-based hydrogen, thanks to a stronger pipeline, higher capital intensity and faster project progress, and could account for around 70% of nearly USD 10 billion in investment in 2026.
- China and Europe lead committed electrolysis projects, with China accounting for more than 60% of capacity by 2026 and 25% of estimated investment. Europe represents less than 20% of capacity but 45% of investment, reflecting higher capital expenditure (CAPEX) per unit of capacity. The United States leads CCUS-based hydrogen projects. Over 85% of investment targets existing hydrogen uses in industry and refineries, or hydrogen-based fuels.
- International public finance for low-emissions hydrogen in emerging economies had grown from a negligible level in 2022 to around USD 3.3 billion in cumulative commitments to governments by the first quarter (Q1) of 2026. This supports technical assistance, broader policy frameworks and, recently, enabling infrastructure. As projects advance, project-level international public finance is gaining prominence, reaching around USD 650 million cumulatively by Q1 2026, mainly for project preparation and reducing financing costs.
- Venture capital (VC) for hydrogen continued to fall in 2025, both in absolute terms and as a share of energy VC, down from a 13% peak in 2023 to 4% in 2025. Aviation attracted the largest share of hydrogen VC, with almost 25%.
- Hydrogen company valuations are being driven to new highs by one firm, while returns show modest signs of stabilisation and recovery. Bloom Energy stands out, adding almost USD 80 billion in market capitalisation in the past year, as surging electricity demand from AI data centres and long gas turbine backlogs boost prospects for its fuel cells, albeit initially running on natural gas.
- Multiple hydrogen technologies have advanced towards commercial deployment since 2020, but maturity remains uneven. High-capture CCUS-based hydrogen production has yet to be demonstrated, while hydrogen use in industry and synthetic hydrocarbons is only now moving to first-of-a-kind projects, more slowly than more modular end-use sectors, such as transport.

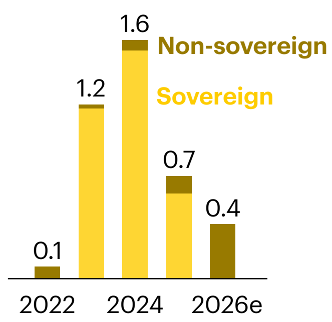
Hydrogen investment and innovation

Electrolyser project investment is scaling fast, international public finance is reaching projects in emerging economies, but hydrogen venture capital continues to decline

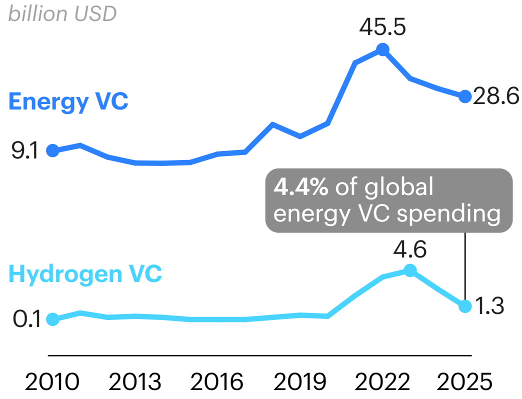
Annual low-emissions hydrogen investment by technology



Annual international public finance to hydrogen
billion USD



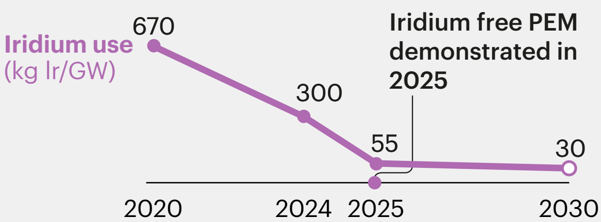
Annual venture capital investment
billion USD



The 2020s have moved key hydrogen technologies from pilots into the commercialisation race

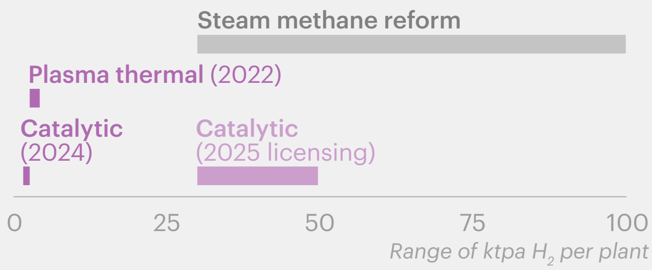
Iridium use in PEM electrolysers

Research demonstrates routes to reduce and recover iridium for PEM electrolysers



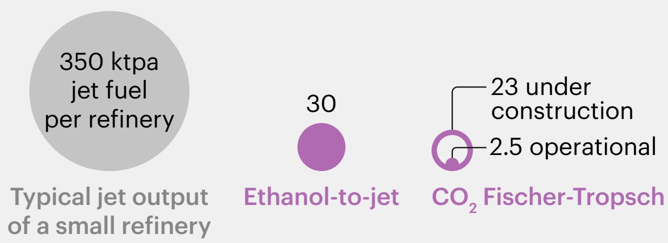
Methane pyrolysis

Demonstrated methane pyrolysis pathways move towards industrial deployment



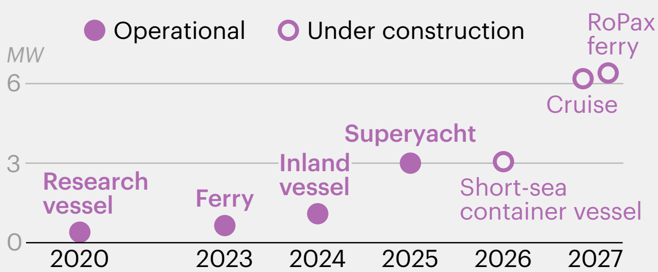
Synthetic hydrocarbons

Ethanol-to-jet plants scaling up; other synthetic fuel plants under construction



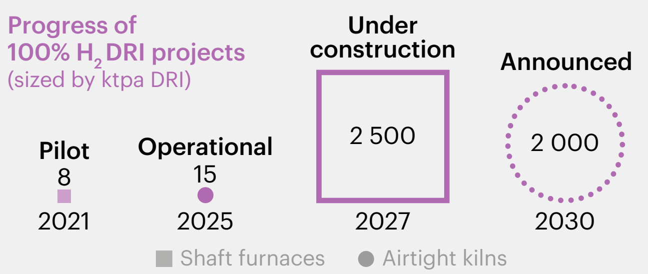
Hydrogen-fuelled ships

Maritime hydrogen fuel cells reach multi-MW scale



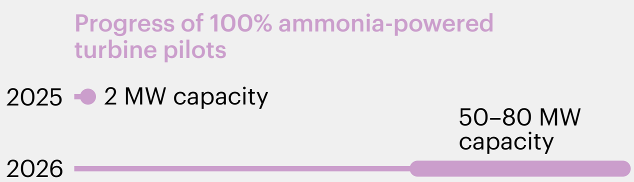
Hydrogen use in ironmaking

First commercial plant using 100% hydrogen for ironmaking nears commissioning



Ammonia turbines for power generation

100% ammonia combustion is demonstrated in large-scale gas turbines



Investment in the hydrogen sector

Spending on production projects under construction

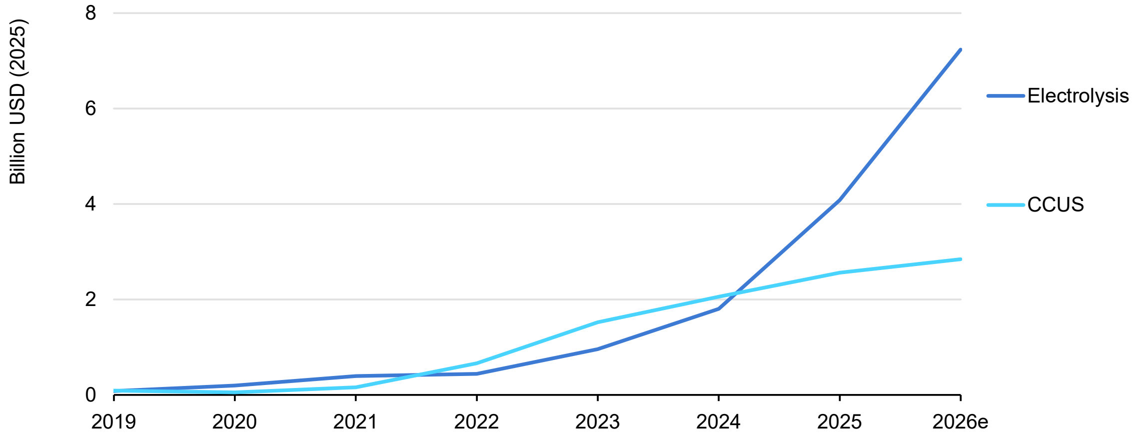
Since the publication of the Global Hydrogen Review 2025 (GHR-25), which tracked committed investments up to the end of August 2025, 44 hydrogen supply projects have reached final investment decisions (FIDs), representing around 330 ktpa of potential low-emissions hydrogen[65] production. Over the same period, 42 projects have been completed and entered operation, adding almost 100 ktpa of estimated low-emissions hydrogen output. As a result, the number of projects under construction worldwide has increased to more than 300, assuming that all projects that have reached FID are now under construction. Once operational, these projects could deliver around 3.2 Mtpa of low-emissions hydrogen, nearly 65% of which would come from electrolytic projects.

Spending on low-emissions hydrogen projects is estimated to have reached almost USD 7 billion in 2025, nearly double the level in 2024 and equivalent to around 0.7% of global investment in energy supply. Spending is set to rise by more than 50% in 2026, reaching more than USD 10 billion, as capital is disbursed for the wave of relatively large projects that have reached FID in recent years. This is equivalent to around 15% of global investment in new greenfield natural gas production in 2025. Low-emissions hydrogen is also taking a growing share of investment in low-emissions fuels, rising from less than 3% of the total in 2020 to potentially more than 30% in 2026, even as investment in biofuels has more than doubled over the same period.

In 2024, spending on CCUS-based hydrogen projects exceeded spending on electrolysis projects, reflecting the larger average size and earlier progress of fossil-based projects with CCUS. However, since 2025, investment has shifted towards electrolysis, driven by a stronger pipeline of new electrolyser project FIDs, slower activity in CCUS-based hydrogen and the higher capital intensity of electrolyser projects. Investment going to electrolysis is also reinforced by structural factors, as more than 30% of CCUS-based hydrogen projects are retrofits relying on existing infrastructure, whereas electrolyser projects are typically developed as greenfield facilities. This comparison excludes investment in dedicated electricity generation. The full capital requirements of electrolytic hydrogen may therefore be even higher still.

[65] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Figure 6.1. Investment in low-emissions hydrogen production installations, 2019-2026e



Notes: CCUS = carbon capture, utilisation and storage. 2026 values are estimated annualised spending on projects that had reached final investment decision (FID) as of May 2026, and are based on known project costs or capital cost assumptions and announced capacities. The 2026e estimates assume that all projects with an announced FID have entered construction and will proceed according to their scheduled operational date. Delays in construction will lead to lower actual spending in 2026, as was the case for the estimates in GHR-25. Only capital expenditures, including installation, on the hydrogen production facility are included and not expenditures on any associated equipment for generating or supplying electricity or other fuel inputs, nor for the transport and storage of CO_2, nor for the conversion or end-use of the hydrogen output. Values for investment in new-build hydrogen production projects equipped with CCUS are inclusive of the costs of the base plant, such as the steam methane reformer, and not only the capital costs of CO_2 capture and any dedicated CO_2 transport and storage infrastructure. Where publicly disclosed, specific project investment data was used instead of cost estimates.

Sources: IEA analysis based on data collected through a survey to OEMs, engineering, procurement and construction (EPC) companies and project developers; data from McKinsey & Company and the Hydrogen Council; BloombergNEF; Argus Media, All rights reserved; Lewis, E. et al (2022) Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies, NETL; IEA GHG (2017) Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

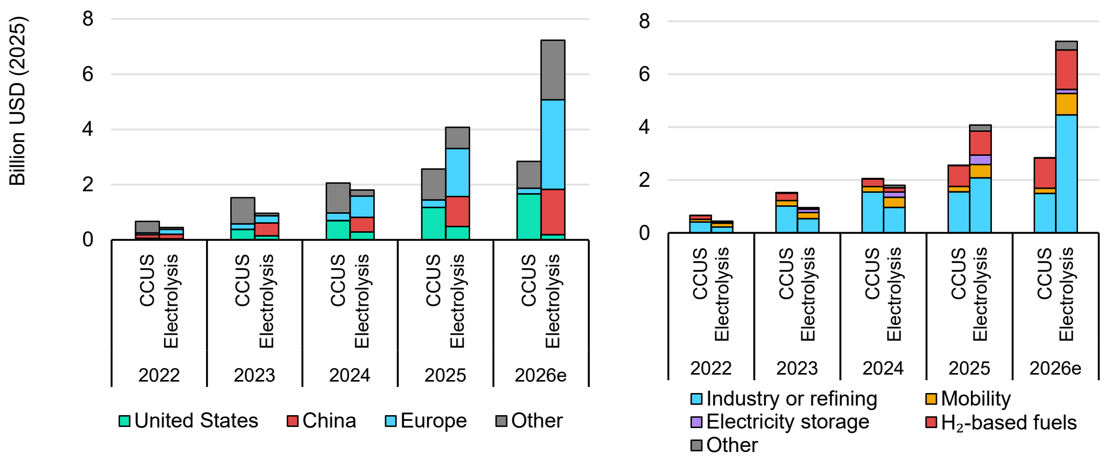
Investment in electrolysis projects surpassed CCUS-based projects in 2025, and the gap is set to widen during 2026.

Since GHR-25, almost 80% of the low-emissions hydrogen production volume reaching FID has been electrolysis-based, compared with less than 65% of potential low-emissions hydrogen production in the overall project pipeline under construction. This is set to increase the weight of electrolysis in hydrogen investments in the coming years. An indication of this shift is already visible in 2026, when electrolysis is expected to account for over 70% of total hydrogen supply investment, exceeding its share of production capacity under construction.

Investment in committed projects is geographically concentrated, broadly reflecting the distribution of capacity, but with notable differences across regions and technologies. With regards to electrolytic hydrogen, the People's Republic of China (hereafter, "China") accounts for more than 60% of committed capacity but less than 25% of estimated investment by 2026, while Europe represents less than 20% of capacity but almost 45% of investment. This is driven by regional cost differences, with lower CAPEX reducing investment needs in Chinese projects. Together, China and Europe account for around 70% of total investment in electrolytic hydrogen production by 2026. For CCUS-based hydrogen, the

United States accounts for about 40% of committed capacity but nearly 60% of estimated investment by 2026. This reflects differences in project design and development approaches: in the United States, most projects involve greenfield construction, whereas in other front-running countries, such as the Netherlands, all projects rely on retrofits, which require lower capital expenditure.

Figure 6.2. Investment in low-emissions hydrogen production installations by region (left) and intended use (right), 2022-2026e



Notes: CCUS = carbon capture, utilisation and storage; H_2 = hydrogen. 2026 values are estimated annualised spending on projects that had reached final investment decision (FID) as of May 2026, and are based on known project costs or capital cost assumptions and announced capacities. The 2026e estimates assume that all projects with an announced FID have entered construction and will proceed according to their scheduled operational date. Delays in construction will lead to lower actual spending in 2026, as was the case for the estimates in GHR-25. Only capital expenditures, including installation, on the hydrogen production facility are included and not expenditures on any associated equipment for generating or supplying electricity or other fuel inputs, nor for the transport and storage of CO_2, nor for the conversion or end-use of the hydrogen output. Values for investment in new-build hydrogen production projects equipped with CCUS are inclusive of the costs of the base plant, such as the steam methane reformer, and not only the capital costs of CO_2 capture and any dedicated CO_2 transport and storage infrastructure. Where publicly disclosed, specific project investment data was used instead of cost estimates. "Other" intended uses include undisclosed end-uses. Projects intended for export are classified under the relevant demand category, based on their intended use in the importing country (where known).

Sources: IEA analysis based on data collected through a survey to OEMs, engineering, procurement and construction (EPC) companies and project developers; data from McKinsey & Company and the Hydrogen Council; BloombergNEF; Argus Media, All rights reserved; Lewis, E. et al (2022) Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies NETL; IEA GHG (2017) Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

Europe and China lead electrolysis investment while the United States leads CCUS-based investment; over 85% of spending targets industry, refining and hydrogen-based fuels.

In terms of end-use application, nearly 60% of investment in 2026 is expected to go to hydrogen production for existing uses, such as oil refining and industrial applications, such as ammonia. More than 25% is directed towards hydrogen-based fuels, including for export. Together, these uses account for more than 85% of total investment in 2026. The distribution is broadly similar across production routes, although electrolytic hydrogen shows a higher share of investment linked to industrial applications and refining, while CCUS-based projects have a higher share linked to hydrogen-based fuels, including a few large projects for exports.

Since GHR-25, only 1 CCUS-based project has reached FID out of the 44 projects in the pipeline, although it represents around 20% of the newly committed production, as CCUS projects are generally larger. This is the Wabash Low-Carbon Ammonia project in the United States, which will restart a petcoke gasification plant that has been idle since 2016 in order to produce 500 ktpa of ammonia, retrofitted to integrate 1.7 Mtpa of CO_2 capture and storage. The project investment is estimated at USD 2.6 billion, supported by a loan of nearly USD 1.6 billion from the US Department of Energy Office of Energy Dominance Financing and backed by Korean companies.

Almost 70% of electrolyser capacity to have reached FID since GHR-25, around 2.4 GW, is in China. The largest project is Phase 2 of China Energy Engineering Corporation's Songyuan Hydrogen Energy Industrial Park, the largest electrolyser project under construction in the country and its first at gigawatt scale. The project targets ammonia and methanol production and is estimated to require CNY 22.6 billion (Yuan renminbi) (USD 3.1 billion), including investment in power generation.

Outside China, around 60% of the remaining electrolyser capacity to have reached FID since GHR-25 is in Spain, with four projects at the hundred-megawatt scale, all of which have benefited from substantial public support. The largest, the 300 MW Moeve Onuba plant in Huelva, received an investment exceeding EUR 1 billion and more than EUR 300 million in grants from Spain's NextGenerationEU funds.[66] The 200 MW La Robla methanol project in León, with an investment of around EUR 900 million, has combined grants from Spain's NextGenerationEU funds and the EU Innovation Fund alongside a EUR 450 million loan from the European Investment Bank (EIB). Repsol has taken FID for two 100 MW electrolyser projects at its refineries in Cartagena and Bilbao, each with an investment of around EUR 300 million, with more than half supported by grants from Spain's NextGenerationEU funds. The project in Bilbao also benefits from a 35% corporate income tax deduction on electrolyser CAPEX under the Basque Register of Clean Technologies support scheme.

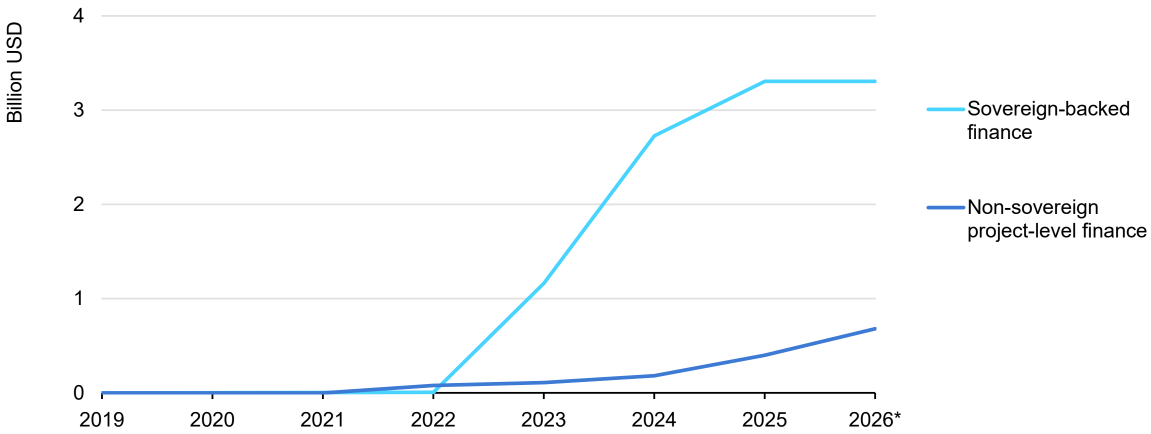
International public finance for low-emissions hydrogen in emerging economies

In 2024, international public finance accounted for around 1.1% of total energy sector financing globally.[67] Despite this relatively small share, it plays a critical role in emerging markets and developing economies (EMDEs) other than China,

[66] The grant was awarded for a 400 MW project. However, only 300 MW have reached FID due to power grid connection constraints. If the project is not expanded to 400 MW, the grant will be reduced proportionally.
[67] "International public finance" includes development finance institutions (DFIs), multilateral climate funds, government donors, philanthropies and some official export credits directed to emerging market and developing economies offered under the OECD arrangement.

where international public finance provides more than 5% of energy investment. This finance is particularly important in regions where access to private capital is expensive, and can be critical for capital-intensive and first-of-a-kind projects such as low-emissions hydrogen. International public finance can be delivered through several channels, but development finance institutions (DFIs) are the largest providers for energy-related projects, often complemented by multilateral climate funds, either through direct support to governments or project-level financing in EMDEs. In the early 2020s, much of this finance went to governments, particularly to help prepare enabling frameworks. As these frameworks begin to emerge, international public finance is increasingly targeting project-level support for first-of-a-kind projects.

Figure 6.3. Estimated cumulative finance from international public financiers to low-emissions hydrogen, 2020-2026



Notes: "International public financiers" includes development finance institutions (DFIs), multilateral climate funds and government donors. For 2026, data are as of May 2026.

Recent developments suggest slower sovereign financing, but international public finance is gaining prominence at project level for low-emissions hydrogen in EMDEs.

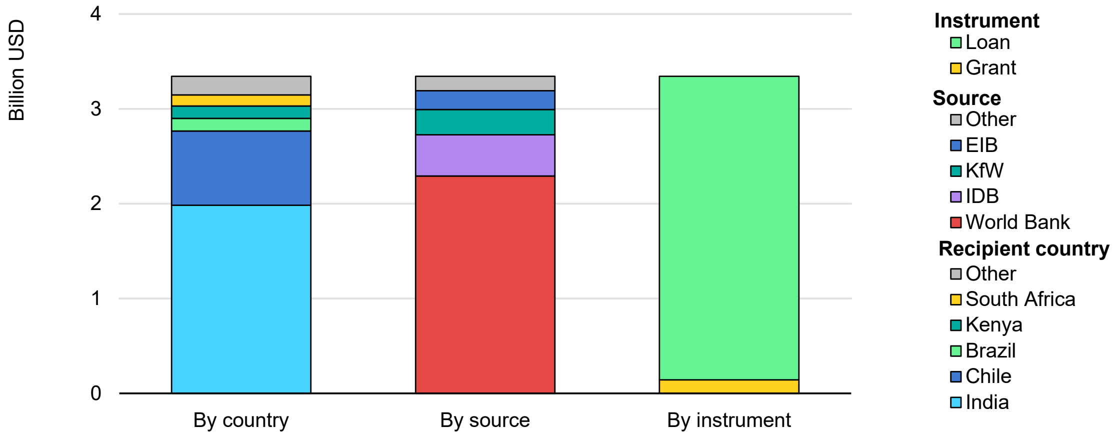
Sovereign financing

Sovereign financing is mainly directed to governments or public entities, often backed by government guarantees. Funding from international public financiers for low-emissions hydrogen has grown from negligible levels in 2022 to around USD 3.2 billion in committed investments by Q1 2026, with announced funding potentially doubling this amount if realised. However, this support remains highly concentrated, with almost 60% allocated to India and nearly 25% to Chile, and has increased only marginally since GHR-25. Sovereign operations take different forms, including policy-based financing that provides support linked to policy programmes such as strategies, as seen in India, where multi-billion-dollar World

Bank loans in 2023 and 2024 are supporting the implementation of its National Green Hydrogen Mission. This includes hydrogen production and electrolyser manufacturing. Additional sovereign lending has been announced, such as a USD 1.5 billion loan to Brazil, although this loan had not been committed at the time of writing.

Loans account for more than 95% of committed funding by value, but grants represent a larger number of smaller transactions and play a distinct role in early market development. They are typically used for technical assistance, advisory services and capacity building, helping governments develop the regulatory and institutional frameworks needed for future projects. While loans are often provided by DFIs or through multilateral climate funds, grants may also come directly from government donors. Examples include Germany's International Cooperation (Deutsche Gesellschaft für Internationale Zusammenarbeit [GIZ]) Hydrogen for a Just Transition programme in South Africa, the African Development Bank (AfDB)'s support to Mauritania on a low-emissions hydrogen auction framework, and the United Nations Industrial Development Organization (UNIDO)'s Global Clean Hydrogen Programme in Africa, Southeast Asia and Ecuador.

Figure 6.4. Estimated committed cumulative finance from international public financiers to governments for low-emissions hydrogen, 2020-2026



Notes: EIB = European Investment Bank; IDB = Inter-American Development Bank; KfW = Kreditanstalt für Wiederaufbau (Germany´s development bank). "International public financiers" includes development finance institutions (DFIs), multilateral climate funds and government donors. For 2026, data are as of May 2026.

Source: IEA analysis based on publicly available information until May 2026.

Loans account for over 95% of sovereign finance to governments, with the World Bank as the largest financier and India as the largest recipient.

Sovereign financing also supports public assets that enable private investment, including port infrastructure, grid connections and transport links. Support to strengthen publicly owned infrastructure includes a USD 90 million World Bank loan for ammonia infrastructure at the Port of Pecém in Brazil, alongside a USD 34 million loan from the Climate Investment Funds, and a USD 400 million framework loan from the EIB to South Africa’s state-owned Transnet, partly to develop hydrogen-related infrastructure. Kenya offers a related example in the power sector: concessional finance from Germany’s DFI Kreditanstalt für Wiederaufbau (KfW) is supporting geothermal capacity expansion by state-owned KenGen. This will provide the electricity needed for an electrolytic hydrogen and ammonia project privately financed by a Chinese company, one of the few projects at or above 100 MW outside China and Spain to have reached FID since GHR-25.

Investments in funds and facilities

Beyond direct lending, international public financiers increasingly channel capital through intermediary vehicles, including funds and blended finance facilities, which enable greater specialisation and help mobilise private capital by combining concessional and commercial funding. Since GHR-25, there has been limited new creation or capitalisation of such vehicles for low-emissions hydrogen, although some existing funds have begun disbursing funding, as shown in the next section.

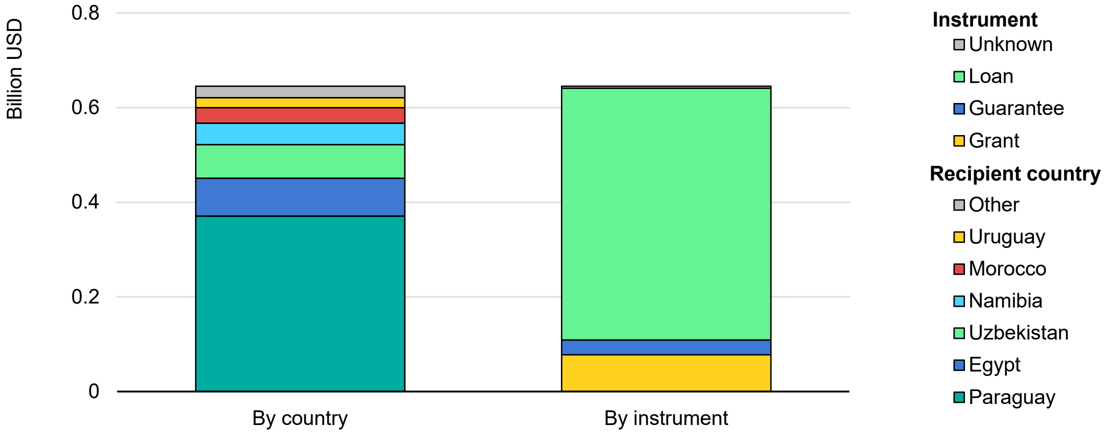
A notable example is the Sustainable Energy Fund for Africa (SEFA), a multi-donor trust fund managed by the AfDB, whose Green Hydrogen Programme was approved in late 2025 and capitalised with funding from the German government to provide up to USD 20 million in development expenditure (DEVEX) support through reimbursable grants[68] to early-stage projects.

Non-sovereign project finance

International public financiers also provide financing directly to companies without government guarantees, typically through the private sector arms of DFIs or via intermediary vehicles and funds. This kind of financing is particularly important for first-of-a-kind projects, where commercial lenders may be deterred by technology and construction risks, as well as by policy risks that can be significant in certain EMDEs. However, other key risks – notably related to offtake – still need to be addressed through long-term contracts before securing debt financing. In total, nearly USD 650 million has been committed by DFIs and DFI/government-backed funds to low-emissions hydrogen projects since 2020.

[68] A reimbursable grant is a grant paid against eligible costs that have already been incurred, rather than provided upfront.

Figure 6.5. Estimated committed finance from international public financiers to companies for low-emissions hydrogen projects, 2020-2026



Notes: "International public financiers" includes development finance institutions (DFIs), multilateral climate funds and government donors. For 2026, data are as of May 2026.

International public finance covers preparatory grants through to larger loans as projects approach FID, with a project in Paraguay receiving the largest loan commitment to date.

Notable examples of non-sovereign public finance since GHR-25 include:

- In September 2025, Uzbekistan's 20 MW Chirchiq project became operational, supported by a USD 55 million senior loan from the European Bank for Reconstruction and Development and up to USD 10 million in concessional finance from Canada's Special Fund for the High Impact Partnership on Climate Action.
- In December 2025, the International Finance Corporation (IFC), part of the World Bank, announced its first low-emissions hydrogen investment: a USD 20 million loan to Grupo Santander for the 77 tpa H_2 Kahirós project in Uruguay, alongside a USD 1 million loan from UNIDO's Renewable Energy Innovation Fund.
- In December 2025, two funds provided DEVEX support to hydrogen projects in Namibia: the AfDB approved a USD 10 million loan from SEFA for the Hyphen project, while the SDG Namibia One Fund committed up to USD 5 million to support development of the Zhero Molecules Walvis Bay project, both targeting ammonia production.
- In March 2026, ATOME's La Villeta project (260 ktpa calcium ammonium nitrate, 20 ktpa H_2), Paraguay, signed a USD 420 million debt package with a consortium of five DFIs, including IDB Invest, the private sector arm of the Inter-American Development Bank (IDB), acting as debt co-ordinator; IFC; the EIB; the Dutch DFI FMO and the Green Climate Fund. Around 25% of the 15-year tenor debt package is provided on concessional terms. DFIs are also participating on the equity side[69]:

[69] The exact amounts are not publicly disclosed and are therefore not included in Figure 6.5.

IFC, Denmark's Investment Fund for Developing Countries and DEG, the private sector arm of Germany's KfW, are part of ATOME's USD 215 million equity consortium alongside private investors.

Most of this support is provided as debt, with grants mainly committed for project preparation support. Financing structures typically combine multiple debt instruments with varying levels of seniority and concessionality.[70] Other financing vehicles, such as the SDG Namibia One Fund for the Hyphen project and the SA-H2 Fund for South Africa's Gauteng methanol project, have secured the right to participate in equity financing if the projects move ahead.

As in the broader energy sector, the use of guarantees remains limited, which also reflects the early stage of the hydrogen sector. The La Villeta project illustrates the type of de-risking instrument that could play a larger role as the market develops, having secured a USD 31 million standby letter of credit facility from IDB Invest. This facility provides a bank guarantee of payment to a third party and would only be called upon in the event of default. For more projects in EMDEs to move forward, guarantees and other de-risking instruments will need to play a larger role in crowding in private capital (see Box 8.1 in Chapter 8).

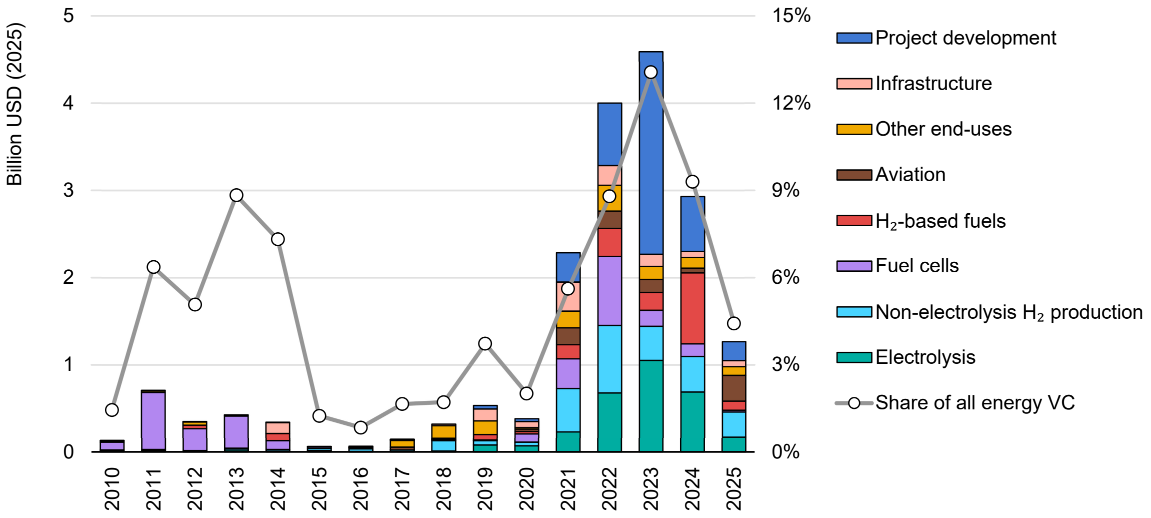
Company financing and market trends

Venture capital investments

Venture capital (VC) investment in hydrogen-focused start-ups continues to decline, both in absolute terms and relative to the broader energy VC landscape. Following a peak in the early 2020s driven by investor excitement around high-potential hydrogen technologies and their positive outlook, total VC fell by more than 50% year-on-year to USD 1.3 billion in 2025, and hydrogen's share of energy VC dropped from a 13% peak in 2023 to just 4% in 2025. Early data for Q1 2026 suggest this contraction is continuing.

[70] Seniority refers to the order in which different lenders are repaid in case of financial distress, with senior debt having priority over subordinated or junior debt. Concessionality refers to financing provided on more favourable terms than market conditions, such as lower interest rates, longer repayment periods or deferred repayment, typically to reduce overall financing costs and improve project viability.

Figure 6.6. Venture capital investment in energy start-ups in hydrogen-related areas, per technology domain, 2010-2025



Notes: H_2 = hydrogen; VC = venture capital. Project development includes start-ups that do not own intellectual property related to technology and raise funds for supply-side project development costs. Other end-uses include steel production, chemicals, waste management and heating.
Sources: IEA analysis based on data from Cleantech Group and Crunchbase.

VC investment in hydrogen continues to decline, with funding shifting away from production technologies, while aviation now accounts for almost 25% of total investment.

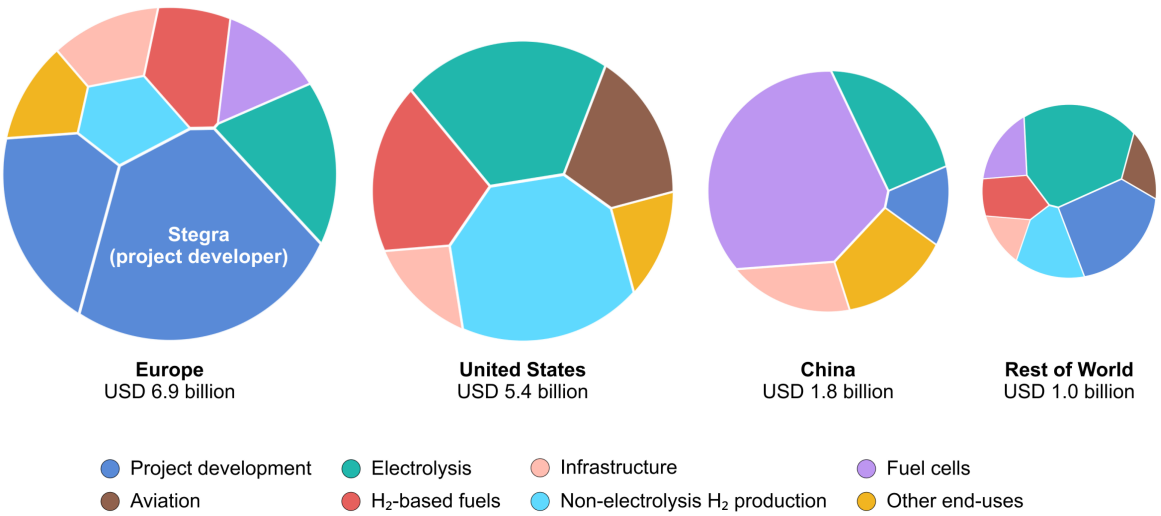
This type of fluctuation is not unusual, as VC activity is influenced both by the outlook for a given technology and by broader macroeconomic conditions. A similar pattern has been observed in electric mobility, where VC has recently declined following several years of strong investment. In hydrogen, however, the slowdown appears to reflect a reassessment of the size of the addressable market and longer timelines for start-ups to reach profitability.

Between 2021 and 2023, around 220 hydrogen start-ups raised equity funding, yet many now face uncertainty in securing follow-on investment amid a tightening market. This trend is already evident in recent data: in 2025, 30 hydrogen start-ups raised follow-on funding, compared with around 50 in 2024, and more than 40 in both 2022 and 2023. Similar trends can be observed for hydrogen-related start-ups raising their first funding round, with fewer than 40 first deals recorded in 2025, down from nearly 50 in 2024, and more than 60 in 2023.

This shift also reflects a broader reallocation of capital within energy and across sectors. Energy VC has decreased by almost 40% compared with its 2022 peak, while the overall VC landscape in 2025 has been dominated by the rapid expansion of artificial intelligence (AI), which attracted around one-third of total VC funding, roughly five times more than energy. While hydrogen attracted less VC, capital has flowed to other areas, with nuclear fusion and fission seeing a fivefold increase in funding between 2023 and 2025. Other segments, including critical minerals and next-generation geothermal, also attracted higher levels of investment in 2025. Investor interest in emerging energy technologies can shift rapidly, and hydrogen is not currently in the spotlight, although activity remains uneven across different hydrogen technologies and geographies.

In 2023 and 2024 VC was concentrated on hydrogen production technologies and hydrogen-based fuels, but in 2025 aviation emerged as the largest segment, accounting for almost 25% of total hydrogen VC. This was driven by large funding rounds from two US-based aviation companies, Zero Avia (USD 150 million) and Heven Aerotech (USD 100 million). Other top recipients in 2025 included C2X, a Danish methanol company, Amogy, a US-based developer of ammonia-to-power systems, and GravitHy, a French company developing hydrogen-based direct reduced iron (DRI). Conversely, electrolysis-focused start-ups have seen funding decline for a second consecutive year, suggesting a more mature market led by incumbents, alongside concerns around overcapacity and limited near-term breakthrough improvements in performance or costs.

Figure 6.7. Cumulative venture capital investment in energy start-ups in hydrogen-related areas per technology domain and region, 2021-2025



Note: H_2 = hydrogen.
Sources: IEA analysis based on data from Cleantech Group and Crunchbase.

Europe attracted the most VC, but around 40% went to a single project developer, while the United States led VC in hydrogen production technologies and China in fuel cells.

European start-ups received close to 50% of hydrogen-related VC in 2025, followed by the United States (35%) and China (9%). This represents a larger share for Europe than in energy VC more broadly, where it accounts for around one-quarter of total funding, compared with roughly one-half for the United States.

However, funding patterns differ by segment. US start-ups continue to dominate hydrogen production technologies and hydrogen-based fuels, raising three-quarters of global VC for non-electrolysis-based production over 2021-25, around 50% for electrolysis, and close to 60% for hydrogen-based fuels. By contrast, European start-ups are more active in project development, infrastructure and end-use applications beyond aviation. They accounted for around 90% of global VC in project development over the same period, as well as about 45% in infrastructure and 40% in end-use sectors (excluding aviation). Much of this reflects a small number of large transactions, notably concerning Stegra, a Swedish developer of hydrogen-based steel plants, which alone raised nearly USD 2.6 billion over the last 5 years, i.e. nearly 20% of cumulative global hydrogen VC. In April 2026, the company announced that it had agreed in principle a further USD 1.6 billion financing round from new and existing investors and lenders. While only part of this round would be counted as VC, given that it includes both equity and debt, it could materially affect 2026 volumes and moderate the decline suggested by early-year data.

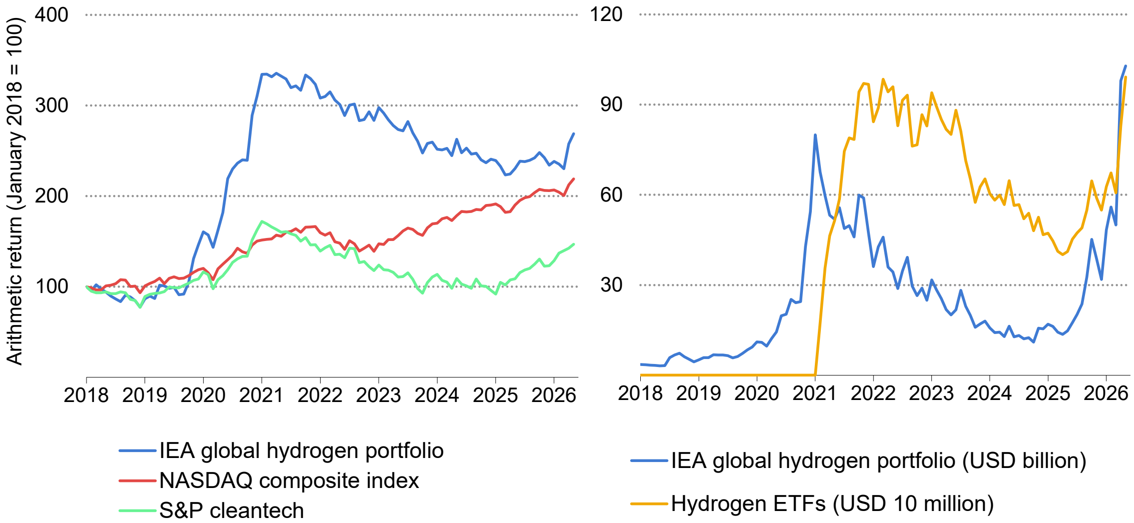
Despite recent challenges, the hydrogen sector continues to generate innovative ideas, with new start-ups being established. Since 2023, close to 150 hydrogen-related start-ups have raised their first funding round. However, without a recovery in capital allocation to the sector – where average deal sizes have fallen by nearly 50% between 2023-24 and 2025 – these start-ups may face limited pathways to scale, which may leave their innovation potential unrealised.

Company financing and capitalisation

Data on the performance of publicly traded companies sheds light on how companies working on hydrogen projects are performing, in terms of their cashflow and ability to raise funds, as well as the expectations of investors. While not all companies active in hydrogen are publicly listed, and many that are have significant operations outside hydrogen, there is a globally representative set of listed firms whose finances are inextricably linked to the health of the low-emissions hydrogen sector. We have assembled a portfolio of 55 publicly traded companies in the sector to track their performance and assess sectoral trends.[71]

[71] Of the 55, 49 were still trading in March 2026. Since GHR-25, three companies have been added: Green Innovation, also known as Hydrogenera, listed on the Bulgarian Stock Exchange in July 2025; Pure Hydrogen changed its name and listing on the Australian stock exchange to Pure One in December 2025; Deokyang Energen listed on the KOSDAQ Stock Exchange in Korea in February 2026. Four companies stopped trading during 2025: Green Hydrogen Systems (Denmark), Hyzon Motors (United States), McPhy (France) and Proton Motor (United Kingdom).

Figure 6.8. Monthly returns (left) and market capitalisation (right) of hydrogen companies, hydrogen funds and relevant benchmarks, 2018-2026



Notes: ETFs = exchange-traded funds. Monthly return = closing adjusted price on last day of month divided by closing adjusted price on last day of previous month, with equal weighting across all firms. IEA's global hydrogen technology portfolio includes 55 public companies whose value is driven primarily by the outlook for low-emissions hydrogen and the tickers of included firms are 0001A0 KS, 2570 HK, 2582 HK, 288620 KS, 336260 KS, 702 HK, ACH NO, ADN US, HPOW LN, ALHAF FP, ALHRS FP, AMMPF US, AQUNU US, ATOM LN, BE US, BLDP CN, CASAL SW, CAVEN NO, CH CN, CI SS, CPH2 LN, CWR LN, F3C GY, FCEL US, FHYD CN, GHY AU, GNCL IT, GREENH DC, H2A GR, H2O GY, HDF FP, HDRO CN, HTOO US, HYDR BU, HYPRO NO, HYSR US, HYT AU, HYZN US, HZR AU, IMPC SS, ITM LN, LHYFE FP, MPHYF PQ, NCH2 GY, NEL NO, NHHH CV, NXH CN, P1E AU, PCELL SS, PHE LN, PLUG US, PPS LN, PV1 AU, SPN AU, TECO NO. S&P cleantech refers to the S&P/TSX Renewable Energy and Clean Technology Index. Values for 2026 cover the period through May 2026.

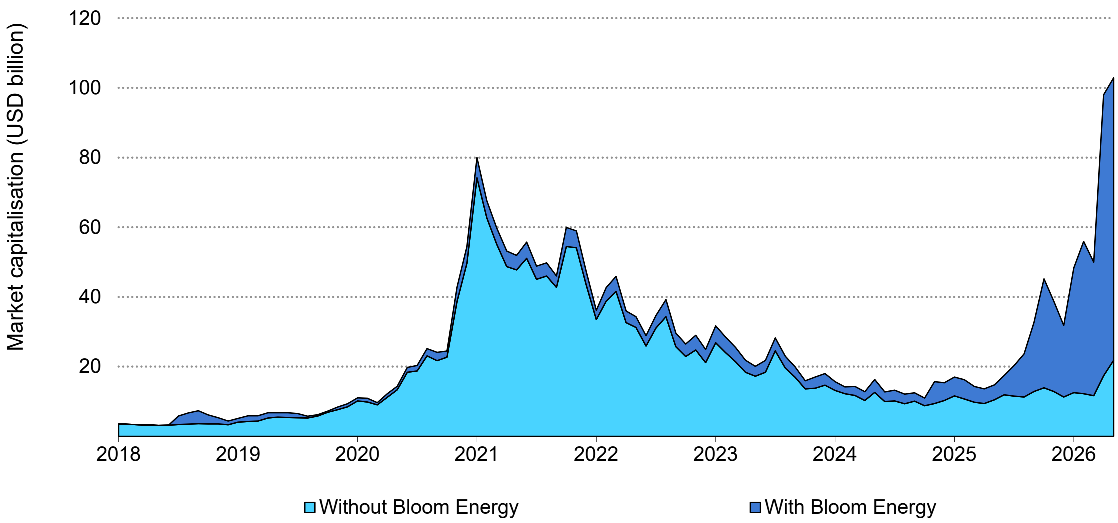
Source: IEA analysis based on Bloomberg terminal data.

Total hydrogen company valuations are being driven to new highs by one firm, while returns across a wider sample show modest signs of stabilisation and recovery.

The valuation of these firms on stock markets is closely linked to the pace of development of large-scale hydrogen projects, many of which have continued to face challenges in the time since the publication of GHR-25. The portfolio represents a mix of different equipment suppliers and a smaller number of project developers. As revenue from large-scale projects continues to underperform compared to the very high expectations of investors in 2021, the portfolio's monthly returns remain below the level reached 5 years ago, when they soared far above the levels of more general technology indices. Since 2023, the broad technology-led US-based market index, the NASDAQ, has grown consistently, driven by strong performance of digital technology firms, especially those active in AI. Since 2025, the S&P Cleantech index has also risen, as the outlook for renewables deployment strengthened. By contrast, since early 2025, our hydrogen portfolio has not generated returns, but it has stabilised and slightly risen in the second quarter of 2026, indicating a healthier market outlook. Furthermore, the market capitalisation – the product of its share price and the total number of shares held by investors – of our portfolio and the market capitalisation of exchange-traded hydrogen investment funds show even brighter trends.

Recent positive trends in our portfolio's performance are not shared by all its constituents. The stabilisation of our portfolio's returns, the sharp rise in market capitalisation and the value of hydrogen investment funds has been propelled by one company, Bloom Energy. Bloom Energy is a US manufacturer of solid oxide fuel cells that listed on the New York Stock Exchange in mid-2018. Since it was founded in 2001, the firm has been a strong proponent of hydrogen energy, but its products can also operate on natural gas. Demand for its products has accelerated since 2025 due to their compatibility with data centre power needs and shortages in the gas turbine market. While Bloom Energy fuel cells for data centres being sold today could run on hydrogen in future, they are intended for use with natural gas in the near term, which weakens the link between the portfolio's aggregate performance and the health of the hydrogen sector. Since the beginning of 2025, Bloom Energy's market capitalisation increased by USD 75 billion to USD 80 billion, taking it from an average of 16% of the portfolio's total market capitalisation in 2018-24 to around 80% in 2026. As a measure of how share price is influenced by expected future earnings (rather than current performance), the firm's revenue rose by just 37% between 2024 and 2025 and its earnings before interest, taxes, depreciation and amortisation fell by nearly 80% over the same period.

Figure 6.9. Market capitalisation of the IEA global hydrogen portfolio, 2018-2026



Notes: IEA's global hydrogen technology portfolio includes 55 public companies whose value is driven primarily by the outlook for low-emissions hydrogen and the tickers of included firms are 0001A0 KS, 2570 HK, 2582 HK, 288620 KS, 336260 KS, 702 HK, ACH NO, ADN US, HPOW LN, ALHAF FP, ALHRS FP, AMMPF US, AQUNU US, ATOM LN, BE US, BLDP CN, CASAL SW, CAVEN NO, CH CN, CI SS, CPH2 LN, CWR LN, F3C GY, FCEL US, FHYD CN, GHY AU, GNCL IT, GREENH DC, H2A GR, H2O GY, HDF FP, HDRO CN, HTOO US, HYDR BU, HYPRO NO, HYSR US, HYT AU, HYZN US, HZR AU, IMPC SS, ITM LN, LHYFE FP, MPHYF PQ, NCH2 GY, NEL NO, NHHH CV, NXH CN, P1E AU, PCELL SS, PHE LN, PLUG US, PPS LN, PV1 AU, SPN AU, TECO NO. Values for 2026 cover the period through May 2026.

Source: IEA analysis based on Bloomberg terminal data.

Electricity demand growth for AI is affecting the IEA hydrogen portfolio, disproportionately boosting the value of one firm selling natural gas fuel cells for data centres.

When Bloom Energy is excluded from the overall portfolio, the market capitalisation increased slightly in the past year and is around the level first reached in mid-2020. This was largely due to stronger performance from Plug Power, a US proton exchange membrane (PEM) electrolyser maker, and Doosan Fuel Cell, a Korean fuel cell manufacturer. However, this is far from making up for the loss of value since 2021 from companies including Plug Power, and also from Ballard Power, Fuel Cell Energy, Nel and ITM Power. In 2025, four companies in the portfolio stopped trading: Green Hydrogen Systems, Hyzon Motors, McPhy and Proton Motor. We are not aware of any forthcoming new listings by hydrogen companies. However, Stegra issued a public investment prospectus in mid-2025 and is likely to work towards a public listing once the financing for the final stages of its first plant's construction has been assured.

Innovation

Hydrogen technologies have continued to reach important milestones since GHR-25, but fewer have advanced in terms of technology readiness levels (TRLs): five in this edition, compared with ten in GHR-25, bearing in mind that this edition covers a slightly shorter period. This reflects broader trends in hardware-based innovation, where progress is uneven and often marked by long plateaus between breakthroughs. Large-scale, non-modular technologies, including several hydrogen technologies, require multi-year construction and commissioning cycles, especially for first-of-a-kind projects, meaning innovation cannot move at the same speed as software innovation.

Noteworthy innovation developments since GHR-25 are illustrated below. They reflect the broad scope of innovation progress taking place across different parts of the hydrogen value chain and across the world, without being exhaustive.[72] The innovations are grouped into five categories building on the approach used in the IEA's State of Energy Innovation report.

Prominent advances in research and prototyping

The share of technologies with a TRL below 4 is relatively small, indicating that most technologies not yet on the market have at least reached the pilot stage. However, this does not imply that R&D activity is limited, as work continues both on breakthrough technologies and on incremental innovations at the sub-system level aimed at improving the performance and reducing the costs of more mature technologies.

[72] The list represents selected events from IEA's ETP Clean Energy Technology Guide, covering recent developments that IEA experts consider to be notable examples of progress at the technology frontier, supported by publicly available online evidence. Inclusion in this list of highlights does not imply any assessment of future impact or potential. Further information on the methodological approach is provided in the Annex of the IEA's State of Energy Innovation 2026.

- **Reducing and recovering iridium for PEM electrolysers**. PEM electrolysers currently require around 300 kg of iridium (Ir) per GW of capacity, with industry targets aiming to reduce this to 100 kg Ir/GW by 2030. Recent developments suggest rapid progress: Ohmium reported achieving 56 kg Ir/GW and aims to reduce this further to below 30 kg Ir/GW in the coming years. VSPARTICLE and Plug Power developed a nanoporous catalyst layer enabling around 90% less Ir utilisation than current stacks, while Toshiba announced a design using 90% less, although the reference level was not specified. In parallel, Johnson Matthey and Syensqo demonstrated kilogramme-scale recovery of platinum group metals (including Ir) from scrap PEM components.
- **Electrocatalytic hydrogen sulphide (H_2S) conversion opens a route to co-produce hydrogen and sulphur**. A new electrocatalysis process in China has demonstrated hydrogen production from H_2S decomposition, achieving conversion rates above 99.999% and producing both hydrogen and sulphur at commercial-grade purity. As H_2S must already be captured and treated in conventional sulphur-recovery units, the process could provide an alternative pathway that directly converts this waste stream into hydrogen and sulphur.
- **Chirality-induced spin selectivity (CISS)-based coatings aim to improve electrolyser efficiency**. Chiral Energy has tested an electrode coating based on CISS, which selectively allows electrons with a given spin orientation to pass. The company reports that this can reduce voltage and increase current density without accelerating stack degradation, with efficiency gains of up to 50%. The technology is at the proof-of-concept stage, and undergoing testing with electrolyser manufacturers.
- **Aluminium-water reactors for hydrogen production reach proof-of-concept scale**. Found Energy is commissioning a 100 kW catalytic aluminium-water reactor in the United States, producing both heat and hydrogen and representing a tenfold scale-up from its 10 kW prototype. In Canada, GH Power has received government funding to validate a similar approach, using aluminium scrap to produce hydrogen and heat while generating alumina as a commercial co-product.

First-of-a-kind pilot and demo achievements

In the hydrogen sector, a significant number of technologies are currently at the first-of-a-kind large pilot and pre-commercial demonstration stages under real-world conditions. These first-of-a-kind pilots are essential to understand performance in real operating environments, while still allowing for further testing and improvement before capital-intensive commercial scale-up.

- **World's largest high-temperature electrolyser enters operation**. A 2.6 MW solid oxide electrolysis cell (SOEC) electrolyser from Sunfire, operating up to 850°C, has started up at Neste's refinery in Rotterdam, the Netherlands. This is bigger than the previous largest high-temperature electrolyser, a 0.7 MW unit installed at a Salzgitter's steel plant in Germany in 2020.
- **World's largest photocatalytic water-splitting plant enters operation**. A 200 tpa facility in China uses 144 heliostats (large mirrors that concentrate

sunlight) to direct solar radiation onto 24 strontium titanate reactors that produce hydrogen from water. The facility was developed by a joint venture between Panzhihua Urban Construction & Transportation and Beijing Nao Hydrogen Power Technology. In Australia, Sparc Hydrogen commissioned a photocatalytic water-splitting reactor in late 2025 and is now testing the technology.

- **World's first centrifugal hydrogen compressor enters demonstration**. Kawasaki Heavy Industries (KHI) has built a demonstration plant in Japan for hydrogen turbo-compressors, featuring high-speed rotation to reduce size to one-seventh of conventional compressors and improved cooling and impeller design to cut electricity consumption by 3-4%.
- **Lined hard rock cavern storage proves hydrogen cycling in real-world tests**. The HYBRIT pilot facility in Sweden, a 100 m³ lined hard rock cavern storing around 70 MWh H_2 (equivalent to 2 t H_2 at 250 bar) was commissioned in 2022. Over 3 years of operation, it demonstrated safe and reliable performance, including through accelerated mechanical tests with repeated pressure swings. In 2026, the pilot was granted an extension to continue the tests until 2031.
- **Marine hydrogen engines complete first land-based demonstrations**. KHI, Yanmar and Japan Engine have conducted land-based trials of marine engines fuelled with liquefied hydrogen (LH_2), which is gasified and supplied at high or low pressure to test different engine configurations. KHI and Yanmar demonstrated hydrogen combustion in medium-speed four-stroke engines (0.8-2.6 MW). Japan Engine demonstrated a low-speed two-stroke engine (up to 5.6 MW), with deployment in a 17 500 deadweight tonnage (DWT) multi-purpose vessel targeted for 2027.
- **Megawatt-scale hydrogen fuel cell system demonstrated in low-altitude flight**. A 7.5-tonne unmanned turboprop aircraft with a 0.9 MW hydrogen fuel cell, developed by Aero Engine Corporation of China, completed its maiden flight at Zhuzhou Lusong Airport, covering 36 km at 220 km/h at an altitude of 300 m. Other megawatt-scale fuel cell systems have previously been tested in flight, such as by Universal Hydrogen, although the company is no longer operating.
- **Largest boiler burning 100% ammonia successfully demonstrated**. A 500 kW boiler using an integrated cracking burner was successfully demonstrated in the United Kingdom. By using waste heat from combustion, the system cracks ammonia to produce sufficient hydrogen to sustain stable combustion, eliminating the need for a pilot fuel.[73]
- **Large-scale gas turbines demonstrate 100% ammonia combustion**. In early 2026, GE Vernova and IHI announced the successful demonstration of 100% ammonia combustion in an F-class gas turbine at a test facility in Japan, building on an earlier demonstration by IHI of running a 2 MW gas turbine on 100% ammonia. In March 2026, IHI, Petronas and Gentari signed an agreement to install a 2 MW ammonia-fired gas turbine at a petrochemical site in Malaysia in 2027. MHI is also developing a 40 MW gas turbine designed to run on 100% ammonia.

[73] Pilot fuel refers to a small quantity of easily ignitable fuel, such as natural gas or diesel, used to initiate and stabilise combustion when the primary fuel is difficult to ignite, such as ammonia, which has a high autoignition temperature and slow flame propagation.

- **One of the world's largest CO_2 methanation plants enters operation**. INPEX and Osaka Gas commissioned a plant in Japan with a capacity of 400 Nm^3 CO_2/h (around 2.5 ktpa of synthetic methane via the Sabatier reaction) in early 2026. This exceeds the capacity of known projects, including Hy2gen's 1.8 ktpa Atlantis plant in Germany, in operation since 2013. The Japanese facility uses captured CO_2, achieves a methane concentration of 96%, and injects the synthetic methane into the gas transmission grid.

Announced commitments to go to the next level

Following demonstration, the next step is scale-up, requiring both engineering innovation to increase plant size and – critically – investment decisions from companies signalling readiness to adopt new technologies. Previous editions of the GHR highlighted key milestones, including the world's first 100% H_2-based DRI plant under construction in Sweden; the first autothermal reforming (ATR) plant with CCUS in the United States (now operational, with the CO_2 capture component still under construction); and the first large-scale salt cavern for electrolytic hydrogen storage, also under construction in the United States. Further scale-up is planned across other applications.

- **World's first commercial-scale ethanol-to-jet plant enters operation**. In late 2025, LanzaJet began producing jet fuel at its Freedom Pines Fuels facility in the United States, with a capacity of around 30 ktpa. While this is below one-tenth of the size of a small refinery, it is sufficient to supply fuel for nearly 600 flights per year between Paris and New York. Also in the United States, Gevo is planning a 90 ktpa alcohol-to-jet plant, with take-or-pay offtake agreements covering around half of capacity, while it seeks additional customers and private equity financing.
- **World's largest CO_2-to-methanol plant using electrolytic hydrogen enters construction**. In 2025, a 42 ktpa methanol plant using CO_2 and electrolytic hydrogen started operations in Denmark, the largest of its kind. Larger projects are planned: Carbon Recycling International is providing the technology for the 170 ktpa Liaoyuan Tianying methanol project in China, which will use electrolytic hydrogen and biogenic CO_2 from biomass combustion, and is under construction with commissioning expected in 2026.
- **First industrial-scale order for an electrified steam methane reformer**. European Energy has agreed to deploy, by 2026, a 10 MW electrified steam methane reformer supplied by SYPOX, to produce around 150 tpd of syngas (approximately 15 tpd H_2) for methanol production, with an electricity consumption of 16.6 kWh/kg H_2. This marks a scale-up from earlier developments, including Topsoe's e-REACT technology, which has been piloted in a facility in Denmark since 2021, and an agreement for a 3 MW electrified reformer, signed in late 2024 between Saudi Aramco and Topsoe.
- **Non-plasma methane pyrolysis pathways move closer to industrial deployment**. Catalytic methane decomposition is among the more advanced non-plasma routes, with Hycamite's 2 ktpa H_2 plant in Finland commissioned in 2024. In 2026, Hazer Group and KBR completed a commercial design package for Hazer's catalytic methane pyrolysis process for plants of 30-50 ktpa H_2,

supporting future licensing. Non-plasma thermal methane pyrolysis is also moving towards larger demonstrations, although from a lower TRL. In late 2025, BASF and ExxonMobil formed a strategic collaboration to deploy BASF's technology at ExxonMobil's petrochemical complex in Texas, the United States, with a planned unit of 2 ktpa H_2 and 6 ktpa of solid carbon. Ekona Power is pursuing a different thermal route based on pulsed combustion, having completed its 0.2 tpd H_2 Gen1 Burnaby pilot in 2025, with plans to expand to 0.5 tpd H_2 (around 180 tpa H_2).

- **Hydrogen fuel cells in maritime applications reach multi-MW scale**. Hydrogen fuel cell capacity has scaled from 22 kW on the Energy Observer research vessel in 2017 to 400 kW on Norway's MF Hydra ferry in 2023, crossing the 1 MW threshold with the H_2Barge 2 inland vessel in 2024 and reaching 3 MW with the Breakthrough superyacht in 2025. Further scale-up is underway: two Torghatten Nord RoPax ferries for the Bodø-Lofoten route in Norway and Viking Libra cruise ships are due to enter service in 2026, with fuel cell systems of 6.4 MW and 6.3 MW, respectively, while the world's first H_2-powered short-sea container vessel, the 3.2 MW Samskip SeaShuttle, had its keel laid in late 2025. Overall, this represents an increase of almost 2.5 orders of magnitude within a decade.
- **First large-scale natural gas transmission pipeline repurposed for hydrogen**. Gascade completed the repurposing of around 400 km of high-pressure natural gas pipeline in less than a year in Germany, commissioning the northern section of its Flow project in late 2025 following hydrogen filling. Although a 12 km natural gas pipeline had already been repurposed for hydrogen in 2018 in the Netherlands, Flow represents the first repurposing at transmission-network scale.
- **Large liquefied hydrogen tanker under development**. In early 2026, KHI and Japan Suiso Energy signed a contract to build a 40 000 m³ liquefied hydrogen tanker, equivalent to 2.7 kt H_2, equipped with boil-off gas recovery and use in a dual-fuel (diesel/hydrogen-electric) generator engine. The vessel is expected to undertake ocean-going trials by 2030. This builds on the Suiso Frontier, the first liquefied hydrogen carrier with a capacity of 1 250 m³ (85 t H_2), which set sail in 2019 and completed its first LH_2 shipments in 2022.

New products and processes hitting the market

Some hydrogen-related technologies are now commercially available in the form of products or processes that were not on the market just a few years ago.

- **Containerised synthetic hydrocarbon fuel units target defence applications**. In March 2026, Germany's INERATEC launched its Lifeline product line of containerised modular fuel synthesis units, with capacities of 4-7 ktpa. The units produce synthetic fuels compatible with existing military vehicles and aircraft. INERATEC and Rheinmetall are seeking financing for first pilots under the wider Giga PtX initiative.
- **Low-speed ammonia engines move from the lab to the shipyard**. In 2025, WinGD's first 52-bore[74] low-speed ammonia engine was installed on EXMAR's

[74] The bore of a marine engine refers to the diameter of its cylinders. Smaller bores (e.g. 50) are used in smaller vessels for regional routes, while larger bores (e.g. 72) are used in larger ships designed for long-distance routes.

mid-size LPG/ammonia carrier built in Korea. By early 2026, China State Shipbuilding Corporation had delivered the first 72-bore low-speed ammonia engine, rated at 14 MW, for a 210 000 DWT bulk carrier to a Chinese shipyard for CMB. Everllence has introduced its ME-LGIA engines, available in up to 80-bore configurations, expected from 2026, and has initial orders for car carriers and very large ammonia carriers.

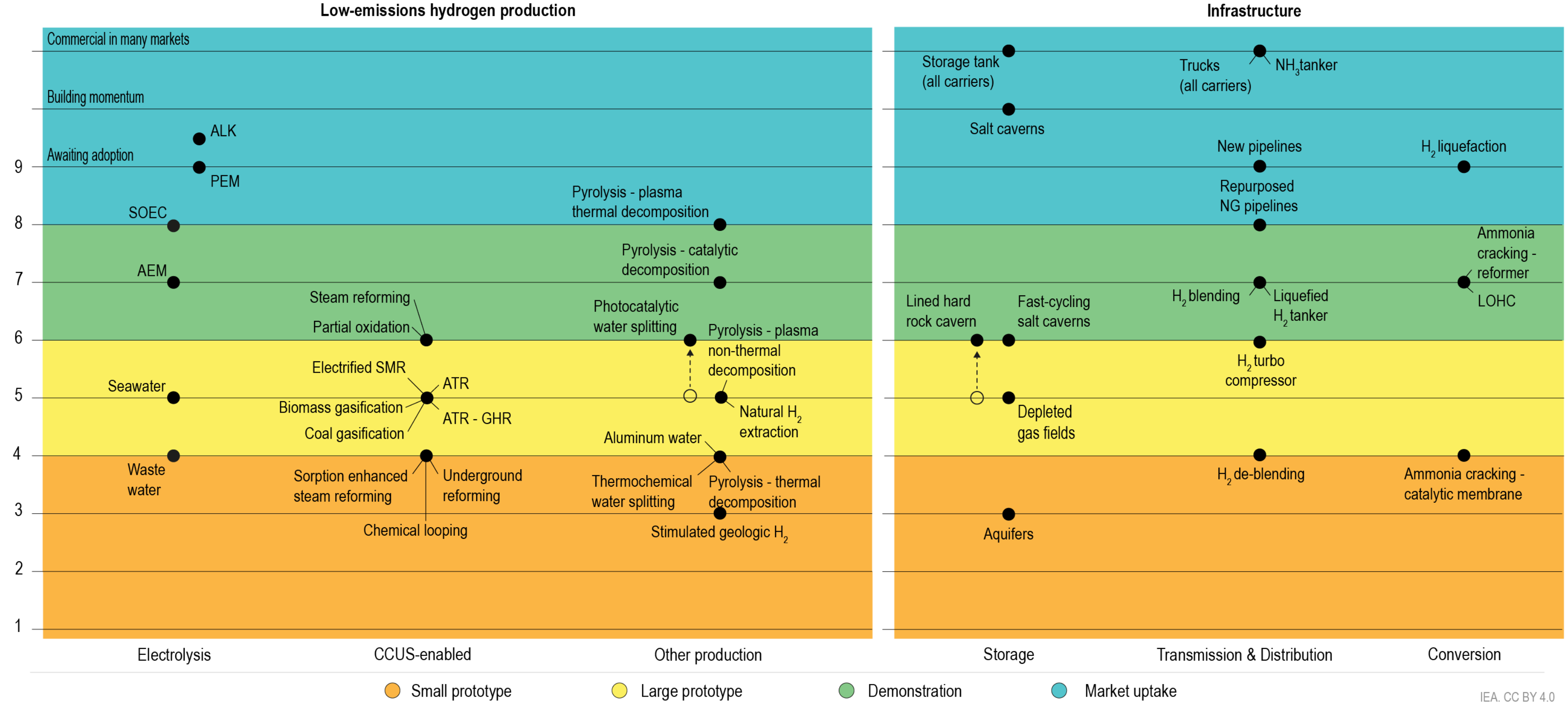
- **Hydrogen-ready direct reduced iron (DRI) gains traction as a flexible option for ironmaking**. MIDREX Flex operates on natural gas and can progressively transition to 100% hydrogen, with hydrogen shares of up to 30% requiring no major equipment changes and higher shares needing limited modifications, particularly to compression systems. The first commercial plant entered operation in late 2024 at Tosyali's 2.5 Mtpa facility in Algeria. Another 2.5 Mtpa plant is under construction at thyssenkrupp Steel in Germany, targeted for completion by end-2026, with hydrogen use planned from 2028 as supply becomes available, alongside a further 2.5 Mtpa project in Libya. ENERGIRON, jointly developed by Tenova and Danieli, can also transition towards 100% hydrogen. A 1 Mtpa facility at Baowu's Zhanjiang steel complex in China entered operation in early 2026, and another is under construction in Mexico.
- **Large 100% hydrogen-ready gas turbines enter operation**. Hydrogen-fired gas turbines are scaling up, from a 12 MW Siemens Energy SGT-400 operating on 100% hydrogen in France in 2023 to Mingyang Smart Energy's 30 MW Jupiter-1 unit in China in 2025. In early 2026, a 75 MW 7E gas turbine from GE Vernova was repurposed in the United States to operate on hydrogen blends of up to 100%. Combustion approaches differ: the Siemens and Mingyang turbines use dry low-emissions (DLE) technology to limit NO_x emissions, while the GE Vernova unit at DeBary uses wet low-emissions (WLE) technology. WLE systems are simpler to retrofit for hydrogen, but DLE technology is more common for new gas turbines and offers higher efficiency.

Enhancements to R&D testing facilities and test sites

Innovation requires R&D and testing, often relying on costly facilities that need high utilisation to justify investment. New infrastructure for testing hydrogen-related technologies is emerging and can generate comparable performance metrics, particularly where shared access maximises use and broadens access.

- **Hydrogen internal combustion engine test facility**. Johnson Matthey has opened such a test centre as part of its medium- and heavy-duty diesel engine centre in Gothenburg, Sweden. It can run full test engines of up to 600 kW for heavy-duty vehicles and evaluate catalyst performance and emissions control systems.
- **Hydrogen transmission training centre**. German gas grid operator OGE has opened a hydrogen training centre in Germany to replicate real operating conditions for hydrogen transmission pipelines and serve as a training facility for both its employees and external participants.

Figure 6.1. Technology readiness levels of technologies for the production of low-emissions hydrogen and infrastructure

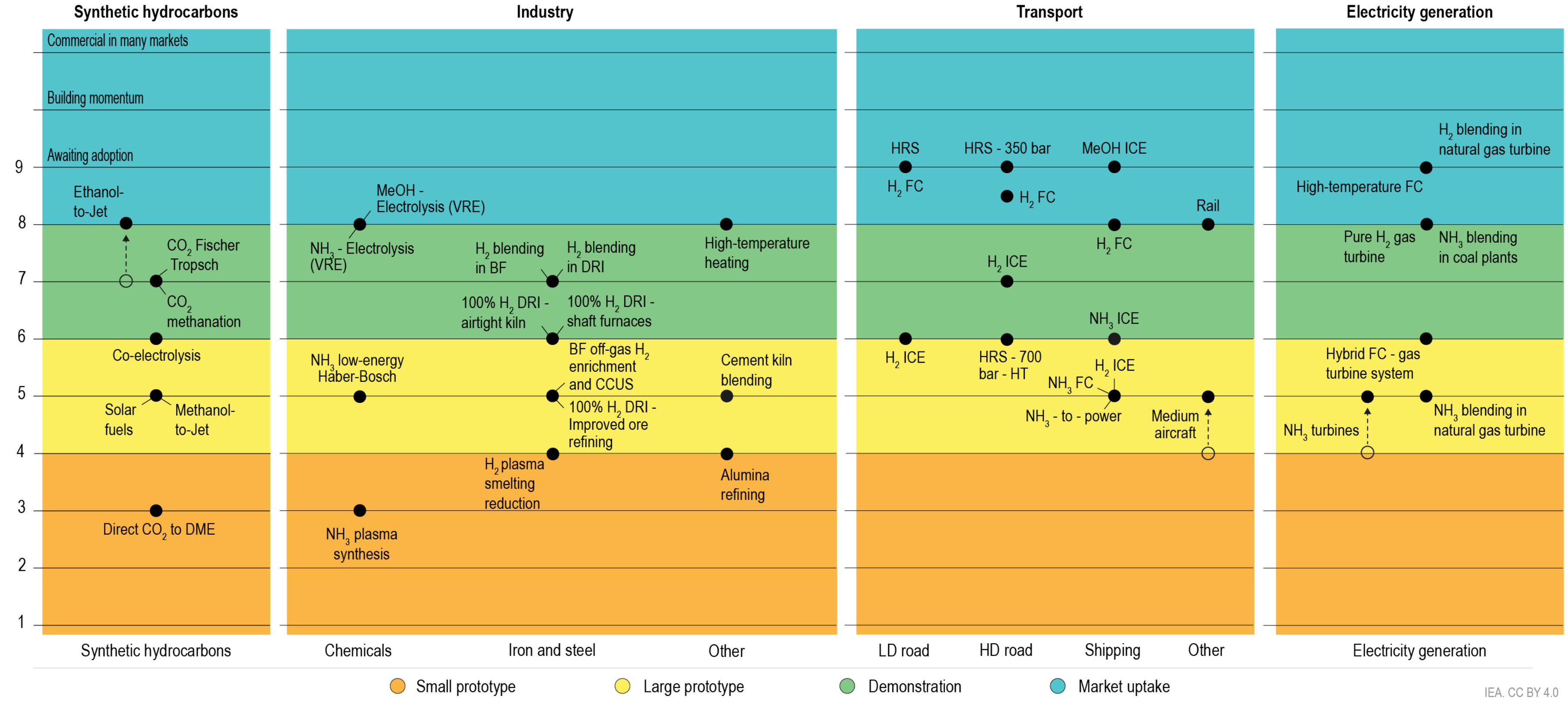


Notes: AEM = anion exchange membrane; ALK = alkaline; ATR = autothermal reformer; CCUS = carbon capture, utilisation and storage; CH_4 = methane; GHR = gas heated reformer; H_2 = hydrogen; LOHC = liquid organic hydrogen carrier; NG = natural gas; NH_3 = ammonia; PEM = proton exchange membrane; SMR = steam methane reformer; SOEC = solid oxide electrolyser cell. Arrows show changes in technology readiness level between mid-2025 and mid-2026. Biomass refers to both biomass and waste. 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 carrier.

Sources: IEA (2026), ETP Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

Technology progress continues across non-electrolytic hydrogen pathways, but hydrogen production with high CO_2 capture rates has yet to be demonstrated at large scale.

Figure 6.2. Technology readiness levels of technologies for the production of synthetic hydrogen-based fuels and other uses



Notes: BF = blast furnace; CCUS = carbon capture, utilisation and storage; CH_4 = methane; DRI = direct reduced iron; DME = dimethyl ether; FC = fuel cell; HRS = hydrogen refuelling station; HD = heavy-duty; HT = high throughput; H_2 = hydrogen; 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. Arrows show changes in technology readiness level between mid-2024 and mid-2025. "Other" in industry includes all industrial sectors except methanol, ammonia and iron and steel production. "Other" in transport includes rail and aviation. Cogeneration refers to the combined production of heat and power.

Sources: IEA (2026), ETP Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

The maturity of hydrogen end-uses remains uneven, with transport and power advancing faster, while industry and synthetic hydrocarbons lag behind due to their larger, less modular scale, but first-of-a-kind projects are moving into construction.

Chapter 7. Policies

Highlights

- A total of USD 41 billion in public funding has been identified in policy updates made since the Global Hydrogen Review 2025 (GHR-25). Nearly two-thirds of this funding is linked to legislation in force and almost 25% has already been disbursed to projects, triggering final investment decisions (FID). As in GHR-25, most of the funding comes from advanced economies and for every dollar going to demand, about 1.5 dollars go to supply.
- The number of national hydrogen strategies has stabilised at 66 globally, and recent updates have focused either on implementing strategy actions (Brazil, Mauritania, Romania) or revising targets downwards (Chile and the Netherlands). Yet most countries remain behind their targets, even when considering projects with strong potential to come online by 2030. Only two countries, the Netherlands and China, are on track to achieve their 2030 targets.
- To support demand creation, the European Commission has proposed a low-emissions steel quota for public procurement, and a quota for low-emissions steel used in cars and vans to contribute to CO_2 emissions reduction targets as part of the Automotive Package. By early June 2026, transposition of the EU Renewable Energy Directive into national legislation had been finalised in 13 member states for the transport sector, creating demand for more than 575 ktpa of low-emissions hydrogen.
- China announced a city clusters programme with a total funding of USD 1.1 billion, aiming to diversify hydrogen uses beyond cars and introducing targets for an end-use hydrogen price of USD 3.6/kg, striving for USD 2.2/kg and 100 000 FCEVs by 2030.
- Japan had selected six winners of its contracts for difference scheme as of late May 2026, adding up to nearly 130 kt of low-emissions hydrogen. Two of these support ammonia imports for the power sector. Germany agreed targets for its hydrogen-capable gas turbine fleet with the European Commission.
- On supply, renewable hydrogen has the most widespread support across countries. However, project cancellations, particularly in Europe, have reduced spending. Multiple EU member states have announced support for electrolyser manufacturing after a common framework for state aid was approved in 2025.
- With regards to standards, India defined emission thresholds for renewable ammonia and methanol, and China defined an efficiency standard of 47.2 kWh/kg (about 71% on a lower heating value) by 2028 at the stack level.

Hydrogen policy and funding

66 countries
have adopted hydrogen strategies

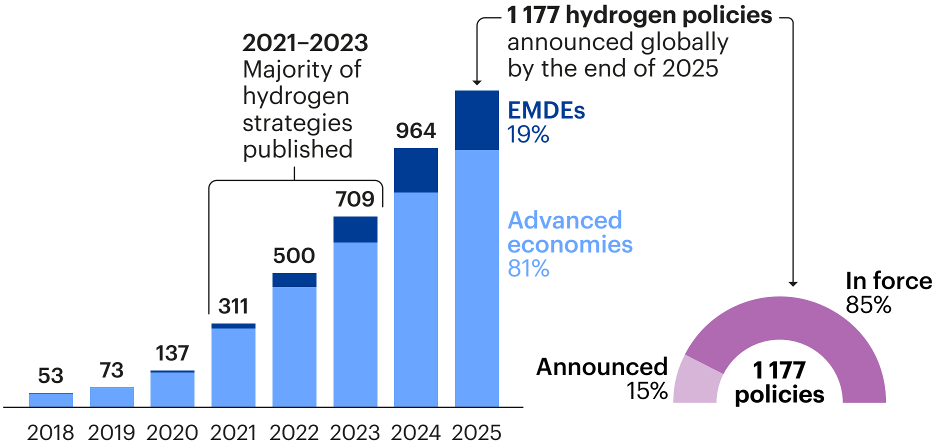
256 policies
have advanced since GHR-25

USD 41 billion
of public funding for policies that have advanced since GHR-25

1.5x more
funding for supply than for demand

2 out of 35 countries
are currently on track to meet their 2030 targets

Today, most hydrogen policies are from advanced economies, but EMDEs are joining the trend



Novel policies supporting hydrogen demand:

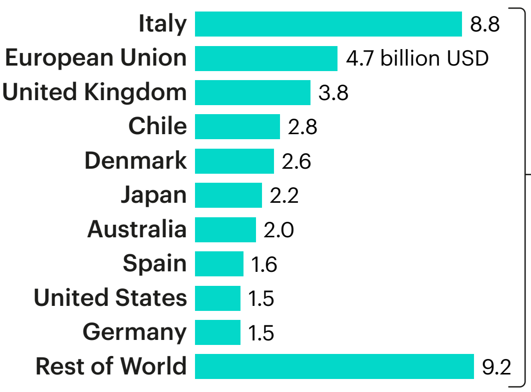
Industrial Accelerator Act (EU)
Proposes a 25% low-emissions steel quota in public procurement

Automotive Package (EU)
Proposed up to 7% of emission reduction targets could be satisified with low-emissions steel

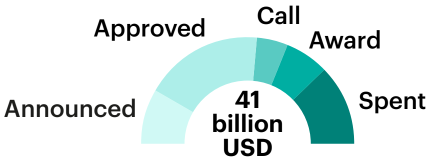
City clusters pilot (China)
$1.1 billion to support five city clusters over a 4-year period, targeting use beyond road transport

Annual funding for hydrogen by region

for policies that have advanced since GHR-25



Funding progress

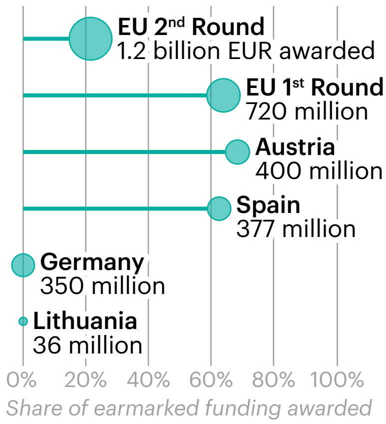


in public funding has made progress since GHR-25

24% disbursed to projects

Implemented policies could create demand for nearly **6 Mtpa low-emissions hydrogen** in 2030

European Hydrogen Bank



Countries are pursuing different approaches to support low-emissions hydrogen

China | 1.8 Mtpa H_2 by 2030

41 hydrogen projects selected by National Energy Administration to be **prioritised for loans/subsidies**

20% subsidy subsidy rate for **renewable methanol**

Japan | 215 ktpa H_2 by 2030

130 000 tonnes H_2 per year supported by Japan's **contract for difference (CfD)** subsidised projects

$2 billion in **loans available** through the state-owned bank for Japanese companies to invest in US companies supplying **ammonia**

European Union | 685 ktpa H_2 by 2030

€2.9 billion provided by the Sustainable Transport Investment Plan through 2027 to promote **scale-up of renewable fuels**

€10.6 billion provided by the Clean Industrial Deal State Aid Framework until 2030 to **support low-carbon fuels and clean tech manufacturing**

India | 510 ktpa H_2 by 2030

724 ktpa H_2 contracted across **13 ammonia auctions**; up to 500 ktpa planned for future **methanol production tenders**

2 GHG standards were defined for **limits on ammonia** (0.38 kg CO_2-eq/kg) and **methanol** (0.44 kg CO_2-eq/kg)

2 countries revised their hydrogen supply targets:

Chile

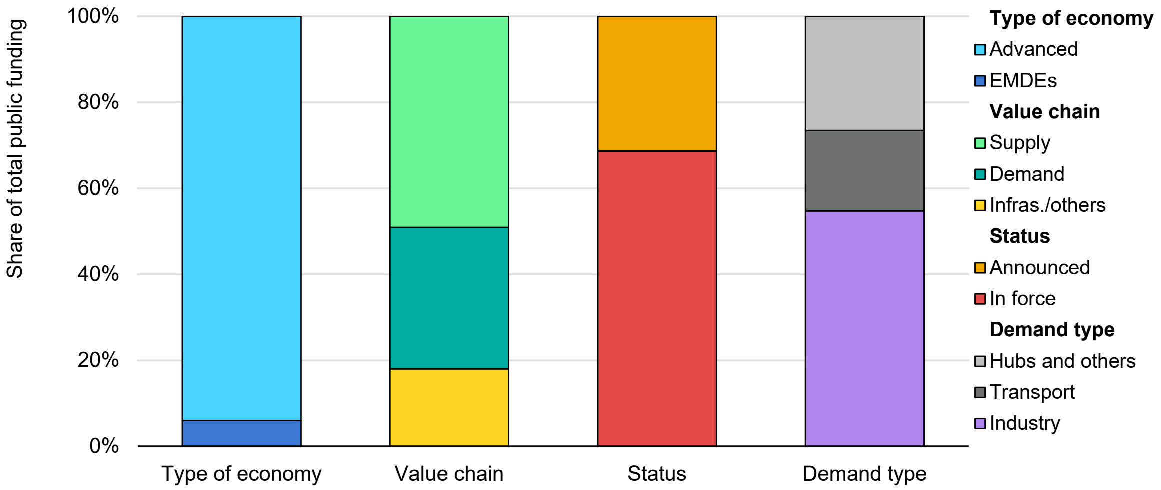
Netherlands

This chapter focuses on updates to the hydrogen policy landscape since the publication of the GHR-25 in September 2025. The analysis is complemented by the IEA's online Hydrogen Tracker, which contains more than 1 200 hydrogen policies worldwide announced or implemented since 2020.

Overview of public funding

More than 250 policies across the entire value chain, backed by public funding totalling USD 41 billion, have progressed since GHR-25. Trends remain broadly similar to GHR-25 when slicing this funding in different ways. Nearly 95% of the funding comes from advanced economies (Figure 7.1), which is partially a reflection of the prevalence of grants, contracts for difference (CfDs) and fixed premiums in these countries, as opposed to other measures that are more difficult to quantify in monetary terms, such as tax incentives, land allocation or simplified permitting. For every dollar going to demand, 1.5 dollars go to supply, which continues to be prioritised ahead of promoting demand. This is also partly due to the choice of instrument, given that mandates and initiatives aggregating demand are commonly used for demand creation but cannot be easily converted to monetary terms. Nearly 70% of the funding is in policies that are already in force and have issued specific awards, and in many cases, contracts have been signed to disburse the funds to specific projects.

Figure 7.1 Share of public funding linked to hydrogen-related policies by location, status and use, 2025-2026



Notes: EMDEs = emerging markets and developing economies; Infras. = infrastructure. Not all the policies can be converted into a monetary value. Funding only for the period since GHR-25 was published in September 2025. Numbers include both specific calls and tenders that have been awarded and announcements of future funding programmes that have been announced since GHR-25. Figure includes funding from national and regional governments but excludes sovereign lending and funding from development finance institutions. For those figures, refer to Chapter 6. Other sectors in the demand type category include power generation and heating.

Almost half of the USD 41 billion of public funding announced or disbursed since GHR-25 is directed towards the supply side and nearly 95% is from advanced economies.

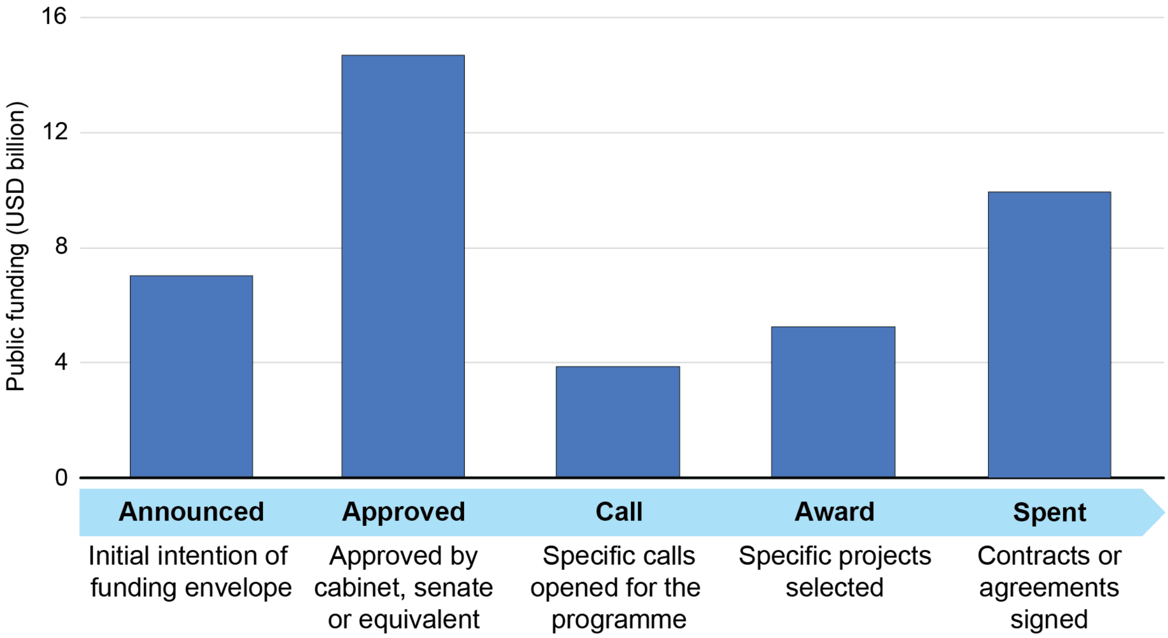
One of the largest funding allocations among policies in force was the approval of the construction of a 133-km hydrogen pipeline from Denmark to Germany, which will be financed with a DKK 7.5 billion (Danish kroner) (USD 1.1 billion) loan for capital expenditures (CAPEX), and operating subsidies of DKK 10.6 billion (USD 1.6 billion) over 30 years. Other large allocations included EUR 6 billion to support the production of 200 ktpa of renewable hydrogen through a CfD scheme in Italy, an AUD 1 billion (Australian dollars) (USD 0.6 billion) call launched for the Headstart programme in Australia, approval of EUR 1.3 billion for Important Projects of Common European Interest (IPCEI) in Italy and EUR 1.1 billion awarded in the third round of the European Hydrogen Bank. By early 2026, France had allocated nearly half of the EUR 9 billion earmarked in its 2020 roadmap.

Public funding attached to different policies goes through different stages of maturity, from announcement to disbursement, and initial estimates of public funding envelopes may differ from the final amounts awarded to specific projects in a tender. In addition, the process from announcement in a strategy document to money flowing to a project may take years. For example, IPCEIs were launched in the European Union in December 2020, with the first wave approved by the European Commission in July 2022, and the fourth in May 2024. Funding then had to be approved by national governments, leading to further delays. By June 2025, 73% of the funding had been allocated to projects by member states. In late 2025, some EU member states were still awarding funds to specific projects (as in Germany) or opening calls for new projects (Slovenia).

Examples of projects that have received public support and have taken FID include an alkaline electrolyser manufacturing capacity in Norway of up to 1 GW/yr (aid can cover up to 60% of the CAPEX and operating costs) and a 140-MW project in Austria. There are also several projects in Spain, including a 300-MW project in Huelva (funded with EUR 760/kW covering 23% of the total CAPEX), a 100-MW project in Cartagena (EUR 1 550/kW covering 52% of the CAPEX), and a 100-MW project in Bilbao (EUR 1 600/kW covering 55% of the CAPEX). Some projects have also received multiple sources of support. For example, Japan is aiming to import ammonia from a project in the United States. On the supply side, that project is receiving a tax incentive from the United States (45Q) and the CfD scheme support from Japan. The import facilities in Japan will receive support under the clusters programme. Furthermore, a Japanese state-owned bank is providing loans for Japanese companies to invest in the company behind the project. In the United States, several tax incentives are stackable, including a production tax credit for renewable electricity (45Y), for renewable hydrogen (45V) and an investment tax credit for batteries (48E).

Of the USD 41 billion of public funding in policies that have advanced since GHR-25, almost 25% has now been spent (i.e. with contracts or agreements signed). Examples include the auctions by the European Hydrogen Bank and the electrolyser projects (343 MW) supported by Poland (USD 560 million). Nearly half of the funding is related to policies that have not yet issued a specific call (Figure 7.2). This includes the announced Sustainable Transport Investment Plan in the European Union (EUR 2.9 billion), grants for the industrial sector in the Netherlands (EUR 662 million) and tax incentives for renewable hydrogen in Chile (USD 2.8 billion).

Figure 7.2 Public funding in policies that made progress since the Global Hydrogen Review 2025 was published by stage, 2025-2026



Notes: Not all the policies can be converted into a monetary value. Funding only for the period since GHR-25. Numbers include both specific calls and tenders that have been awarded, and announcements of future funding programmes that have been made since GHR-25 was published in September 2025.

Most of the USD 41 billion of public funding in policies updated since GHR-25 is now in advanced stages, with projects selected or agreements signed.

Strategies and targets

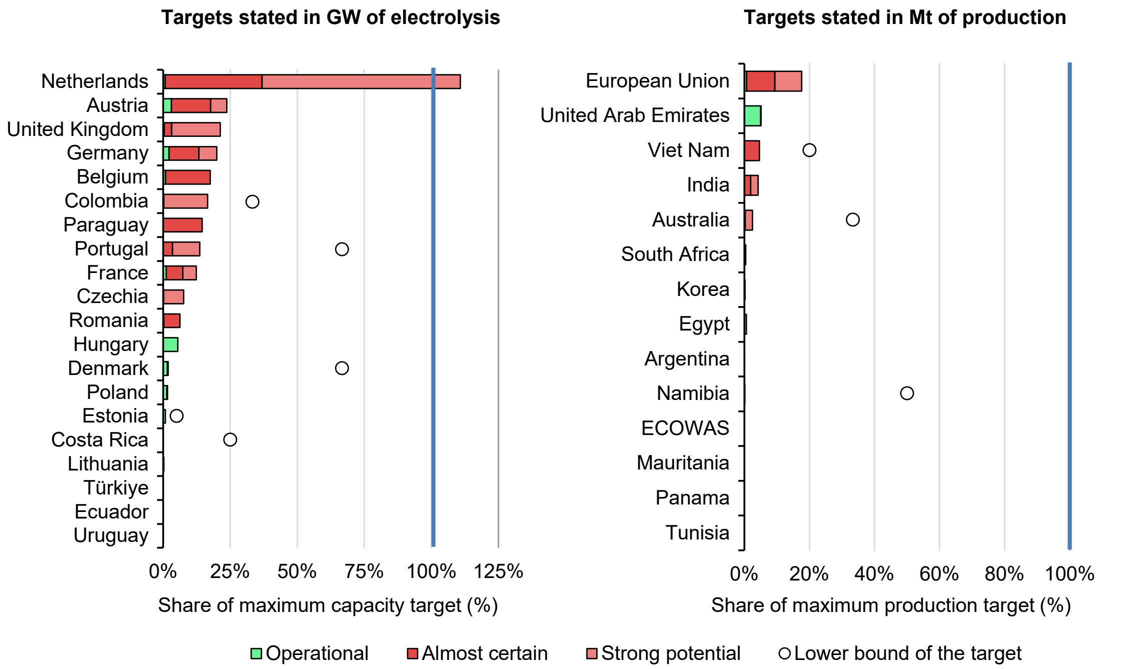
The number of hydrogen strategies being announced has now stabilised and there are 66 strategies in place today. Since GHR-25, only Montenegro has published a strategy and Georgia has announced plans to develop one. The European Union published the Sustainable Transport Investment Plan, which earmarks EUR 2.9 billion until the end of 2027 to promote the scale-up of renewable and low-carbon[75] fuels to reach the targets in EU aviation and shipping regulations.

[75] See Explanatory notes annex regarding the use of the term "low-carbon" hydrogen in this report.

The main ways in which strategies have developed have been either to move forward through concrete actions or for targets to be revised to make them more realistic. Examples of the former include Romania's action plan, which defines 33 actions across four main objectives for the 2025-2030 period; a technology roadmap from Brazil, which estimates potential demand and production costs to 2050; and Mauritania signing framework agreements with private companies as a follow-up to its Green Hydrogen Code. With regards to targets, Chile revised down its targets from 25 GW in 2030 to 8-15 GW by 2035, and the Netherlands now expects 1.2 GW of electrolysis to be online by 2030 (compared to an initial 3-4 GW target). India is making progress on deployment, but its 5 Mtpa target may be achieved only after 2030 depending on market demand and confirmed offtake. The People's Republic of China (hereafter, "China") defined a production target of 300 ktpa by 2030 in its 15th Five-Year Plan, and is on track to achieve this target by 2027. China also defined renewable hydrogen as one of the six future industries for potential economic growth, targeting wider use beyond road transport and as part of the development of zero-carbon industrial parks.

However, most countries are well behind their 2030 targets (Figure 7.3). Considering projects that have strong potential to be operational by 2030 (see Chapter 3), i.e. that would still require significant policy support and an acceleration of execution, only 2 out of 35 countries or regions are on track to achieve their 2030 targets. Firstly, the Netherlands had set a target of 3-4 GW of electrolysis by 2030 in its 2020 hydrogen strategy, but market development has been slower than expected. In 2024, a government agency assessed that the country was on track to achieve 1.2-1.5 GW by 2030, and in September 2025, the government announced that the 3-4 GW target would be delayed to 2035, with 1.2 GW expected for 2030. Secondly, China is on track to overachieve its 2030 target, with the projects with strong potential or more certain adding up to nearly 1.9 Mt in 2030. At the other end of the spectrum are countries with limited operational capacity and an immature project pipeline that remains far from realisation. This is the case for Argentina, Chile, Ecuador, Egypt, Mauritania, Namibia, Panama, Tunisia and Uruguay.

Figure 7.3 Renewable hydrogen production targets by country or region in comparison with likelihood of project pipeline reaching completion, 2030



Notes: ECOWAS = Economic Community of West African States. All numbers are expressed as a share of the maximum target. Targets are shown in announced units to avoid making assumptions on the average capacity factor for electrolysis. China is excluded from the chart to avoid distorting the scale, and because its 2030 target is 300 ktpa, while its project pipeline with all projects with up to strong potential is more than six times this target. The Netherlands updated its target to 1.2 GW in 2030 and 3-4 GW in 2035. Spain updated its target to 12 GW in its National Energy and Climate Plan from September 2024. "Strong potential" refers to projects without FID that have strong potential to become operational by 2030 according to the methodology developed in the GHR-25, updated for this report.

Most countries are well behind their production targets, even when considering projects with strong potential to come online by 2030.

Demand creation

The main developments related to demand creation seen in the past year have been the increased use of loans and loan guarantees, incentives for low-emissions steel in the automotive sector, and co-ordination instruments in the European Union, such as the Hydrogen Mechanism and the e-SAF Early Movers' Coalition. A wide range of approaches are being used to promote demand for low-emissions hydrogen,[76] tailored to different sectors and regions. However, progress remains slow. For example, transposition of the EU Renewable Energy Directive (RED) into national legislation is still ongoing. Progress in the power sector mainly came from countries in Asia, and there were developments related to hubs in

[76] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Brazil, India and the Netherlands. Policies that are already in force today would be sufficient to support up to 5.5 Mtpa of low-emissions hydrogen demand by 2030.

In industry, the Netherlands issued a letter of intent to Tata Steel to provide a loan equivalent to one-sixth of the investment for a new direct reduction plant to be commissioned by 2028, and expected to operate first with natural gas, gradually shifting to biomethane and hydrogen starting in 2032. The Netherlands also proposed a new instrument (EUR 662 million) to support industrial users in meeting the RED quotas. The scheme is still under development, but early proposals include a contract duration of 4-8 years and the need to have a firm supply agreement when bidding, to avoid speculative bids. Funding would be enough to promote about 18 ktpa of demand,[77] which is less than 2% of the current hydrogen demand. The Climate Investment Fund from the World Bank invited Brazil, Egypt, Mexico, Namibia, South Africa, Türkiye and Uzbekistan to participate in its USD 1 billion industry decarbonisation programme, with Namibia opening a call for interest until November 2025 and Brazil making a proposal with five steel and fertiliser projects.

In the power sector, Singapore selected the consortia for supply of low- or zero-carbon ammonia for power generation (55-65 MW of electricity) and bunkering was completed. The next step will be to perform front-end engineering design. Korea cancelled a tender for power generation due to a mismatch between the time horizon of the tender (support for co-firing with ammonia until 2043) and the national goal for coal phase-out (2040). Japan announced the results of its third long-term decarbonisation power auction, which included two hydrogen-fired units (253 MW) and two ammonia co-firing units (264 MW of ammonia co-firing capacity). From this third round, support expanded to cover fuel costs as well (with the first two rounds having supported CAPEX alone). From the fourth round, projects will be subject to screening criteria to ensure that those most relevant to policy are selected. Germany reached an agreement with the European Commission for its power plant strategy, which aims to secure electricity supply. The strategy includes a condition that all units should be capable of firing hydrogen and fully decarbonised by 2045, and sets a target of 2 GW of hydrogen power capacity by 2040 and another 2 GW by 2043.

Efforts were also made to aggregate demand from different users and co-ordinate with supply. The EU Hydrogen Mechanism opened its first supply call in November 2025, with more than 260 projects submitting their proposals. The offtake call was opened until March 2026, with specific suppliers and users matched in April 2026. The instrument is meant to provide infrastructure developers and financiers visibility of the project pipeline, in addition to providing a matchmaking function, and is expected to have multiple rounds per year once fully developed. In the first

[77] Assuming cap price (EUR 9/kg H_2) and a contract duration of 4 years.

round, there were 265 projects, adding up to 17.6 Mtpa on the supply side, and the mechanism created 273 unique offtake supplier combinations, with 87% of the off-takers receiving at least one expression of interest. In addition, the e-SAF Early Movers' Coalition was launched in December 2025, bringing together eight EU member states that aim to mobilise at least EUR 500 million for synthetic kerosene projects. Germany has already proposed to support these auctions with up to EUR 2 billion. The coalition aims to use double-sided auctions, like those of H2Global, with the first auction planned for 2026.

China announced the establishment of a city clusters pilot programme with a total funding of CNY 8 billion (Yuan renminbi) (USD 1.1 billion) to support five city clusters over a 4-year period. The programme aims to expand renewable hydrogen use beyond fuel cell electric vehicles (FCEVs), including renewable ammonia and methanol, steel, industrial heating, heavy-duty transport and hydrogen-blended combustion. Innovative applications in rail, shipping, aviation, back-up power and off-road vehicles are also encouraged. Targets for the pilots include lowering the end-use hydrogen price to below CNY 25/kg (USD 3.5/kg) and striving for CNY 15/kg (USD 2.1/kg) in some regions, and 100 000 FCEVs by 2030. Funding will be allocated based on a reward-based system. The rewards will be tiered based on the application of end-products or the scale of hydrogen consumption.

There were also examples of public procurement in Europe. One is the EU Industrial Accelerator Act, which aims to strengthen the region's industrial leadership in strategic sectors and accelerate industrial decarbonisation investments. A measure to achieve this is the introduction of a 25% low-emissions steel quota in public procurement, coupled with the introduction of certification standards and carbon-intensity labelling. Furthermore, for hydrogen auctions or for public schemes supporting electrolyser manufacturing capacity, EU member states should include in the pre-qualification criteria that electrolysers used to produce the hydrogen and one or two additional main specific components shall originate from the European Union. The Act still needs to be negotiated by the European Council and Parliament, which means it may still change. Another much smaller example is from the United Kingdom, where renewable hydrogen will be used during the construction of a tunnel. The supply will be 2 500 tonnes of hydrogen for a total contract value of USD 44 million, implying a cost of USD 17.6/kg.

The European Commission proposed the Automotive Package, which includes measures to promote demand for low-emissions steel that could in turn trigger demand for low-emissions hydrogen in the region. The package introduces a 90% tailpipe emissions reduction target for cars and vans from 2035, and the remaining 10% can be met by trading certificates for the use of "low-carbon" steel (up to 7%), renewable fuels of non-biological origin (RFNBO) and biofuels (up to 3%).

With regards to the transposition of the EU RED into national legislation, most progress has been made for the transport sector, where the possibility to count the hydrogen used in refineries towards the target of 1% of transport demand by 2030 has facilitated implementation. By early June 2026, 13 out of 27 EU member states – representing more than 60% of the transport energy demand across the European Union – had transposed the Directive for the transport sector. This is enough to trigger demand for at least 575 ktpa of hydrogen, which is comparable to the 630 ktpa of low-emissions hydrogen production projects that are now operational or have reached FID. A further seven member states are in the process of transposing the Directive for transport, but only four are currently doing so for industry. Belgium, France, Germany and Spain have also defined RFNBO quotas beyond 2030, which provides additional visibility on market demand necessary for investments. However, EU member states have used different absolute targets, sub-targets by transport mode, non-compliance penalties, and multipliers (energy content to be counted towards the target), which could be difficult for project developers working across borders to navigate (Figure 7.4). Germany, which has the largest energy demand for transport in the European Union, has the highest non-compliance penalty (EUR 14.4/kg), and RFNBO can additionally generate credits under the GHG reduction system with a multiplier of 3 until 2036, which could generate another EUR 8.8/kg of incentives based on the average certificate price in early 2026.

Germany and the Netherlands have policies in place to address the low utilisation of hydrogen refuelling stations (HRSs) in the early stages of deployment. In Germany, HRSs can receive up to 50% of the eligible costs and fuel cell electric trucks can receive subsidies covering up to 80% of the purchase price difference with a comparable diesel truck. Vehicles included in the funding application should cover at least 10% of the daily HRS capacity. In the Netherlands, the Hydrogen in Mobility Subsidy Scheme can subsidise up to 40% of the HRS and 80% of the purchase price difference with internal combustion engine vehicles. The application should include at least one transport or logistics company, the vehicles in the application should use at least 300 kg per day (kg/d) of the HRS capacity (which has a minimum size of 1 000 kg/d) and at least half of that should be used by buses, medium- and heavy-duty trucks.

Table 7.1 The transposition of the transport targets of the EU Renewable Energy Directive into national legislation

Country	Status	Quota			Multipliers	Refinery route[79]	Penalty (EUR/kg)
		RFNBO + biofuels[78]	RFNBO (road)	RFNBO (other)			
Belgium	🟡	1% (2028); 2.5% (2029); 4% (2030)	1% (2030); 6% (2035); 8% (2040)	Shipping: 0.4% (2028); 1.2% (2030)	2 (road transport) 3 (shipping)	☑ [80]	9.9
Bulgaria	🟡	5.5% (2030)	1% (2030)	Shipping: 1.2% (2030)	-	-	-
Czechia	🟢	1.25% (2026) 5.5% (2030)	1% (2030	-	2 (road transport)	☑	9.8
Denmark	🟢	5.1% (2030)	0.9% (2030)[81]	-	2 (road transport)	-	-
Finland	🟢	3% (2025); 10% (2030)	1.5% (2028-2029); 4% (2030)	-	2 (road transport) 1.5 (shipping/aviation)	☑ [82]	6.6
France	🟡	3.45% (2030)	0.1% (2026)[83] 1.2% (2030)[6]	Aviation: 1.2% (2030), 2% (2032), 5% (2035)	-	-	13.2
Germany	🟢	-	0.1% (2026);1.2% (2030); 12% (2040)	-	Road: 3 (2025), 1 (2038); Other: 4.5 (2025), 1.5 (2038)	☑	14.4
Greece	🟡	1% (2025) 5.5% (2030)	1% (2030); 1.2% (2030); 12% (2040)	-	2 (road transport) 1.5 (shipping/aviation)	☑	8.4
Hungary	🟢	1% (2026) 5.5% (2030)	1% (2030)	-	2 (road transport) 1.5 (shipping/aviation)	☑	10
Ireland	🟡	8% (2026); 21.5% (2030)	0.1% (2028); 2.5% (2030)	-	2 (road transport) 1.5 (shipping/aviation)	-	-

[78] Advanced biofuels produced with feedstocks listed in the Annex IX part A of the RED 2001/2018 (REDII) and DR 2024/140
[79] If hydrogen used in refineries is allowed to count towards the target
[80] Up to 85% (to promote direct use of hydrogen)
[81] Excluding aviation
[82] Up to 0.5% before 2030 and 1% after 2030
[83] Quotas for low-carbon hydrogen and RFNBO

Country	Status	Quota			Multipliers	Refinery route[79]	Penalty (EUR/kg)
		RFNBO + biofuels[78]	RFNBO (road)	RFNBO (other)			
Italy	🟢	8% (2030)	1% (2030)	-	2 (road transport) 1.6 (refineries)	☑	-
Latvia	🟢	5.5% (2030)	1% (2030)	-	-	☑	8.4
Lithuania	🟢	1% (2025); 5.5% (2030)	1% (2030); 1.07% (2030)	1.2% (2030)	2 (road transport) 3 (shipping/aviation)	-	7.2
Netherlands	🟢	3.15% (2026); 9.87% (2030)	0.05% (2026); 1.07% (2030)	Shipping: 0.32% (2030)	-	☑	-
Poland	🟡	-	1% (2030)	-	3 (shipping/aviation)	-	1.4
Portugal	🟡	Road: 15% (2030) Maritime: 9% (2030)	0.2% (2027); 1.5% (2030)	0.2% (2027); 1.2% (2030)	2 (road transport) 1.5 (shipping/aviation)	☑	5
Romania	🟢	1% (2025); 5.5% (2030)	0.1% (2026); 1% (2030)	-	2 (road transport) 1.5 (shipping/aviation)	-	6
Slovakia	🟢	8.2% (2022); 11.4% (2030)	0.5% (2030)	-	1.5 (shipping/aviation)	-	6
Slovenia	🟢	1% (2025), 5.5% (2030)	1% (2030)	-	-	☑	-
Spain	🟡	5.2% (2028), 8% (2030), 18.5% (2040)	0.7% (2028), 2.5% (2030), 7.5% (2040)	-	-	☑	-

🟢 In force 🟡 Public consultation

Notes: RFNBO = renewable fuels of non-biological origin. Biofuels refer to advanced biofuels produced with feedstocks listed in the Annex IX part A of the RED 2001/2018 (REDII) and DR 2024/140. The RFNBO target for Denmark excludes aviation; RFNBO quotas for France are for "low-carbon" hydrogen and RFNBO. The refinery route means that hydrogen used in refineries is allowed to count towards the target. The refinery route in Belgium allows up to 85% of the target to promote direct use of hydrogen, while Italy allows up to 50%. The refinery route in Finland is up to 0.5% before 2030 and 1% after 2030. Italy defines a non-compliance penalty of EUR 4 000 per certificate but does not specify the energy content of a certificate.

The EU Renewable Energy Directive has been transposed into national laws in diverse ways, potentially creating challenges for project developers.

Mitigation of investment risks

On the supply side, a wide range of policy instruments have been used (Figure 7.5). Grants are the most common among developed economies, with CfDs also being used in the past couple of years and more recently double-sided auction schemes. CfDs remove the price risk for project developers, providing more visibility and certainty on project revenues and making projects more suited to financing (i.e. improving bankability). The strike prices for CfD schemes have been relatively high. In the United Kingdom, for example, strike prices averaged USD 10.9/kg H_2, partly due to the small size (5-24 MW) of the projects, which was not enough to achieve economies of scale. Double-sided auction schemes have the advantages of promoting price discovery, cost effectiveness (smallest public funding), demand aggregation and, like CfDs, price certainty, as well as revenue certainty through bankable long-term offtake agreements. These have been introduced by H2Global, which has received funding from Australia, Canada, Germany and the Netherlands. Most of the policy support has been in form of operating expenditure (OPEX) support for 10-15 years, which is the factor with the highest impact on project bankability.

Table 7.2 Policies with known specific incentives for low-emissions hydrogen production

Region	Programme name	Funding[1] (EUR M)	Pathways	Status	Capacity	Incentive
Austria	Auction-as-a-service	400 (10 years)		Awarded	290 MW	USD 0.8/kg H_2
Australia	Headstart	721 (10 years)		Awarded	1 500 MW	USD 0.37 - 4.3/kg H_2
Australia	Production tax credit	3 900 (2024-2034)		Open to applications	-	USD 1.33/kg H_2
Denmark	Power-to-X tender	167 (10 years)		Awarded	130 MW	USD 0.13 - 0.93/kg H_2
European Union	EHB 1st auction	695 (10 years)		Awarded	1 142 MW	USD 0.43 - 0.55/kg H_2
European Union	EHB 2nd auction	271 (10 years)		Awarded	381 MW	USD 0.38 - 2.16/kg H_2
European Union	EHB 3rd auction	1 090 (10 years)		Awarded	1 085 MW	USD 0.48 - 1.21/kg H_2
Germany	H2Global	397 (6-7 years)		Awarded	100 MW	USD 5.3/kg H_2
India	SIGHT	110 (3 years)		Awarded	724 ktpa ammonia	USD 3.8 - 4.9/kg H_2
Italy	Two-way CfD	6 000 (10 years)		Approved	200 ktpa hydrogen	USD 3.3/kg H_2
Netherlands	OWE Large scale	700 (5-10 years)		Awarded	602 MW	USD 2 045/kW
Netherlands	SDE++ 2024	650 (15 years)		Awarded	8 ktpa	USD 6.3/kg H_2
Netherlands	SDE++ 2025	1 160 (15 years)		Bids received	276 MW	USD 75/t CO_2

Region	Programme name	Funding[1] (EUR M)	Pathways	Status	Capacity	Incentive
Portugal	CfD	140 (10 years)	Renewable	Awarded	3.6 ktpa hydrogen	USD 4.4/kg H_2
Spain	Auction-as-a-service	241 (10 years)	Renewable	Awarded	210 MW	USD 0.7 - 2.9/kg H_2
United Kingdom	HAR	241 (10 years)	Renewable	Awarded	125 MW	USD 9.1 - 11.4/kg H_2
United States	45V	400 (2025-2029)	All	Open to applications	-	USD < 3/kg H_2

Production pathways Renewable Gasification All
Policy instrument Fixed premium Grant Tax incentive Double auction Contract for difference

Notes: CfD = contract for difference; EHB = European Hydrogen Bank; HAR = hydrogen allocation round; OWE = subsidy for hydrogen production by electrolysis; SDE++ = Sustainable energy production subsidy scheme; SIGHT = Strategic Interventions for Green Hydrogen Transition; 45V = tax code from the Inflation Reduction Act. Values for the Headstart programme are not targets or conditions for the programme, but the result of the funding committed to the first two large-scale projects. The production tax credit in Australia is uncapped; funding refers to the amount budgeted when the measure was announced; the tax credit is provided to all projects meeting the criteria. Prices for Germany and India correspond only to supply bids rather than the cost gap or incentive because offtake bids have not been made. H2Global has multiple tenders but only the first is included since it is the only one that has been awarded. Numbers for the SDE++ 2024 and the United Kingdom represent the strike price (incentive will depend on the reference price). The incentive in the third EHB auction excludes the maritime-aviation topic due to small project sizes.

Countries are using a diverse set of instruments to promote low-emissions hydrogen production, with renewable hydrogen receiving the most widespread support.

The European Hydrogen Bank (EHB) is one of the main instruments to mitigate investment risks at the EU level. For the first call, seven projects with a cumulative electrolyser capacity of 1 502 MW and funding of EUR 720 million were initially selected. Grant agreements were signed with six projects and one project then withdrew, which means the final funding was EUR 464 million for 942 MW. The second call also awarded lower funding and capacity than planned. The initial call was for EUR 1.2 billion and 15 projects for a total of EUR 992 million (2 337 MW) were initially selected but only 6 ended up signing grant agreements for a total of EUR 271 million (381 MW) after 19 projects[84] withdrew their applications. Changes in market conditions and to planned off-takers were among the reasons behind cancellations. The auction design and completion guarantee requirement ensured that funds were allocated to the most mature projects that were able to comply with project timelines specified. The national auction-as-a-service[85] had more success, but also faced project cancellations. Austria earmarked EUR 400 million for the second EHB round, and in October 2025, four projects were selected for a total funding of EUR 275 million and one project was paused. In January 2026, a funding agreement for EUR 123 million was signed with one project and in February an agreement for EUR 100 million was signed with another, with the other two projects pending. Spain earmarked EUR 377 million, and initially awarded the full amount to three projects (485 MW), but one of them withdrew later, so two new projects were selected and the final funding was EUR 240 million for four projects (210 MW). Lithuania earmarked EUR 36 million but no Lithuanian projects bid in the second EHB round, so the funds were not used. Germany had initially earmarked EUR 350 million for the first EHB round but later scrapped the scheme.

The third call of the EHB had an earmarked budget of EUR 1.3 billion and awarded EUR 1.1 billion to nine projects with a cumulative capacity of 1.1 GW of electrolysis with an annual average production of 130 ktpa of hydrogen. Germany had earmarked an additional EUR 1.3 billion to this call through the "auction-as-a-service" scheme, which allows for use of the same competitive process to clear projects and award additional funding without the need for an extra auction. Germany's support is dedicated to projects starting operations in 2031 in Denmark that intend to export to Germany. Spain also used the same scheme, initially earmarking EUR 415 million, which was later increased to EUR 440 million, which nearly matched what was ultimately awarded. This was enough to support three projects with a cumulative electrolyser capacity of 250 MW. Grant agreements are

[84] Initially seven projects withdrew their application, which led to inviting new projects from the reserve list to prepare grant agreements, which was followed by further withdrawals.
[85] Member states can use the EU auction results to fund projects not selected by the European Commission, leveraging the existing administrative process to support additional projects without running a new process.

expected by the fourth quarter of 2026. A fourth call is pending depending on budget availability and policy priorities.

By early June 2026, Japan had selected six winners of its CfD scheme. This policy addresses the cost gap for domestic and imported hydrogen with contracts issued for 15 years and projects starting operations by the end of fiscal year 2030. A total volume of 772 kt of ammonia from the Blue Point project in Louisiana (United States) was supported through the scheme, with the bulk to be used for power generation and the rest for industrial heating (see Chapter 3). A smaller volume of less than 8 ktpa of hydrogen was also supported in another four domestic projects. The six projects add up to nearly 130 kt of low-emissions hydrogen. For reference, current hydrogen demand in Japan is 2 Mt and its 2030 target is 3 Mt. There were 27 bids in total, and more projects could be selected on a rolling basis based on budget availability. In addition to policy support, the projects importing ammonia from the Blue Point project have also received loans from a state-owned bank.

Elsewhere, the New Industry Brazil programme in Brazil has a budget of BRL 300 billion (Brazilian reals) (USD 58 billion) to boost productivity, sustainability and innovation in the industry sector during the 2024-26 period. In December 2025, 189 projects were selected, including 44 renewable hydrogen projects, for support in the form of loans, equity and grants. Brazil also selected five projects under the Climate Investment Funds Industry Decarbonisation programme, which could receive up to USD 250 million in concessional financing. In China, the National Energy Administration pre-selected 41 hydrogen projects which will be prioritised for preferential loans and subsidies. In India, 13 tenders for offtake of 724 ktpa of ammonia were awarded in August 2025 at a price of USD 575-745/t NH_3. Supply and purchase agreements were signed for 11 projects for a total of 650 ktpa in March 2026, while 2 buyers withdrew from the process. The offtake agreements are for 10 years, and incentives are provided for the first 3 years with the expectation that the cost gap with ammonia produced from unabated gas will narrow as scale, technology learning, and market demand grow. In the event that the cost decrease is lower than expected, full government support would mean exceeding the earmarked funding.

In terms of electrolyser and fuel cell manufacturing, the European Commission approved the Clean Industrial Deal State Aid Framework in June 2025. This simplifies state aid rules and facilitates public support in five areas, including low-carbon fuels and clean technology manufacturing. Under this framework, several EU member states have already announced specific support for manufacturing, including Austria (EUR 100 million), France (EUR 1.1 billion), Germany (EUR 3 billion), Greece (EUR 400 million), Hungary (EUR 4.1 billion), Italy (EUR 1.5 billion) and Spain (EUR 408 million). Separately, the European Commission selected one project for increasing automation of proton exchange membrane electrolyser stacks in its first call for net zero technologies and opened a second call with EUR 2.9 billion of funding (across all net zero technologies and also supporting deployment). Australia opened an AUD 200 million (USD 140 million) call to support clean technology manufacturing.

Certification, standards and regulations

The economies that are the most active in supporting hydrogen already have certification schemes in place. Specific methodologies for measuring carbon intensity are still missing for some countries (e.g. Brazil and India), and they are likely to benefit from the ISO 19870 standard series defining the methodology for determining GHG emissions. The standard for hydrogen production was published in April 2026, while the standards for gaseous and liquid hydrogen, ammonia and liquid organic hydrogen carriers should be finalised in 2026. A recent review of 28 certification schemes found significant differences regarding reporting of product attributes, operational setup and procedures, and the chain of custody model. These could have an adverse effect on the trade of certified hydrogen (derivatives), which highlights the need to collaborate on mutual recognition of the schemes.

Since GHR-25, the European Commission has published the delegated act for "low-carbon hydrogen" with the same GHG threshold as for RFNBO (3.4 kg CO_2 equivalent (CO_2-eq)/kg H_2) and methodologies (as per the Methane Regulation) and default emission values for the production and transport of methane. It also specified that by July 2028, the Commission will evaluate the impact of introducing alternative production pathways (e.g. nuclear). The European Commission will also propose a targeted review of the production criteria for RFNBO by the second quarter (Q2) of 2026. India set emission standards for renewable ammonia and renewable methanol with respective thresholds of 0.38 kg CO_2-eq/kg and 0.44 kg CO_2-eq/kg. The scope for the emissions measurement is from electricity to product, measured as an average over the preceding 12 months. Finland issued its first guarantee of origin for hydrogen, Australia's guarantee of origin scheme started operating (initially for renewable hydrogen and to be expanded to other pathways and derivatives) and CertifHy continues to be used to certify RFNBO projects.

In China, several government bodies jointly issued a document setting a performance target for water electrolysers to achieve a stack-level power consumption of less than 4.2 kWh/Nm³ (46.7 kWh/kg) by 2028. This target excludes balance-of-plant equipment. If achieved, this could bring Chinese stacks on par with – or with an even higher efficiency than – stacks manufactured elsewhere in the world. The National Energy Administration in China issued guidelines for the energy sector (including seven hydrogen categories) where standardisation work will be carried out during 2026.

Most of the activity in regulation and financing of hydrogen networks was in Europe. The European Commission granted special status to 100 hydrogen-related projects.[86] This status enables expedited regulatory processes and permitting and makes them eligible for funding from the Connecting Europe Facility, which is a funding instrument for trans-European networks with a total budget of EUR 5.8 billion for 2021-27. The European Grids Package was approved in December 2025. This includes financing, simplified permitting and integrated planning of the hydrogen networks. In addition, the network operators for hydrogen published a public consultation in March 2026 on de-risking options for hydrogen investment in networks, including the use of a tariff approach based on inter-temporal cost allocation and an amortisation account, combined with an EU-backed guarantee in case of underutilisation.

In the United Kingdom, the government has earmarked GBP 500 million (USD 659 million) for the first regional hydrogen transport and storage network. In November 2025, GBP 164 million (USD 216 million) was awarded to three projects to move to the front-end engineering design phase. In Germany, the hydrogen network will open in early 2026 for capacity reservations for 2026-30. In addition, the Hydrogen Acceleration Act was approved by the German cabinet in October 2025. This policy aims to simplify planning and approval procedures, as well as procurement processes, in order to accelerate the ramp-up of hydrogen infrastructure. This is achieved by introducing maximum deadlines for approval procedures, shortening appeal processes and introducing requirements for digitalisation, for example.

[86] 51 pipeline projects, 22 electrolyser plants, 18 storage projects and 9 import terminals.

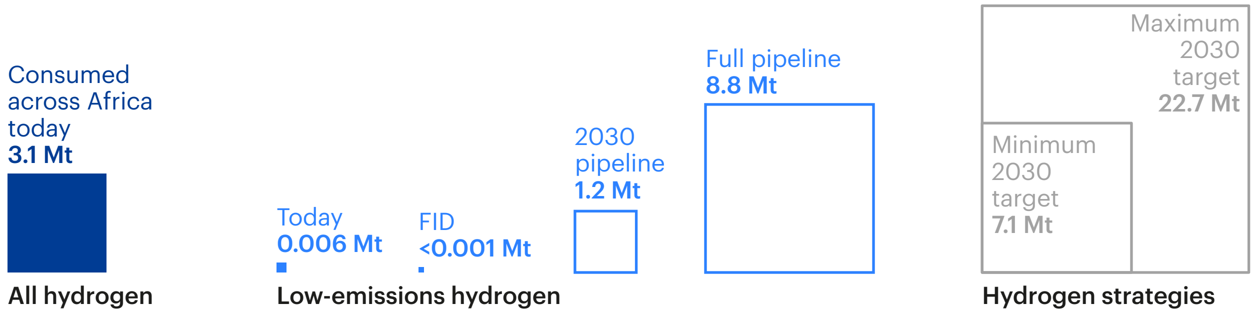
Chapter 8. Africa in focus

Highlights

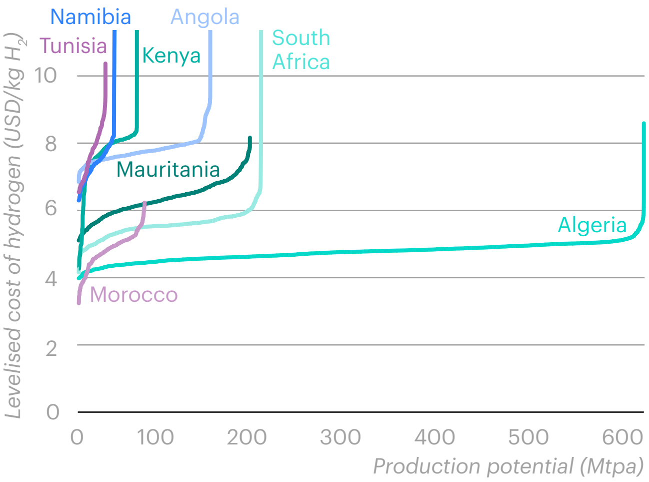
- Hydrogen use in Africa reached 3.1 Mt in 2024, about 3% of the global total. Hydrogen production accounted for about 6% of the region's gas demand and 2% of regional CO_2 emissions. Hydrogen use is concentrated in 6 countries (out of 54), with Egypt representing nearly half, followed by Algeria (20%), Nigeria (17%), South Africa (5%), Libya (5%) and Equatorial Guinea (3%). Ammonia production accounted for nearly three-quarters of hydrogen demand.
- Today, only 6 kt of low-emissions hydrogen are produced in Africa, exclusively from renewables. The hydrogen project pipeline to 2030 has 31 projects, which could allow increasing production to 1.2 Mt, but only 1 has reached final investment decision (FID). Many projects are at the GW-scale, and will take time to bring to fruition. Chinese companies have been active in financing and developing projects in Africa, as well as supplying equipment to these projects.
- Africa's fertiliser use is about one-sixth of the global average and the continent has a large food trade deficit. Domestic production of ammonia could improve access to nitrogen fertilisers, supporting higher agricultural productivity and food production, while reducing exposure to price volatility. If Africa were to achieve its fertiliser use targets, it would create demand for 1.5 Mt of hydrogen, although more than 80% of the announced ammonia capacity is intended for exports.
- Today, over 80% of Africa's ironmaking capacity is based on direct reduced iron (DRI), which provides a strong basis for blending hydrogen with natural gas in existing and new plants. Africa is a net exporter of iron ore, and iron ore production could more than double by 2030 should plans materialise. Integrated strategies combining iron ore, natural gas, renewables and demand could allow African countries to displace imports and create more domestic value.
- Africa exports nearly 75% of its methanol production today (3% of global trade). Displacing production with renewable methanol could free up some natural gas to reduce imports and help address dwindling domestic production (Egypt) or increase exports (Equatorial Guinea). In shipping, African ports can offer alternative fuels and contribute to the development of shipping corridors.
- Near-term actions include reducing the cost of capital through blended finance funds, offtake guarantees, credit guarantees and insurance. A balance between domestic hydrogen use and exports could provide the greatest opportunities for deployment, and longer-term growth can be enabled by planning the rollout of hydrogen infrastructure and developing certification schemes today.

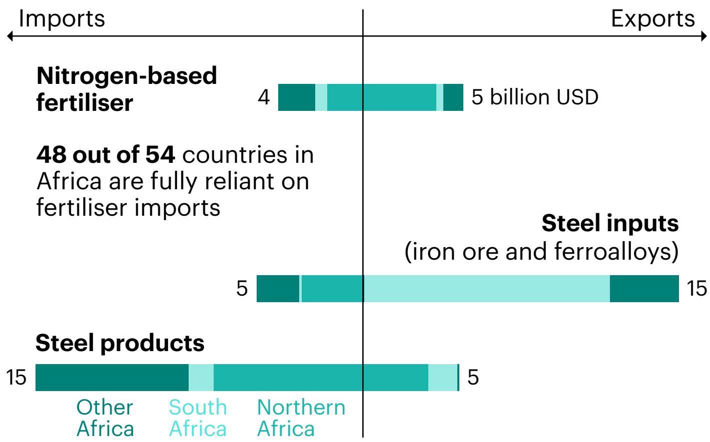
Status and prospects for hydrogen in Africa

Africa consumes 3.1 Mt of hydrogen today; the project pipeline to 2030 adds up to 1.2 Mt but only 2% has taken FID and strategies have very ambitious targets for low-emissions hydrogen

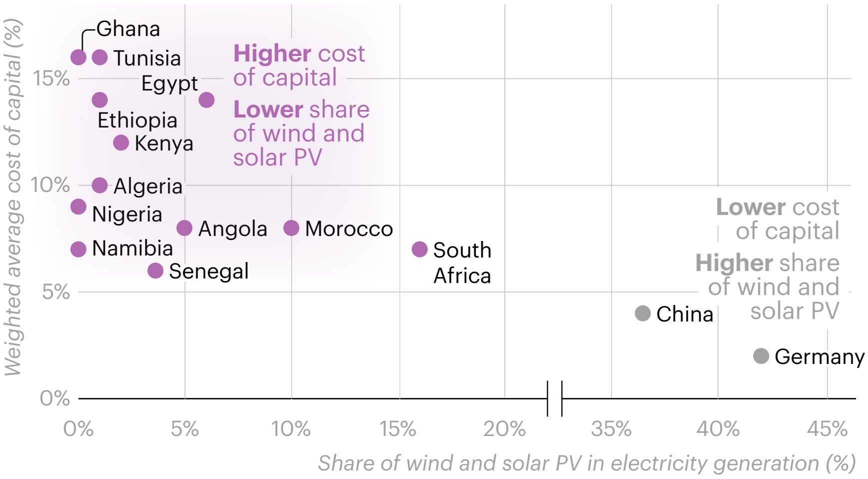


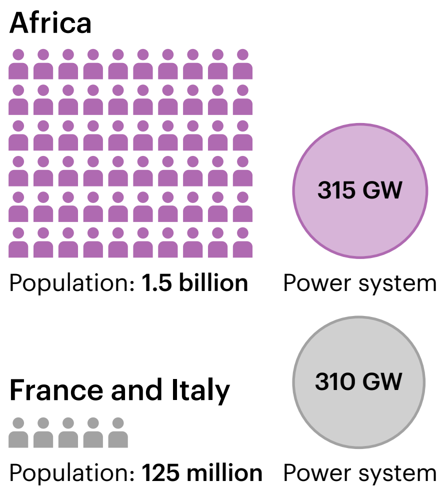
Africa has vast renewable potential – converting this to low-emissions hydrogen and derivatives could reduce import reliance on steel products and fertilisers, strengthening food security





High cost of capital and relatively low electricity and renewable penetration are the two main barriers that Africa faces in tapping into these opportunities





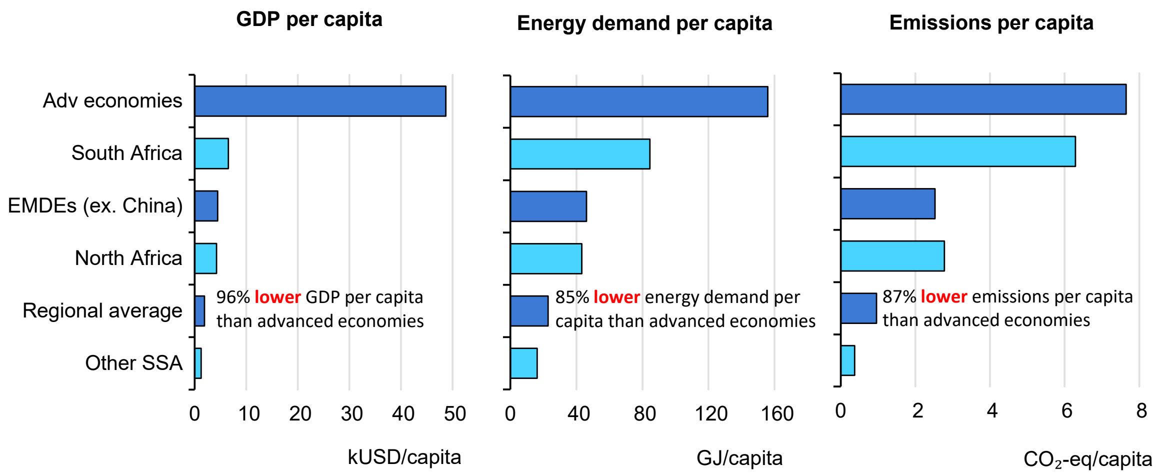
Short-term actions to overcome barriers:

- Use **policy and financial instruments** to reduce the cost of capital
- Incorporate hydrogen in long-term planning for **critical infrastructure**
- Support **deployment of renewables**, creating positive spillover effects for hydrogen
- Leverage **existing hydrogen applications** to anchor demand
- Ensure hydrogen projects provide tangible **socio-economic benefits**
- Develop **certification schemes** for hydrogen and its derivatives

Overview of the region

Africa is home to about 1.5 billion people, or almost 20% of the global population, yet it represents just over 5% of global energy demand. Nearly 55% of this demand is satisfied with fossil fuels, 25% with traditional use of biomass, 15% with modern bioenergy and the rest with other renewables. Africa has a population of similar size to all advanced economies combined, yet its per capita energy demand is 85% lower (Figure 8.1). There is a wide spectrum of energy use across Africa, with a factor of nearly 40 between countries with the highest and the lowest per capita energy consumption. Of the more than 700 million people that still lack access to electricity globally, nearly 600 million are in Africa. This is roughly equivalent to the entire population of Japan, Mexico and the United States combined. Even some of the continent's largest economies, like Angola, Ethiopia and Nigeria, still face a significant access gap, ranging from nearly 30% to more than 55% of the population. The situation is more acute for clean cooking, to which nearly 2 out of every 3 people in Africa lack access.

Figure 8.1 GDP, energy demand and emissions per capita for Africa compared to other regions, 2025

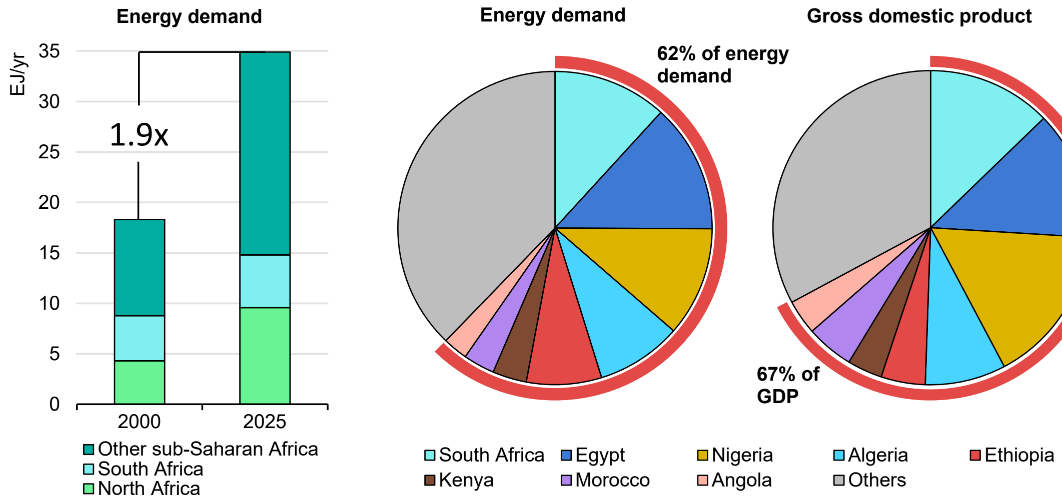


Note: Adv. = advanced; EMDEs (ex. China) = emerging markets and developing economies excluding China; Other SSA = other sub-Saharan countries besides South Africa.

African countries are far less energy-intensive and have far lower emissions than advanced economies, with energy demand set to grow alongside economic development.

Africa's economy has grown at an annual rate of nearly 4% since 2000, twice the pace of advanced economies, yet it accounts for less than 3% of global GDP. Africa's output is more geared towards agriculture (which represents 13% of gross value added [GVA]), construction and resource extraction (each around 5% of GVA) than to services, unlike advanced economies. However, despite the larger share of agriculture in its GVA, the total GVA of Africa's agricultural sector is still roughly 55% lower than that of advanced economies. Economic growth, like energy use, is highly unequal across Africa. Just eight countries (Algeria, Angola, Egypt, Ethiopia, Kenya, Morocco, Nigeria and South Africa) represent 67% of the continent's GDP, and these same countries represented 62% of energy demand in the first half of this decade (Figure 8.2). Certain economic activities are more prominent in specific countries. For example, in Algeria, chemicals represent nearly 6% of the GVA, about four times the regional average. Similarly, South Africa has double the GVA in basic metals (including the production of precious metals) than the regional average.

Figure 8.2 Energy demand and gross domestic product by region, 2000-2025



Source: IEA analysis based on data from World Bank for GDP.

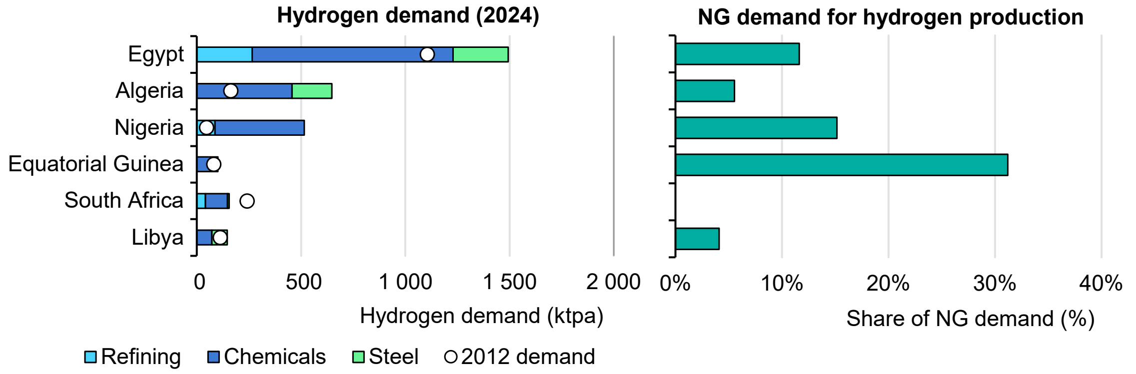
Energy demand in Africa has nearly doubled since 2000, but remains highly concentrated.

Economic growth, industrial development and access to energy are among the top priorities for Africa. If well designed, large-scale hydrogen projects can support other policy priorities, contributing to industrial development while creating spillover effects for the development of energy and transport infrastructure. The vision is for strategic investment in hydrogen and related industries to create a virtuous cycle that expands energy access and drives productivity, which in turn attracts more investment. Hydrogen could also contribute to improving Africa's acute water stress: if water for electrolysis is sourced from desalination plants, they could be oversized to supply local communities as well. Water desalination represents less than 2% of the overall hydrogen project expenses and hydrogen could create economies of scale to provide clean water to other uses. Such positive development, however, will not materialise automatically: it requires strong policies to ensure local value creation and benefit-sharing. Existing efforts towards this aim still need to prove successful.

The status of hydrogen and government strategies today

Hydrogen demand in Africa reached 3.1 Mt in 2024, up from 1.8 Mt in 2012 (Figure 8.3). Nearly all the demand comes from just 6 countries (out of 54). Egypt alone represented half of the regional demand, followed by Algeria (20%), Nigeria (17%), South Africa (5%), Libya (5%) and Equatorial Guinea (3%).[87] Ammonia production accounted for nearly three-quarters of hydrogen demand, followed by refining with 13%. All the countries with demand from refining, except for Egypt, had a relatively small demand, at less than 100 ktpa, which would not be enough to achieve economies of scale in production. In the past decade, Nigeria has expanded its hydrogen use by almost eleven times while Algeria has done so by nearly four times. In contrast, Morocco has lost the small production capacity in refining that it once had, and demand in South Africa has fallen by a third, driven mainly by declining demand in steel. In terms of infrastructure, Africa has 13 ammonia terminals, of which only four are in sub-Saharan Africa. Nearly 90% of the demand in 2024 was satisfied with hydrogen produced from natural gas, 3% was produced from coal and the rest was from industrial by-product. At a regional level, hydrogen production accounted for 6% of the gas demand in 2024 and 2% of regional energy-related CO_2 emissions.[88]

Figure 8.3 Hydrogen demand and natural gas demand for hydrogen production in Africa, 2024



Notes: NG = natural gas. Equatorial Guinea stopped methanol production in 2025 (see Methanol section). Chemicals include hydrogen demand for ammonia and methanol. There is a lack of country-level data for the split of hydrogen production and industrial by-product, so the figure assumes all countries have the same split as the regional average (about 90% from natural gas reforming).

Sources: IEA analysis based on data from Argus Media Group, All rights reserved; International Fertilizer Association; World Steel Association.

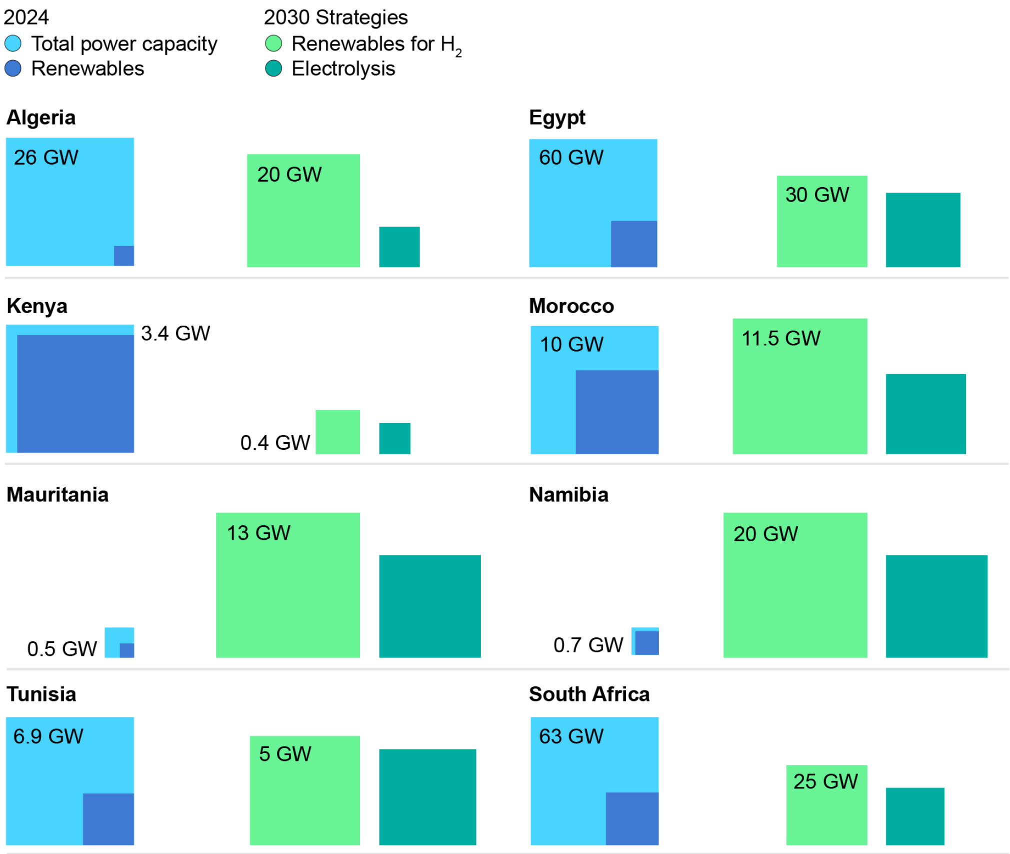
Hydrogen demand in Africa was 3.1 Mt in 2024, consuming 6% of regional gas production.

[87] All the hydrogen demand in Equatorial Guinea was for methanol production, but the country stopped methanol production in 2025 (see methanol section).

[88] This includes direct emissions from hydrogen production and CO_2 used in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply.

Eight African countries, accounting for nearly three-quarters of the current regional hydrogen demand, have a hydrogen strategy in place: Morocco (2021), Namibia (2022), Algeria (2023), Kenya (2023), Mauritania (2023), South Africa (2023), Tunisia (2024) and Egypt (2024). There is one strategy at the regional level from the Economic Community of West African States (2023). With regards to certification, only Kenya has defined sustainability criteria (including GHG thresholds) for hydrogen and ammonia production. Of the hydrogen-related United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP) initiatives, 33 countries, representing 54% of the current regional renewable capacity, endorsed the target of tripling renewables by 2030. Six countries, of which only Egypt has current demand (accounting for 50% of the current regional total) signed the Declaration of Intent from COP 28 for mutual recognition of certification schemes. Seven countries with no hydrogen demand today signed the Hydrogen Declaration from COP 29.

Figure 8.4 Renewable and electrolysis capacities in hydrogen strategies compared to current capacities, 2024-2030



Notes: 2040 values are used for Algeria since it is the only strategy without 2030 numbers. Figure uses the average of the range provided for renewables and electrolysis in strategies for Egypt, Kenya and Morocco.

Sources: IEA analysis based on data from strategies: Morocco (2021); Namibia (2022); Algeria (2023); Kenya (2023); Mauritania (2023); South Africa (2023); Tunisia (2024); Egypt (2024).

Full implementation of existing hydrogen strategies would require renewable capacities comparable to today's entire power system by 2030.

Morocco's strategy is based solely on renewable hydrogen, with the dual objective of domestic ammonia production for the fertiliser industry and for export until 2030, with other applications becoming cost-competitive over time as production costs come down. Production could reach 415-905 kt in 2030, requiring 2.8-5.2 GW of electrolyser capacity and 8-15 GW of renewables. This increases to 31-53 GW of electrolysis in 2050, producing 4.6-9.2 Mt of hydrogen with 75% for exports. Producing these volumes would require cumulative investments (since 2020) of USD 85-114 billion. To achieve these targets, Morocco has implemented the "Morocco Offer", which provides facilitated land access,[89] a benefit of up to 30% of the investment amount, tax incentives to support projects, and incentives for the development of supporting infrastructure. The framework has a streamlined selection and contracting process, supported by dedicated governance and co-ordinated by a single focal point. In the first tranche, six projects signed preliminary land reservation agreements in February 2026.

Namibia's strategy depicts a long-term vision centred around the development of three renewable hydrogen valleys across the country. Despite not having any hydrogen demand today, the ambition of the strategy is to produce 1-2 Mt of renewable hydrogen in 2030, ramping up to 10-15 Mt in 2050, driven by ammonia, synthetic fuels and iron exports. This would require an electrolyser capacity of 10 GW by 2030, increasing to 128 GW by 2050. As reference, the total installed generation capacity in Namibia was less than 700 MW in 2024. Production cost estimates are ambitious, reaching a minimum of USD 1.2-1.3/kg by 2030 and less than USD 1/kg by 2050. Fulfilling the vision could increase GDP by 30% in the 2030-40 period, creating 280 000 jobs in 2030 and 600 000 in 2040. The strategy defined 12 actions to be completed by March 2025 on setting up the operational structure within the government and the country, mobilisation of finance and local ecosystems and inclusive development. This included enacting the Synthetic Fuels Act, although as of early June 2026 this is not yet in place. The targets were confirmed in late 2025 in the National Development Plan, which included 1.3 Mt of ammonia and 2 Mt of hydrogen-based iron by 2030.

Algeria aims to produce both hydrogen with renewables and from fossil fuels with carbon capture, utilisation and storage (CCUS). Its vision entails producing 0.9-1.2 Mt of renewable hydrogen for exports and 300 kt of fossil-based hydrogen for the domestic market in 2040. This would require 2.5 GW of electrolysis, nearly 20 GW of renewables and a cumulative investment of about USD 25 billion. The main targeted hydrogen applications are industrial feedstock and power. The strategy defines 17 actions across seven pillars with deadlines ranging from 2025 to 2050. Incentives for projects include exemption from several taxes during the project implementation phase, exemption from corporate income tax for 5-10 years after starting operations and exemption from land tax for 10 years.

[89] The government has identified nearly 1 million hectares (ha) that could be suitable for renewable hydrogen. The initial tranche will be for 300 000 ha with up to 30 000 ha for each project.

Kenya focuses on renewable hydrogen to displace imports of methanol and fertilisers, and meet domestic demand. Targets for 2027 include 100 MW of electrolyser installed capacity, 20% substitution of nitrogen fertiliser imports and 100% substitution of methanol imports. In contrast to other African countries, Kenya aims to satisfy domestic production before exporting. The roadmap has been developed around four objectives: improving the balance of payments, improving food security, industrialisation and decarbonisation, and attracting investments. Actions were defined for 2024 and 2025, mostly focusing on co-ordination, planning and administrative changes to support hydrogen. Kenya has tax incentives in place in export processing zones to promote renewable hydrogen production and already has a 120-MW project under construction scheduled to start operations in late 2027.

Mauritania's strategy sets targets for renewable hydrogen while recognising, but not targeting, low-emissions hydrogen[90] from gas. The strategy is geared towards exports of steel, methanol, ammonia and ammonium nitrate, aiming to capture 1.5% of the global hydrogen market and up to 1% of the global green steel market by 2050. Production targets ramp up from 1.2 Mt of hydrogen (exported as 6.9 Mt of ammonia) in 2030 to 6.5 Mt in 2050, nearly all for exports. This would require an investment of USD 22.7 billion to deploy 13 GW of renewables and 6.5 GW of electrolysis by 2030, and nearly USD 213 billion – almost 20 times the country's current GDP – by 2050. Mauritania's is one of the few African strategies to include water supply and infrastructure. Mauritania issued the Green Hydrogen Code in 2024 to establish regulations for developing renewable hydrogen projects and provides tax incentives for these projects. The government has also signed at least seven agreements for land concessions to projects, aiming to produce 23 Mt of ammonia. However, the two largest projects, accounting for 20 Mt of ammonia, have since been put on hold.

South Africa's strategy focuses on renewable hydrogen, despite the large economic dependence on coal today. The vision includes deploying 13 GW of electrolysis and 25 GW of renewables by 2030, increasing to a respective 41 GW and 80 GW by 2050. For reference, the total power capacity was 70 GW in 2024. The capacities envisaged would be enough to produce about 1.6 Mt of hydrogen by 2030, increasing to 3.8 Mt by 2050 (with half for exports) and would require investing USD 18.4 billion by 2027. South Africa has tax incentives in place, but they are either non-hydrogen specific (special economic zones), for earlier maturation phases (feasibility studies), or have expired (renewable energy tax incentive).

Tunisia focuses on renewable hydrogen, targeting 320 kt of hydrogen production (mainly for export), 3.9 GW of electrolysis, and 5 GW of renewables in 2030. By 2050, this increases to 8.3 Mtpa of total hydrogen production, including 6 Mt for

[90] See the Annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

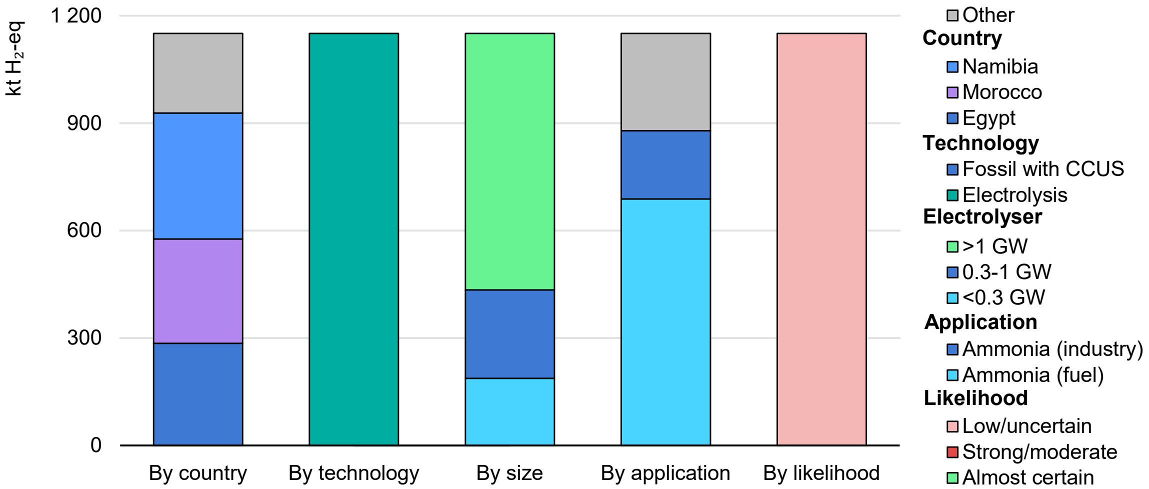
export by pipelines, requiring 87 GW of electrolysis and 100 GW of renewables. Together, this would require a cumulative investment of about USD 130 billion. Short-term use is targeted in chemicals and refining, with long-term use for electricity storage and synthetic fuel for heavy-duty trucks and aviation. As reference, Tunisia had less than 7 GW of total installed capacity and less than 1 GW of renewables in 2024. The strategy defines some broad areas of action including the definition of special economic zones, hydrogen production from offshore wind, funding support from multilateral development banks and tax incentives. These actions have not yet made it to specific concrete legislation.

Egypt targets production from renewable hydrogen. Its strategy explores two scenarios with demand increasing from 1.5-3.2 Mt in 2030 (1.4-2.8 Mtpa for export) to 5.8-9.2 Mt in 2040 (3.8-5.6 Mtpa for export). This would require 13-27 GW of electrolysis and 19-41 GW of renewables by 2030, increasing to 48-76 GW and 72-114 GW, respectively, by 2040. As reference, in 2024, Egypt had 60 GW of total power installed capacity, of which renewables accounted for less than 8 GW. Achieving the 2040 production levels would require a cumulative investment of around USD 60 billion, potentially increasing GDP by USD 10-18 billion by 2040. The strategy defines several high-level actions, and some incentives have already been introduced. In January 2024, the government introduced tax incentives for renewable hydrogen, including refunding 33-55% of the income tax related to hydrogen production or the expansion of production, exemption from VAT for equipment and exported production, exemption from property tax, stamp tax and documentation fees. Furthermore, the government designated 41 700 km^2 of land for renewables to be used for hydrogen production, and 27 memoranda of understanding (MoUs) and 10 binding framework agreements were signed with project developers.

Low-emissions hydrogen production potential

Today, Africa produces about 6 kt of low-emissions hydrogen, mostly from electrolyser projects in South Africa (60 MW), Egypt (15 MW) and Namibia (12 MW). Together with a project pipeline of 31 projects that could come online by 2030, low-emissions hydrogen production could reach 1.2 Mt. The top three countries (Egypt, Morocco, Namibia) account for more than 80% of this production and electrolysis accounts for 100% of the low-emissions hydrogen production that could be online by 2030 (of which nearly two-thirds are in GW-scale projects) (Figure 8.5). The project pipeline to 2030 adds up to 17 GW, leading to an average size of 560 MW, which would be difficult to bring to fruition in just 4 years. Some of the largest projects include those from S2H2+Bm (~500 kt of hydrogen, equivalent to around 3 GW of electrolysis capacity), Hyphen Hydrogen Energy (3 GW) and Ocior Energy (~1 Mt of ammonia, equivalent to around 2 GW of electrolysis capacity). Just 2% of the capacity in the pipeline has reached FID and many of the projects have not reported progress in years. Another 20 projects have a start date after 2030. The full pipeline considering these projects adds up to 8.5 Mt of capacity (with more than 1.9 Mt in Egypt), but most of these are mega projects in very early stages of development with a low likelihood of materialising in the short term.

Figure 8.5 Breakdown of announced low-emissions hydrogen projects in Africa, 2030

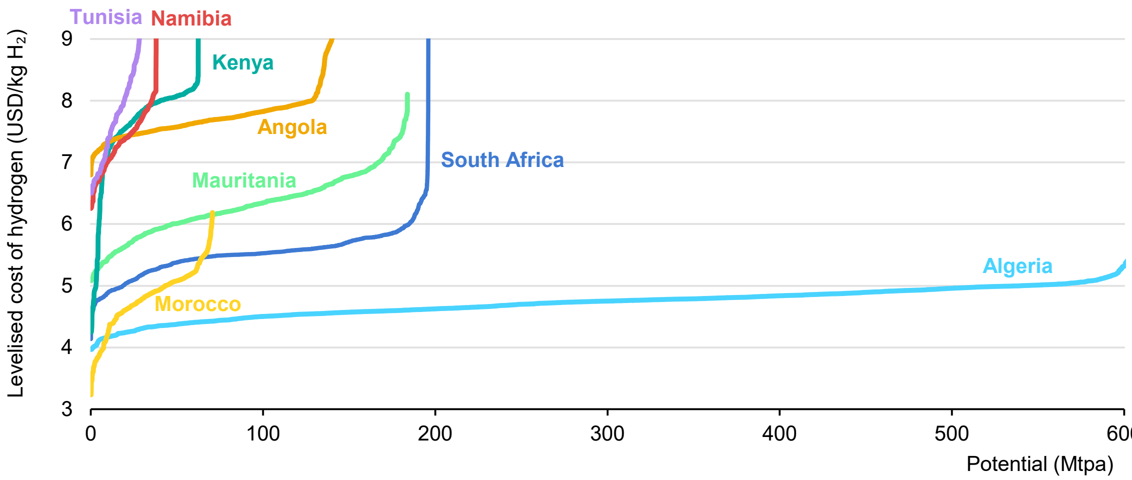


Notes: "Low potential" and "uncertain" refer to projects without FID that have a low likelihood to become operational by 2030 according to the methodology developed in the GHR-25, updated for this report. Only projects with a disclosed start year are included.
Source: IEA Hydrogen Production Projects Database (June 2026).

The project pipeline in Africa adds up to 1.2 Mt by 2030, but the chances of it all materialising by then appear very limited.

Africa has vast renewable resources, with more than 1 000 TW of solar and onshore wind technical potential, which would be enough to produce more than 45 000 Mtpa of hydrogen. More than 60% of the potential is in countries that are currently active on hydrogen (either through policies or projects), including Algeria, which alone holds 14% of the regional potential. All these countries have a renewable potential that would be more than sufficient to satisfy their domestic electricity demand and hydrogen production. Some of the best solar resources are in the south (Namibia and South Africa) and the north (Algeria, Egypt and Libya), while the best wind resources are in the Sahara Desert and the Horn of Africa. Additionally, South Africa holds 89% of the global platinum-group metals reserves and is already the second-largest global producer. These reserves could be used to establish a supply chain for their use in proton exchange membrane (PEM) electrolysers.

Figure 8.6 Supply cost curves for renewable hydrogen in selected African countries, 2030



Notes: Based on cost-optimal configurations based on solar PV and onshore wind. Potential shown in the figure is restricted to 25% of the technical renewable potential. Solar PV capital expenditure (CAPEX) is USD 950-1 040/kW; onshore wind CAPEX is USD 1330-1 720/kW. Water cost is not included.
Source: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Africa has vast renewable potential, but the main barrier preventing countries from tapping into those resources is the high cost of capital.

The main barrier to exploiting this potential economically is the high cost of capital in the region, which offsets the high quality of renewable resources. Some countries, like Tunisia or Ghana, have a weighted average cost of capital (WACC)[91] of nearly 16%, while others like Namibia, Morocco and South Africa are lower, at 6.6-8.3%. However, these are all higher than in advanced economies (e.g. the WACC in Germany was 2.3% in 2024) and the People's Republic of China (hereafter, "China") (3.6% in 2024). Therefore, the high hydrogen production cost is mostly driven by the WACC rather than by the capital expenditure (CAPEX) or capacity factor. The cheapest hydrogen that can be produced in the region is in Morocco, at USD 3.2/kg, which has 12% of the 120 Mtpa of renewable hydrogen that could be produced below a threshold of USD 4.5/kg (Figure 8.6). More than 80% of the potential below this threshold is in Algeria. Among the economies currently pursuing hydrogen projects, the production cost for Kenya starts at USD 4.2/kg, for Mauritania at USD 5.1/kg and for Angola and Namibia at around USD 6.5/kg. Kenya and Morocco have relatively steep supply cost curves, with production cost increasing by 70% and 40%, respectively, once 20% of the potential is used. Potential may be further

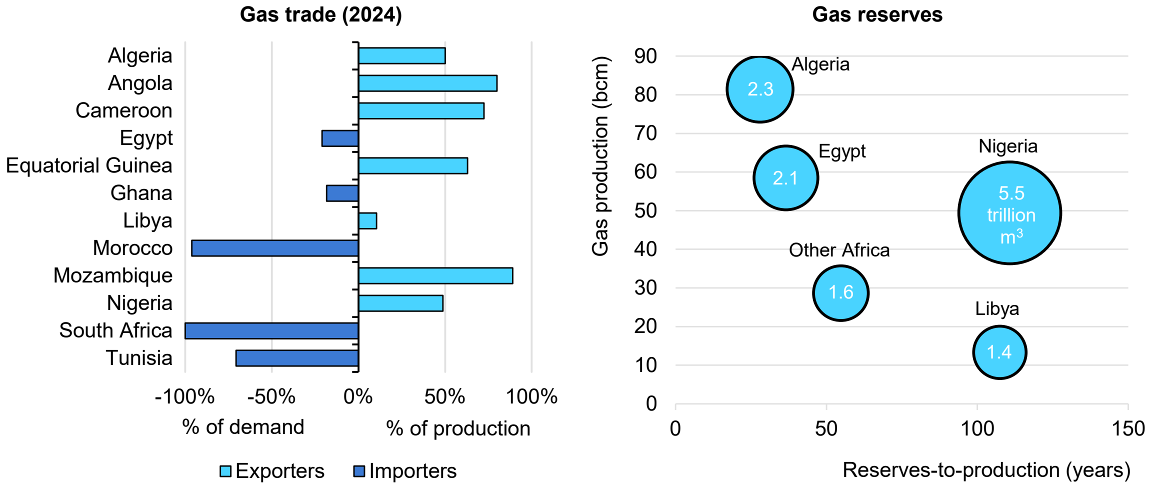
[91] These are real after-tax values based on renewable deployment in these countries. They do not reflect the use of concessional finance or other instruments. For more details, refer to IRENA (2025) Renewable-Power-Generation-Costs-in-2024.

constrained, considering proximity to existing infrastructure and potential competition with other land uses in these areas, such as agriculture, industry and urban development. While the share with the lowest cost would be used to satisfy domestic electricity demand, the potential is large enough to still have low-cost resources for hydrogen production.

Chinese companies have been active in financing and developing projects in Africa and supplying equipment. In Kenya, a 100 ktpa renewable ammonia plant will use geothermal electricity to produce fertilisers for the domestic market, displacing imports. Kaishan Group is financing the full USD 800 million of investment and developing the project, while Sungrow Hydrogen and CRRC Zhuzhou will provide the electrolysers. In Egypt, a subsidiary of United Energy Group, an integrated energy company, signed an MoU with domestic companies to perform feasibility studies for a 175 ktpa renewable ammonia plant. In Ethiopia, the Investment Commission (a government agency) approved a project which includes renewables, ammonia production, power transmission equipment and wind turbine manufacturing with a total investment of USD 14-15 billion. In Morocco, Guofu Hydrogen will supply a 20-MW electrolyser for a contract value of USD 6.2 million (USD 310/kW) to GF Hydrogen Africa. Guofu Hydrogen will also support a research centre in Morocco by supplying an electrolyser, a fuel cell system and 60 engineers. The company also plans to invest USD 30 million to build a 1 GW/yr manufacturing plant in Morocco.

Africa also has potential to produce low-emissions hydrogen from natural gas with CCUS. Africa holds 7% of global gas reserves, with 88% concentrated in four countries (Nigeria, Algeria, Egypt and Libya), which are also the largest gas producers in the region (accounting for 83% of production). Nigeria and Libya could maintain current production levels for more than a century, whereas Algeria and Egypt could maintain them for 28 and 37 years (Figure 8.7), respectively, which makes hydrogen production from natural gas more difficult to justify. The region exports nearly 30% of its gas production, but the situation differs by country. Algeria and Nigeria exported nearly half of their production in 2024, which means they have a large surplus that could be used for low-emissions hydrogen, while Libya only exported 10% of its production and Egypt had to use imports to satisfy 23% of its demand. Elsewhere, the largest gas exporter is Mozambique, which exports nearly 90% of its production of 13 bcm, a production level comparable to Libya's. This is followed by Angola and Cameroon, exporting 80% and 72%, respectively, of their production. Exporting low-emissions hydrogen from natural gas can provide a way to tap into a market with different dynamics, providing diversification and hedging against short-term fluctuations in price variations.

Figure 8.7 Gas trade and gas reserves for selected African countries, 2024



Source: IEA analysis based on Energy Institute for gas reserves.

Algeria, Libya and Nigeria are large gas exporters today, with substantial gas reserves that could be used to produce low-emissions hydrogen.

There are currently no CCUS projects in the hydrogen project pipeline in Africa. More broadly, there are no CCUS plants operating in Africa today. There is only one large-scale plant in the pipeline, a 1.6 Mt CO_2/yr capture plant for natural gas processing in Libya with planned operations before 2030. There are some direct air capture plants in Kenya, including the exploration of a 1 Mt CO_2/yr plant. As a reference, at the global level there are 77 projects in operation, adding up to 63 Mt CO_2/yr and the full pipeline adds up to nearly 430 Mt CO_2/yr. There is also limited policy support for CCUS in the region. Only a few nationally determined contributions mention CCUS without concrete legislation or measures. For example, Nigeria signals the potential adoption of CCUS technologies after 2035, in particular for the cement sector, Tunisia identifies CCUS as an area for further research, Malawi highlights CCUS as the largest lever for GHG reduction potential by 2040 by using it in thermal power plants from 2030, and Togo identifies CCUS as one area that could receive investment conditional on foreign financial support. Some countries have done an initial assessment of CO_2 storage potential, including Mozambique, Nigeria and South Africa (including offshore storage), as well as countries in North Africa.

In terms of production costs, North Africa has the lowest costs for renewables thanks to its lower WACC, and it also has a low cost for production from gas with CCUS, thanks to low-cost gas from Algeria. CAPEX for renewables is relatively low across the continent. For example, in South Africa, the government approved four solar PV projects in December 2025 with an equivalent CAPEX of USD 980/kW, similar to the USD 1 015/kW approved in July 2025. In Morocco, specific CAPEX has been higher, due to plants being smaller (20-85 MW), and given that there have not been any recent bids for solar PV. CAPEX for solar PV was USD 1 230/kW in 2018. In Egypt, a solar PV project reached FID in December 2025 with a specific CAPEX of USD 700/kW (also including a large battery), and another with USD 925/kW in January 2026, and as low as USD 525/kW in July 2025. By comparison, China, which deployed more than 60% of the global PV capacity in 2025, had a CAPEX of USD 590/kW in 2024.

In terms of levelised costs of electricity, auction bids for solar PV in South Africa were USD 28-33/MWh in 2022 decreasing from USD 60/MWh in 2015. In Morocco, bids were as low as USD 47/MWh for solar PV and USD 31/MWh for onshore wind as early as 2016. In Tunisia, tenders for 100-200 MW solar PV systems were awarded for USD 32/MWh in 2024. To put these numbers into perspective, an electricity price of USD 30/MWh is equivalent to about USD 1.6/kg H_2. However, these prices are market-specific, influenced by the auction design, and are not necessarily reflective of the true project costs.

For natural gas, there are two price tiers, one for the domestic market, which is subsidised, and one for exports. In 2024, nearly 50% of the domestic gas production was priced below production cost, 20% was sold at the cost of production, 11% was sold through bilateral agreements between a large producer and a large user and just 11% was sold on gas-gas competition (i.e. based on supply and demand). The subsidised price for gas (that could presumably be the price for hydrogen production) was less than USD 1/MBtu in 2024 in Algeria, USD 3.5/MBtu in Nigeria and above USD 5/MBtu in Egypt. Previous assessments have estimated that about 85% of Algeria's production can have a cost of below USD 1/MBtu, so even without subsidies, recovering production costs alone would lead to low hydrogen costs. In Mozambique, production costs are estimated to be USD 2.1/MBtu. As reference, a gas price of USD 3/MBtu would be equivalent to about USD 0.45/kg.

From a resource perspective, the development of hydrogen production from natural gas with CCUS does not require additional gas demand, if projects replace already existing hydrogen production from unabated natural gas, which is mainly used for fertiliser production in Africa today. Despite the huge technical potential for renewable electricity, deployment capacity for renewable hydrogen is limited, at least in the short term. This potentially introduces competition among electricity uses for the renewable electricity. Given the widespread lack of electricity access and low electricity per capita in the countries that do have access, providing access to electricity for social and economic development remains a priority. However, hydrogen projects do not have to compete with other priority uses, such as electricity access, and could instead support other policy priorities by catalysing investment, mobilising finance, developing infrastructure and contributing to industrial development. Strategies and roadmaps for hydrogen could be linked to overall electricity sector planning. Government support or concessional financing for renewable hydrogen projects could be tied to conditions to improve access to electricity and water in a region. So far, only a few projects are considering providing electricity to national electricity grids. For example, the Hyphen project in Namibia plans to feed surplus renewable electricity into the grid and also provide water to a nearby town.

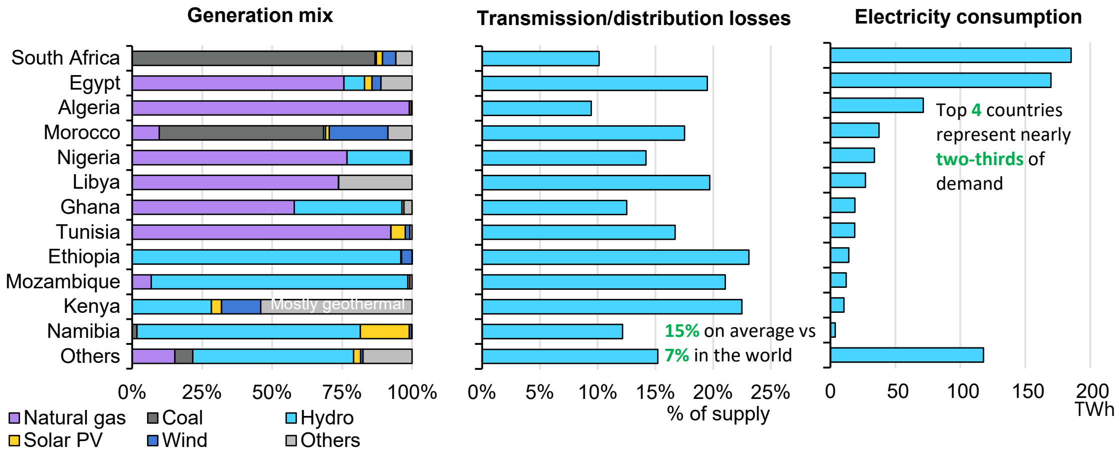
Power sector

African countries generated almost 925 TWh of electricity in 2024, almost as much as Japan, a country with 8% of Africa's population. About 45% of the generation was from North Africa and 25% from South Africa. More than 40% of generation was from natural gas, another 26% from coal and 7% from oil. Nuclear is largely absent in the continent except for in South Africa, which has two reactors in operation since the mid-1980s. Among the countries with hydrogen policies or projects, 99% of the power generation in Algeria was from natural gas, more than 85% of generation in Egypt was from fossil fuels, and nearly 60% of the generation in Morocco and 85% in South Africa was from coal. Despite the relatively small size of the power sector, the energy flows are still significant when compared to hydrogen. For example, if all the existing renewables were hypothetically to be used for hydrogen production, it would be enough to produce more than 4 Mtpa of hydrogen, while the gas consumption of the power sector would be equivalent to 20 Mtpa.

The average renewable market share in African countries was 25% in 2024, with nearly three-quarters of the market share coming from hydropower, largely concentrated in Angola, Egypt, Ethiopia and Mozambique. Among the countries with hydrogen strategies, only Kenya and Namibia had a renewable penetration higher than 30% (Figure 8.8). These two countries, together with Morocco, had a penetration of variable renewables of nearly 20%. However, the size of the power system in Namibia is just 4.9 TWh, equivalent to that of a mid-size US city (with around 395 000 people).

The power system in Africa produced nearly 480 Mt CO_2 in 2024, representing one-third of the continent's energy-related emissions. Electricity production had a regional average emissions intensity of 510 g CO_2/kWh, which is 14% higher than the global average. Countries range from less than 25 g CO_2/kWh in Namibia to nearly 850 g CO_2/kWh in South Africa. As reference, electrolysis needs to use electricity with an emissions intensity lower than 200-240 g CO_2/kWh to have lower emissions than steam methane reforming.

Figure 8.8 Electricity generation, transmission losses and demand for major electricity producing countries in Africa, 2023



Note: Wind refers to onshore wind since there is no offshore wind in Africa.

25% of Africa's power generation mix is renewable, with some smaller countries having a large share of hydropower, but grid losses were double the global average.

African countries had about 300 GW of generation capacity in 2024, with more than 70% of this as unabated fossil fuels. There were nearly 80 GW of renewable capacity, of which 45 GW was from hydropower, 20 GW from solar PV, and 9 GW from onshore wind (there is no offshore wind capacity in Africa). South Africa had nearly a quarter of the regional renewable capacity, including half of the solar PV. As reference, countries with hydrogen strategies would need up to 125 GW of renewables to satisfy their targets. Based on current forecasts, renewable capacity could more than double to 165-195 GW by 2030. The largest increase is expected to be in Nigeria, which could increase its renewable capacity by more than 4.5 times. Egypt could add 5.5 GW of renewable capacity, which would less than double its current capacity. Coal generation capacity is expected to shrink by 17% by 2030 based on current policies, and even more if announced pledges are achieved. Meanwhile, gas generation capacity could expand by nearly 10%.

All African countries have defined a renewable target. Targets to 2030 add up to 77 GW in North Africa, 40 GW in South Africa and 123 GW in the rest of Africa, which would mean nearly tripling current capacity. Among the countries active on hydrogen, South Africa is on track to achieve its 2030 renewable target. Egypt would meet only 40% of its target. Algeria would need to increase its existing renewable capacity by more than 30 times to meet its 2030 target. The other countries would meet 55-75% of their targets. South Africa approved a master plan in 2025 which included the deployment of 3 GW of renewables per year, increasing to 5 GW/yr by 2030 to reach 40 GW by 2030 (from 16 GW in 2025).

Renewables are being deployed in Africa thanks to a mix of auctions, corporate power purchase agreements, decentralised generation and electrification. Auctions are in place in Botswana, Egypt, Morocco, South Africa and Tunisia. South Africa launched its auction programme for renewables in 2011 as an alternative to a feed-in tariff and as follow-up to the Integrated Resource Plan 2010-2030, which targeted 42% of capacity additions by 2030 to be from renewables. There have been seven rounds since then, selecting a mix of solar PV, onshore wind and concentrated solar power (CSP) projects. Morocco launched its auction scheme in 2010, where a specific piece of land is allocated to renewables and developed in phases, similar to the land allocation model pursued for hydrogen in the Moroccan Offer. These auctions have been targeted to solar PV and CSP combined with storage in the latest rounds. Egypt launched both a feed-in tariff scheme and an auction scheme in 2014, with bidding processes starting in 2015, the first projects coming online in 2017, and shifting towards competitive bidding after 2019.

Average transmission and distribution grid losses in Africa are more than double than the global average (7%). Four of the five North African countries have losses of more than 15% of electricity supply, and some of the countries aiming to develop hydrogen have losses of more than 20%.

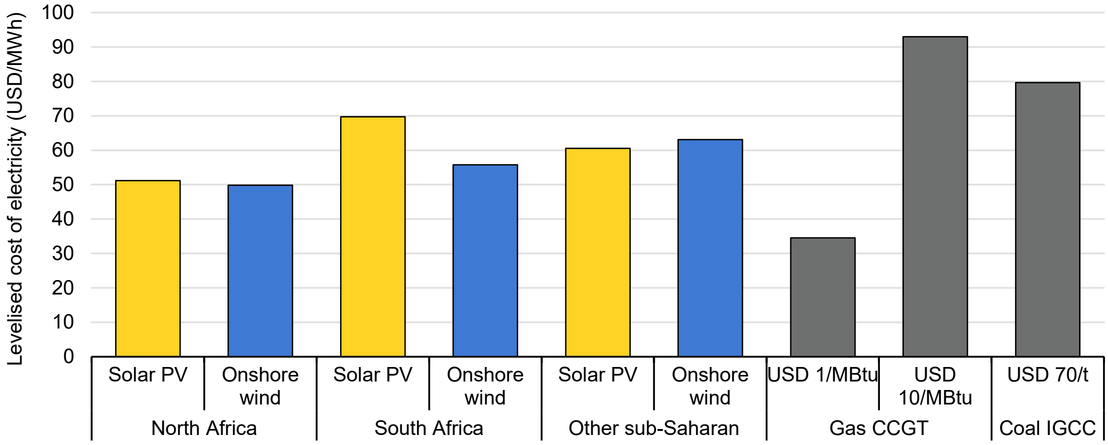
The electricity consumption of African countries was 750 TWh in 2024, with the four largest consumers (South Africa, Egypt, Algeria and Morocco) representing more than 60% of the regional demand. Regional demand has been growing at an annual pace of 3% since 2000, which is roughly the same as the global average. Three countries (Egypt, Algeria and Morocco) contributed to half of the net growth. Additionally, sub-Saharan countries had the largest relative growth, with 5% average annual growth since 2000 (from the smallest base). Buildings accounted for nearly 60% of final electricity demand in 2024, increasing by a factor of 2.5 from 2000 levels, followed by industry with 39% of demand.

For solar PV, like other regions, Africa has a large dependence on imports from China, which represented nearly 80% of the solar PV imports. Imports to Africa have grown from 3 GW in 2021, at an average price of USD 270/kW for the panels, to nearly 19 GW in 2025 at an average price of USD 95/kW.

Africa's electricity grid is largely underdeveloped, which creates additional challenges for hydrogen projects. Sub-Saharan Africa (excluding South Africa) has less than 10% of the transmission grid length per capita of the European Union. As in other energy-related areas, there is a wide range of grid regulation and development status across African countries. Power sector structures range from state-owned to unbundled markets, with Egypt, Kenya and

South Africa moving towards competitive markets. Methodologies for cost allocation and rate-setting vary across countries, which affects electricity costs for hydrogen projects. Transmission is often provided by vertically integrated companies, which complicates the estimation of wheeling charges. These factors tend to favour off-grid configurations, which prevents electrolysers from delivering flexibility to the grid in hydrogen projects, and also means they cannot benefit from grids that are largely decarbonised today.

Figure 8.9 Levelised cost of electricity for renewables and fossil fuels across African regions, 2024



Notes: CCGT = combined cycle gas turbine, IGCC = integrated gasification combined cycle. Cost of capital of 6% for renewables. Capacity factor of 16-21% for solar PV, 26-37% for onshore wind, 50% for gas and 70% for coal. Efficiency of 59% for gas turbines and 43% for coal gasification.

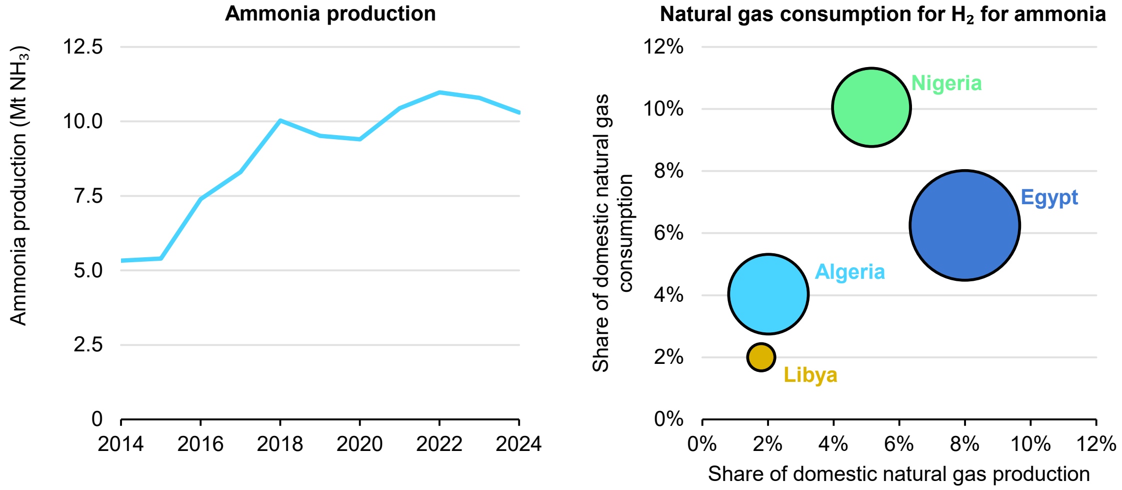
Renewables are already cost-competitive with fossil fuels, with the additional benefits of price stability, lower pollution and larger potential.

Grid expansion would not only benefit hydrogen projects – it would also be a cornerstone for electricity access. Some of the areas where further work would be beneficial include regional interconnection planning (such as the African Continental Master Plan), improved grid reliability (less frequent and shorter outages), grid planning, lower transmission losses, power market vertical unbundling, clear and standardised permitting processes and tariff-setting methodologies.

Ammonia and fertiliser production

In 2024, Africa produced over 10 Mt of ammonia, nearly 6% of global output, requiring nearly 2 Mt of hydrogen. Ammonia production was therefore the continent's dominant source of hydrogen demand, representing 60% of total consumption. In producing countries, the natural gas used to produce hydrogen for ammonia accounted for around 2-10% of domestic gas consumption.

Figure 8.10 Ammonia production, 2014-2024, and related natural gas use for hydrogen production in Africa, 2024



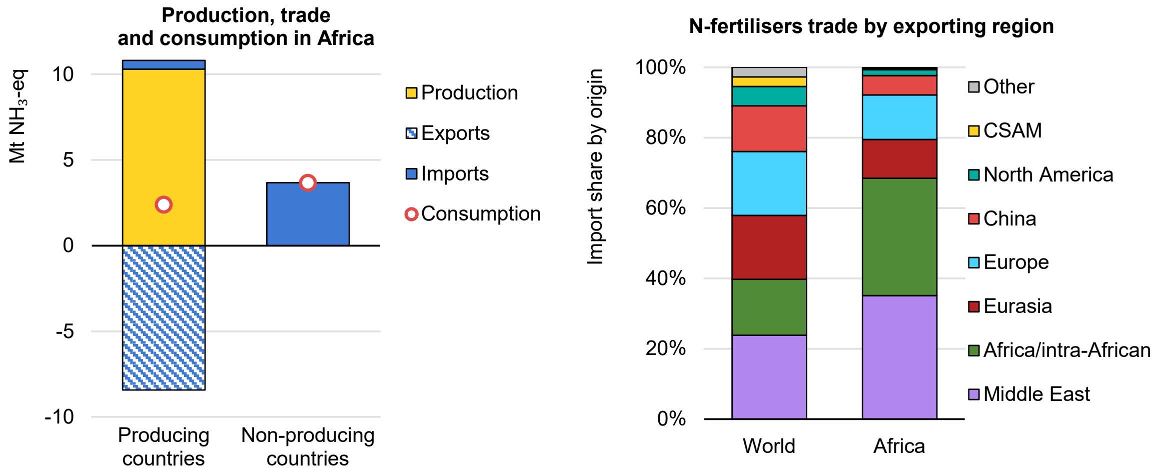
Note: Bubble size reflects the absolute amount of natural gas, in energy terms, consumed to produce hydrogen for ammonia production.
Source: International Fertilizer Association (2026), IFASTAT Portal.

Renewable ammonia could free up natural gas for other uses and help narrow Africa's fertiliser application gap.

While Africa exports more nitrogen-based fertilisers[92] than it imports, generating export revenues of around USD 5 billion for producing countries, trade patterns vary widely across countries. Production is concentrated in Algeria, Egypt, Nigeria, Libya and South Africa, with all except South Africa primarily targeting export markets. Zambia commissioned its first plant in late 2025. Other African nations are net importers, particularly of solid nitrogen fertilisers, which are easier to transport than liquefied ammonia. In sub-Saharan Africa, excluding Nigeria, this resulted in a trade deficit of nearly USD 2 billion in 2024, equivalent to more than 0.1% of their GDP.

[92] Nitrogen-based fertilisers refer to products in which nitrogen is the primary nutrient, and includes ammonia, urea, ammonium nitrate, ammonium sulphate and calcium ammonium nitrate fertilisers, and excludes those containing phosphorus or potassium.

Figure 8.11 Characterisation of nitrogen-based fertiliser trade balance in Africa, 2023



Notes: CSAM = Central and South America; NH_3-eq = ammonia equivalent. Ammonia imports and consumption are expressed in ammonia equivalent, including the ammonia-equivalent consumption of all nitrogen-based fertilisers.
Sources: FAO (2026), Land, Inputs and Sustainability: Fertilizers by Nutrient (accessed on 24 March 2026); International Fertilizer Association (2026), IFASTAT Portal.

A few African countries produce ammonia mainly for export, while the rest of the continent relies on imports, two-thirds of which come from the Middle East or elsewhere in Africa.

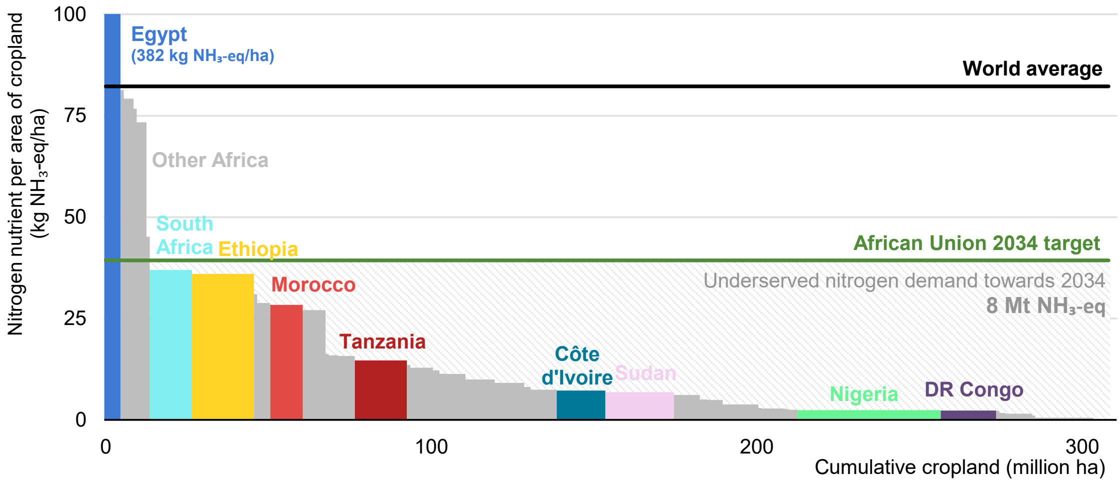
Potential opportunities in the fertiliser sector

Globally, around 70% of ammonia is used for fertilisers, suggesting that future demand for low-emissions ammonia in or from Africa may be closely linked to fertiliser use – if it can be produced at competitive costs. Nitrogen-based fertiliser consumption across Africa currently accounts for more than 5 Mt of ammonia equivalent, having grown by nearly 35% over the past decade – well above the global average of around 4% – yet part of this reflects cropland expansion rather than intensification, as fertiliser application rates increased by less than 25%. The continent's export-oriented ammonia production structure, concentrated in a few countries, contrasts with generally low fertiliser use. Egypt is a notable exception,[93] with among the highest nitrogen fertiliser application rates per hectare globally and accounting for 30% of Africa's nitrogen fertiliser use. Across the rest of Africa, fertiliser use is around one-sixth of the global average, leading to some of the lowest crop yields worldwide. Agricultural productivity growth is failing to keep pace with one of the world's fastest-growing populations. Africa produces nearly 6% of the world's ammonia, yet accounts for nearly 20% of global cropland and only 4% of global nitrogen fertiliser use.

[93] Egypt stands out as one of the most nitrogen fertiliser-intensive agricultural systems in the world, reflecting a highly irrigated system (which drives nitrogen losses through leaching and waterlogging) concentrated on limited arable land along the Nile, multi-cropping practices, and the widespread adoption of high-yielding cereal varieties with strong nitrogen responses.

The scale of unmet need is visible in trade outcomes. Africa's food[94] trade deficit reached around USD 22 billion in 2024, equivalent to almost 1% of GDP. The 2006 Abuja Declaration on Fertilizers set a target of increasing fertiliser use to 50 kg of nutrients per hectare by 2015, but by 2023 application rates remained below 23 kg/ha. In May 2024, African Union member states responded by committing to the 10-year Africa Fertilizer and Soil Health Action Plan, with goals to triple fertiliser use by 2034 (from 2020 levels) and expand domestic manufacturing. If these goals were to be achieved, and assuming nitrogen accounts for 60% of the nutrient target, ammonia demand could increase by more than 8 Mt, equivalent to around 1.5 Mt of hydrogen. African producing countries currently export around 8 Mt of ammonia, but only 15% is traded within the continent, suggesting scope to expand intra-African trade. Even so, meeting future demand at scale will also require higher domestic production.

Figure 8.12 Nitrogen-based fertiliser consumption in Africa based on application intensity and cropland per country, 2023



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Note: NH_3-eq = ammonia equivalent; DR Congo = Democratic Republic of Congo.
Source: FAO (2026), Land, Inputs and Sustainability: Fertilizers by Nutrient (accessed on 24 March 2026).

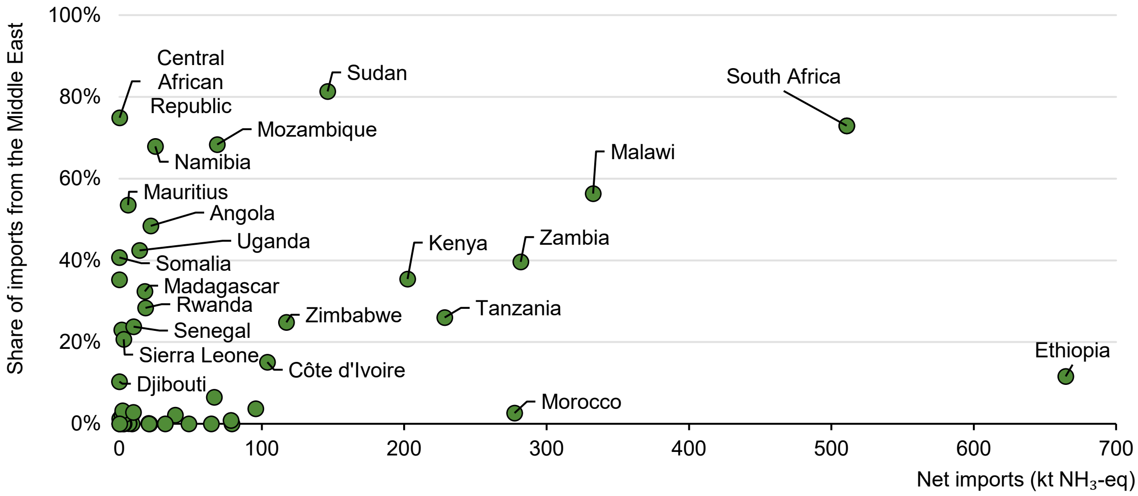
Fertiliser use is highly concentrated, with 10% of cropland consuming over half of all nitrogen, but meeting fertiliser goals could create over 8 Mt of additional ammonia demand.

Most African countries rely entirely on fertiliser imports, leaving them exposed to international price volatility. Prices spiked in 2021-22 following Russia's full-scale invasion of Ukraine, causing nitrogen application rates to fall by up to 20% in Africa compared to 2020, with knock-on impacts on food production. Prices have risen

[94] Food is defined as traded products intended for human consumption, based on the Harmonized System (HS 2022), including HS chapters 02-04, 07-11 and 16-22, as well as selected products within Chapter 12, limited to edible products, excluding seeds for sowing and other non-food uses.

again in early 2026 amid shipping disruptions through the Strait of Hormuz, with sub-Saharan African countries particularly exposed, given that around 35% of their imports come from the Middle East. This share can reach as much as 80% in some countries, such as Sudan.

Figure 8.13 Nitrogen-based fertiliser imports in Africa and share of imports from the Middle East, 2023



Notes: NH_3-eq = ammonia equivalent. Ammonia imports are expressed in ammonia equivalent, including the ammonia-equivalent consumption of all nitrogen-based fertilisers. This figure (Figure 8.13) is based on FAOSTAT data for nitrogen nutrient imports in fertilisers and is not directly comparable with estimates based on anhydrous ammonia trade in figures 1.2, 1.4 and 1.5. In countries such as Morocco, imported ammonia is largely used as an industrial input to produce phosphate-based fertilisers, such as mono-ammonium phosphate (MAP) and di-ammonium phosphate (DAP), much of which is subsequently exported. These ammonia imports are therefore reflected in trade statistics but not necessarily in nitrogen nutrient imports for domestic agricultural use.

Source: FAO (2026), Land, Inputs and Sustainability: Fertilizers by Nutrient (accessed on 24 March 2026).

The Middle East is Africa's largest trade partner for nitrogen-based fertilisers, but reliance on these imports varies widely.

Enhancing access to affordable nitrogen-based fertilisers

Improving access to nitrogen-based fertilisers is the central priority for Africa, particularly in sub-Saharan Africa, with affordability guiding which production pathways to pursue. The most suitable technology will vary across countries, depending on their resource endowments and existing infrastructure.

Natural gas production is expected to grow in several sub-Saharan African countries, including Angola, Mauritania, Mozambique, Senegal and Tanzania, with liquefied natural gas (LNG) export terminals already operational, under construction or planned in some cases. Countries with natural gas resources that exceed their domestic demand could consider converting part of this gas into ammonia and fertiliser products, helping to serve domestic markets, foster intra-

African trade with countries that have limited or no access to natural gas, and create opportunities in global fertiliser trade. This would build on historical trade patterns in which ammonia and methanol served as traded forms of natural gas before LNG became widespread.

Producing the additional 8 Mt NH_3-eq output needed to meet Africa's nitrogen fertiliser application target domestically, using conventional natural gas-based hydrogen, would generate less than 25 Mt CO_2-eq, equivalent to around 0.06% of the world's current energy-related GHG emissions. This represents a marginal increase in emissions relative to the potential benefits of higher agricultural productivity and improved food security, while also helping reduce pressure for agricultural land expansion and associated land-use change emissions.

Countries without access to natural gas, or with exceptionally strong renewable energy resources, could produce low-emissions ammonia. Kenya, which is entirely reliant on imported fertilisers, explicitly recognises in its hydrogen strategy the role that domestic low-emissions ammonia could play in reducing this exposure. Early examples are already emerging, including demonstration projects in Kenya and Namibia, as well as a large-scale geothermal-powered electrolytic hydrogen project under construction in Kenya targeting urea and calcium ammonium nitrate production. Kenya's baseload geothermal resources enable higher electrolyser utilisation, which lowers hydrogen production costs.

Strengthening the resilience of complex fertiliser supply chains

Morocco is the world's second-largest phosphate producer, holding around two-thirds of global phosphate rock reserves and accounting for 25% of global ammonium phosphate exports. Unlike potash, phosphate rock requires chemical processing before it can be taken up by plants, typically into mono- and di-ammonium phosphate (MAP and DAP) fertilisers using ammonia, making Morocco structurally dependent on imported ammonia to upgrade its reserves into exportable fertilisers. Morocco imported more than 1.6 Mt of ammonia in 2024 – 10% of global ammonia trade, and around 85% of Africa's total ammonia imports – generating an import deficit of more than USD 1.5 billion, offset by nearly USD 7 billion in compound fertiliser export revenues. This dependence on imported ammonia is particularly notable given the absence of domestic natural gas production, but Morocco's excellent renewable energy resources, the world's largest phosphate reserves, established deep-water port infrastructure, and growing international demand for low-emissions fertilisers all mean it is well positioned to develop domestic low-emissions ammonia. In this context, state-owned OCP (one of the world's largest phosphate fertiliser exporters) has announced several projects to produce ammonia from electrolytic hydrogen, aiming to produce 3 Mt of ammonia by 2032, as a hedge against market volatility. Achieving this goal could require over 5 GW of dedicated renewable energy capacity, depending on the balance between solar PV and wind generation, equivalent to roughly a third of Morocco's national renewable energy target of 15 GW by 2030.

While Morocco is by far the largest exporter of MAP and DAP, other African countries, such as Senegal and Tunisia, also import ammonia to produce and export ammonium phosphate fertilisers and could capture similar opportunities. New phosphate mining projects under development in Congo (Brazzaville) and Guinea-Bissau, expected to come online after 2027, point to longer-term opportunities to integrate domestic ammonia production into fertiliser value chains.

Trade opportunities from low-emissions production

Trade is a major driver of low-emissions hydrogen project announcements, with more than 80% of announced African ammonia capacity intended for export, spanning projects in Egypt, Mauritania, Morocco, Namibia and South Africa, with some also targeting bunkering near key maritime routes. African exporters could help diversify global fertiliser supply chains, currently concentrated in Russia and the Middle East, which together account for nearly 60% of global urea trade, compared with less than 20% for Egypt, Algeria and Nigeria combined. However, a global market for low-emissions ammonia products has yet to emerge, and key policy uncertainties remain, notably around the application of the EU Carbon Border Adjustment Mechanism (CBAM) to ammonia and fertilisers, and, for marine bunkering, the adjournment of the International Maritime Organization (IMO) Net-Zero Framework decision from 2025 to 2026.

International co-operation and long-term offtake agreements will be critical to realising these opportunities, as illustrated by the Egypt Green Hydrogen project in Ain Sokhna, which secured a 7-year ammonia offtake agreement through the first H2Global auction in 2024, though FID has yet to be taken. Intra-African trade represents a further avenue for growth, though non-tariff measures, particularly divergent fertiliser standards, remain an obstacle that the African Continental Free Trade Area, currently being implemented, could help progressively reduce.

Unlocking Africa’s potential for low-emissions ammonia

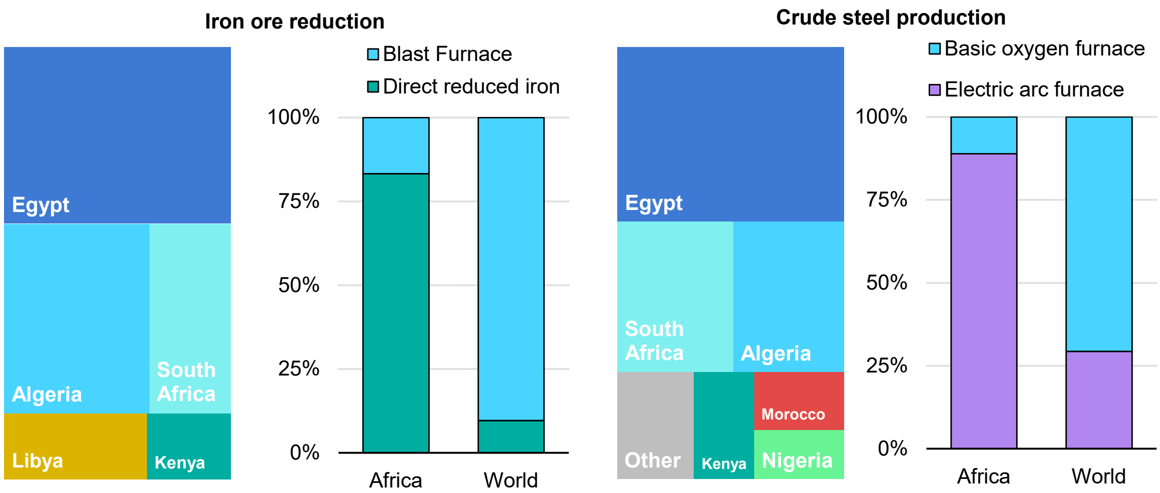
Africa’s announced low-emissions hydrogen project pipeline totals around 1.2 Mt by 2030, two-thirds of which is intended for ammonia production, equivalent to around 3.5 Mt of ammonia. This is a third of the continent’s entire current production, and would have applications ranging from fertilisers to marine bunkering. Less than 3% of announced projects have reached FID, with many large-scale and oriented towards export markets that have yet to materialise.

Africa's strong renewable energy potential provides a credible basis for cost-competitive ammonia production, but cheap finance will remain a key determining factor, as it accounts for up to half of the levelised cost (Box 8.1). Unlocking this potential may therefore require a reorientation towards near-term opportunities in affordable domestic fertiliser access, alongside longer-term ambitions in international markets.

Iron and steel production

Africa produced under 20 Mt of iron in 2024, accounting for approximately 1.4% of global output – nearly double its output a decade earlier. Production is concentrated in five countries – Egypt, Algeria, South Africa, Libya and Kenya – and is predominantly based on direct reduced iron (DRI), which represents more than 80% of African output compared with around 10% globally. North African countries use almost 4% of their natural gas production for DRI. This ironmaking structure underpins Africa's growing role in global DRI markets: output has nearly quadrupled over the past decade, lifting its share of global production from around 5% to over 10%, reflecting a production base built to leverage abundant and cheap natural gas in North African countries. Blast furnace ironmaking is mostly limited to South Africa and a plant being commissioned in Zimbabwe. In South Africa, abundant coal resources and reliance on imported natural gas favour the blast furnace route, which uses coal, yet production has fallen by 40% over the past decade.

Figure 8.14 Iron ore reduction and crude steel production in Africa, 2024

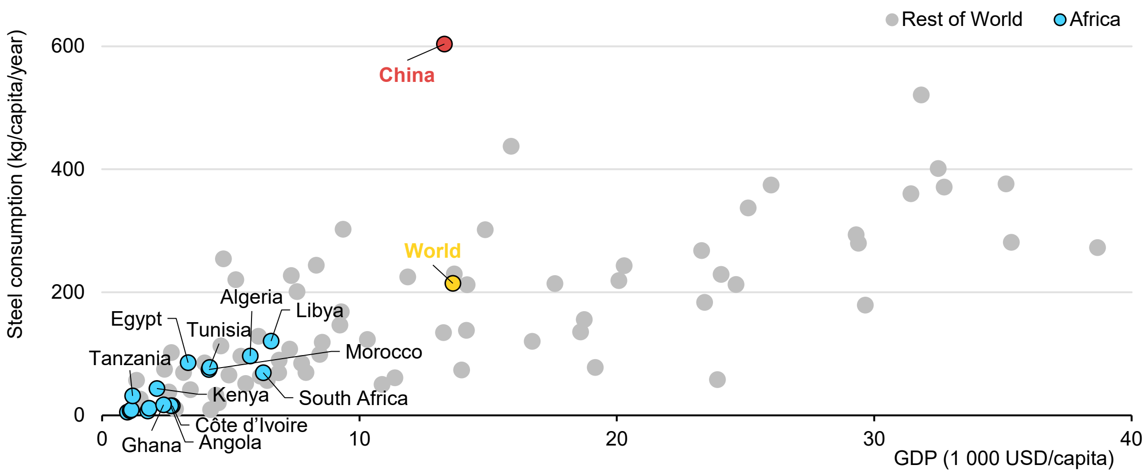


Source: IEA analysis based on World Steel Association (2025), World Steel in Figures 2025.

Strengths upstream in iron ore contrast with low steel production, with ironmaking largely based on DRI in countries with natural gas production.

Africa's DRI-dominated structure carries through to steelmaking. The continent produced less than 30 Mt of crude steel in 2024, accounting for around 1.5% of global output, with electric arc furnaces (EAF) representing nearly 90% of production compared with less than 30% globally. Beyond integrated DRI-EAF producers, several countries operate EAF-based mills processing scrap, while others have no domestic steel production capacity at all and rely entirely on imports, primarily from China and, to a lesser extent, from elsewhere in Africa. Finished steel consumption reached just over 35 Mt in 2024 – around 2% of global demand – slightly below the levels reached prior to 2020. Steel consumption per capita stands at around 25 kg, just over one-tenth of the global average of 215 kg, with particularly low levels across sub-Saharan countries other than South Africa.

Figure 8.15 Apparent steel consumption and GDP by country, 2024



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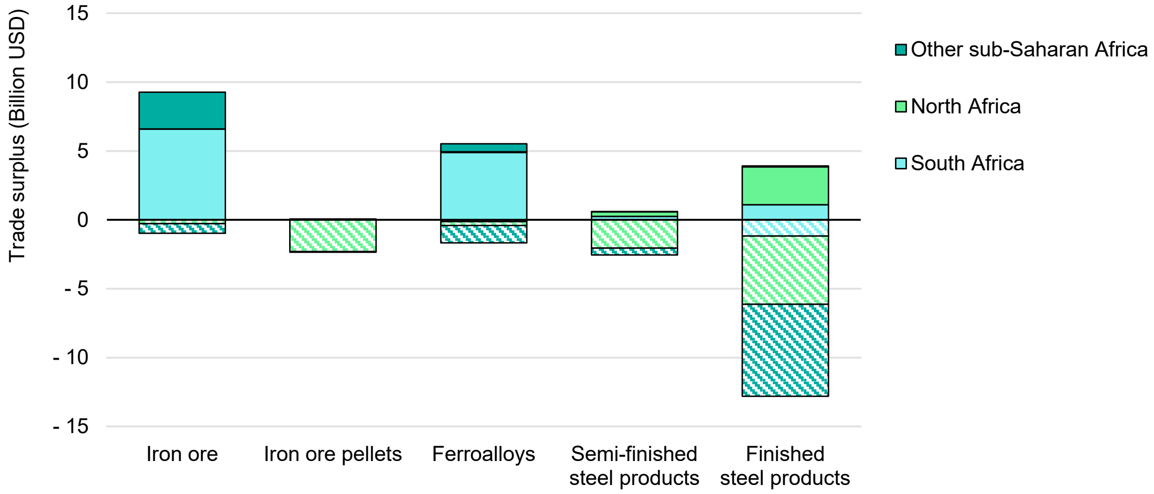
Note: For representation purposes, only countries with GDP per capita below USD 40 000 in purchasing power parity terms are shown.
Source: IEA analysis based on World Steel Association (2025), World Steel in Figures 2025.

Africa's low steel consumption per capita, particularly in sub-Saharan Africa, points to substantial demand growth potential as infrastructure needs rise with development.

Africa's net imports of finished and semi-finished steel products reached USD 11 billion in 2024. While South Africa and Egypt record net trade surpluses, the rest of the countries on the continent are significant net importers, even where domestic consumption remains relatively low. This dependence is particularly pronounced in sub-Saharan Africa, where steel imports represented around 0.5% of GDP in 2024, reflecting limited domestic production capacity and a strong reliance on foreign supplies.

Figure 8.16 Trade balances of iron and steel-related products in value terms in Africa, excluding intra-regional trade, 2024



Note: A negative value denotes a net trade deficit for the region or country.
Source: IEA analyses based on CEPII (2026), BACI dataset.

In 2024, South Africa had iron ore and ferroalloy trade surpluses of 3% of GDP, while other sub-Saharan African countries faced net steel-related imports equal to 0.5% of GDP.

Africa's ironmaking serves two distinct markets with different priorities. Steel is a foundational input for Africa's development, supporting infrastructure expansion, urbanisation and industrialisation. Starting from a low per capita base, domestic demand is expected to grow driven by these trends, with access to affordable, good-quality steel as a key consideration. In export markets, GHG intensity is likely to become an increasingly important factor, influenced by external policy frameworks such as the EU CBAM. However, demand for low-emissions steel remains uncertain and will depend on evolving global market conditions and policy developments. Participation in relevant international discussions could help African producers position themselves. Serving both markets calls for a steelmaking base that is cost-competitive and scalable, while retaining the flexibility to meet Africa's climate ambitions and the carbon intensity requirements of export markets.

Bridging from natural gas to low-emissions hydrogen in ironmaking

Africa's growing DRI capacity provides a strong basis for blending hydrogen with natural gas in existing and new plants. North Africa is particularly well positioned in this regard, combining natural gas availability that supports near-term deployment of gas-based DRI with strong renewable energy potential that could enable low-cost hydrogen production over time. Its relatively young, gas-based DRI fleet is well suited to hydrogen blending, and new plants are increasingly built with dual-fuel configurations, enabling a gradual shift towards higher shares of hydrogen.

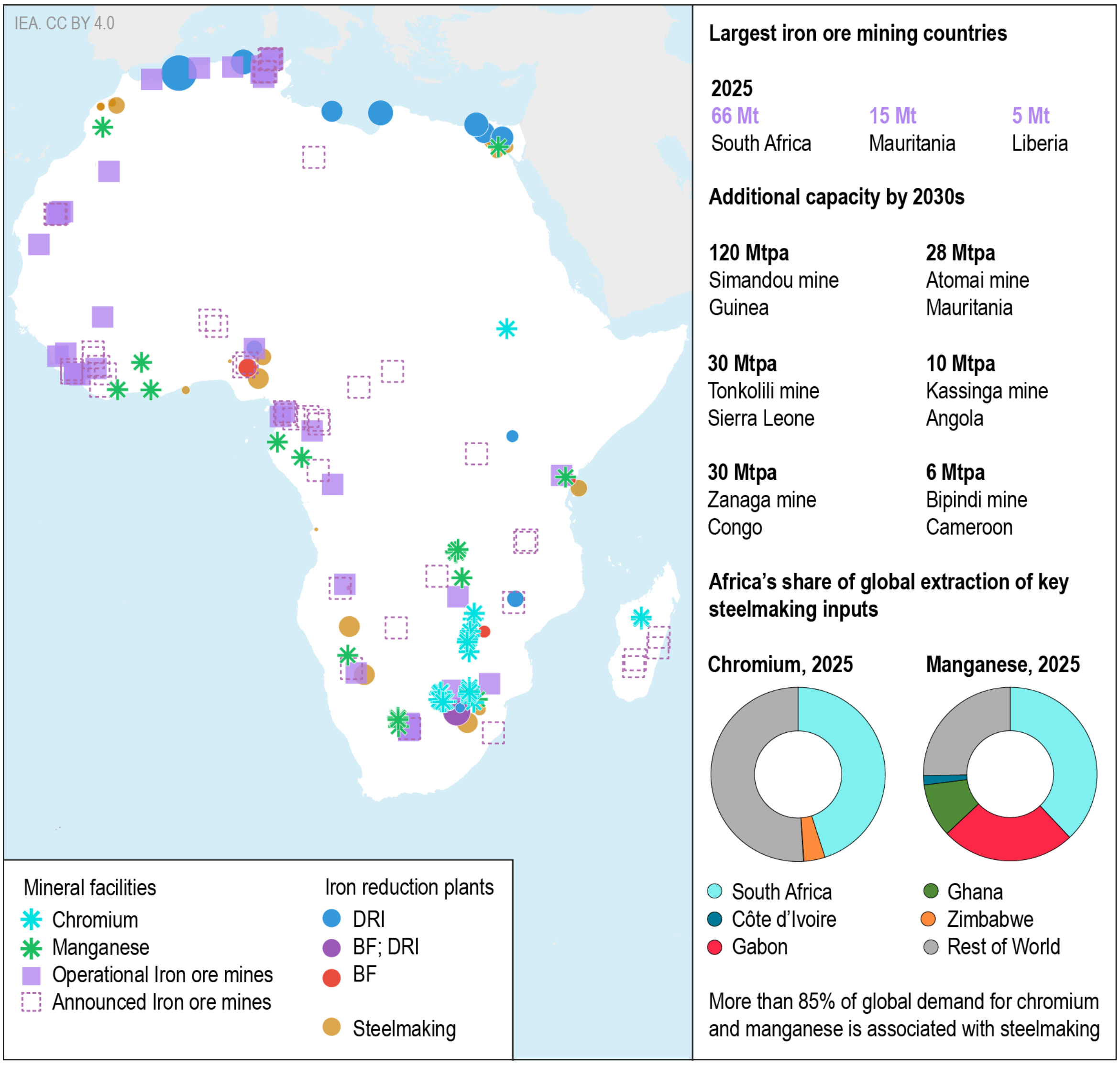
In 2025, Turkish steel producer Tosyali commissioned the world's first MIDREX Flex DRI plant in Algeria (2.4 Mtpa DRI) – a technology licensed by Japan's Kobe Steel – capable of operating on natural gas and, with minor modifications, on 100% hydrogen. In the same year, Tosyali ordered a MIDREX Flex facility for Libya (2.5 Mtpa) to supply regional and European markets. Also in Libya, the Libyan Iron and Steel Company and Danieli signed a MoU for a 2 Mtpa DRI and hot briquetted iron (HBI) plant based on Energiron technology, capable of operating on natural gas-hydrogen blends of up to 100% hydrogen, with an offtake agreement for Italian steelmakers. Together, these three plants would consume more than 400 ktpa of hydrogen if operated on 100% hydrogen.

Beyond North Africa, several sub-Saharan countries with significant natural gas resources have strong structural potential for gas-based DRI, supported by growing local steel demand and ambitions to monetise natural gas through domestic industry. Angola is the most advanced, with the Tosyali Sonangol Cassinga DRI-EAF plant expected to start operations in 2027, leveraging the country's natural gas. Nigeria has launched a 10-year roadmap for the revitalisation of its steel sector, targeting 10 Mt of liquid steel production by 2030, and using public procurement policies to incentivise regional offtake. Where new capacity is developed in these countries, deploying flexible dual-fuel technologies could preserve the option to increase hydrogen use over time, creating opportunities to decarbonise and access export markets with emissions thresholds or premiums.

Adding value in Africa: Iron ore mining as an anchor for steelmaking

In 2024, Africa produced around 89 Mt of iron ore, predominantly in South Africa, followed by Mauritania and Liberia, which together account for nearly 90% of the continent's output. With the exception of South Africa, ironmaking and iron ore mining remain largely disconnected. Iron ore production in North Africa is equivalent to just over 10% of domestic demand, leaving the region heavily reliant on imports, mainly from iron pellets from Brazil and the Middle East, at a cost of more than USD 2.5 billion in 2024. Exploration activity accelerated across West and Central Africa in the early 2000s, but extended periods of low iron ore prices and a lack of transport infrastructure linking inland deposits to ports stalled new project development.

Figure 8.17 Iron ore, chromium and manganese mining, and iron ore reduction and steelmaking capacity in Africa



Notes: DRI = direct reduced iron; BF = blast furnace. Circle size indicates installed capacity for iron ore reduction and steelmaking plants only.

Sources: IEA analysis based on Global Energy Monitor (2026) Global Iron and Steel Tracker - March 2026 (V1) release; Global Energy Monitor (2025) Global Iron Ore Mines Tracker – August 2025 (V1) release; US Geological Survey (2026), Chromium Statistics and Information: Mineral Commodity Summaries 2026; US Geological Survey (2026), Iron Ore Statistics and Information: Mineral Commodity Summaries 2026; US Geological Survey (2026), Iron Ore Statistics and Information: Minerals Yearbook 2023; US Geological Survey (2026), Manganese Statistics and Information: Mineral Commodity Summaries 2026; US Geological Survey (2024), Compilation of GIS data for the mineral industries and related infrastructure of Africa.

Africa's resource endowment provides a strong basis to develop integrated steel value chains, combining iron ore, alloying elements, natural gas and renewable energy.

Iron ore exports nonetheless represent a significant revenue opportunity, as illustrated by South Africa, whose exports reached nearly USD 7 billion in 2024, equivalent to around 1.7% of its GDP. By the early 2030s, African production could exceed 200 Mtpa[95], largely driven by the ramp-up of the high-grade ore Simandou project in Guinea (120 Mtpa). Realising this potential requires investment in regional transport connectivity, mainly rail and port corridors. Where designed as common-user infrastructure, this infrastructure could open the door to broader industrial development. Examples include the ArcelorMittal Yekepa-Buchanan railway in Liberia, which is open to third-party users, and the 670-km Trans-Guinean Railway serving Simandou, together with the deep-water port at Moribayah.

Africa could go beyond exporting raw ore and use its broader resource endowment to develop an integrated steel ecosystem, as recognised in South Africa's Just Energy Transition Investment and Implementation Plans, for example. A coherent steel strategy would link iron ore, natural gas, renewable energy and key alloying elements – including manganese and chromium,[96] for which Africa is today the world's largest producer – with regional demand through co-ordinated industrial corridors spanning beneficiation, pelletisation, ironmaking and steelmaking. Such an approach could capture a greater share of the steel value chain, stabilise revenues from associated mineral exports, whose prices are often volatile, and strengthen the manufacturing base underpinning Africa's development ambitions.

In locations with abundant renewable resources and proximity to iron ore deposits but limited access to natural gas, hydrogen-based ironmaking for export represents a further step in this direction. Since hydrogen transport remains challenging, exporting iron products such as DRI or HBI offers a more practical route to market. HyIron's Oshivela plant in Namibia (15 ktpa DRI, with an option to expand to 1 Mtpa by 2030) became the first facility in the world to produce DRI using 100% hydrogen in 2025. Mauritania's AMAN project is similarly considering HBI exports, leveraging its proximity to local iron ore deposits and excellent renewable resources.

Hydrogen use in other sectors

Methanol

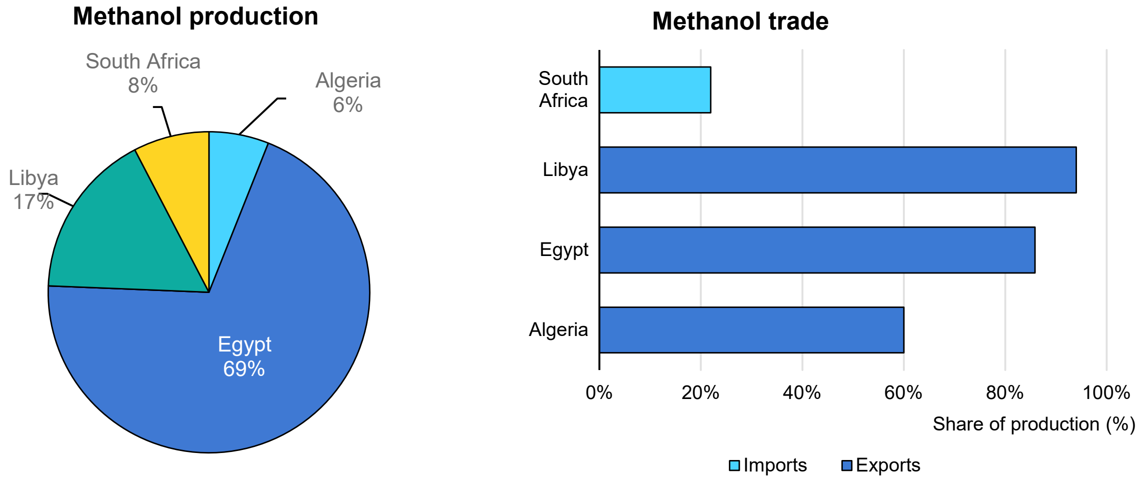
Africa accounted for just over 1% of global methanol production in 2025, a significantly smaller share than other emerging economies such as Latin America (over 6%) and Southeast Asia (3%). Furthermore, this share has declined in recent

[95] Iron ore projects in Africa are typically developed through joint ventures involving national entities and international partners. For example, Simandou in Guinea is being developed through joint ventures involving the Government of Guinea, Rio Tinto and Chinese partners; Mauritania's Atomai project is being developed through a joint venture between Saudi company HADEED and the state-owned SNIM; and in Sierra Leone, the Tonkolili mine is majority-owned by Chinese companies.

[96] Manganese and chromium are essential alloying elements in steelmaking. Manganese is used in most steel grades (typically 0.5–1.5% by weight), improving strength and removing impurities, while chromium is mainly used in stainless and alloy steels (generally above 10.5% in stainless steel). More than 85% of global manganese demand and chromium production are used in steelmaking.

years, while Latin America and Southeast Asia's shares remained broadly stable. Most methanol production in Africa is dedicated to exports, as in Latin America (Southeast Asia is a net importer). However, Latin America captured 14% of global exports in 2025, compared with less than 3% for Africa. Less than 25% of Africa's production is dedicated to meeting domestic demand. Only Nigeria and South Africa meet a significant fraction of their domestic demand through imports. In 2025, South Africa (which represents 40% of Africa's demand), covered 20% of its demand through imports. Nigeria was entirely reliant on imports to meet its demand, although it accounts for less than 5% of the continent's total demand.

Figure 8.18 Methanol production and trade in selected African countries, 2025



Source: IEA analysis based on data from Argus Methanol Analytics, [Argus Media Group](), All rights reserved.

The majority of Africa's methanol production is exported, and only a small share meets almost all domestic demand in the continent.

Methanol production in Africa is highly concentrated in Egypt, which accounted for almost 70% of continental production in 2025 (Figure 8.18). Until 2024, Equatorial Guinea was also a large producer, with similar production levels to Egypt. However, in 2025 Atlantic Methanol announced the shutdown of its 1 Mtpa production plant (in operation since 2001),[97] after having declared force majeure in 2024 due to the reduction of natural gas supplies from Marathon Oil (an Atlantic Methanol shareholder) to prioritise higher-margin LNG sales.[98] This has resulted in a higher concentration of production in Egypt, even at plant level. Since 2011, there has been only one plant in operation in Egypt, from Methanex, with a production capacity over 1 Mt of methanol. The rest of the continent's production

[97] Chevron says Equatorial Guinea methanol unit will shut, Argus Media Group, All rights reserved (18 February 2025).
[98] Equatorial Guinea Ampco declares methanol force majeure, Argus Media Group, All rights reserved (19 December 2024).

is based in smaller plants in Libya, South Africa and Algeria. Almost all methanol production in Africa is based on the use of unabated natural gas. The only exception is South Africa, where all methanol production is based on coal. This is a legacy of the long-standing experience of Sasol (the only producer in the country) in the coal-to-chemicals technology.

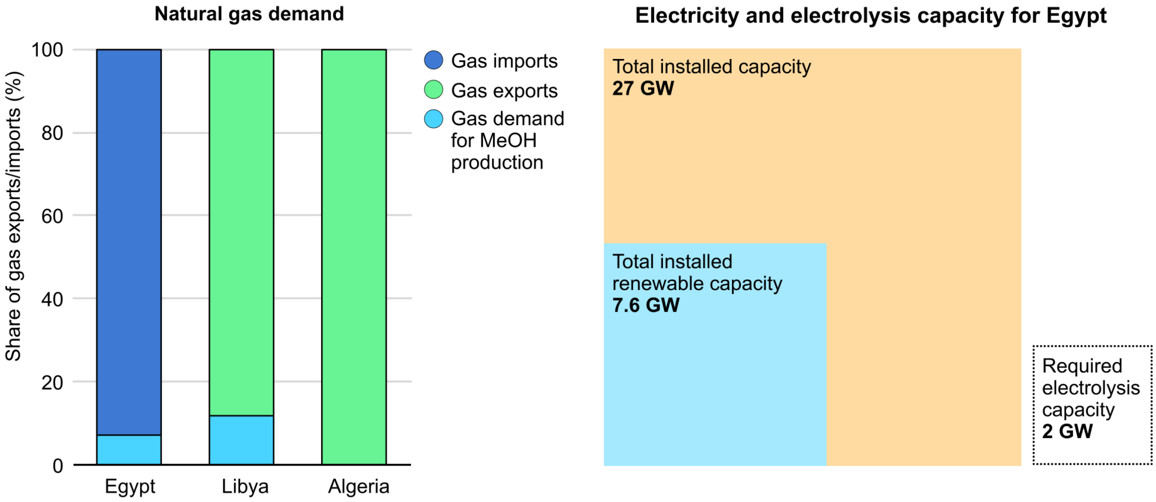
In the near term, considering the low domestic demand, the countries that are better placed to develop low-emissions methanol projects (particularly renewable-based) are those with existing production, particularly Egypt. Such projects could create an economic opportunity to export this commodity to emerging markets, such as the European Union, or to supply potential new demands in the shipping sector. Producer countries benefit from key enabling conditions to develop the novel industrial value chain required, such as the presence of a skilled workforce in the chemical sector and existing infrastructure. There have been some initial efforts for the development of renewable methanol projects in Egypt and South Africa. However, they remain at very early stages of development and limited progress has been reported since the projects were announced.

The benefits that renewable methanol production can offer vary across African countries. In Egypt, methanol production required around 1 bcm of natural gas in 2024. This is less than 2% of natural gas demand in the country, but Egypt has recently become an importer of natural gas. In 2021, Egypt was a net natural gas exporter, generating close to USD 4 billion of income, whereas in 2024 it became a net-importer, generating a trade deficit of USD 4 billion. The expected decline in domestic natural gas production coupled with growing demand from industry and, particularly, power generation will likely increase this trade deficit. The same may happen in Libya, where natural gas exports have declined in recent years, while production of methanol has ramped up since 2023, after 2 years with no production. Algeria is a methanol exporter and also a large natural gas exporter (half of domestic gas production is exported). Switching to renewable-based methanol would free up a larger share of domestic natural gas production for exports, although the impact would be limited, given its low production of methanol.

Replacing fossil-based production of methanol with production based on electrolysis and renewable electricity implies a significant resource challenge. Replacing all gas-based production in Egypt would require around 2 GW of electrolysis.[99] For reference, the total installed electricity capacity in Egypt is 27 GW, with less than 8 GW being renewables (Figure 8.19).

[99] Assuming an electrolyser efficiency of 60% on a lower heating value basis and 5 000 operating hours a year.

Figure 8.19 Natural gas demand for methanol production in selected countries, 2024, and electrolysis capacity required to meet methanol production in Egypt



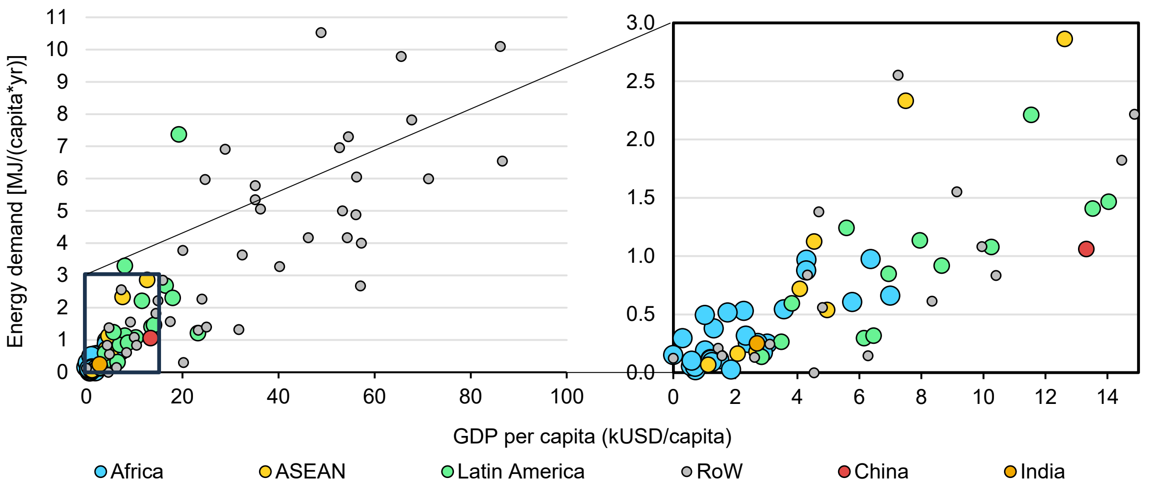
Note: MeOH = methanol.

Switching today's fossil-based methanol production to electrolysis with renewables could improve the gas trade balance in Egypt and Libya, but would entail resource challenges.

Aviation

Energy demand for aviation in Africa totalled less than 500 PJ/yr in 2025, almost half of which was met with kerosene imported from outside the continent. Africa accounts for around 3% of global energy demand for aviation, lower than its share in total energy demand (5%) and population (19%). Energy demand per capita for aviation in Africa (0.3 MJ/year) is much smaller than the world average (1.8 MJ/year), and also smaller than in Latin America (1.3 MJ/year) and Southeast Asia (1.5 MJ/year) (Figure 8.20). This is linked to the lower economic development in Africa, which has several countries with among the world's lowest GDP per capita. Low energy demand for aviation limits the short-term prospects for the adoption of synthetic jet fuel at scale, although these could appear as the continent develops and jet fuel demand increases. However, there are some short-term opportunities that could be explored.

Figure 8.20 Energy demand per capita for aviation in relation to GDP per capita, 2024



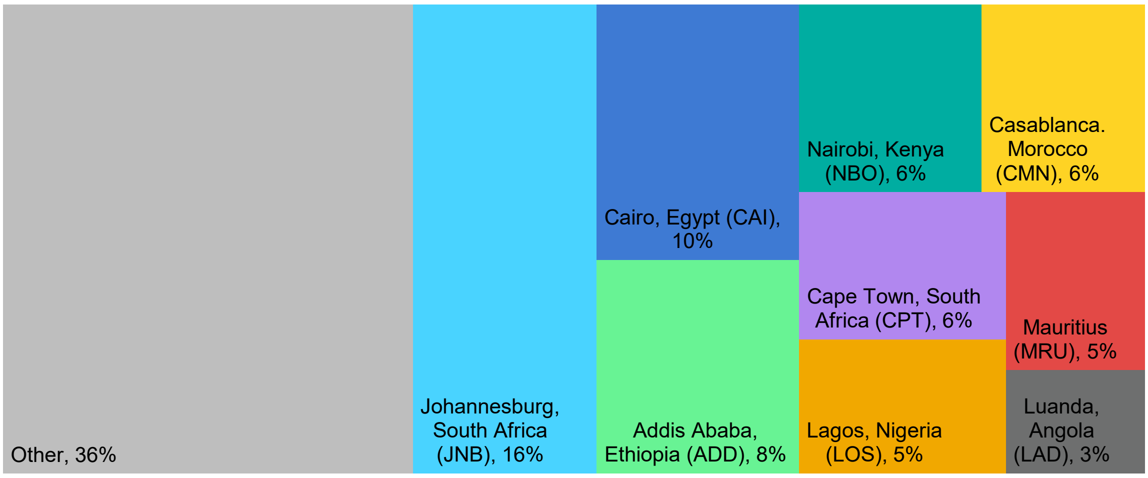
Notes: ASEAN = Association of Southeast Asian Nations; RoW = Rest of World. Singapore (51 MJ per capita per year), United Arab Emirates (39 MJ per capita per year) and countries with a population smaller than 3 million people that had a high energy demand per capita are not represented in the figure to avoid distorting the axes.
Source: IEA analysis based on International Monetary Fund for GDP.

Practically all of Africa's population is well below the global average energy consumption per capita for aviation.

The aviation sector in Africa is highly concentrated across a small number of airports (see Figure 8.21). Two medium-size airports[100] (Cairo, with around 30 million passengers per year; and Johannesburg, with around 20 million passengers per year) account for more than 25% of the jet fuel demand in Africa. This large concentration of demand offers an opportunity to create scale for the adoption of synthetic aviation fuel, although doing so would be challenging. Replacing the jet fuel demand in these two airports with synthetic kerosene would require 5-8 GW of electrolysis capacity. The first steps could be facilitated by state-owned companies, since the largest airports in the continent are managed by state-owned companies and several airlines with major market shares in those airports are also under state ownership (Table 8.1). This could also facilitate co-ordination for the procurement of these fuels in the early stages of market development.

[100] For comparison, the largest airport in the world, Atlanta International Airport, serves more than 100 million passengers per year and the 50 largest airports in the world each serve more than 47 million passengers.

Figure 8.21 Africa fuel demand distribution across airports in the continent, 2024



Note: Abbreviations in brackets represent the International Air Transport Association airport code.
Source: IEA analysis based on data from ATSLAB.

The jet fuel demand of all African airports combined is just 2.5 times the demand of the largest airport in the world, and is concentrated in a small number of medium-size airports.

Table 8.1 African airports with largest fuel demands, operators and largest airlines serving them

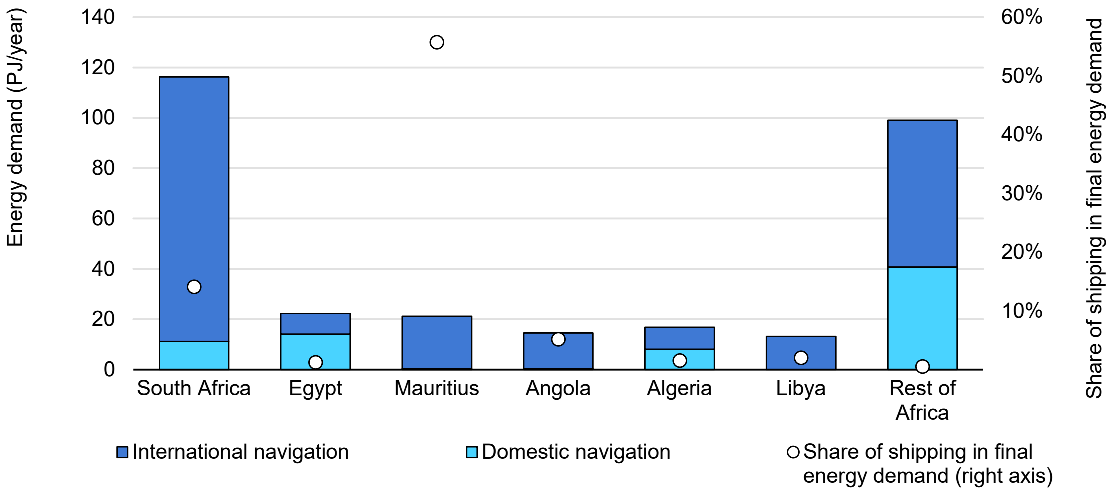
Airport	Management company (all state owned)	Airlines
Johannesburg (South Africa)	Airports Company South Africa	Airlink, private South African Airways, state owned
Cairo (Egypt)	Egyptian Holding Company for Airports and Air Navigation	EgyptAir, state owned
Addis Ababa (Ethiopia)	Ethiopian Airports Enterprise	Ethiopian Airlines, state owned
Nairobi (Kenya)	Kenya Airports Authority	Kenya Airways, private Jambojet, private
Casablanca (Morocco)	Office National des Aéroports	Royal Air Maroc, majority state owned

In terms of enabling factors for the production of synthetic aviation fuel, South Africa is a world leader in Fischer–Tropsch (FT) technology, largely due to the presence of Sasol. This technology has been traditionally applied to the production of liquid fuels from coal gasification, but longstanding experience with FT and more recent experience with renewable electricity (Sasol operates more than 700 MW of renewable capacity in South Africa) – could support the early adoption of synthetic kerosene. Sasol is already a partner of the HySHiFT consortium aiming to develop synthetic kerosene production in South Africa.

Shipping

Energy demand for shipping in Africa reached around 300 PJ in 2025 (less than 3% of global demand), with around three-quarters of this demand dedicated to international shipping. The adoption of low-emissions hydrogen-based fuels (such as ammonia and methanol) in international shipping will depend on the implementation of IMO regulations. However, a decision on these regulations has been postponed until the end of 2026 following an adjournment of discussions in October 2025, which has led to uncertainty in the sector that could delay the uptake of these fuels.

Figure 8.22 Energy demand in shipping in African countries, 2025



IEA. CC BY 4.0

South Africa alone is responsible for more than 40% of Africa's energy demand in shipping.

Demand for shipping is strongly concentrated in South Africa, which counts on three important bunkering hubs (Durban-Richards Bay, Saldanha Bay-Cape Town and Nqgqura-Gqeberha), although they have recently suffered supply limitations from local refineries. These ports are well placed to adopt ammonia and methanol as alternative fuels, thanks to their existing infrastructure (such as storage terminals for both ammonia and methanol) and operational expertise with these chemical products (see Hubs section). However, activities for the adoption of hydrogen-based fuels in these ports to date have been limited to preliminary studies. Mauritius is another major bunkering hub in Africa, located on a key shipping route connecting Asia, southern Africa and South America. Moreover, over half of the energy demand in the country is dedicated to international maritime bunkers. Recent disruptions in the Red Sea have increased bunkering demand in Mauritius. However, given the limited land availability, it is unlikely that a significant fraction of its demand could be produced locally, meaning that it would remain dependant on imports in the case of a switch to alternative fuels.

In addition to bunkering ports, other opportunities lay in major container ports such as Tangier Med, Morocco, (Africa's largest container port, located next to the Strait of Gibraltar, which one-fifth of global maritime trade passes through every year) or in the large concentration of ports in Egypt, around the Suez Canal (Port Said, El Sokhna, Damietta, Alexandria). The latter ports combine large maritime traffic (about 15% of global maritime trade volume typically passes through the Suez Canal), existing infrastructure and deep experience in handling these chemicals (particularly ammonia). In addition, almost all the large projects for the production of low-emissions hydrogen-based fuels (mostly ammonia) that have been announced in Egypt would be located close to the Suez Canal. The location of these ports on major shipping routes and the proximity to potential large supply capacities for hydrogen-based fuels opens the possibility to develop corridors for alternative shipping fuels in co-operation with other ports in Asia, Europe and Latin America. Some initial steps towards the adoption of alternative fuels have already been taken by these ports, such as the first methanol bunkering operation in East Port Said in August 2023.

Although efforts for the adoption of these fuels are at very early stages on the continent, governments are exploring some initiatives, such as participating in the development of green shipping corridors. At the end of 2025, there were four green shipping corridors involving African partners at different stages of development, including an initiative announced by Ghana in September 2025. Another nine corridors, at least, will need to pass through Africa, either through the Suez Canal or through the Cape Route, one of which (the Rotterdam-Singapore Green and Digital Shipping Corridor) is among the most advanced of these global initiatives.

Hubs

Industrial hubs can aggregate demand across multiple users, creating the economies of scale needed to reduce costs and support investment in costly shared infrastructure. When developed as common-user infrastructure, these assets can be jointly used by several stakeholders, lowering individual cost burdens and reducing exposure in the case that one user's utilisation falls short. In Africa, hydrogen hubs could help catalyse investment in enabling infrastructure, addressing current under-investment while leveraging complementarities across sectors and delivering wider economic benefits.

The viability of hydrogen hubs is shaped by access to enabling infrastructure, including electricity and gas grids, rail and roads, as well as water supply, whether from freshwater resources or through desalination. In addition, hubs may cluster near ports, given their reliance on trade in raw materials and equipment. Local conditions, such as workforce availability, service industries and social acceptance, also play an important role.

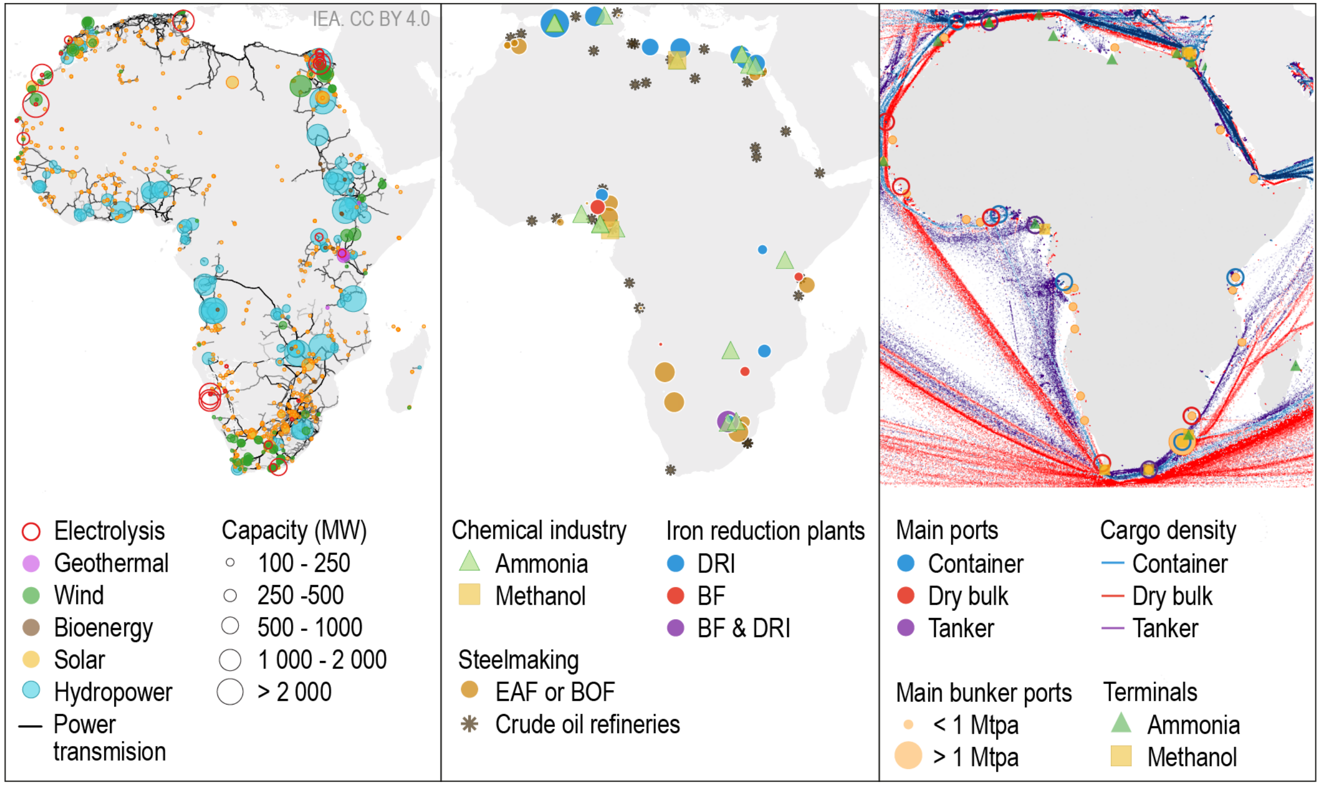
Previous editions of the Global Hydrogen Review have identified three hub archetypes for hydrogen that could also be relevant to Africa:

Industrial demand hubs would centre on fertiliser and chemical plants, steel facilities and refineries. Demand could come from two sources: substituting existing natural gas use, and developing new low-emissions industries to meet domestic demand while enabling trade, including within Africa. Substitution is particularly relevant in countries where gas production is declining or import dependence is increasing. In Egypt, whose natural gas trade balance has fluctuated (see Methanol section above), and in South Africa, which relies on gas imports from Mozambique, well-established industrial clusters provide a strong basis for low-emissions hydrogen industrial hubs. These include the Alexandria-Greater Cairo-Suez Canal corridor and the Gauteng-Johannesburg area. In contrast, in natural gas-rich countries such as Algeria, Libya and Nigeria, early adoption may be driven by export opportunities for manufactured products if overseas demand emerges. Other countries that have limited industrial bases today but benefit from favourable resources could develop new regional industrial hubs. Kenya, for example, is leveraging its geothermal resources to make ammonia, aiming to satisfy its domestic demand while targeting exports of nitrogen-based fertilisers to neighbouring African markets.

Bunkering and distribution hubs make use of port infrastructure to store and supply hydrogen-based fuels to the shipping sector, although their development ultimately depends on demand from ships and the evolution of international regulations. Ports located near major maritime chokepoints are particularly well positioned, including those around the Suez Canal in Egypt, the Strait of Gibraltar – notably Tangier Med and the planned Nador West Med in Morocco – and the Cape of Good Hope in South Africa, where ports such as Durban already serve as major bunkering hubs. Disruptions to traffic through the Red Sea, including the Bab el-Mandeb Strait and the Suez Canal, have led to re-routing via the Cape of Good Hope, increasing voyage distances and fuel consumption. This is already boosting bunkering demand in ports that have traditionally played a smaller role and could create opportunities for the supply of low-emissions fuels, including in Namibia (Walvis Bay and Lüderitz) and in West African ports, such as in Côte d'Ivoire, Ghana and Togo, which are already close to high-traffic container routes.

Supply hubs are located in regions with exceptional renewable energy potential and available land for large-scale generation but limited local industrial demand. Where port infrastructure exists, supply could be established relatively quickly, although more remote locations requiring new port development will face longer timelines, as the costs of underutilised infrastructure can be prohibitive in early project phases. Different models are now emerging. Some target exports of ammonia and nitrogen-based fertilisers – as in Angola's Capanda, Mauritania's Megaton Moon and Namibia's Hyphen projects. The viability of these projects hinges on competitive hydrogen costs, underpinned by high capacity factors and committed foreign off-takers, which lower the cost of capital and attract foreign direct investment. Others seek to add value to existing resource exports by integrating low-emissions hydrogen into mining supply chains, such as Mauritania's iron ore or Morocco's phosphate industries. North Africa is also exploring hydrogen pipeline export routes to Europe. The SoutH2 Corridor, led by European transmission system operators, aims to connect North Africa with Italy, Austria and Germany through a 3 300 km hydrogen corridor in the 2030s. SeaCorridor is studying a potential southern connection to SoutH2, including a dedicated offshore hydrogen pipeline across the Strait of Sicily between Tunisia and Italy, and two onshore links in Tunisia: one connecting to the Algerian border at Oued Saf-Saf, along existing natural gas pipelines, and another extending to southern Tunisia.

Figure 8.23 Energy supply, industrial activity and port infrastructure relevant to hydrogen development in Africa, latest available data



Note: DRI = direct reduced iron; BF = blast furnace; EAF = electric arc furnace; BOF = basic oxygen furnace.

Sources: IEA analysis based on IEA (2026), Hydrogen Production and Infrastructure Projects databases (June 2026); IEA (2024), Energy Technology Perspectives 2024; FracTracker Alliance (2026), Oil Refining and Capacity; Global Energy Monitor (2026), Global Chemical Inventory – November 2025 (V1); Global Energy Monitor (2026), Global Iron and Steel Tracker - March 2026 (V1) release; Global Energy Monitor (2025), Global Iron Ore Mines Tracker – August 2025 (V1) release; Global Energy Monitor (2026), Renewables and other power; Open Infrastructure Map (2026), OpenStreetMap database; United Nations Global Platform (2024), Automatic Identification System data; Verschuur (2022), Ports' criticality in international trade and global supply-chains.

Early low-emissions hydrogen projects are most likely to emerge near existing industrial hubs and major shipping routes, where demand proximity, logistics and resource endowment align.

Near-term actions

Use policy and financial instruments to reduce the cost of capital. Renewable hydrogen projects are capital-intensive assets, which makes the production cost largely dependent on cost of capital. Financing costs can account for around 30-40% of the levelised cost of hydrogen, with each percentage-point increase adding around USD 0.2/kg H_2. Most African countries have a high risk premium based on perceived and actual risks. Out of the 54 African countries, only Botswana and Mauritius have investment grade sovereign bonds[101] across all rating agencies, which means that a higher interest rate needs to be paid to borrow capital, borrowing is more difficult and transaction costs are increased. Reducing financing costs will be essential to improve the competitiveness of hydrogen production. A combination of de-risking instruments can be used to address this (see Box 8.1) underpinned by predictable and stable policy and regulatory support.

Balance existing hydrogen demand and exports to create demand for low-emissions hydrogen. While exports are a main driver of low-emissions hydrogen projects, targeting domestic demand first can have multiple benefits, including larger domestic added value, lower complexity, lower investment and infrastructure needs, and gradual deployment. Algeria, Egypt and Nigeria have an existing hydrogen demand that would be enough to achieve economies of scale in production while displacing imports of hydrogen derivatives and improving energy security. Other countries that do not have existing demand, like Namibia, can leverage exports to spur domestic socio-economic development and investment in the power sector. Having a mix of domestic and foreign demand can also help to mitigate the currency exchange risk. Low-emissions hydrogen production in Egypt and South Africa could displace natural gas imports, increasing energy security, and these two countries already benefit from large industrial activity. Additionally, these projects could displace imports of hydrogen derivatives. Establishing realistic targets is one of the first steps as part of hydrogen strategy, as has already been done by countries including Kenya and South Africa.

Prioritise hydrogen derivatives like ammonia and steel to step up the value chain. Domestic production of ammonia and steel can have the additional benefits of higher investment when compared to hydrogen production alone, with larger economic impact and job creation. Furthermore, when exported, they allow a larger share of the value added to be captured, given the additional domestic conversion steps, which represents an advantage compared to hydrogen production alone. These can lead to positive spillovers for domestic infrastructure

[101] This is an indication of the perceived risks affecting sovereign credit and repayment ability based on the institutional, economic, fiscal and monetary situation of each country.

development and local innovation ecosystems. Iron ore production in Africa could more than double by 2030 with announced projects, and when combined with its rich deposits for alloying elements, like chromium and manganese, this provides an opportunity for steel production. Direct reduced iron furnaces can be flexible and shift from natural gas to hydrogen as low-emissions hydrogen ramps up over time. For ammonia, the added value can be higher if used for fertiliser production and could contribute to developing the downstream food industry and closing the regional food trade deficit.

Incorporate hydrogen in long-term planning for critical infrastructure. Hydrogen pipelines and ports have long lead times and require planning well in advance for future developments. At the same time, countries targeting exports, like Namibia or Mauritania, have limited existing infrastructure. Making these a reality would entail a larger effort, but would also create the opportunity to design integrated infrastructure that can be used for multiple hydrogen carriers in order to provide more flexibility and resilience. This could be done by assigning a state entity or port authority as the co-ordinator of infrastructure development that involves private participation. Co-ordination would be critical for electricity grid expansion required to deliver electricity access and electricity to hydrogen projects. Additionally, this would require defining the technical standards and regulations, including methodologies for tariff-setting, conditions for network access and administrative processes.

Ensure low-emissions hydrogen projects provide tangible socio-economic benefits and support broader development goals. Large-scale hydrogen projects should support, rather than compete with, key policy priorities such as economic development, energy and water access. Socio-economic considerations should be incorporated into the project design and evaluation to ensure that local communities benefit from the investment. This can include infrastructure development, such as the electricity grid or water supply. This would require regulation and the inclusion of these criteria as part of the conditions for project approval (or land allocation) and the allocation of benefits such as tax incentives. These criteria are currently largely missing and represent a barrier to deployment. Introducing such criteria could create a virtuous circle, benefiting projects by improving the fiscal and macroeconomic situation of countries, which could be reflected in lower country risk and the availability of a skilled workforce domestically.

Support deployment of renewables, which can create positive spillover effects for hydrogen development. Of the 54 African countries, only Kenya and Morocco have a penetration of solar and wind of more than 10% in a power system of more than 10 TWh. More experience is needed in the deployment of these technologies, which will help reduce the CAPEX and the cost of capital, build experience across the private sector across all development stages, develop a track record for lending institutions and attract more private capital.

Build a domestic skilled workforce and technological expertise. Developing these industries requires a workforce large enough and with the right skills. This could be achieved by strategic partnerships, for example, by coupling foreign investment with conditions on a share of domestic labour or partnering with industry to develop new education programmes. Upskilling and reskilling workers from related sectors can also be an option, as has already been done in Egypt, Kenya, Morocco, Nigeria and South Africa, among other countries. Leveraging existing programmes like RES4Africa and expanding them to hydrogen could also facilitate implementation. This process should encompass equity considerations throughout, to ensure that all groups have equal access to such programmes.

Develop certification schemes for hydrogen and its derivatives. Certification can serve multiple purposes including tracking of sustainability attributes (such as GHG emissions), implementation of policies such as targets, quotas or tax credits, creation of a differentiated low-emissions hydrogen market, and facilitation of cross-border trade. Nearly three-quarters of the low-emissions hydrogen project pipeline capacity aiming to start operations by 2030 in Africa targets exports. Certification is essential to enable this, and also to enable interoperability with other schemes. In this respect, six countries, of which only Egypt has demand today, accounting for 50% of the current regional hydrogen demand, signed the Declaration of Intent for mutual recognition of certification schemes. Multiple countries have certification as part of their strategies, but only Kenya has defined sustainability criteria (including GHG thresholds) for hydrogen and ammonia production. For countries that still do not have a standard in place, there is an opportunity to use the International Organization for Standardization (ISO) standard for GHG measurement of hydrogen production that was published in April 2026, with standards for hydrogen conversion processes expected by the end of 2026.

Box 8.1 Risk-mitigation instruments to decrease the cost of finance of hydrogen projects in Africa

Reducing the cost of capital requires more than financial instruments alone. It starts with developing stronger enabling environments, followed by project preparation support, deploying targeted instruments to reduce specific project risks, and – where risks remain – credit enhancement to crowd in private capital.

Strengthening enabling conditions is the first layer of de-risking:

- **Reducing sovereign and political risk**, which is often high in Africa and raises financing costs even in countries with no recent default history. Some actors argue that current rating methodologies can understate the credit quality of many African countries. The African Union's Common African Position on Debt, presented in 2025, sets out a framework for debt-management reform. At the national level, stronger rule of law, regulatory transparency and credible dispute-resolution mechanisms can help narrow the gap between perceived and actual risk.

- **Stable and predictable energy and industrial policies**, which improve demand visibility, reduce regulatory uncertainty and strengthen institutional credibility, lowering the perceived risk of adverse policy shifts and disputes.
- **Reliable enabling infrastructure**, including access to power grids, ports, water and transport networks, which have long lead times, and where common-user infrastructure can also anchor broader industrial development

Public finance can absorb early-stage risks and improve financing terms:

- **Project preparation support** can help develop feasibility studies and other development expenditures (DEVEX), which may become sunk costs if projects do not proceed. This reduces the need for scarce and expensive equity and debt at initial stages. Recent disbursements from international public financiers target DEVEX through grants or loans for hydrogen projects in Morocco, Namibia and South Africa (see Chapter 6).
- **Blended finance** can improve financing terms as projects mature. Concessional loans, subordinated equity and junior debt from international public financiers offer lower-cost capital, longer tenors or more risk-tolerant financing tranches. By taking higher-risk positions in the capital structure, public finance can reduce the exposure of commercial lenders, which may offer better terms. The IEA estimates that international concessional funding for clean energy investments needs to more than triple to support projects in emerging economies. Kenya's Olkaria ammonia facility has concessional finance from Germany's development finance institution, KfW, supporting KenGen's geothermal expansion linked to the project. The SDG Namibia One Fund and South Africa's SA-H2 Fund, both blended finance vehicles with a focus on hydrogen, have secured rights to participate in equity financing in projects they are currently supporting through DEVEX.

Targeted instruments can reduce specific bankability risks by shifting them away from the project developer to parties better able to manage them, reducing their likelihood and limiting their financial impact:

- **Revenue risk mitigation** through long-term offtake agreements that give visibility over demand and prices. These can include take-or-pay commitments, minimum purchase volumes, fixed or indexed prices and hard-currency payments.* In H2Global's first renewable ammonia auction, Fertiglobe was awarded a 7-year purchase agreement for ammonia from Egypt, with guaranteed minimum offtake volumes and a fixed euro-denominated price, but H2Global is now proposing longer tenors in new auctions. For domestic offtake, government-backed guarantees can strengthen buyer creditworthiness, as in South Africa's electricity auctions.

- **Technology risk mitigation,** particularly for first-of-a-kind projects, through original equipment manufacturer (OEM) performance guarantees and warranties, which may be supported by Technology Performance Insurance from insurers, strengthening confidence in equipment performance. Examples include solutions by New Energy Risk and Munich Re's HySure.
- **Construction risk mitigation**, through fixed-price engineering, procurement and construction (EPC) contracts with liquidated damages, to limit cost over-runs and delays. This is critical, as EPC represents a large share of project costs: Atome's Villeta project in Paraguay has a fixed-price lump-sum EPC contract with Casale worth USD 465 million, around 70% of total project costs.
- **Foreign exchange risk mitigation** for projects serving domestic markets, for which revenues are in local currency and debt and equipment costs are often denominated in hard currency. Currency depreciation can therefore raise debt financing costs. Mitigation options include hard-currency or indexed offtake agreements, as sometimes used in renewable electricity auctions, local-currency lending or hedging instruments, such as those offered by TCX.

Where risk remains, credit enhancement instruments can improve project bankability by limiting lender exposure in the event of default. However, despite their potential to mobilise private finance, guarantee instruments account for only 4% of multilateral development banks commitments in EMDEs, suggesting significant scope to scale them up to crowd in private capital, including for hydrogen.

- **Project-level credit enhancement** includes loan guarantees, credit guarantees or first-loss facilities, such as the African Development Bank (AfDB)'s USD 470 million partial credit guarantee to Morocco's OCP for low-carbon fertilisers.
- **Country and political risk coverage** protects investors against non-economic risks, such as expropriation, war or civil unrest. Instruments include political risk insurance and partial risk guarantees from institutions such as the AfDB and the World Bank's Multilateral Investment Guarantee Agency, which in May 2026 announced a goal to double its issuance of guarantees in Africa.

*Hard currency refers to a widely accepted and internationally tradable currency, such as the US dollar or euro. Local currency refers to the domestic currency of the country where the project is located. Across Africa, infrastructure investments are typically denominated in hard currency due to high rates of local currency inflation and related depreciation.

Annex

Explanatory notes

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.

Reporting hydrogen demand

In this report, demand includes hydrogen that has been intentionally produced for utilisation, including pure hydrogen (used in applications such as ammonia production and refining), and hydrogen which is mixed with carbon-containing gases (for example, synthesis gas used in applications such as methanol production and steel manufacturing). It excludes hydrogen which is present in residual gases from industrial processes (e.g. coke ovens and steam crackers), which are 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 applications like glassmaking, electronics and metal processing.

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 efforts to reduce emissions and enhance energy security are expected to drive up hydrogen use in some of these new applications, 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 direct reduced iron (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 reporting.
- 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.

Project status

For the analysis of the pipeline of announced projects, four potential statuses have been considered:

- Operational: includes projects that are already producing hydrogen, even if they are in a ramp-up period and have not achieved 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.

Scenarios in the Global Hydrogen Review

The analysis presented in this Global Hydrogen Review relies on two scenarios

- The Stated Policies Scenario (STEPS) is designed to reflect the direction of travel of the global energy sector based on current energy-related policies, including those that have already been adopted, announced, or are in the advanced planning stage – even if they are not yet enshrined in law or regulations. Examples of the latter include power sector development plans aimed at achieving a certain mix of generation assets by a specific date, regulatory reforms in the transport sector and energy efficiency targets for appliances. Policy targets are not assumed to be automatically met: in each case, their prospects are assessed taking account of market, infrastructure readiness and financial constraints. The STEPS assumes that time-bound policies continue beyond the currently-stated durations and retain a similar pace of change. However, it does not assume that aspirational goals, such as those included in the Paris Agreement, are achieved.
- The Net Zero Emissions by 2050 Scenario (NZE Scenario) is a normative scenario that maps out a global pathway for the energy sector to achieve net zero carbon dioxide (CO_2) emissions by 2050, consistent with the long-term goal of limiting the rise in global average temperatures to 1.5°C (with a 50% probability). In contrast with previous editions, the NZE Scenario is no longer a low-overshoot scenario: it assumes that warming exceeds 1.5°C degrees for several decades before returning below 1.5°C by 2100. This adjustment reflects persistently high emissions in recent years and the slow deployment of some key technologies. Achieving this pathway requires not only a very rapid transformation of the energy sector but also large-scale deployment of CO_2 removal technologies, which remain unproven at large scale.

Projections and estimates

Projections and estimates in the Global Hydrogen Review 2026 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 December 2025.

Voluntary willingness to pay

While policy frameworks and regulatory instruments play a central role in creating demand for low-carbon and hydrogen-based solutions, voluntary willingness to pay (WtP) can act as an important complementary demand-side signal. Voluntary WtP reflects the extent to which consumers, corporates, and other market participants are willing to voluntarily pay a premium for lower-emission products and services, beyond minimum regulatory requirements.

In the context of hydrogen deployment, voluntary WtP can help accelerate early demand, support first movers, and partially de-risk investment decisions, particularly in sectors exposed to end consumers. However, evidence suggests that voluntary WtP is highly heterogeneous across sectors and regions and, on its own, is generally insufficient to fully close the cost gap with conventional alternatives. As such, its role should be understood as complementary to policies, standards, and public support mechanisms, rather than as a standalone driver of scale.

The following tables present selected examples of voluntary WtP by sector and region, illustrating how voluntary demand signals are already emerging and interacting with policy frameworks and market dynamics.

Global

Sector	
Aviation	In a McKinsey survey of more than 5 500 passengers worldwide, 40% of travellers stated that they would be willing to pay at least 2% more for carbon-neutral tickets, although price and connectivity continue to outweigh sustainability in booking decisions. In another survey conducted in 2022 with more than 7 000 participants, 90% of respondents stated that they would be willing to pay more to limit the climate impact of flights.
Shipping	In a McKinsey survey of 250 global shippers and logistics providers, more than 7 in 10 companies stated that they would be willing to pay a premium for lower-emission shipping services, in a context where more than 65% of US consumers actively seek sustainable products and around 80% report being willing to pay a premium for them.
Steel	According to a McKinsey survey of more than 100 materials buyers and suppliers, most steel buyers are already paying a green premium for lower-carbon products, although the level of this premium varies widely. Looking ahead to 2030, respondents do not expect a significant increase in current green premium levels but do expect the payment of such premiums to remain a structural feature of the market. In another survey, 45% of respondents stated that they would be willing to pay a premium for CO_2 reductions above 25%, and 57% for reductions above 50%, although between 10% and 20% reported that their organisations are not currently willing to pay any premium for lower-emissions steel and concrete.

North America

Sector	
Aviation	In an RMI survey based on 23 companies (including airlines, logistics service providers and corporate customers), respondents indicated a WtP a premium for sustainable aviation fuel (SAF) compared to a fossil reference price of USD 2.29/gal. However, WtP decreases with longer contract durations, suggesting that buyers are reluctant to lock in long-term agreements at current price levels and may expect SAF costs to decline as the market matures.
Steel	In a BCG global survey of 1 750 automotive consumers, 57% of respondents stated that they would “definitely” or “probably” consider net-zero production when purchasing their next passenger vehicle, while 88% indicated WtP at least a small green premium (≥0.4%). In the United States, around 47% of car consumers reported a WtP a premium of up to 3%. In a survey of 1 251 US drivers commissioned by Industrious Labs, 81% of respondents expressed support for automakers switching to clean steel, while 62% indicated WtP up to USD 500 more per vehicle. In addition, 76% of respondents supported federal or state policies to facilitate the transition.

European Union

Sector	
Steel	According to industry statements from Swedish low-emissions steel producer Stegra, customers have demonstrated WtP a premium for low-carbon steel, with recent contracts reportedly reflecting premiums of around 35%, compared to approximately 25% in earlier agreements.
Refining	According to data from the EU Innovation Fund hydrogen auction, industrial off-takers show the highest price levels for renewable hydrogen, with a volume-weighted average price of EUR 6.95/kg.

China and Japan

Sector	
Steel	In a BCG global survey of automotive consumers, the likelihood of considering net-zero production varies significantly across countries, reaching 90% of respondents in China (highest) and 39% in Japan (lowest). WtP was also found to be higher in China, with around 47% of car consumers indicating a WtP up to 9% more for low-emission vehicles. In addition, among “eco-curious” consumers, approximately 50% in both China and Japan reported WtP around 9% more (equivalent to approximately EUR 4 100 and EUR 4 500, respectively).

Currency conversions

This report provides the stated values of programmes and projects in the currency stated in their announcement. In many instances these values 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 2026 values, average exchange rates are based on the International Monetary Fund.

Financial data and company portfolios

In Chapter 6 and the question relating to geological hydrogen in Chapter 1, the figures illustrating financial performance are based on different portfolios of companies:

- Hydrogen: IEA's global hydrogen technology portfolio includes 61 public companies whose value is driven primarily by the outlook for low-emissions hydrogen. The tickers of included firms are: ADNH US, HPOW LN, ACH NO, AMMPF US, BLDP CN, AQUNU US, BE US, CASAL SW, CI SS, CWR LN, CPH2 LN, 336260 KS, H2O GY, FHYD CN, NHHH CV, FCEL US, HTOO US, GNCL IT, GHY AU, GREENH DC, ALHAF FP, HZR AU, HDF FP, ALHRS FP, HYPRO NO, HYON NO, HYZN US, IMPC SS, 332142Z LN, ITM LN, LHYFE FP, MPHYF PQ, NEL NO, NXH CN, NCH2 GY, PLUG US, PCELL SS, PHE LN, PPS LN, 0051720D US, PV1 AU, F3C GY, 288620 KS, 702 HK, SPN AU, HYSR US, TECO NO, VDNT US, VIHD US, CAVEN NO, H2A GR, CH CN, HDRO CN, 2582 HK, 2570 HK, HYT AU, ATOM LN, 0001A0 KS, P1E AU, HYDR BU, AFC LN. 57 of them have reported values represented in this report.
- Natural hydrogen: based on the NatH2 Index; includes 9 public companies in this report: HDRO US, HYDR US, HJEN US, HGEN LN, HTWO IM, HDRO LN, ANRJGBX EZ, BNEHETC LX, HYDE SW, HYDR TO, HYDR CN. Some of these companies are also included in the Hydrogen portfolio.
- Upstream oil and gas: major public companies whose core business is related to the exploration of oil and gas resources. In total, 37 companies are represented, whose tickers are: COP US, CNQ CN, EOG US, NVTK RM, DVN US, 1605 JP, AKRBP NO, HES US, APA US, EXE US, PTTEP TB, FANG US, VAR NO, STO AU, AR US, CTRA US, HBR LN, EQT US, SLAV RU, TOU CN, MEG CN, CHRD US, RRC US, MUR US, CIVI US, VRN CN, MFGS RM, CRC US, SM US, 1662 JP, PR US, MTDR US, ARX CN, RDGZ KZ, WCP CN, CRGY US, MEDC IJ.
- Hydrogen ETFs: major Exchange-Traded Funds whose value is driven primarily by the outlook for low-emissions hydrogen: 11 are represented here: HDRO US, HYDR US, HJEN US, HGEN LN, HTWO IM, HDRO LN, ANRJGBX EZ, BNEHETC LX, HYDE SW, HYDR TO, HYDR CN.

Sources of information

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Abbreviations and acronyms

AaaS	Auctions-as-a-Service
ACES	Advanced Clean Energy Storage
AEM	anion exchange membrane
AfDB	African Development Bank
AFIR	Alternative Fuel Infrastructure Regulation
AI	artificial intelligence
ALK	alkaline
ASEAN	Association of Southeast Asian Nations
ASME	American Society of Mechanical Engineers
ATR	autothermal reformer
AUD	Australian dollar
BF	blast furnace
BOF	basic oxygen furnace
BoP	balance of plant
BRL	Brazilian reals
CAPEX	capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CCfD	carbon contract for difference
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CEF	Connecting Europe Facility
CfD	Contract(s) for difference
CHPS	Clean Hydrogen Portfolio Standard
CH_4	methane
CISS	chirality-induced spin selectivity
CNY	Yuan renminbi
COP	Conference of the Parties
CO_2	carbon dioxide
CSP	concentrated solar power
DAC	direct air capture
DAP	di-ammonium phosphate
DEVEX	development expenditure
DFI	development finance institution
DKK	Danish kroner
DLE	dry low-emissions

DME	dimethyl ether
DOE	Department of Energy (United States)
DRI	direct reduced iron
EAF	electric arc furnace
EAX	East Asia LNG price assessment
ECOWAS	Economic Community of West African States
EFTA	European Free Trade Association
EHB	European Hydrogen Bank
EIB	European Investment Bank
EMDEs	emerging markets and developing economies
EPC	engineering, procurement and construction
e-SAF	hydrogen-based synthetic fuels
ETF	exchange-traded funds
ETS	Emissions Trading System
EU	European Union
EUR	Euro
EV	electric vehicle
FC	fuel cell
FCEV	fuel cell electric vehicles
FEED	front-end engineering design
FID	final investment decision
FT	Fischer–Tropsch
GBP	British pound
GEF	Global Environment Facility
GHG	greenhouse gas
GHR	Global Hydrogen Review
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit (German International Cooperation)
GVA	gross value added
GVW	gross vehicle weight
HAR	Hydrogen Allocation Round (United Kingdom)
HBI	hot briquetted iron
HD	heavy-duty
HEFA	hydroprocessed esters and fatty acids
HHI	Herfindahl–Hirschman Index
HRS	hydrogen refuelling station(s)
HS	Harmonized System
HVDC	high-voltage direct current
HVO	hydrotreated vegetable oils
H_2	hydrogen
H_2S	hydrogen sulphide
IAA	Industrial Accelerator Act
ICSS	integrated gasification combined cycle
IDB	Inter-American Development Bank
IFC	International Finance Corporation
IMO	International Maritime Organization

INR	Indian rupee
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Projects of Common European Interest
Ir	iridium
ISCC	International Sustainability and Carbon Certification
ISO	International Organization for Standardization
KHI	Kawasaki Heavy Industries
LCOE	levelised cost of electricity
LCOH	levelised cost of hydrogen
LCOP	levelised cost of production
LH_2	liquefied hydrogen
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
LTDA	Long-Term Decarbonized Capacity Auction
MAP	mono-ammonium phosphate
MD	medium-duty
MeOH	methanol
METI	Ministry of Economy, Trade and Industry (Japan)
MoU	Memorandum of Understanding
NECP	National Energy and Climate Plan
NG	natural gas
NH_3	ammonia
NO_x	nitrogen oxides
OEM	original equipment manufacturer
OPEX	operating expenditure
PEM	proton exchange membrane
PtX	power-to-X
PV	photovoltaic
RED	Renewable Energy Directive (European Union)
RFNBO	renewable fuels of non-biological origin
R&D	research and development
SAF	sustainable aviation fuel
SECI	Solar Energy Corporation of India
SEFA	Sustainable Energy Fund for Africa
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
SSA	sub-Saharan Africa
STEPS	Stated Policies Scenario
STIP	Sustainable Transport Investment Plan
SUV	sports utility vehicle
TRL	technology readiness levels
TSO	transmission system operator
TTF	Title Transfer Facility
UNFCCC	United Nations Framework Convention on Climate Change

UNIDO	United Nations Industrial Development Organization
USD	United States dollars
VC	Venture capital
VRE	variable renewable electricity
WACC	weighted average cost of capital
WLE	wet low-emissions
WtP	willingness to pay

Units

A	ampere
bar	bar
bbl	barrel
bcm	billion cubic metres
boe	barrel of oil equivalent
°C	degrees Celsius
cm	centimetre
DWT	deadweight tonnage
EJ	exajoule
g	gramme(s)
gal	gallon
GJ	gigajoule
Gt	gigatonne
GW	gigawatt(s)
GWh	gigawatt hour
GWP	Global Warming Potential
GW/yr	gigawatts per year
ha	hectare
inch	inch
kbpd	thousand barrels per day
kg	kilogramme
kg/d	kilogrammes per day
km	kilometre
km/h	kilometres per hour
knots	knots
kt	kilotonne
ktpa	kilotonnes per annum
kW	kilowatt
kWh	kilowatt-hour
m	metre(s)
m^3	cubic metre(s)
mbpd	million barrels per day
MBtu	Million British thermal units
MJ	megajoule
Mt	Million tonnes
Mtpa	Million tonnes per annum

MW	megawatt
MWh	megawatt hour
Nm^3	Normal cubic metre
PJ	petajoule
t	tonne(s)
tpa	tonnes per annum
tpd	tonnes per day
TW	terawatt
TWh	terawatt hour

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