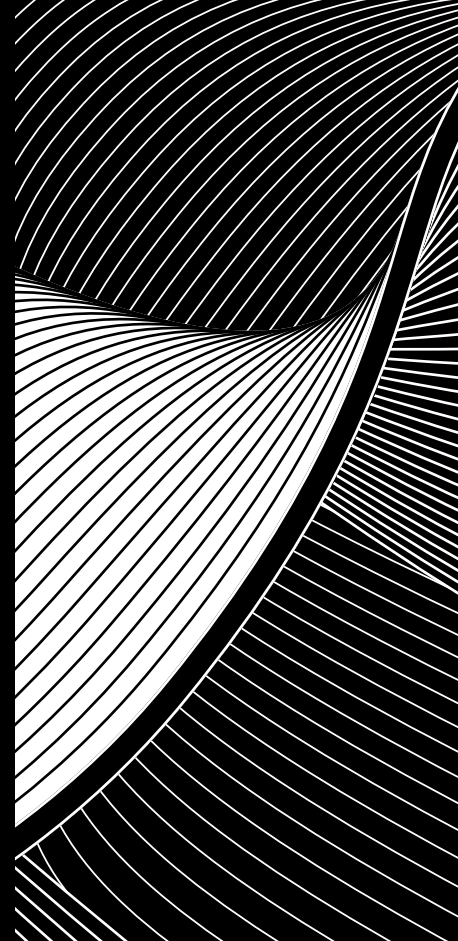


MACQUARIE ASSET MANAGEMENT

Pathways

Hydrogen: Charting a course through cost reduction and infrastructure

June 2025



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Executive summary



Demand outlook: Current hydrogen demand is approximately 90 megatonnes (Mt), most of which are grey hydrogen, which is produced from fossil fuels and used as feedstocks in oil refining and chemicals. Near-term growth in green hydrogen, produced via electrolysis, will be driven by traditional applications adapting to clean fuel mandates and regulations. By 2050, green hydrogen demand is projected to be ~300 Mt on average – three times current demand – with additional hydrogen demand driven mainly by emerging uses in transport, steel, and seasonal energy storage.



Cost and adoption barriers: The production cost of green hydrogen is mainly driven by the cost of the electrolysis system and electricity prices. In our view, the levelised cost of hydrogen (LCOH) needs to be at \$US2.0-2.5 per kilogram (kg) to be price competitive without policy support, but our modelled LCOH is currently \$US6.4 per kg. The high cost makes near-term adoption heavily policy dependent.



Achieving LCOH target: A substantial drop in renewable electricity costs is essential for cost-competitive green hydrogen. In our model, achieving a target LCOH of \$US2.0-2.5 per kg by 2050 requires a 65% reduction in electrolyser costs (implying a 9% learning rate) and a 45% decline in renewable electricity prices. However, even under an optimistic 15% learning rate scenario, a 36% reduction in power costs is still needed to achieve the target.



Storage and transport: The true cost of hydrogen extends beyond production, encompassing storage requirements and transportation infrastructure that can make or break its business case for adoption. Storage and transportation costs significantly impact the final price paid by end users, varying between \$US2 and \$US10 per kg today based on infrastructure availability, logistical constraints, and consumption patterns. Large-scale hydrogen infrastructure implementation could reduce transport and storage costs by up to 30% and 60%, respectively.



Government initiatives: Major economies have set ambitious hydrogen production targets and allocated substantial funding to support the hydrogen industry. While most policies focus on renewable hydrogen production, demand-side incentives are increasingly being acknowledged by governments as a means to stimulate hydrogen adoption.

Introduction



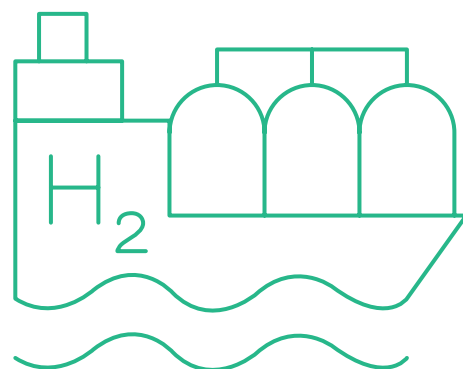


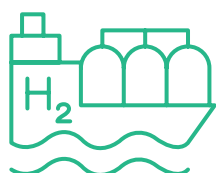
Hydrogen is the most abundant element in the universe, making up about 90% of the known universe from an atom count perspective or 75% from a weight perspective. It also releases minimal carbon dioxide (CO₂) when burnt (water is the primary by-product), has a very high specific energy (at 33.3 kilowatt-hours per kilogram (kWh/kg), it is roughly three times that of gasoline), and can be used in a very broad range of applications. It thus holds vast potential to transform the global economy from one that is heavily reliant on fossil fuel-based energy to one that produces minimal amounts of CO₂.

There are, however, many challenges on the road to hydrogen adoption. Green hydrogen is currently expensive, not just relative to fossil fuels but also relative to other decarbonisation options. Hydrogen transportation and storage infrastructure is not yet deployed at scale to meet the sector's emerging needs, though some existing large scale gas transportation and storage infrastructure that can be repurposed. However, scale and technological improvements could see green hydrogen cost falls dramatically in the years ahead, hydrogen combines well with renewables-based power generation, and government support is building.

In this Pathways paper we explore all these issues and more. The first section details hydrogen's use cases (both current and potential) and considers their viability going forward. Section two examines the levelised cost of green hydrogen, its key drivers, and its likely evolution in the years and decades ahead. We explore what we think is needed to make green hydrogen cost competitive and discuss the likelihood of such factors occurring based on the available evidence. Section three examines the current state of hydrogen infrastructure and storage and the extent to which this can add to the cost of hydrogen for consumers. The final section overviews government policy in the world's major economies and the support that is currently being provided and its efficacy.

Hydrogen demand: Traditional and new applications





Hydrogen's atomic structure makes it highly reactive. It is therefore often found in compounds, most notably water.¹ Extracting hydrogen from compounds requires breaking apart the chemical bonds, which in turn requires significant amounts of energy.

The source of the energy used to break the bonds determines the naming of hydrogen, with grey hydrogen referring to hydrogen produced from fossil fuels, blue being grey hydrogen combined with a carbon capture and storage system (CCS), and green hydrogen referring to hydrogen produced from renewable electricity via electrolysis.

Hydrogen has numerous use cases, both current and potential. It can be used as a fuel, a feedstock, for heat generation and for energy storage. In this section we provide an overview of these use cases and consider the potential total demand for hydrogen going forward. Potential demand shows just how significant a contribution hydrogen can make to the energy transition, but it is also important because of the scalability of production – greater production reduces per unit cost, which can unlock additional use cases. There are two broad categories of hydrogen use cases: traditional applications and new applications.

1. That said, molecular hydrogen (i.e. hydrogen not bound to other elements) does exist, and relatively pure hydrogen has been found in underground reservoirs finds are referred to as “natural hydrogen” in analogy to “natural gas”, both found by drilling into underground reservoirs.

Traditional applications: Feedstock use in the main

Hydrogen has long been used as a feedstock in various industries, most notably in oil refining but also in fertiliser and industrial chemicals manufacturing (Figure 1). Almost all hydrogen used in these applications today is grey hydrogen, which is derived from fossil fuels. In 2023, hydrogen demand from traditional applications amounted to 73 Mt, comprising 24 Mt from oil refining and 15 Mt and 33 Mt from methanol and ammonia, respectively. In addition, there was 16 Mt of hydrogen created as a by-product of oil refining and reapplied in oil refining.²

Given these sectors require hydrogen as a chemical feedstock, substitution is challenging to find and may prove to be impractical. A switch to green hydrogen will likely imply an increase in cost for these sectors, unless the cost of green hydrogen at the point of use – encompassing not only the production costs but also the costs of transportation, storage, and distribution to the final point of consumption – drops to \$US1-2 per kg, the same level as grey hydrogen.³ A carbon price would also increase costs, by pushing up the price of the grey hydrogen currently used. Figure 1 below provides an overview of each of the main traditional applications of hydrogen.

Figure 1:
Traditional applications of hydrogen

Application	Hydrogen role	Description
Oil refining	Feedstock	Hydrogen is a key feedstock in oil refining. It is used mainly to remove sulphur and other impurities (hydrotreating) and manipulate hydrocarbon molecules into different forms (hydrocracking). Hydrogen is also a by-product in oil refining, primarily created during catalytic naphtha reforming and can be reapplied in oil refining.
Ammonia (fertilisers and chemicals)	Feedstock	Ammonia, which is produced by combining hydrogen with nitrogen, is one of the most common industrial chemicals. 77% of ammonia is used to produce fertiliser today. Other industrial applications of ammonia include explosives and wastewater treatment, among others.
Methanol (chemicals)	Feedstock	Methanol is derived from combining hydrogen with CO ₂ . Methanol is an essential chemical building block for many consumer and industrial products, including plywood, synthetic fibre, high-performance plastics, and pharmaceuticals.

Source: BloombergNEF (BNEF), Macquarie Asset Management analysis.

2. BloombergNEF (BNEF), “New Energy Outlook 2024”, May 2024.
3. Montel, “Hydrogen production cost trends 2025”, 13 February 2025.

New applications: The fuel of the future

In recent years, the versatility of hydrogen, combined with the fact that it is a clean-burning molecule, has resulted in it attracting considerable market attention due to its potential to replace fossil fuels, especially in hard-to-abate sectors.

At present hydrogen is used mainly as a feedstock, but it can also be used as fuel and as heat, and many of the new applications use hydrogen in this way. Figure 2 below provides a summary of each of these potential use cases. In 2023, new applications consumed only 5.7 Mt of hydrogen,⁴ equivalent to just 6% of global hydrogen consumption of 94 Mt.⁵ But they hold vast potential – forecasters are expecting hydrogen demand to reach roughly 340-420 Mt by 2050 (see Figure 15 on page 30) and the potential demand under ideal conditions from a hydrogen perspective is likely a multiple of that.

Figure 2:
Selected new applications of hydrogen

Application	Hydrogen role	Description
Shipping	Fuel	There are multiple sustainable fuel pathways for the shipping sector, all requiring hydrogen to a greater or lesser extent. Among them, both methanol and ammonia – the main non-biological alternative fuel options being considered – are derived from hydrogen. Hydrogen is also used as a feedstock in processing biofuel.
Aviation	Fuel	Hydrogen is a key feedstock in the production of synthetic sustainable aviation fuel (eSAF). Other SAF production pathways, such as biomass-based hydroprocessed esters and fatty acids (HEFA), also require hydrogen for converting and refining the biomass into SAF. ⁶ In addition, it can be used directly as a fuel in hydrogen-powered aircrafts.
Heavy trucks ⁷	Fuel	Instead of fossil fuels, trucks can be powered by hydrogen used in an internal combustion engine or a fuel cell, which produces electricity via an electrochemical reaction.

4. BNEF, “New Energy Outlook 2024”, May 2024.
5. Including 16 Mt of hydrogen created as a by-product of oil refining and re-applied in oil refining.
6. SkyNRG, “Technology Basics”, accessed May 2025.
7. While passenger cars can also be powered by hydrogen, fuel cell vehicles (FCVs) are generally considered not competitive in this market segment given its relatively high price and low energy efficiency relative to battery electric vehicles, which is the main decarbonisation option for passenger cars at present.

Firming the power system	Fuel	Hydrogen or ammonia provides flexible and dispatchable power to complement wind and solar in the power system, potentially taking over the role currently played by natural gas. Excess renewable power can be stored as hydrogen, which can be converted back to meet electricity demand when renewable output is low.
Steel	Feedstock and heat	Hydrogen can displace almost all need for fossil fuels in steelmaking by acting as both the feedstock for the chemical reaction necessary to reduce iron ore to pig iron, and by providing the high-temperature heat for the steel-making process.
High-temperature heat (cement, aluminium and glass)	Heat	High-temperature heat (above 500C) is a vital input to the manufacture of everyday products like cement, aluminium and glass. Hydrogen can substitute for fossil fuels in these applications.
Space and water heating	Heat	Renewable hydrogen could be blended into and even fully substitute natural gas in providing building heat.

Sources: BNEF, Macquarie Asset Management analysis.

Beyond the challenge of being more expensive than grey hydrogen, green hydrogen also needs to compete with other decarbonisation options. For instance, hydrogen may not play a significant role in space and water heating, as electric heat pumps have emerged as more energy efficient and a potentially cheaper option to decarbonise. The superior energy efficiency of heat pumps is uncontested, but they also represent a higher up-front cost for homeowners, and significant investment in infrastructure and pipelines may ultimately be needed in many countries if they are to be used at scale. In many jurisdictions, the regulatory preference for heat pumps has failed to achieve the desired take-up, leaving the door ajar for hydrogen to potentially find a role in decarbonising space heating for users currently relying on natural gas. Figure 3 on the next page provides a summary of each potential use case, as well as the main other decarbonisation options for each.

Figure 3:
Grey benchmark for hydrogen and decarbonise options apart from hydrogen

Application	Grey benchmark	Non-hydrogen-based decarbonisation options
Fuel-cell heavy trucks	Fossil fuel internal combustion engine (ICE) trucks	Battery electric trucks
Primary steel	Coal	CCS
		Molten oxide electrolysis
High-temperature heat	Natural gas, coal and oil	Biofuel
		CCS
Buildings	Natural gas, coal and oil	Heat pump
		Biomass
Firming the power system	Natural gas and coal	Battery storage (intraday storage)
		Pumped hydro (seasonal storage)
		Compressed air energy storage (seasonal storage)
		Biomethane
		CCS
Shipping	Fossil fuel-based marine oil and liquefied natural gas (LNG)	Biofuel
		Electric vessel
		Direct air capture (DAC)
Aviation	Jet fuel (kerosene)	Non-H ₂ -based SAFs (e.g. HEFA)
		Electric aircraft
		DAC

Source: Macquarie Asset Management analysis. HEFA = hydroprocessed esters and fatty acids.

There is considerable uncertainty about the (hydrogen) price point that unlocks these use cases, not least because that will depend upon the cost evolution of other decarbonisation options. BNEF's estimates suggest that in the absence of policy intervention, the price required for green hydrogen become price competitive with fossil fuel-based technology in these new applications range between \$US0.94 and \$US4.0 per kg, and to see a significant increase in demand, the price will need to fall to roughly \$US2.0-2.5 per kg.⁸

Moreover, there are a range of other considerations and challenges that will need to be addressed for these new applications to be realised.

- **Infrastructure readiness and availability.** The adoption of hydrogen in new applications requires substantial investment in infrastructure for transport, storage and other ancillary facilities such as refuelling stations for hydrogen fuel cell cars. Unlike natural gas or other fossil fuels, hydrogen has storage and transportation challenges due to its low volumetric energy density and the need for high compression or liquefaction. The development of hydrogen pipelines, refuelling stations, and storage facilities is essential but is lagging the capacity needed for widespread adoption. We discuss this in detail in section three.
- **Public acceptance.** Public acceptance is another critical factor influencing hydrogen adoption. There can be public resistance to new technologies due to concerns about safety, cost and the unknowns associated with large-scale implementation. This is particularly important for retail consumer-facing applications, such as the heating of residential homes.

- **Regulatory environment.** Supportive regulatory frameworks and policies are crucial for hydrogen to compete with established fossil fuels, particularly in instances where it is not price competitive on a standalone basis. Subsidies, tax incentives, carbon pricing mechanisms, and mandates can significantly affect the economic viability of hydrogen projects. For example, the development of the European Hydrogen Bank within the EU aims to support hydrogen projects through subsidies and investment incentives. Section four provides a summary of hydrogen policies in selected markets.

Finally, it is worth noting that hydrogen is not precluded from a role in decarbonising these sectors, even in the absence of a drastic reduction in levelised cost of hydrogen (LCOH) in the near term. This is because price is not the sole concern in hydrogen adoption. The cost and technology readiness of hydrogen relative to alternative decarbonisation options (such as battery trucks for heavy transportation, carbon capture and storage for high-temperature heat, and heat pumps for space heating) can have a significant impact on the adoption rate of hydrogen among the new applications.

8. BNEF, "Hydrogen Economy Outlook", 30 March 2020.

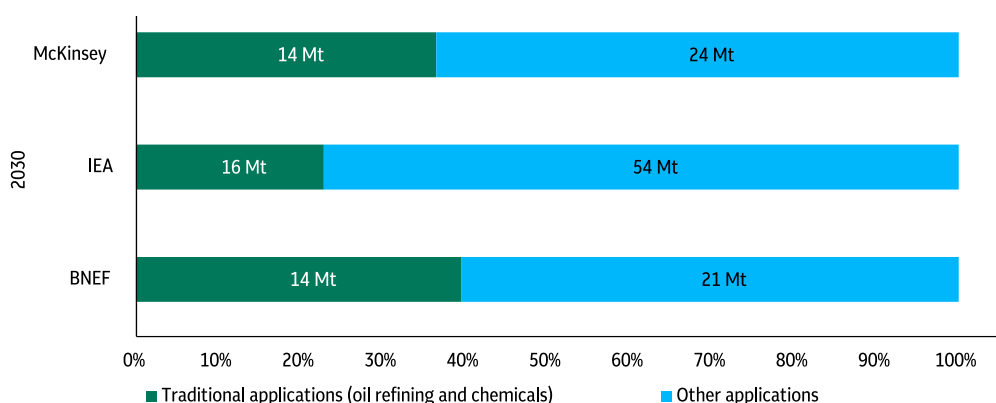
Demand outlook by use case

Traditional applications: Oil refining and chemicals

Due to the lack of a substitute for hydrogen, the switch from grey to low-carbon hydrogen to reduce emissions appears inevitable for traditional applications. In addition, within the EU there is a binding target of 42% of renewable hydrogen in total industrial hydrogen consumption by 2030. However, such a switch has its challenges. Moving to green hydrogen is challenging initially because no infrastructure is in place to supply users in traditional oil refining or chemicals. A switch to blue hydrogen is simpler as it retains the legacy logic of producing the hydrogen on-site from fossil fuels. However, the sequestration logistics for the captured CO₂ are currently an unresolved question for many users, although there are promising steps in some areas. For example, HyNet, an industrial cluster in North West England is building out hydrogen pipeline infrastructure and has recently reached final investment decision on the CO₂ storage aspect of the cluster.

Traditional applications are nevertheless expected to be a key driver of low-carbon hydrogen demand in the near term due to mandates and clean fuel regulations. By 2030, forecasters project that oil refining and chemicals will consume about 100 Mt of hydrogen.⁹ This figure includes 14-16 Mt of low-carbon hydrogen, which represents 23-40% of total projected low-carbon hydrogen demand by 2030 (Figure 4). The momentum is evident in the European Hydrogen Bank's first round subsidy auction, in which over half of the winners intend to produce green hydrogen for oil refining or green ammonia.¹⁰

Figure 4:
Traditional applications' low-carbon hydrogen demand as percentage of total low-carbon hydrogen in 2030 by forecaster



Source: BNEF, "New Energy Outlook 2024", May 2024; International Energy Agency (IEA), "Global hydrogen demand in the Net Zero Scenario, 2022-2050", 26 September 2023; McKinsey, "Global Energy Perspective 2023: Hydrogen outlook", 10 January 2024; Macquarie Asset Management analysis.

9. BNEF, "New Energy Outlook 2025 Data Viewer", 15 April 2025; IEA, "Hydrogen Net Zero Emissions Guide", September 2023.

10. Hydrogen Insight, "Who are the winners of €720m of European Hydrogen Bank funding — and who will buy their subsidised H₂?", 2 May 2024.

The switch from grey to low-carbon hydrogen is expected to gather pace beyond 2030. By 2050, most of the hydrogen consumed by traditional applications is projected to be low-carbon hydrogen. However, there is some uncertainty about the overall volume of hydrogen that will be consumed by these applications. The demand for oil refining will likely decrease from its current level as it is being replaced by cleaner alternatives. In addition, as ammonia-based fertilisers emit nitrous oxide (a greenhouse gas that is 273 times more potent than CO₂ over a 100-year horizon), in a net-zero scenario agriculture will have to cut fertiliser consumption.¹¹ These uncertainties are reflected in the wide range of hydrogen demand projections for traditional applications in 2050 – for example, the IEA projects that in the net zero scenario, industrial applications will consume 109 Mt of low-carbon hydrogen, while BP projects 171 Mt for the same use cases.

New applications: Transportation, steel and firming up the power system

Among the new applications, transportation (mainly shipping and aviation), steel, and seasonal power storage are seen as the most

promising. However, in many instances the adoption of hydrogen will require new or repurposing of existing infrastructure and significant cost declines. As a result, the use of hydrogen by these sectors is unlikely to become mainstream until after 2030. However, by 2050 they are projected to consume ~200 Mt of low-carbon hydrogen per year, which represents 45-64% of their projected global low-carbon hydrogen demand (see Figure 15 in the next section for an overview by forecaster).

Transportation: Government policies driving demand

In terms of new applications of hydrogen, shipping and aviation have shown pleasing momentum so far. This is mainly because most pathways to decarbonisation for these two sectors involve hydrogen: in shipping, methanol and ammonia (the two major low-carbon shipping fuels) are both hydrogen derivatives (Figure 5); in aviation, most SAF production pathways involve hydrogen to varying degrees (eSAF is hydrogen-based while most other production pathways use a small amount of hydrogen for refining).

11. BNEF, “New Energy Outlook 2024”, May 2024.

Figure 5:
Different options to decarbonise the shipping sector

	Options	Merits	Key challenges
Hydrogen and derivatives	Renewable methanol	Relatively easy to handle	Cost and availability of CO ₂ from carbon capture (e-methanol)
		Only minor engine modification required	Only small reduction in tank-to-wake (TTW) emissions ¹²
	Clean ammonia	Carbon-free molecular structure	Not commercially available yet
		Close to zero TTW emissions	High toxicity Require chilled or pressurised fuel tanks
	Liquid hydrogen	Close to zero TTW emissions	Low energy density
			Require specialised fuel tanks
Other options	Sustainable biofuels	Mature technology	Limited supply of feedstock
		Does not require engine modification	Only small reduction in TTW emissions
	Electric vessels	High life-cycle energy efficiency	Limited shipping range and capacity due to low energy density of batteries
		Low TTW emissions	Require port charging infrastructure
	Air capture	No fuel or engine change required	Not commercially available yet (onboard air capture)
			High current production costs (direct air capture)

Source: Macquarie Asset Management analysis.

12. Tank-to-wake emissions refer to the greenhouse gases and pollutants emitted during the combustion of fuel in a vehicle's engine, from the point the fuel is stored in the tank to its complete use in propulsion.

By 2030, aviation and shipping are anticipated to see the beginnings of hydrogen integration. In shipping, methanol-compatible ships are currently being built and ammonia-powered vessels are being developed through various demonstration projects and pilot programs. Adoption of methanol and ammonia is further encouraged by the International Maritime Organization (IMO)'s agreement in April 2025 to introduce a new fuel standard and a global pricing mechanism for emissions for ships over 5,000 gross tonnage, which will enter into force in 2027.¹³ Similarly, in aviation, while eSAF remains significantly more expensive than other SAF pathways, some level of hydrogen demand is guaranteed by EU's ReFuelEU Aviation initiative – it requires aviation fuel suppliers to ensure that all fuel made available to aircraft operators at EU airports contains a minimum of 1.2% of synthetic fuels from 2030 onward. Countries such as Singapore and Japan, which are also implementing SAF mandates, may also adopt similar approaches to promote eSAF production, especially given the supply constraints of biomass-based pathways. Given the scale of investment in infrastructure and supportive policies required, hydrogen use in shipping and aviation is expected to scale primarily after 2030.

In road transportation, fuel cell vehicles (FCVs) are not currently expected to play a major role in global decarbonisation, largely due to the cost and the early lead of battery electric vehicles. However, this outlook is evolving. Particularly in parts of Asia where new use cases and models are emerging. For countries like Japan and South Korea, which are likely to rely on imported clean energy such as hydrogen and its derivatives, FCVs could still prove attractive. These imports could be used either to charge battery EVs or directly power FCVs. In centralised fleet applications – where hydrogen supply can be guaranteed and infrastructure concentrated – FCVs may offer a competitive and cost-effective alternative, especially when supported by government subsidies. If major manufacturers begin offering affordable FCV models, this could further shift the market and expand deployment beyond early niche applications.

By 2050, hydrogen and derivatives are expected to become a mainstream fuel for both the shipping and aviation industries, contributing significantly to their decarbonisation efforts. For shipping, ammonia is expected to account for 43% of the fuel mix by 2050, while in aviation the mandated shares of eSAF in the EU will increase progressively until 2050 to 35%.¹⁴ While there is considerable uncertainty in long-term projections and carbon credits have a potential role to play, transportation could have the highest consumption of hydrogen among all sectors by 2050, with projected demand ranging from 147 Mt to 193 Mt, which is roughly 1.5 to 2 times the current global demand for hydrogen.

13. International Maritime Organization (IMO), "IMO approves net-zero regulations for global shipping", 11 April 2025.

14. Source: IRENA, "A Pathway to Decarbonise the Shipping Sector by 2050," October 2021; IATA, "Statement on refuel EO proposals," April 2023.

Green steel: Decarbonising a hard-to-abate sector

The steel industry is the largest emitting manufacturing sector and accounts for about 7% of all man-made emissions today.¹⁵ In traditional steelmaking, primary steel is produced first using a blast furnace (BF) with coke (a coal derivative) as a reducing agent to turn iron ore into liquid iron (also known as pig iron), followed by a basic oxygen furnace (BOF) which blows pure oxygen into a bath of liquid iron and steel scrap to reduce its carbon content and other impurities. This is known as the BF-BOF route (Figure 6).

An alternative route to a blast furnace is the direct reduction process, which reduces iron by removing oxygen directly from iron ore with the help of a reagent, which is usually a natural

gas derived high hydrogen concentration gas mix. The direct reduced iron (DRI) is then further processed through an electric arc furnace (EAF), which uses electricity to melt the metal for purifying, alloying and further processing. This alternative is known as the DRI-EAF route. 91% of the primary steel¹⁶ made today is produced via the BF-BOF route, while the DRI-EAF route accounts for the remaining 9%.¹⁷ Despite being 20% more energy intensive than the BF-BOF route, the DRI-EAF route emits 20% less carbon emissions, mainly because of the use of natural gas instead of coke.¹⁸ Replacing natural gas with low-carbon hydrogen as the reagent in the DRI stage, combined with EAF powered by renewable energy, can further reduce carbon emissions to less than 10% of their current level.¹⁹

15. World Economic Forum, "The Net-Zero Industry Tracker", 28 July 2022.

16. Primary steel is made from iron ore, while secondary steel which is produced from recycling steel scrap. Currently, primary steel and secondary steel respectively account for 79% and 21% of steel production.

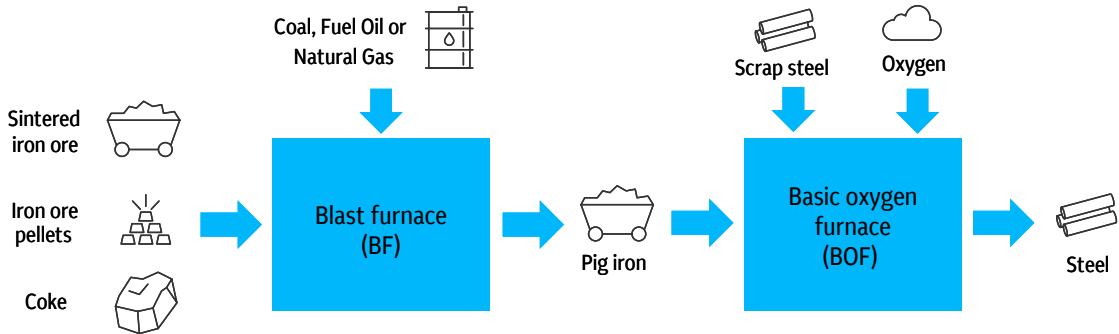
17. Columbia Business School, "Decarbonizing Steel", 16 September 2024.

18. The Oxford Institute For Energy Studies, "Stainless Green: Considerations for making green steel using carbon capture and storage (CCS) and hydrogen (H₂) solutions", May 2023.

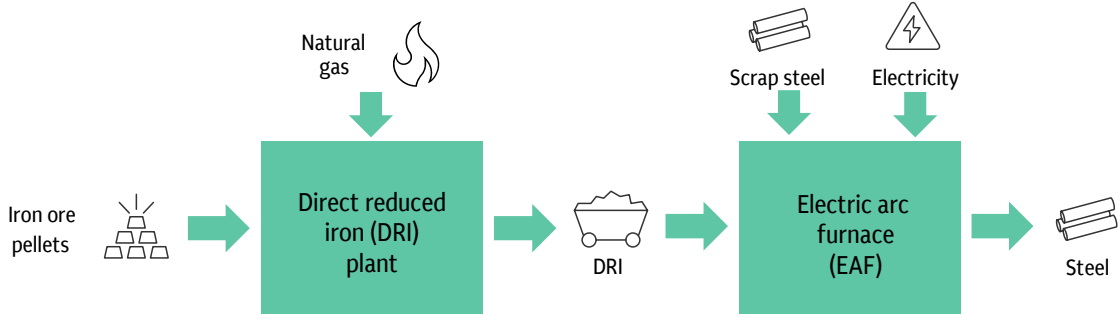
19. Columbia Business School, "Decarbonizing Steel", 16 September 2024.

Figure 6:
Different routes of steelmaking

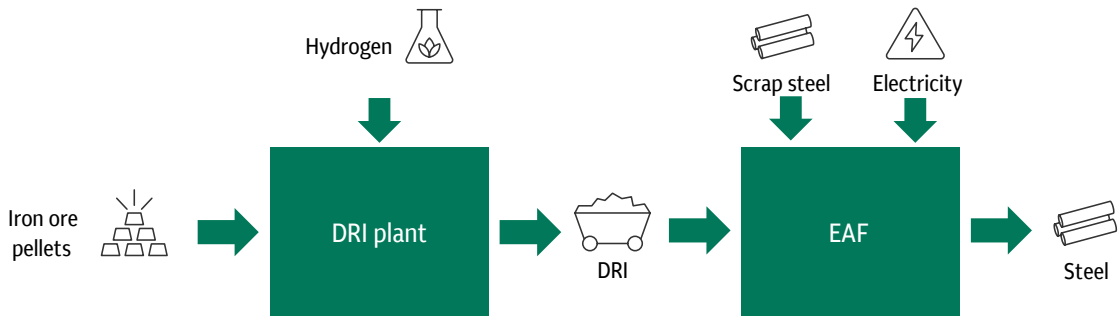
BF-BOF route



DRI-EAF route with natural gas



DRI-EAF route with green hydrogen



Source: Harpprecht, Naegler, Steubing, Tukker and Simon, “Decarbonization scenarios for the iron and steel industry in context of a sectoral carbon budget: Germany as a case study”, October 2022; Wang, Zhao, Babich, Senk and Fan, “Hydrogen direct reduction (H-DR) in steel industry—An overview of challenges and opportunities”, December 2021.

Like the mobility sector, green steel is one of the more promising new applications of hydrogen because of the limitations of other decarbonising options – scrap recycling cannot deal with demand increments and CCS and electrolytic steel manufacturing are still in their infancy. CCS does not, however, have the same feedstock constraint as scrap and it is applicable to both BF-BOF and DRI-EAF steelmaking facilities and can also be retrofitted to existing facilities. Nonetheless, its applicability is limited by the necessity of having accessible transportation and storage sites for captured CO₂. Geological, logistical and regulatory constraints mean that CCS is not always an easy or cheap option to deploy. For example, in Germany steel plants can capture CO₂ at source, but the current legislation prohibits storing CO₂ under national territory. In addition, neither CCS nor hydrogen shows a clear cost advantage over the other today and both have a 20-50% price premium range compared to conventional steel.²⁰

Despite being a promising decarbonising option, hydrogen-based steelmaking is not expected to become mainstream by 2030, mainly because commercial green steel production, such as HYBRIT and Stegra in Sweden, is only expected to begin in the next few years. The production of hydrogen-based green steel is expected to become more prevalent by 2050, when the cost of green hydrogen is lower than it is today, and carbon pricing may have increased the cost of traditional steelmaking.

Firming the power system: peaking power and seasonal energy storage

One of the interesting characteristics of hydrogen is its suitability for long-term or seasonal energy storage. Unlike batteries, which can be optimal for short-duration and intraday storage due to their high round-trip efficiency, hydrogen can effectively store energy for months without significant energy losses. This characteristic makes it a promising option for balancing seasonal variations in renewable energy supply, storing surplus energy produced during summer for use in winter. For seasonal energy storage, hydrogen will have to be stored underground and drawn when it is needed.

Other low-carbon seasonal energy storage options include pumped hydro storage, compressed air energy storage (CAES) and natural gas with CCS. Among them, pumped hydro storage systems are the most technologically mature. Pumped hydro stores excess electricity by pumping water from a lower reservoir to an upper one. When the stored energy needs to be deployed, water is released through turbines to generate electricity. Pumped hydro storage systems are capable of storing large amounts of energy and have high round-trip efficiencies of 70-87%,²¹ whereas green hydrogen has only 30-35% if reconverted to electricity.²² However, the availability of this solution is limited to topologically appropriate locations. In addition, extreme weather due to global warming means that filling reservoirs can become more challenging as droughts are becoming more frequent.

20. The Oxford Institute For Energy Studies, “Stainless Green: Considerations for making green steel using carbon capture and storage (CCS) and hydrogen (H₂) solutions”, May 2023.

21. National Renewable Energy Laboratory, “Pumped Storage Hydropower”, 2024.

22. The Centre For Sustainable Road Freight, “Technologies for Large-Scale Electricity Storage”, 8 November 2020.

CAES stores excess electricity by compressing air and forcing it into underground storage and then releasing the air back to the atmosphere through expander turbines to generate electricity when needed. It has a round-trip efficiency of 40-70%. However, CAES requires specific geological conditions, such as suitable underground caverns. CAES stores a fraction of energy per volume of underground cavern compared to the use of this same cavern for hydrogen storage. Given the geological scarcity of usable sites, these will have a higher value for storage of hydrogen, thus potentially pushing CAES out of the market. In contrast, because hydrogen storage requires lower volumes per quantity of energy stored, a wider choice of geologically adequate sites exists, although salt caverns will remain prime objects of interests due to their filling and gas tightness characteristics and low cost. Natural gas with CCS is also an option to manage seasonal energy demand. The main advantage of this option is that it is compatible with the existing infrastructure. However, similar to green steel, applying CCS requires appropriate CO₂ transport and storage systems, which are not always available. Further disadvantages include the high capital costs of CCS which, at low load factors, increase the marginal cost of electricity generation to a level higher than using hydrogen as a fuel for peakers.

Given the pros and cons of these options, it is likely that a combination of these options will be required for seasonal energy storage in a net zero scenario, and both cost and geology will decide what is the best option for any specific project. As such, it is particularly difficult to forecast hydrogen demand for this sector. Forecasts for hydrogen consumed by the power sector in 2050 range from 18 Mt to 92 Mt, which reflects the uncertainty.

Green hydrogen: Its levelised cost trajectory





Today green hydrogen is generally more expensive than blue hydrogen, which is in turn more expensive than grey hydrogen. Blue hydrogen is produced by adding a CCS to the production of grey hydrogen, which uses fossil fuel as a feedstock. That implies blue hydrogen would never become cheaper than grey hydrogen, without carbon pricing or some other financial support.

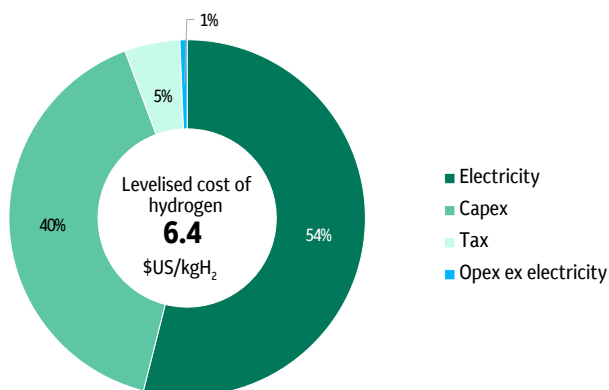
Green hydrogen, on the other hand, is produced via electrolysis – splitting water into hydrogen and oxygen – and does not use any fossil fuels as inputs. It therefore has the theoretical potential to be cheaper than grey hydrogen. In this section we examine the levelised cost of green hydrogen, its main drivers, as well as its likely trajectory over the next three decades or so.

For green hydrogen, the LCOH has four components, with the first two being the main cost drivers:

1. The cost of the electrolysis system used to split water into hydrogen and oxygen (capital expenditures, or capex)
2. The cost of the renewable electricity used as the power source for the electrolyser
3. Other operating expenses (opex) such as maintenance and insurance costs
4. Tax

The cost shares of each of these components varies by region and through time, a point we expand on later in the section. Figure 7 below shows the cost breakdown of our model of a 50 megawatt (MW) plant in Western Europe. Over 50% (54% to be precise) is electricity, 40% is capex and the rest are tax (5%) and opex excluding electricity (1%).

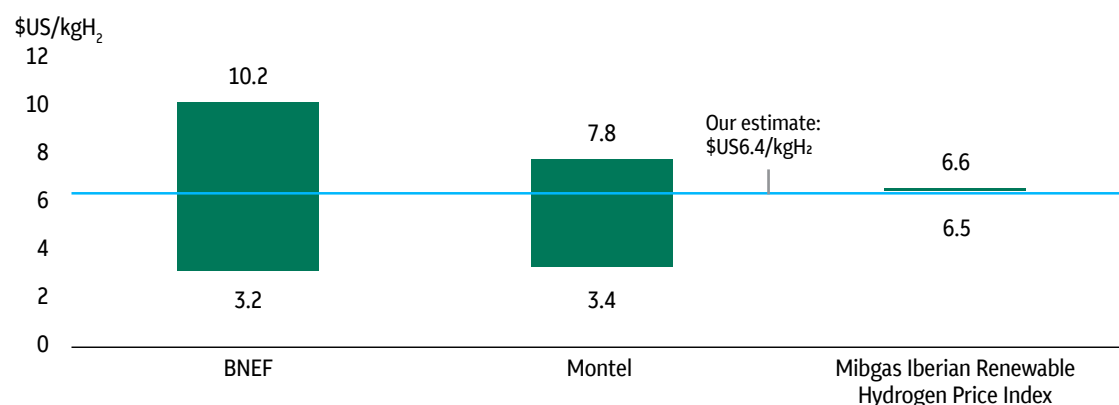
Figure 7:
Costs of green hydrogen by component (our model)



Source: Macquarie Asset Management analysis.

Our modelled cost aligns well with estimates from other sources. As Figure 8 below shows, our \$US6.4 per kg is in the middle of the ranges quoted by both BNEF (\$US3.2-10.2 per kg) and Montel²³ (\$US3.4-7.8 per kg). Moreover, it is very close to the \$US6.5-6.6 per kg of the Mibgas Iberian Renewable Hydrogen Price Index.²⁴ It is important to note that the LCOH does not account for transportation and storage expenses. These additional costs can meaningfully increase the cost of hydrogen for end users. For a detailed discussion, please refer to the hydrogen transportation and logistics section.

Figure 8:
Our modelled cost of green hydrogen aligns with the market



Source: BNEF, “Hydrogen Levelized Cost Outlook 2025”, 23 December 2024; Montel, “Hydrogen production cost trends 2025”, 13 February 2025; Mibgas Iberian renewable hydrogen price index; Macquarie Asset Management analysis. BNEF’s range represents the range of their modelled LCOHs for 2025. For Mibgas Iberian Renewable Hydrogen Price Index, the value represents the index average between 16 December 2024 (the index launch date) and 22 April 2025.

The electrolysis system: Scaling production will be key

The electrolyser used to produce green hydrogen comprises an electrolyser stack (the component in which electrolysis occurs) and other supporting units such as the power electronics, water pump, and gas separator. There are several types of stacks, but alkaline and proton exchange membrane (PEM) stacks are the main technologies used for commercial production of green hydrogen today. Alkaline electrolyzers are an established technology with a relatively low unit cost and long operational history; PEM electrolyzers have higher energy conversion efficiency and are better able to respond to variable loads, making it a potentially better option for projects based on intermittent renewable power supply not connected to the grid. Figure 9 provides a summary of the advantages and disadvantages of each.

23. Montel is a European energy and electricity market information provider.

24. Mibgas is the official operator of the regulated gas market in Spain and Portugal. The Mibgas Iberian renewable hydrogen price index reflects the levelised cost of producing EU-compliant renewable hydrogen in the Iberian Peninsula.

In addition to electrolyzers, a green hydrogen production plant requires ancillary facilities such as a cooling system, water supply, and potentially temporary hydrogen storage. Installing electrolyzers and ancillary facilities also incurs planning, construction and project management costs.

Figure 9:
Alkaline vs PEM electrolyser

	Alkaline electrolyser	PEM electrolyser
Advantages	• Lower cost due to the use of relatively inexpensive materials • Higher tolerance for impurities in the feedstock e.g. sulphur and CO₂. • Longer operational life (up to 80,000 hours)	• Higher energy conversion efficiency • Rapid response to power change • High purity hydrogen production • Compact design
Disadvantages	• Lower energy conversion efficiency • Slower response to power change,	• Higher cost due to the use of a platinum group metals-based catalyst • No long-term track record yet

Sources: Senza Hydrogen, “PEM Hydrogen Generator VS Alkaline Hydrogen Generator”, accessed May 2025; Hydrogen Insight, “Which type of electrolyser should you use? Alkaline, PEM, solid oxide or the latest tech?”, 5 July 2023; Macquarie Asset Management analysis.

The cost of a new green hydrogen production plant today varies across different markets and technologies. A recent electrolyser price survey shows that alkaline electrolysis systems produced and installed in China are the cheapest, costing \$US600 per kilowatt (kW) installed. This is about a quarter of the cost of systems in Europe and the US based on Western suppliers, where costs are in the range of \$US2,000-3,000 per kW of installed capacity for both alkaline and PEM electrolysis systems.²⁵

Deploying Chinese electrolyzers could reduce capex in the West. That said, Chinese electrolyzers are, on average, sold at a 33% price premium in Europe relative to in China, due to higher margin and extra costs associated with adjustments to Western health and safety requirements and materials (e.g. the grade of steel required for export and product certification).²⁶

In Europe where the installed cost in mid-scenario is roughly \$US2,500 per kW, switching to a Chinese electrolyser would reduce the capex by 19% or \$US475 per kW (Figure 10).²⁷ In our model of a 50 MW project, this translates into a LCOH reduction of \$US0.7 per kg, assuming that efficiency remains the same. However, these cost advantages are sometimes offset by concerns over overstated hydrogen yields, political sensitivities, and strategic technology considerations. These factors have made some Western hydrogen project developers cautious about using Chinese equipment.

25. BNEF, “Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech”, March 2024.
26. Hydrogen Insight, “Cheap Chinese hydrogen electrolyzers will not flood global markets or damage Western suppliers”, 12 December 2022.
27. BNEF, “Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech”, March 2024.

That said, China's significant electrolyser manufacturing overcapacity – driven by strong state support and domestic deployment targets – may increasingly translate into competitively priced exports. In certain jurisdictions, especially across Asia, this could spur growth in hydrogen supply backed by Chinese electrolysers.

Figure 10:
Chinese and Western alkaline electrolysers' cost breakdown, mid-scenario (\$US/kgH₂)

	China	Europe/US	Chinese equipment in Europe/US
Electrolyser	243	799	324
Ancillary facilities	151	750	750
EPC and other costs	206	951	951
Total	600	2,500	2,025

Source: BNEF, "Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech", March 2024. EPC refers to engineering, procurement, and construction.

Scaling up the volume of installed electrolyser capacity is key to meaningful cost reduction. Generally speaking in manufacturing, as accumulated production volume increases there is a learning effect resulting in cost reductions from process improvements, technological advancement, and economies of scale.²⁸ In mathematical terms, this learning rate is expressed as a unit cost reduction percentage resulting from each doubling of the accumulated volume. Based on historical data on electrolysis system costs, the overall learning rate of turnkey alkaline and PEM electrolysis installations is projected to be about 9% in a mid-scenario.²⁹ This estimation is arrived at by breaking electrolyser project costs into three components (stack and power supply; balance of plant; other project costs) and applying learning curve analysis to each of these components. The learning rate is a key variable in the likely cost evolution of green hydrogen and there is naturally plenty of uncertainty about what it is indeed likely to be, a point we take up later in this section.

28. Commonly known as the learning curve theory and in evidence in a range of industries.

29. TNO, "Projections of electrolyzer investment cost reduction through learning curve analysis", 20 January 2022.

Renewable electricity: A key determinant over the long run

Renewable electricity, mainly from wind and solar, is a major operational cost in the production of green hydrogen. Moreover, as the cost of electrolysis systems decrease over time as production scales, the cost of electricity will become an increasingly large, and therefore important, component of the LCOH.

Grid connection also has an impact on electricity cost. Plants only powered by wind or solar face intermittent power supply – they are unable to operate when the wind is not blowing and the sun is not shining. This in turn leads to intermittent hydrogen output, making it challenging for a plant to find offtakers among industrial users in the absence of a larger interconnected hydrogen delivery system, integrating dispatchable sources or significant storage volumes, as these users require stable hydrogen supply. The capacity factor is also generally lower in this set-up, which increases the capex contribution to LCOH. However, blending hydrogen into existing gas grids to act as an intermittent offtaker of last resort would help alleviate this issue whilst wider hydrogen transportation infrastructure is built.

The grid can serve as a backup power source to enable hydrogen production when there

is insufficient wind/solar power. Where electricity supply is not obtained from on-site generation or through a private wire, network use charges can add to the paid electricity cost and thereby to the LCOH. However, some countries, e.g. Germany, have recently moved to exempt grid fees for hydrogen production, which could lower this cost burden in the short to medium term. In addition, even when network use charges come at a cost, a grid connection offers potential advantages as well: Markets with a high renewable energy penetration intermittently saturate demand, resulting in electricity prices tending towards zero during these hours, resulting in opportunities to purchase electricity below the levelised cost of generation. Further, a grid connection provides access to all suppliers of electricity and thus the potential to operate the asset for longer hours, although limitations due to regulatory requirements for green hydrogen production coinciding with the time of generation of renewable energy are being introduced. Ultimately, the grid provides reliable stand-by power to maintain safe electrolyzers control, which would have to be procured in a more costly manner in an off-grid application. As green hydrogen demand scales, access to affordable renewable electricity may increasingly come under pressure from competing source of demand, such as data centres.

Cost of capital: Impacts at the margin

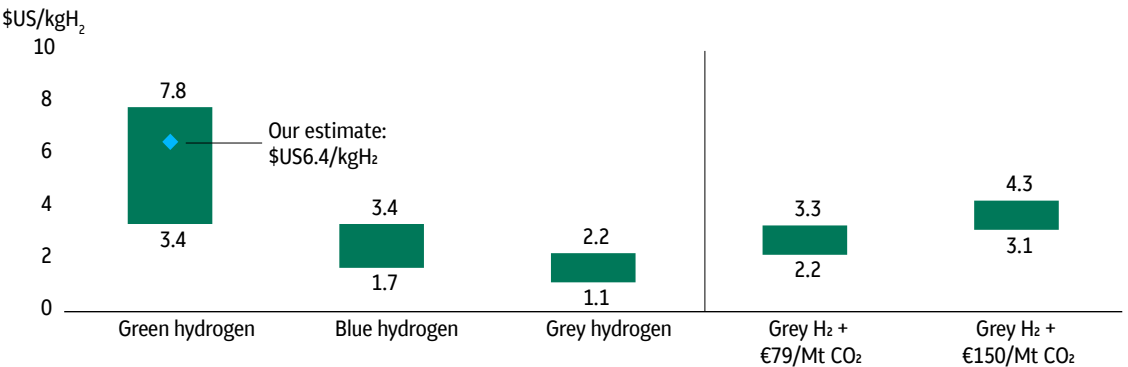
The cost of capital also plays a role in determining LCOH. Given commercial production of green hydrogen is relatively new, investors generally expect a higher return relative to more established lower risk technology like solar to compensate for higher project risks.³⁰ We assume a 9.6% weighted cost of capital (WACC) in our model. An increase or decrease in the WACC of three percentage points would translate into a LCOH change of about \$US0.3 per kg in our model.

The outlook for the price of hydrogen: Different technologies and the impact of carbon pricing

The interdependence of hydrogen demand and supply is clear – the demand for hydrogen is a function of its price, and the cost of production (and thus the price) is a function of the production volume, which is in turn influenced by the demand. In terms of assessing the outlook for pricing, demand, and the size of market opportunity, the challenge presented by this inherent circularity is eased somewhat by the fact that there is already existing demand for grey hydrogen of roughly 90 Mt.

With the world on a decarbonisation path, this hydrogen demand should, in time, be provided by green or blue hydrogen. This is helpful because it provides a base for analysing and thinking about the likely evolution of the hydrogen market. As discussed above, blue hydrogen is currently cheaper than green hydrogen, with grey hydrogen (without a carbon price) cheaper still. Figure 11 below shows our estimates of current market pricing, along with the impact of different carbon prices.

Figure 11:
Cost of hydrogen by type and impact of carbon price



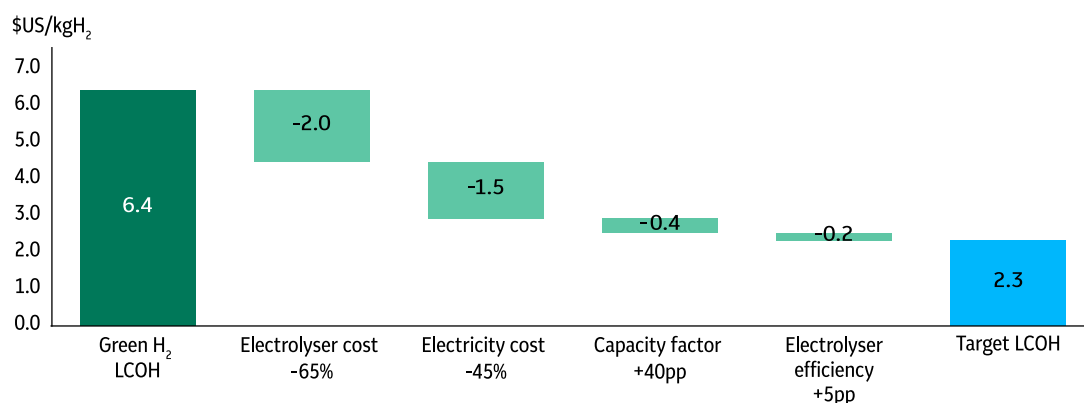
Source: Montel, “Hydrogen production cost trends 2025”, 13 February 2025; Macquarie Asset Management analysis.

30. International Renewable Energy Agency, “Green Hydrogen Cost Reduction Scaling up Electrolysers to Meet the 1.5C Climate Goal”, 2020.

Grey hydrogen production emits around 12 kg of CO₂ for each kilogram of hydrogen produced.³¹ This means that the current EU emission trading scheme carbon price of €79 per Mt would increase the cost of hydrogen by about \$US1 per kg. This is close to the level required to make blue hydrogen cheaper than grey, although a carbon price in the €100-150 range is likely to create a greater degree of confidence in this and increase the number of projects for which this applies.

Green hydrogen has the potential to be cheaper than both grey and blue hydrogen, however, and to unlock some applications (i.e. to be competitive with other alternatives) the price may have to drop to \$US2-2.5 per kg. Figure 12 below shows a bridge for how we can potentially reach this price level. In short, a 45% decline in the price of electricity combined with a roughly two-thirds decline in the per unit of cost of the electrolyser is enough to get to a price level that would unleash significant amounts of demand. The question is whether these declines can be achieved.

Figure 12:
Cost declines needed to reach \$US2-2.5 per kg



Source: Macquarie Asset Management analysis.

Fortunately, there are estimates for future electricity prices that we can use. Figures 13 and 14 on the next page show the BNEF projections for the levelised cost of electricity (LCOE) for wind and solar out to 2050. We have included storage as the need for that is likely to increase significantly over the time frame under consideration (the LCOE declines for solar and wind without storage are very similar, however). The average expected price decline across both technologies for all three countries is 43% by 2050. The largest declines by country are 43.4% in China (wind), 57.4% in the US (solar) and 42% in Germany (wind). While there is naturally uncertainty surrounding these projections (the ultimate price could turn out to be higher or lower), they suggest that a ~45% decline in the cost of electricity by 2050 is not an unreasonable working assumption.

31. IEA, "Global Hydrogen Review 2024", October 2024.

Figure 13:
LCOE for onshore wind with storage
by country

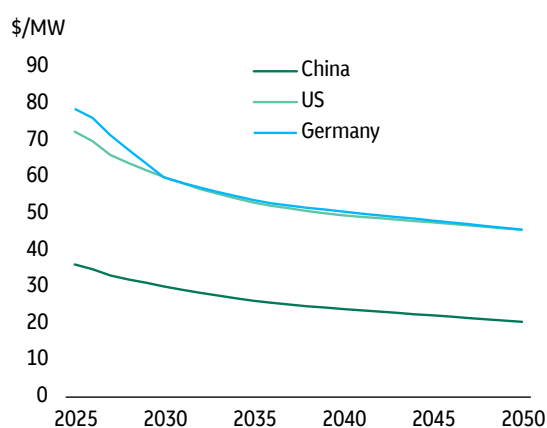
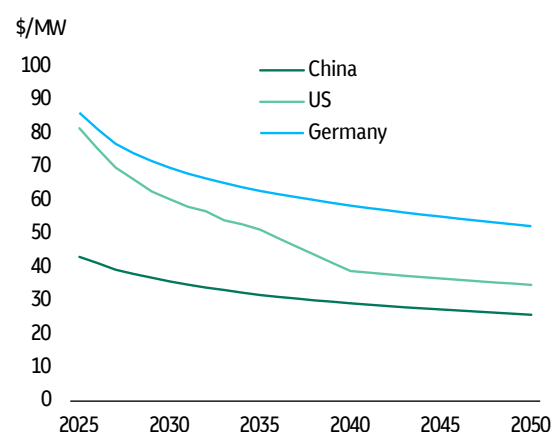


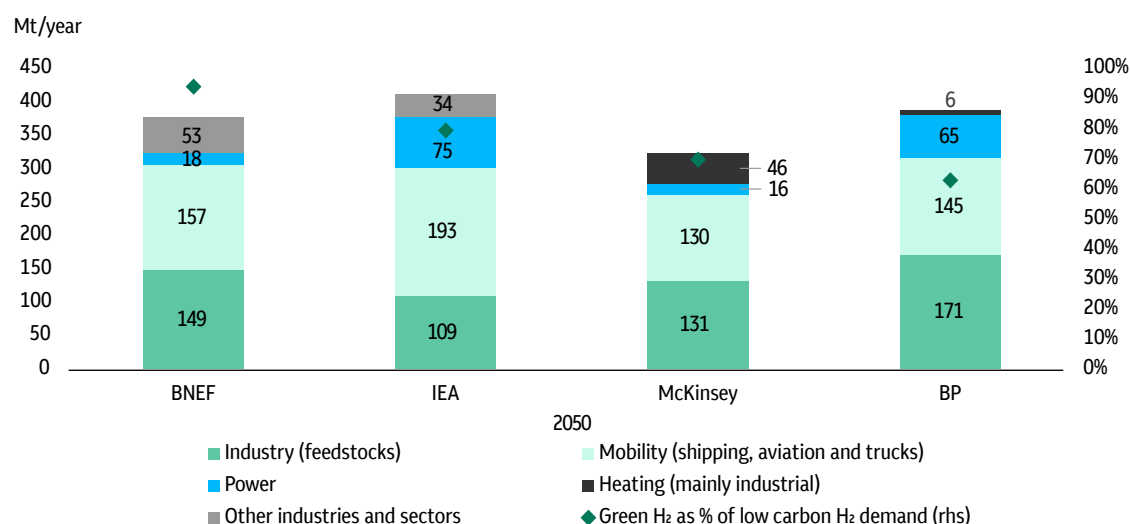
Figure 14:
LCOE for solar with storage
by country



Source: BNEF, March 2025.

However, to achieve \$US2-2.5 for hydrogen we would also need to see a roughly two-thirds decline in the per unit cost of electrolyzers. The trajectory of electrolyser cost will, in turn, depend on the volume of hydrogen demanded, so having an idea of the demand profile over the next 25 years is helpful in this regard. Figure 15 on the next page shows the demand expectations for a range of forecasters. While different forecasters may have different cost evolution assumptions, they all have quite similar estimates for demand for hydrogen in 2050, with the projections ranging from a low of 344 Mt to a high of 417 Mt.

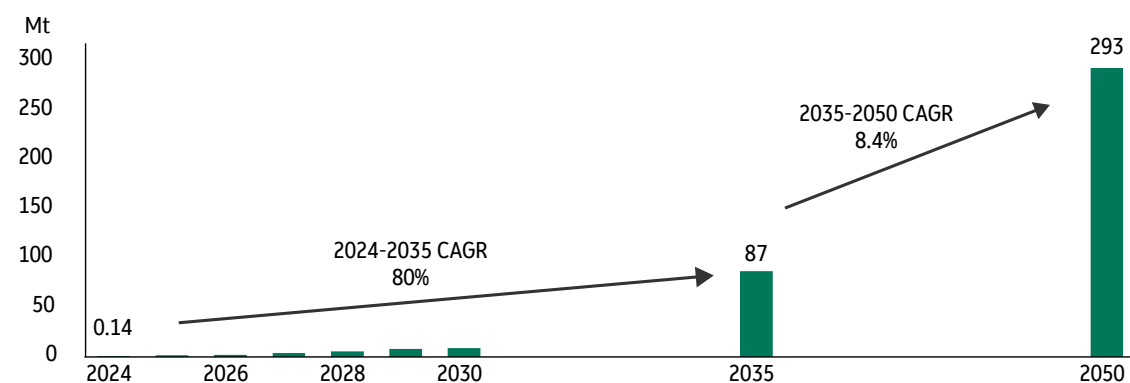
Figure 15:
Low carbon hydrogen demand in 2050 by forecaster



Sources: IEA, McKinsey, BP, BNEF, Macquarie Asset Management analysis.

The average of these forecasters is 385 Mt of demand for low carbon (blue and green) hydrogen, 76% (or 293 Mt) of which is expected to be green hydrogen. These forecasters also assume that by 2035 green hydrogen demand will be around 87 Mt. Figure 16 shows the trajectory and implied compound annual growth rates (CAGRs). The CAGR to 2035 is so large simply because the demand starting point is so low.

Figure 16:
Demand trajectory for green hydrogen (average of major forecasters)



Source: Macquarie Asset Management analysis. Average of demand forecasts by IEA, McKinsey, BP and BNEF.

Figure 17 below translates this demand profile into the electrolyser capacity needed to meet that demand, and applies the 9% learning rate discussed earlier to derive the implied cost in \$US per kW of the electrolyser. In all three cases (base case, China and West) the 9% learning rate implies a 65% drop in the cost of the electrolyser, which from Figure 17 is the decrease we roughly need to reach \$US2.0-2.5 per kg for green hydrogen.

Figure 17:
Green hydrogen demand and electrolyser cost evolution

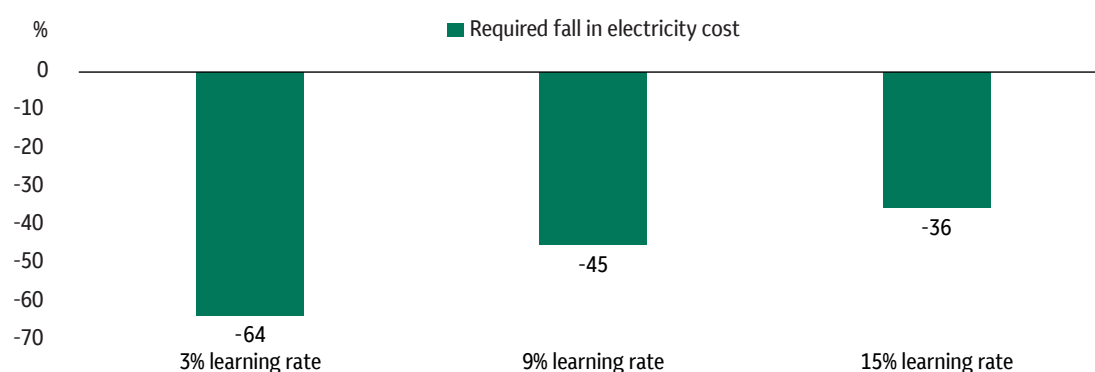
	Green H ₂ demand	Implied cumulative electrolyser capacity requirement	Modelled case	BNEF China	BNEF West
	Mt	MW	\$US/kW	\$US/kW	\$US/kW
2024	0.14	1,683	2,000	600	2,500
2035	87	1,073,000	837	251	1,046
2050	293	3,613,667	706	212	882

Source: Macquarie Asset Management analysis. The implied cumulative electrolyser capacity requirement is calculated based on the assumptions of 60% electrolyser efficiency and 4,500 full load hours per year. Higher electrolyser efficiency and/or full load hours will result in a lower capacity requirement.

It is, however, worth noting that there are many other considerations here:

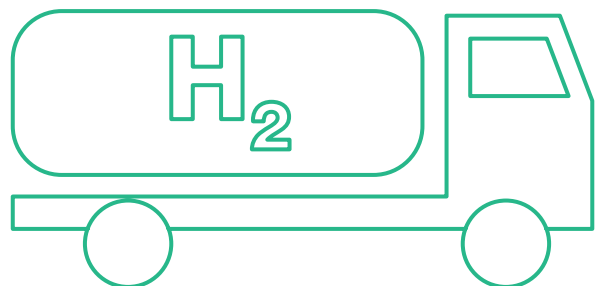
- The 9% learning rate for electrolyzers may or may not be realistic, and learning rate has a meaningful impact on electrolyser cost evaluation. In our model, a 3% learning rate will result in an electrolyser cost of \$US1,429 per kW in 2050, which is 102% higher than our base-case assumption. On the other hand, a 15% learning rate will result in an electrolyser cost of \$US332 per kW, which is 53% below our base case. This would also have implications for the electricity cost reduction required to achieve an LCOH of \$US2.3 (target LCOH in Figure 12), as shown in Figure 18. In case of a 3% learning rate, the cost of electricity would need to fall by 64% to achieve \$US2.3, while if the learning rate is 15% a small 36% reduction would be required. Two points are notable here:
 - There is a significant asymmetry in the sensitivity here, which is due to the multiplicative nature of these two variables' impact on LCOH.
 - Even in an optimistic learning rate scenario, a large fall (here 36%) in the cost of power is still required. In short, a significant decline in the cost of power is a necessary condition for cost-competitive green hydrogen.
- As the renewables buildout expands, there will be times of the day where the power price drops to very low levels (this is already occurring in places such as Germany, Spain and California). When power is virtually free, using it to produce green hydrogen can make a lot of economic sense. However, we think availability of mid-stream hydrogen infrastructure – especially large-scale hydrogen storage – is important for this to become a viable option. It is because most hydrogen offtakers require stable supply of hydrogen, meaning that storage will be needed to manage production variability.

Figure 18:
Required fall in electricity cost to achieve a \$US2.3 LCOH under different electrolyser learning rate assumptions



Source: Macquarie Asset Management analysis.

Hydrogen transportation and logistics: An underestimated barrier to adoption





The delivered cost of hydrogen depends on more than just production. Storage and transportation costs also play important roles in shaping the final price paid by end users, which can vary widely depending on infrastructure availability, logistical constraints, and hydrogen consumption patterns.

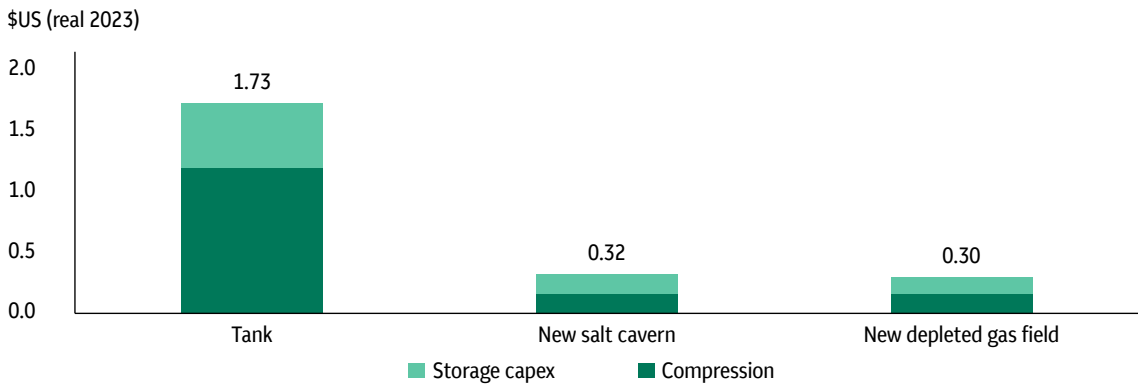
Hydrogen storage: Usage pattern determines the best solution

Hydrogen is typically stored as compressed gaseous hydrogen (CGH₂), which increases its volumetric energy density for efficient storage by compressing gaseous hydrogen which is produced at relatively low pressures (20-30 bar). High-pressure tanks and natural underground sites such as salt caverns and depleted gas fields are the main options for hydrogen storage in this form.

Salt caverns and depleted natural gas fields are significantly cheaper than tanks on a per-kilogram-of-hydrogen-stored basis (Figure 19). These natural underground sites are best for scenarios requiring long-duration or seasonal storage at a large volume, such as power systems that rely on hydrogen to buffer fluctuations in renewable output. However, the availability of these sites is limited by geology. They are also not suitable for users that require frequent access to storage, as pressure swings need to be limited to preserve the structural integrity of the sites, thereby limiting the cycle rates, i.e. the number of times the site can be filled and emptied in a year.³² Therefore, for users at industrial clusters where pipelines can supply hydrogen continuously and require only a small storage capacity, a fleet of on-site high pressure tanks often remains the preferable storage solution.

32. UK Department of Energy Security & Net Zero, "Hydrogen Transport and Storage Cost Report", December 2023.

Figure 19:
Storage cost of 1 kg of CGH₂ by technology



The chart above is based on the following assumptions:

	Tank	New salt cavern	New depleted gas field
Cycles/year	120	9	2
Pressure (Bar) ³³	700	250	250

Source: UK Department of Energy Security & Net Zero, “Hydrogen Transport and Storage Cost Report”, December 2023. Figures represent CGH₂ storage.

Hydrogen transportation: Pipelines needed for transport at scale

Just as important as storage is the method of transporting hydrogen. Several pathways exist, from tanker trucks to dedicated transmission pipelines. Trucking, typically carrying CGH₂, is suitable for lower volumes, allowing project developers to avoid the high capital costs of new pipeline systems. This model, however, quickly becomes expensive when scaled to larger volumes or stretched over long distances. Pipelines – either retrofitted from existing natural gas pipelines or built anew – offer the most cost-efficient option for large-scale hydrogen distribution in the long term (Figure 20).

33. Hydrogen is typically produced at relatively low pressures (20-30 bar) and require compression to increase its density for efficient storage and transportation. For high-pressure tank storage, it is typically compressed to 350-700 bar. For natural storage sites, the pressure is subject to geological constraints and typically no more than 300 bar.

Figure 20:
Hydrogen transportation options and cost ranges

	Trucks	Pipelines	Shipping
Most suitable for	Small volume (0-10 tonnes/day)	Mid-large volume (>10 tonnes/day)	Intercontinental, mid-large volume
Description	Hydrogen can be transported as CGH ₂ or liquid organic hydrogen carrier (LOHC) via truck. CGH ₂ is most suitable for short distance, and LOHC is most suitable for long distance.	Hydrogen is typically transported as CGH ₂ through pipelines. These pipelines can be specifically constructed for this purpose (new pipelines) or adapted from existing natural gas pipelines (repurposed pipelines).	Hydrogen can be transported in various forms, but the primary options currently being considered are ammonia and LOHC.
Price range (\$US/kg, real 2022)	0.65-0.76 (CGH ₂ , 1-10 km) 0.96-3.87 (LOHC, 100-1000 km)	<0.03 (Repurposed or new, 1-10 km) 0.04-0.32 (Repurposed, 100-1000 km) 0.73-5.14 (New, 100-1000 km)	>3 (Ammonia, >1000 km)

Source: BNEF, "Hydrogen: The Economics of Pipeline Transport", May 2022.

Germany's large scale Hydrogen Core Network plan is one of the major hydrogen pipeline projects in Europe.³⁴ It aims to connect the country's major industrial regions and facilitates hydrogen flows from production sites to end users. Spanning more than 9,000 kilometres, the system will comprise 60% repurposed pipelines and 40% new pipelines.³⁵ The network is currently planned to be built and become operational in phases between 2025 and 2032, at an estimated cost of €18.9 billion. That said, there are still some uncertainties around whether the timeline and cost estimates will be met. Of note, this network is critical for the RWE-TotalEnergies Green Hydrogen deal recently signed in March 2025. The deal involves a supply of 30,000 tonnes of hydrogen per year from RWE to TotalEnergies from 2030 until 2044, making it the largest volume of green hydrogen contracted with a producer in Germany.³⁶ The construction of a 600-kilometer new pipeline, which forms part of the network, will be necessary to enable hydrogen delivery from RWE's Lingen plant to TotalEnergies' Leuna refinery, which are on opposite sides of Germany.³⁷

34. Federal Ministry for Economic Affairs and Climate Action.

35. Bundesnetzagentur, "Bundesnetzagentur approves hydrogen core network", 22 October 2024.

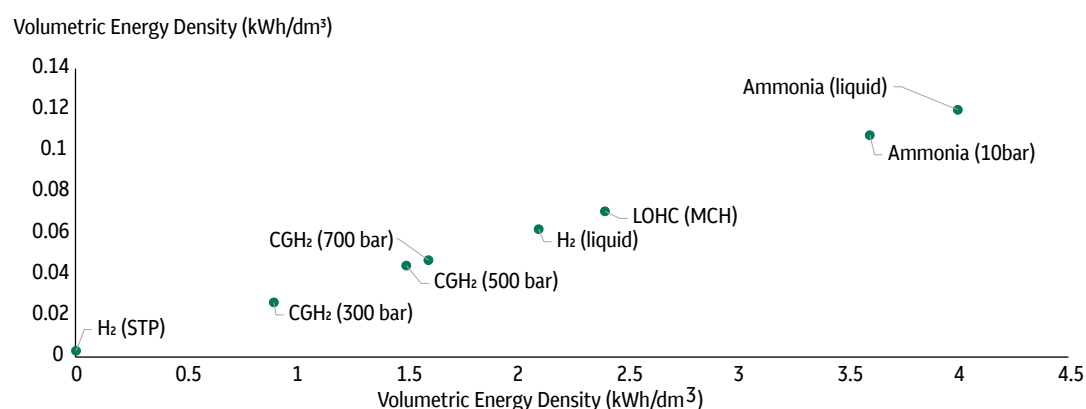
36. TotalEnergies, "Germany: TotalEnergies and RWE join forces on green hydrogen to decarbonize the Leuna refinery", 12 March 2025.

37. BNEF, "TotalEnergies-RWE Green Hydrogen Deal Shows Policy Is Key: React", 13 March 2025.

Hydrogen blending in existing natural gas networks also deserve attention as a transitional strategy. It allows partial decarbonisation without substantial new infrastructure. Blend ratios are typically capped at 20% due to pipeline material constraints and end-user appliance specifications, and the blended gas can be used for power generation or heating. However, this adaptation is not without challenges for industrial offtakers and power plants, as they require stable supply characteristics and must modify processes to accommodate the new blend, making it difficult to increase the blend ratio. Nonetheless, in some regions, this strategy is viewed as a viable stepping stone toward dedicated hydrogen transport networks.

For long distance intercontinental transportation, shipping is the main option. Shipping CGH_2 is unviable given its relatively low volumetric energy density (Figure 21). Instead, Ammonia is the main carrier of hydrogen considered for maritime transport because of its relatively high volumetric energy density as well as the existence of established ammonia trade, meaning that transport and storage of ammonia are well tested.³⁸ However, reconverting ammonia back into hydrogen incurs extra costs and consumes additional energy, introducing efficiency penalties. There are also concerns about emissions of nitrogen oxides (an air pollutant) from ammonia combustion. Therefore, ammonia is most suitable for use cases where its direct consumption is possible.³⁹ LOHCs are another alternative gaining momentum. These carriers chemically bind hydrogen to a stable organic liquid, making storage and transportation simpler under ambient conditions. Yet the dehydrogenation process requires energy input, an expense that must be weighed against the ease of handling and existing infrastructure compatibility. Ultimately, each global transport method has its pros, cons and cost considerations, influencing how the hydrogen supply chain might scale internationally.

Figure 21:
Energy density vs volumetric H_2 content of hydrogen forms



Source: UK Department of Energy Security & Net Zero, "Hydrogen Transport and Storage Cost Report", December 2023. H_2 (STP) is hydrogen at standard temperature and pressure are defined as 0°C (273K) and 1.013 bar, respectively. Methylcyclohexane (MCH) is a form of LOHC.

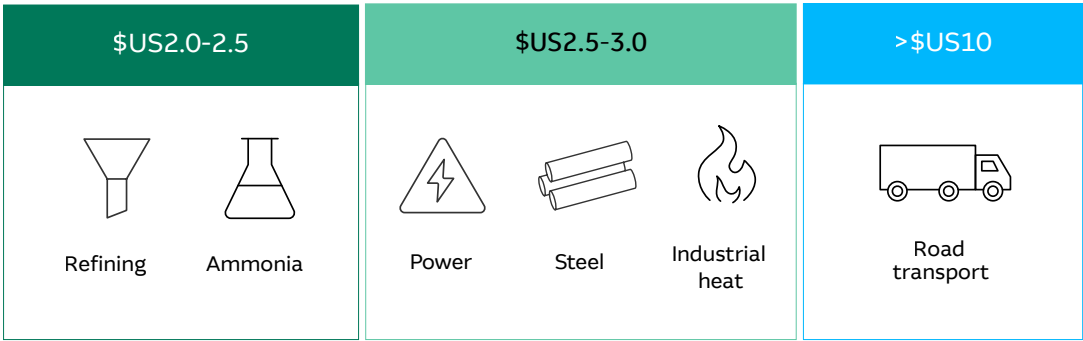
38. Drewry, "Ammonia shipborne trade: Navigating the bubble for sustainable growth", 19 March 2024.

39. Drewry, "Ammonia shipborne trade: Navigating the bubble for sustainable growth", 19 March 2024.

Storage and transportation dynamics can meaningfully alter total delivered hydrogen costs and are estimated to currently add anywhere from \$US2 to \$US10 to the delivered costs to end users today (Figure 22).⁴⁰ Industrial users that use hydrogen to refine oil or produce ammonia see some of the least expensive transport and storage costs, at roughly \$US2.0-2.5 per kg of hydrogen. Their advantage stems from relatively steady, high volume hydrogen demand combined with their need only for small capacity of storage with high utilisation rates.

Costs for the power sector, steelmaking and industrial heat users hover around \$US2.5-3.0 per kg of hydrogen, as the power sector needs a large volume of seasonal storage to align with renewable energy availability while steelmaking and cement making (industrial heat) have lower site-level demands and thus distribution rates. In contrast, sectors such as road transport face transport and storage prices at around \$US10 per kg of hydrogen, due to the dispersed nature of fuelling stations, the relatively low distribution volumes to individual stations, and the capital expenses tied to refuelling stations.⁴¹

Figure 22:
Average hydrogen transport and storage cost estimates by end-use sector



Source: Shafiee and Schrag, “Carbon abatement costs of green hydrogen across end-use sectors”, October 2024.

40. Shafiee and Schrag, “Carbon abatement costs of green hydrogen across end-use sectors”, October 2024. The estimates assume storage via salt cavern or compressed gas and transportation via truck and pipeline.
41. Shafiee and Schrag, “Carbon abatement costs of green hydrogen across end-use sectors”, October 2024.

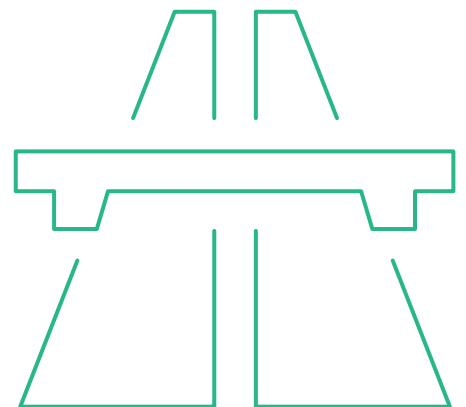
That said, transportation and storage costs can decrease significantly with increased scale and adoption. BNEF estimates that the cost of transporting hydrogen could be reduced by up to 30% when these options are implemented on a large scale. This reduction is driven by economies of scale, technological advancements, and efficiency improvements.⁴² Savings would come from lower conversion costs across all transport methods, a shift from container transport to large ships for shipping, and the use of higher-pressure tube trailers for trucks. Similarly, storage costs can also benefit from widespread adoption, with estimated savings ranging from 11% for pressurised tanks to 67% for rock caverns.⁴³

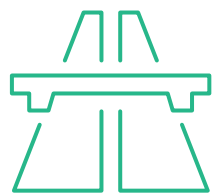
In summary, the true cost of hydrogen extends beyond production, encompassing storage requirements and transportation infrastructure that can make or break the business case for adoption. Different sectors face different cost realities, shaped by variables such as daily usage patterns, distance to production facilities and existing pipeline or port infrastructure. Large-scale pipeline investments can facilitate low-cost distribution, while more dispersed applications likely heavy-duty freight may face steeper costs. Meanwhile, technological innovations in shipping, specialised carriers like ammonia and LOHCs, and the promise of incremental solutions such as blending are expanding hydrogen's horizons.

42. BNEF, "Hydrogen: The Economics of Transport", 17 October 2019.

43. BNEF, "Hydrogen: The Economics of Storage", 10 July 2019.

Hydrogen policies: Driving scale and developing infrastructure is key





The global hydrogen market is evolving rapidly, driven by ambitious targets set by major economies (Figure 23). These targets, often aimed at 2030, seek to rapidly increase the production of renewable hydrogen. Substantial funding has been allocated to support the hydrogen industry, and a variety of incentive mechanisms such as production tax credits, subsidies, grants, and contracts-for-difference (CfD) programs are being utilised to stimulate

the market. Additionally, there is a growing recognition of the importance of demand-side incentives, with relevant policies being implemented in the EU, Japan, and South Korea. These policies particularly focus on decarbonising hard-to-abate sectors such as industry, transportation, and power generation, as exemplified by the EU's Renewable Energy Directive III and Japan's initiatives in hydrogen utilisation for power generation.

Figure 23:
Hydrogen production targets in selected markets

Country/bloc	Target
EU	40 gigawatts (GW) of electrolyser capacity and 10 Mt of green hydrogen production per year by 2030. It also aims to have 10 Mt of green hydrogen import by 2030
US	50 Mt of clean hydrogen per year by 2050, with interim targets of 10 Mt by 2030 and 20 Mt by 2040
UK	Low-carbon hydrogen production of 10 GW by 2030
China	100,000 to 200,000 tonnes/year of renewable hydrogen production by 2025
Japan	15 GW of electrolyzers installed by 2030 by Japanese companies globally
South Korea	1 Mt hydrogen (25% green and 75% blue) by 2030 and 5 Mt of hydrogen (60% green and 40% blue) by 2050
Australia	1 GW of electrolyser capacity for hydrogen production targeted for 2030

Sources: Economist Intelligence Unit (EIU), Baker McKenzie, European Parliament, Macquarie Asset Management analysis.

EU: The most advanced support regime

The EU has established one of the most comprehensive policy frameworks globally for promoting renewable hydrogen. The strategy, first outlined in July 2020, focuses on hard-to-abate sectors and aims to develop 40 GW of electrolyser capacity within the EU by 2030 and support an additional 40 GW in neighbouring countries. The EU's commitment has been further solidified by the REPowerEU Plan of 2022, which aims to produce 10 Mt of renewable hydrogen domestically by 2030 and import an additional 10 Mt of hydrogen and hydrogen derivatives. Of the total imports, 6 Mt would be hydrogen while 4 Mt would be ammonia, reflecting a pragmatic approach considering current infrastructure capabilities and transport logistics.

Funding to support these objectives is substantial. Between 2021 and 2027, the budget for hydrogen exceeds €200 billion (\$US228 billion) and since 2021 the EU had already disbursed about €7 billion (\$US8 billion) to support projects (Figure 24).

This includes subsidy auctions conducted by the European Hydrogen Bank (H₂ Bank), whereby renewable hydrogen producers bid for production subsidies offered as a fixed premium per kilogram of renewable hydrogen produced. The pilot auction in 2024 resulted in support for six projects with nearly €0.7 billion (\$US0.8 billion) to produce 1.51 Mt of renewable hydrogen over 10 years.⁴⁴ The second round, totalling €2 billion (including €1.2 billion (\$US1.4 billion) from EU funds and an additional €0.7 billion (\$US0.8 billion) from Spain, Lithuania, and Austria for their own projects), closed in February 2025.⁴⁵ Notably, the EU funding component of this second round received 61 bids totalling over €4.8 billion (\$US5.5 billion), four times the available budget.⁴⁶ Allocation result for this component was announced on 20 May 2025, with 15 winning bids receiving a combined €992 million (\$US1.1 billion) in EU funding.⁴⁷ A third, €1 billion (\$US1.1 billion) round will take place in 3Q 2025.⁴⁸

44. European Commission, "Winners of first EU-wide renewable hydrogen auction sign grant agreements, paving the way for new European production", 7 October 2024.

45. European Commission, "Joint press release by the Commission, Spain, Lithuania and Austria on the European Hydrogen Bank's 'Auctions-as-a-Service' scheme, increasing the funding for clean investments", 18 November 2024.

46. European Commission, "Over-subscribed European Hydrogen Bank auction receives 61 bids for Innovation Fund support, including 8 maritime projects", 7 March 2025.

47. European Commission, "Nearly €1 billion awarded to boost development of renewable hydrogen", 20 May 2025.

48. European Commission, "The Clean Industrial Deal: A joint roadmap for competitiveness and decarbonisation", 26 February 2025.

Figure 24:
Allocated budgets and granted amounts by European hydrogen-dedicated subsidy programmes

Funding programmes	Climate/clean tech dedicated budget relevant for H ₂ (€ billion)	Amount granted for H ₂ since 2021 (€ billion)
ETS Innovation Fund (2020-2030) (exclude H ₂ Bank)	37	2.8
European Hydrogen Bank (H ₂ Bank)	3	1.9
Horizon Europe (2021-2027) (exclude Clean Hydrogen Partnership)	32.4	0.5
Clean Hydrogen Partnership	1	0.7
Connecting Europe Facility-Energy (CEF-E) (2021-2027)	3.5	<0.1
Connecting Europe Facility-Transport (CEF-T) (2021-2027)	15.5	0.4
Programme for the Environment and Climate Action (LIFE) (2021-2027)	1.9	<0.1
AFIF -included in CEF-T (2021-2023)	1.5	0.2
Modernisation Fund	33.6	0.4
European Regional Development Fund	47.3	Unknown
Breakthrough Catalyst	0.4	Unknown
InvestEU	9.9	Unknown
Cohesion Fund	15.9	Unknown
Total	202.9	6.9

Sources: EY & Hyvolution, "European Hydrogen Index 2025", January 2025; Hydrogen Europe, "Clean Hydrogen Monitor 2024", November 2024.

National-level financial mechanisms further supplement EU-wide efforts. Germany exemplifies this through its €3 billion (\$US3.4 billion) state aid scheme to support the development of Hydrogen Core Network, a network of hydrogen pipelines currently under construction to facilitate long distance hydrogen transport.⁴⁹ Germany's recently announced €500 billion (\$US569 billion) infrastructure fund also includes €100 billion (\$US114 billion) for the Climate and Transformation Fund, which aims to support hydrogen infrastructure development among other things.

In addition to supply-side measures, the EU also stands out as one of the few markets that has acted to foster renewable hydrogen demand. To date, the EU has introduced a range of demand-side instruments, most notably the following:

- **Renewable Energy Directive III (RED III)** states that 42% of industrial hydrogen use must comply with RFNBO (Renewable Fuels of Non-Biological Origin) rules by 2030 and 60% by 2035.⁵⁰ RFNBO rules is a set of criteria that hydrogen must meet to qualify as renewable under EU law.
- **ReFuelEU Aviation Mandate** requires that from 2030 onwards, at least 1.2% of the fuel supplied at EU airports must be eSAFs. The proportion is set to increase to 35% in 2050.⁵¹

- **FuelEU Maritime regulation** sets annual greenhouse gas intensity reduction targets (versus 2020 baseline) for energy used on board ships, from 2% in 2025 to 80% in 2050.⁵² These targets push the sector toward low-carbon fuel options, many of which are hydrogen derivatives, e.g. renewable methanol and green ammonia.

In fact, in terms of volume, EU mandates account for 70% of the renewable hydrogen mandates set for 2030 globally (2.1 Mt out of 3 Mt).⁵³ One of the hydrogen deals enabled by these demand-side incentives is the RWE-TotalEnergies agreement recently signed in March 2025. While the capex subsidy from Germany helped to reduce RWE's hydrogen cost, the agreement's main enablers appear to be RED III quotas and Germany's policy of allowing emissions reductions from the use of green hydrogen to be triple-counted in its national greenhouse gas emissions reductions quota (known as the THG quotas). It is believed that these demand side incentives drove TotalEnergies to switch to green hydrogen from grey hydrogen, even though the cost of green hydrogen is about three times the cost of grey hydrogen today (Figure 25).⁵⁴

49. European Commission, "Commission approves €3 billion German State aid scheme to support the development of Hydrogen Core Network", 21 June 2024.

50. European Parliament Research Service, "EU rules for renewable hydrogen", April 2023.

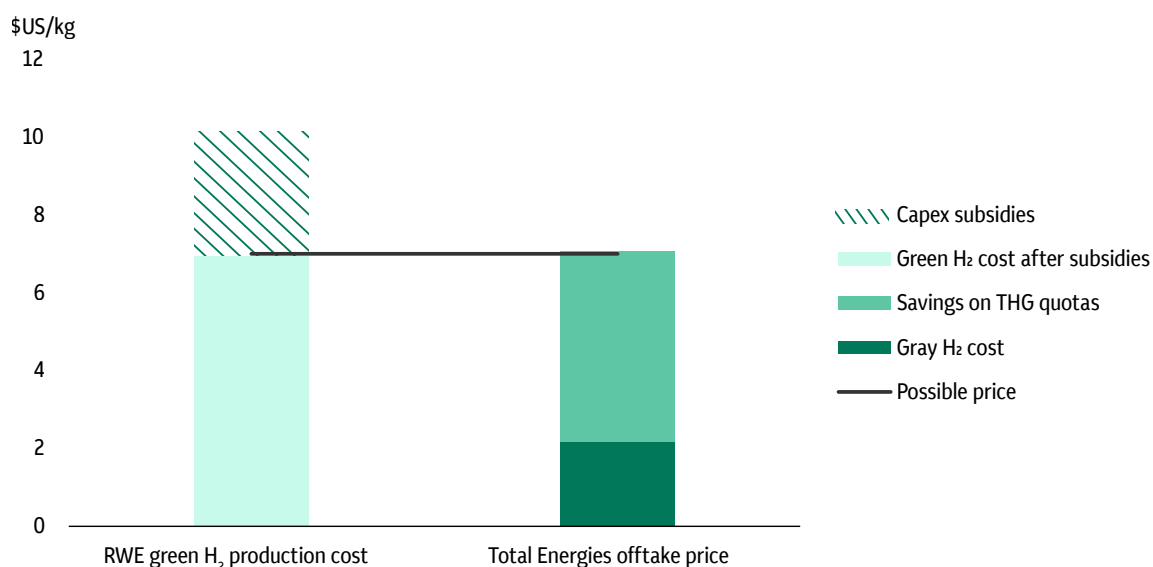
51. European Commission, "ReFuelEU Aviation".

52. European Hydrogen Observatory, "FuelEU Maritime", 28 June 2024.

53. BNEF, "1H 2025 Hydrogen Market Outlook", 7 April 2025.

54. BNEF, "TotalEnergies-RWE Green Hydrogen Deal Shows Policy Is Key: React", 13 March 2025.

Figure 25:
Illustrative prices under the RWE-TotalEnergies contract



Source: BNEF, "TotalEnergies-RWE Green Hydrogen Deal Shows Policy Is Key: React", 13 March 2025. Assumes RWE's subsidy covers 70% of project capex and a power price of \$US100 per megawatt-hour (MWh). THG quota price based on BNEF's assumption of €150 per tonne of CO₂.

US: Uncertainty hinders policy impact

The most notable hydrogen policies to date in the US are the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act, commonly known as the Bipartisan Infrastructure Law. The IRA aims to incentivise hydrogen production by providing a low-carbon hydrogen production credit of \$US0.6-3.0 per kg of hydrogen, depending on the carbon intensity of production.⁵⁵ In addition, the Bipartisan Infrastructure Law allocates \$US9.5 billion to hydrogen projects, comprising \$US8 billion for the creation of hydrogen hubs,⁵⁶ \$US1 billion for funding hydrogen electrolysis research, and \$US500 million for the development of clean hydrogen manufacturing and recycling technologies.⁵⁷

55. US Department of The Treasury, "U.S. Department of the Treasury, IRS Release Guidance on Hydrogen Production Credit to Drive American Innovation and Strengthen Energy Security", 22 December 2023.

56. US Department of Energy.

57. This includes up to \$US7 billion to establish six to 10 regional clean hydrogen hubs across America the Regional Clean Hydrogen Hubs Program (H₂Hubs).

However, while the IRA was signed into law in August 2022, the guidelines surrounding how to qualify for the credits were not published until 3 January 2025.⁵⁸ Although the final rules were less stringent than the earlier draft, many stakeholders viewed the delay as a missed opportunity.⁵⁹ With lingering uncertainty around how the Trump administration will approach tariffs, IRA tax credits, and broader energy policy, many developers have opted to pause or shelve US hydrogen projects until the policy environment stabilises.

UK: Pioneer of the hydrogen subsidy auction

The UK has a near-term target of having 1 GW of electrolyser capacity in construction or operation by the end of this year, and a medium-term target to have 10 GW of low carbon hydrogen production capacity – with at least half of them for green hydrogen – by 2030.⁶⁰

The Hydrogen Allocation Round is the main hydrogen funding mechanism in the UK. Subsidies are awarded via auctions and paid under a CfD-style scheme, whereby the amount of subsidy fluctuates depending on the natural gas price.⁶¹ Notably, subsidies are only paid once projects start producing hydrogen. To date, two rounds of auctions have taken place:

- The first Hydrogen Allocation Round (HAR1), also the first ever national green hydrogen subsidy auction in the world, was launched in July 2022 with results announced in December 2023. In this round, 11 projects to develop 125 MW of electrolyser capacity across the UK were selected to receive a strike price of £241 per MWh over a period of 15 years, which translates into an effective strike price of £9.49 (\$US12.64) per kg of green hydrogen.
- The second Hydrogen Allocation Round (HAR2) for up to 875 MW of electrolyser capacity was announced in December 2023. In April 2025, the government announced a shortlist of 27 projects with a combined green hydrogen production capacity of 765 MW.⁶²

Another major funding mechanism is the Net Zero Hydrogen Fund, a separate £240 million (\$US320 million) fund. Unlike HAR1 and HAR2, the fund is for the development of green hydrogen projects, i.e. before projects become operational. More than £90 million (\$US120 million) has been channelled to support the construction of HAR1 projects.⁶³

58. US Department of The Treasury, “U.S. Department of the Treasury Releases Final Rules for Clean Hydrogen Production Tax Credit”, 3 January 2025.

59. BNEF, “New Hydrogen Tax Credit Guidelines May Run Into Trump Wall”, 10 January 2025.

60. UK Department for Energy Security & Net Zero, “Hydrogen production delivery roadmap”, 14 December 2023.

61. Hydrogen Insight, “UK allocates more than £2bn of subsidies to 11 green hydrogen projects in first auction round”, 14 December 2023.

62. UK Department for Energy Security & Net Zero, “Hydrogen Allocation Round 2 (closed to applications)”, 7 April 2025; Hydrogen Insight, “UK’s shortlist for second round of green hydrogen subsidies falls short of 875MW cap, putting 1GW target for 2025 at risk”, 8 April 2025.

63. UK Department for Energy Security & Net Zero, “Hydrogen Production Business Model / Net Zero Hydrogen Fund: HAR1 successful projects (published December 2023)”, 13 December 2023.

China: Limited policy incentives but still leading in terms of production capacity

China is the largest producer of hydrogen in the world, accounting for about 30% of global hydrogen production. Most of the Chinese hydrogen production is still from unabated coal gasification today.⁶⁴ That said, in the Mid-and-Long-Term Hydrogen Industrial Development Plan 2021–2035 published in 2022, the government calls hydrogen ‘a core component’ of China’s future energy system and set a target to produce 100,000–200,000 tonnes of annual green hydrogen production capacity by the end of 2025.⁶⁵

Despite having an ambitious hydrogen roadmap,⁶⁶ China has actually offered limited subsidies thus far: In 2023, the central government launched a grant scheme to subsidise green hydrogen projects, covering 15% of capex capped at CNY300 million (\$US41 million) per qualified project.⁶⁷ There is also a subsidy program to encourage the adoption of FCVs in selected cities that provides annual subsidies of up to CNY1.7 billion (\$US230 million).⁶⁸

Government targets, together with relatively low electrolyser cost in China, appear to have motivated large state-owned enterprises (SOEs) to build green hydrogen projects. While direct subsidies remain limited, the active role of SOEs signals strong alignment with national strategic goals. In 2023, China accounted for 80% of the global electrolyser capacity that started operation.⁶⁹ This reflects a broader pattern seen in other clean technology sectors such as solar, batteries, and EVs, where coordinated government support – rather than upfront subsidies – catalysed rapid domestic deployment and global competitiveness. However, a lot of these projects started before securing offtake, with only a handful of China’s large-scale projects under construction securing significant (>80%) offtake coverage.⁷⁰ This raises concerns about project profitability and highlights the potential need for further policy intervention to stimulate end-user demand for green hydrogen.

64. IEA, “Global Hydrogen Review 2024”, October 2024.

65. National Development and Reform Commission (NDRC), China, “The Mid-and-Long-Term Hydrogen Industrial Development Plan (2021–2035) (氢能产业发展中长期规划 (2021–2035年))”, 2022.

66. IEA, “Global Hydrogen Review 2024”, October 2024.

67. BNEF, “China Hydrogen Subsidies Too Small to Have Major Impact”, 11 September 2023.

68. Center for Strategic & International Studies, “China’s Hydrogen Industrial Strategy”, 3 February 2022.

69. IEA, “Global Hydrogen Review 2024”, October 2024.

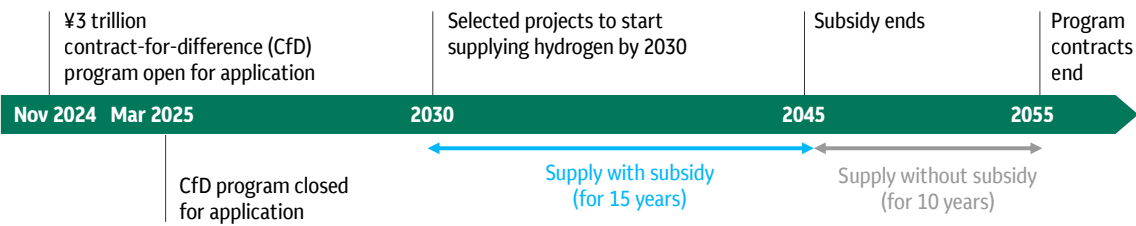
70. S&P Global, “Chinese plans to boost low carbon hydrogen offers few surprises”, 6 January 2025.

Japan: Large subsidy program recently introduced to speed up hydrogen adoption

Japan’s Basic Hydrogen Strategy, updated in 2023, plans to achieve an annual domestic hydrogen consumption of 3 Mt by 2030, 12 Mt by 2040, and 20 Mt by 2050.⁷¹ To achieve these targets, Japan plans to invest a total of ¥15 trillion (\$US104 billion) from the public and private sectors in building a hydrogen supply chain over a period of 15 years. Japan also has specific targets on FCVs, aiming to have 800,000 FCVs and 1,000 refuelling stations by 2030.⁷² A maximum of ¥2.55 million (\$US17,713) is currently available per FCV.⁷³

More recently, Japan passed the Hydrogen Society Promotion Act in May 2024.⁷⁴ The legislation has enabled a ¥3 trillion (\$US90 billion) CfD program to close the price gap between fossil fuels and hydrogen, both domestically produced and imported.⁷⁵ Under the program, the government will pay the difference between a fluctuating fossil fuel-linked ‘reference price’ and a guaranteed ‘base price’ (strike price) for each kilogram produced.⁷⁶ To be eligible, suppliers must include an offtaker from hard-to-abate sectors like industry and transport in their plans. Proposals focusing solely on power generation are ineligible, but hydrogen use in power, such as ammonia co-firing with coal, can receive subsidies when combined with plans for other sectors. Contract winners, which will be selected from a tender closed recently in March 2025,⁷⁷ will be offered 25-year contracts, with subsidies provided for the first 15 years (Figure 26). They must begin supplying hydrogen by 2030.

Figure 26:
Timeline of Japan’s Contract for Difference program



Source: BNEF, “Japan’s \$19B Hydrogen Subsidy Boon for Industry, Transport”, 4 December 2024.

71. The Ministerial Council on Renewable Energy, Hydrogen and Related Issues, Japan, “Basic Hydrogen Strategy”, 6 June 2023.
72. <https://www.mfat.govt.nz/en/trade/mfat-market-reports/japan-hydrogen-strategy-november-2023>.
73. Japan Next Generation Vehicle Promotion Center, “銘柄ごとの補助金交付(Subsidy Allocation By Type)”, 28 March 2025.
74. White & Case, “Japan’s Hydrogen Society Promotion Act comes into effect”, 30 October 2024; Nishimura & Asahi, “Key Points of the Japanese CfD for Low-carbon Hydrogen”, 8 October 2024.
75. Agency for Natural Resources and Energy, Japan, “Hydrogen Society Promotion Act Enacted Toward a Forthcoming Hydrogen-based Society Part 2: Utilization of Clean Hydrogen”, 10 September 2024.
76. Hydrogen Insight, “Japan invites first applications for clean hydrogen CfDs under giant \$20bn tender scheme”, 3 December 2024.
77. Agency for Natural Resources and Energy, Japan.

South Korea: Focus on hydrogen co-firing and hydrogen vehicles

South Korea is one of the few markets that has policy incentives already in place to stimulate hydrogen demand. As part of South Korea's Clean Hydrogen Portfolio Standard (CHPS), Korea Power Exchange (KPX) conducts hydrogen power auctions with a CfD mechanism to procure electricity produced from hydrogen and those generated by co-firing hydrogen or ammonia with natural gas or coal.⁷⁸ The first round of clean hydrogen power auction, which tendered 15-year contracts starting from 2028, was concluded in December 2024 with Korea Southern Power selected to produce 750 gigawatt-hours (GWh) of ammonia-coal co-fired electricity with blue ammonia sourced from Western Australia.⁷⁹ The South Korean government is expected to conduct more rounds of auctions to reach its target of 13 terawatt-hours (TWh) of capacity by 2030.

The South Korean government is also targeting a transport network fuelled by hydrogen and is offering a range of subsidies: the government has offered subsidies to hydrogen-powered vehicle purchases, with KRW721.8 billion (\$US0.5 billion) in subsidies available this year for 11,000 cars and 2,000 buses.⁸⁰ In addition, in May 2024, South Korea's Ministry of Environment announced KRW8.2 billion (\$US5.7 million) worth of subsidies to 152 hydrogen refuelling station operators to help lowering the cost of purchasing hydrogen.⁸¹ Furthermore, South Korea offers hydrogen fuel subsidies for operators of hydrogen fuel cell-powered buses, with the amount recently increased to KRW5,000 (\$US3.47) per kg since March 2025. The government expects this to cut hydrogen fuel costs by 22% and make hydrogen buses cost competitive.⁸²

Australia: More subsidies are coming

Given its location, Australia is anticipated to become a key player in low-carbon hydrogen generation. Through the first round of the Hydrogen Headstart program, the Australian federal government has provided \$A2 billion (\$US1.28 billion) in revenue support for large-scale renewable hydrogen projects through competitive hydrogen production contracts. In the 2024-25 Federal Budget, the federal government announced the second round of the program, which provides an additional \$A2 billion (\$US1.28 billion) in funding.⁸³ The government further committed to providing an \$A2 (\$US1.28) incentive per kg of renewable hydrogen produced for up to 10 years from 2027 to 2040, for projects that reach final investment decision by 2030.⁸⁴

In addition, Australia and Germany signed a historic green hydrogen importing deal in September 2024. Under this agreement, H2Global, Germany's hydrogen importing mechanism, will hold a special \$A660 million (\$US422 million) auction exclusively for green hydrogen imports from Australia.⁸⁵ H2Global, using a CfD approach, will purchase green hydrogen from the lowest-price Australian bidders and sell it to the highest bidders in Europe.

78. Hydrogen Insight, "South Korea launches world's first auction for clean-hydrogen power generation", 24 May 2024.

79. Ammonia Energy Association, "Korea Southern Power selected as final bidder in national clean power auction", 16 December 2024.

80. Chosun Biz, "Korea offers subsidies for hydrogen cars and buses in 2025", 1 January 2025.

81. Hydrogen Insight, "South Korea hands out billions of won in hydrogen fuel subsidies to support struggling refuelling station owners", 1 May 2024.

82. Hydrogen Insight, "South Korea slashes fuel costs for hydrogen buses by 22% with huge subsidy increase", 24 February 2025.

83. Department of Climate Change, Energy, the Environment and Water, Australia.

84. Australian Taxation Office, "Critical Minerals and Hydrogen Production Tax Incentives", 12 March 2025.

85. The Hon Chris Bowen, Minister for Climate Change and Energy and The Hon Robert Habeck, German Vice Chancellor and Minister for Economic Affairs and Climate Action, "Joint media release: \$660m to advance Australia and Germany's cooperation on energy and climate", 13 September 2024.

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