Hydrogen Council

McKinsey & Company

Hydrogen Insights

A perspective on hydrogen investment, market development and cost competitiveness

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Executive summary

Hydrogen is gathering strong momentum as a key energy transition pillar

Underpinned by a global shift of regulators, investors, and consumers toward decarbonization, hydrogen (H_2) is receiving unprecedented interest and investments. At the beginning of 2021, over 30 countries have released hydrogen roadmaps, the industry has announced more than 200 hydrogen projects and ambitious investment plans, and governments worldwide have committed more than USD 70 billion in public funding. This momentum exists along the entire value chain and is accelerating cost reductions for hydrogen production, transmission, distribution, retail, and end applications.

Similarly, having grown from 60 to over 100 members since 2020, the Hydrogen Council now represents more than 6.6 trillion in market capitalization and more than 6.5 million employees globally.

This report provides an overview of these developments in the hydrogen ecosystem. It tracks deployments of hydrogen solutions, associated investments and the cost competitiveness of hydrogen technologies and end applications. Developed collaboratively by the Hydrogen Council and McKinsey & Company, it offers a fact-based, holistic, quantitative perspective based on real industry data. Along with the report, the Hydrogen Council is launching Hydrogen Insights - a subscription service that provides granular insights and data about the hydrogen ecosystem and its development.

Deployment and investments: Announced hydrogen investments have accelerated rapidly in response to government commitments to deep decarbonization

More than 200 hydrogen projects now exist across the value chain, with 85% of global projects originating in Europe, Asia, and Australia, and activity in the Americas, the Middle East and North Africa accelerating as well.

If all projects come to fruition, total investments will exceed USD 300 billion in hydrogen spending through 2030 – the equivalent of 1.4% of global energy funding. However, only USD 80 billion of this investment can currently be considered “mature,” meaning that the investment is either in a planning stage, has passed a final investment decision (FID), or is associated with a project under construction, already commissioned or operational.

On a company level, members in the Hydrogen Council are planning a sixfold increase in their total hydrogen investments through 2025 and a 16-fold increase through 2030. They plan to direct most of this investment toward capital expenditures (capex), followed by spending on merger and acquisition (M&A) and research and development (R&D) activities.

The global shift toward decarbonization backed by government financial support and regulation is supporting this momentum. For instance, 75 countries representing over half the world’s GDP have net zero carbon ambitions and more than 30 have hydrogen-specific strategies. Governments have already pledged more than USD 70 billion and included new capacity targets and sector level regulation to support these hydrogen initiatives. For example, the EU has announced a 40-gigawatt (GW) electrolyzer capacity target for 2030 (up from less than 0.1 GW today) and more than 20 countries have announced sales bans on internal combustion engine (ICE) vehicles before 2035. In the US, where federal emission standards for new vehicles have lagged behind those in the EU, state-level initiatives in California and 15 other states have set ambitious targets to transition not only passenger cars but also trucks to zero-emission status by 2035. In China, the 2021-24 fuel cell support program will see the equivalent of USD 5 billion spent on fuel cell vehicle deployment, with a strong emphasis on the development of local supply chains.

Supply: If scaled up with the right regulatory framework, clean hydrogen costs can fall faster than expected

With the advent of hydrogen giga-scale projects, hydrogen production costs can continue to fall. For renewable hydrogen, the biggest driver is a quicker decline in renewables costs than previously expected, driven by at-scale deployment and low financing costs. 2030 renewable costs could be as much as 15% lower than estimated just a year ago. The strongest reductions are expected in locations with optimal resources such as Australia, Chile, North Africa and the Middle East.

But lower renewable costs are not enough: for low-cost clean hydrogen production, value chains for electrolysis and carbon management need to be scaled up. This will not happen on its own: a further step-up of public support is required to bridge the cost gap, develop low-cost renewable capacities and scale-up carbon transportation and storage sites. For the cost projections in this report, we assume an ambitious development of the use of hydrogen in line with the Hydrogen Council vision. For electrolysis, for example, we assume 90 GW deployment by 2030.

Such a scale-up will lead to a rapid industrialization of the electrolyzer value chain. The industry has already announced electrolyzer capacity increases to over approximately 3 GW per year, and will need to scale rapidly beyond that. This scaling can translate into system costs falling faster than previously estimated, hitting USD 480-620 per kilowatt (kW) by 2025 and USD 230-380 per KW by 2030. System costs include stack and balance of plant but exclude transportation, installation and assembly, costs of building and any indirect costs.

At-scale deployment of renewable hydrogen will require the development of giga-scale hydrogen production projects. Such projects with purpose-built renewables can boost utilization by merging multiple renewable sources, such as a combined supply from onshore wind and solar photovoltaics (PV), and by overbuilding renewables supply versus electrolyzer capacity.

In combination, projections show that renewable hydrogen production costs could decline to USD 1.4 to 2.3 per kilogram (kg) by 2030 (the range results from differences between optimal and average regions).[1] This means new renewable and gray hydrogen supply could hit cost parity in the best regions by 2028, and between 2032 and 2034 in average regions.

In parallel to renewable hydrogen production, low-carbon hydrogen production from natural gas has continued to evolve technologically. With higher CO_2 capture rates and lower capex requirements, low-carbon hydrogen production is a strong complementary production pathway. If carbon transportation and storage sites are developed at scale, low-carbon hydrogen could break even with gray hydrogen by the end of the decade at a cost of about USD 35-50 per ton (t) of carbon dioxide equivalent (CO_2e)[1].

Distribution: Cost-efficient transmission and distribution required to unlock hydrogen applications

With hydrogen production costs falling, transmission and distribution costs are the next frontier when it comes to reducing delivered hydrogen costs. Longer-term, a hydrogen pipeline network offers the most cost-efficient means of distribution. For example, pipelines can transmit 10 times the energy at one-eighth the costs associated with electricity transmission lines and have capex costs similar to those for natural gas. The industry can partially reuse existing gas infrastructure, but even newly constructed pipelines would not be cost prohibitive (assuming leakage and other safety risks are properly addressed). For example, we estimate the cost to transport hydrogen from North Africa

1 These costs reflect pure production costs and assume a dedicated renewable and electrolysis system for renewable hydrogen. They do not include costs required for baseload supply of hydrogen (e.g., storage and buffers), costs for redundancies, services and margins; they also do not include any cost for hydrogen transportation and distribution.

to central Germany via pipeline could amount to about USD 0.5 per kg of H_2 – less than the cost difference of domestic renewable hydrogen production in these two regions.

In the short- to medium-term, the most competitive setup for large-scale clean hydrogen applications involves co-locating hydrogen production on- or near-site. The industry can then use this scaled production to supply the fuel to other hydrogen users in the vicinity, such as refueling stations for trucks and trains, and smaller industrial users. Trucking the fuel to such users typically offers the most competitive form of distribution, with costs below USD 1 per kg of H_2.

For longer-distance transport by ship, hydrogen needs to be converted to increase its energy density. While several potential hydrogen carrier approaches exist, three carbon-neutral carriers – liquid hydrogen (LH_2), liquid organic hydrogen carriers (LOHC) and ammonia (NH_3) – are gaining most traction.[2] The cost-optimal solution depends on the targeted end-use, with deciding factors including central versus distributed fueling, the need for reconversion, and purity requirements.

At-scale, international distribution could arrive by 2030 at total costs of USD 2-3/kg (excluding cost of production), with the lion´s share of costs needed for conversion and reconversion. For example, if the targeted end application is ammonia, shipping costs add only USD 0.3-0.5/kg to the total cost. If the targeted end application is for liquid hydrogen or hydrogen with a high purity requirement, shipping as liquid hydrogen might add only USD 1.0-1.2/kg, with additional benefits for further distribution from port. These cost levels would enable global trade in hydrogen, connecting future major demand centers such as Japan, South Korea, and the EU to regions of abundant low-cost hydrogen production means like the Middle East and North Africa (MENA), South America or Australia. Like hydrogen production, carriers need substantial initial investments, and the right regulatory framework to bridge the cost delta in the first decade.

End applications: Falling clean hydrogen costs and application-specific cost drivers improve the cost competitiveness of hydrogen applications

From a total cost of ownership (TCO) perspective (including hydrogen production, distribution and retail costs) hydrogen can be the most competitive low-carbon solution for 22 end applications, including long haul trucking, shipping and steel. However, pure TCO is not the only driver of application adoption: future expectations on environmental regulations, demands from customers and associated "green premiums," as well as the lower cost of capital for ESG-compliant investments will all influence investment and purchase decisions.

In industry, lower hydrogen production and distribution costs are particularly important for cost competitiveness as they represent a large share of total costs. Refining is expected to switch to low-carbon hydrogen over the next decade. For fertilizer production, green ammonia produced with optimized renewables should be cost competitive by 2030 against gray ammonia produced in Europe at a cost of less than USD 50 per ton of CO_2e. Steel, one of the largest industrial CO_2 emitters, could become one of the least-cost decarbonization applications. With an optimized setup using scrap and hydrogen-based direct reduced iron (DRI), green steel could cost as little as USD 515 ton of crude steel, or a premium of USD 45 per ton of CO_2e by 2030.

In transport, lower hydrogen supply costs will make most road transportation segments competitive with conventional options by 2030 without a carbon cost. While battery technology has advanced rapidly, fuel cell electric vehicles (FCEVs) are emerging as a complementary solution, in particular for heavy-duty trucks and long-range segments. In heavy-duty long-haul transport, the FCEV option can achieve breakeven with diesel in 2028 if hydrogen can be made available for USD 4.5 per kg at the

[2] Synthetic methane produced from biogenic or air-captured CO_2 represents a potential fourth candidate to be studied further.

pump (including hydrogen production, distribution and refueling station costs). Furthermore, hydrogen combustion (H_2 ICE) offers a viable alternative in segments with very high power and uptime requirements, including heavy mining trucks.

Hydrogen is likewise advancing in trains, shipping, and aviation. Clean ammonia as a shipping fuel will be the most cost-efficient way to decarbonize container shipping by 2030, breaking even with heavy fuel oil (HFO) at a cost of about USD 85 per ton of CO_2e.[3] Aviation can achieve competitive decarbonization via hydrogen and hydrogen-based fuels. The aviation industry can decarbonize short- to medium-range aircrafts most competitively through LH_2 directly, at a cost of USD 90-150 per ton of CO_2e. Long-range aircrafts can be decarbonized most competitively using synfuels, at a cost of about USD 200-250 per ton of CO_2e, depending on the CO_2 feedstock chosen.

Other end-applications such as buildings and power will require a higher carbon cost to become cost competitive. However, as large-scale and long-term solutions to decarbonize the gas grid, they will still see strong momentum. In the United Kingdom, for example, multiple landmark projects are piloting the blending of hydrogen into natural gas grids for residential heating. Hydrogen as a backup power solution, especially for high power applications like data centers, is also gaining traction.

Implementation: Capturing the promise of hydrogen

Strong government commitment to deep decarbonization, backed by financial support, regulation and clear hydrogen strategies and targets, has triggered unprecedented momentum in the hydrogen industry. This momentum now needs to be sustained and the long-term regulatory framework set.

These ambitious strategies must now be translated into concrete measures. Governments, with input from businesses and investors, should set sector-level strategies (e.g., for the decarbonization of steel) with long-term targets, short-term milestones, and the necessary regulatory framework to enable the transition. The industry must set up value chains for equipment, scale up manufacturing, attract talent, build capabilities, and accelerate product and solution development. This scale up will require capital, and investors will play an outsized role in developing and pushing at-scale operations. All this will require new partnerships and ecosystem building, with both businesses and governments playing important roles.

To get things started, strategies should aim at the critical "unlocks," like reducing the cost of hydrogen production and distribution. We estimate roughly 65 GW of electrolysis are required to bring costs down to a break-even with gray hydrogen under ideal conditions, which implies a funding gap of about USD 50 billion for these assets. Support is also required to scale up carbon transport and storage; hydrogen shipping, distribution and retail infrastructure; and the take up of end applications.

One place to support deployment is the development of clusters with large-scale hydrogen offtakers at their core. These will drive scale through the equipment value chain and reduce the cost of hydrogen production. By combining multiple offtakers, suppliers can share both investments and risks while establishing positive reinforcing loops. Other smaller hydrogen offtakers in the vicinity of such clusters can then piggy-back on the lower-cost hydrogen supply, making their operations breakeven faster.

We see several cluster types gaining traction, including:

- **Port areas** for fuel bunkering, port logistics, and transportation
- **Industrial centers** that support refining, power generation, and fertilizer and steel production
- **Export hubs** in resource-rich countries

[3] Alternatives such as synthetic methane from biogenic or air-captured CO_2 in current liquefied natural gas (LNG) vessels were not in the scope of this report and require further study.

Successful clusters will likely involve players along the entire value chain to optimize costs, tap into multiple revenue streams and maximize the utilization of shared assets. They should be open to additional players and infrastructure should allow for ready access where possible.

The next few years will be decisive for the development of the hydrogen ecosystem, for achieving the energy transition and for attaining the decarbonization objective. As this report shows, progress over the past year has been impressive, with unprecedented momentum. But much lies ahead. The companies in the Hydrogen Council are committed to deploying hydrogen as a critical part of the solution to the climate challenge and *Hydrogen Insights* will provide a regularly updated, objective and global perspective on the progress achieved and the challenges ahead.

Hydrogen Insights draws upon the **collective knowledge** of Hydrogen Council members

109 ▶
companies

>6.8
tm market cap

>6.5
mn employees

I | Introduction and methodology

Hydrogen Insights is a leading global perspective on hydrogen

The 109 members of the Hydrogen Council represent over USD 6.8 trillion in market capitalization and more than 6.5 million employees. *Hydrogen Insights* represents a collaborative effort between Hydrogen Council members and McKinsey & Company to bring forth an objective, holistic and quantitative perspective on the use of hydrogen as a decarbonization option based on real industry data.

As such, *Hydrogen Insights* aspires to offer the pre-eminent industry perspective on market deployment, investment momentum and cost competitiveness within the hydrogen industry. Along with the report, the Hydrogen Council is launching *Hydrogen Insights* as a subscription service, providing granular insights and data about the hydrogen ecosystem and its development.

Exhibit 1: Hydrogen Council Members

The *Hydrogen Insights* report methodology

Before explaining the results, the following provides a description of the methodological approach used in this analysis.

Evaluating hydrogen investment, deployment, and market momentum

The report team estimated the total hydrogen investment through 2030 based on an analysis of three main investment funding categories: direct investment into private sector projects, government production targets and public funding, and upstream/indirect investment required to support announced project investments.

Direct private sector investment. The report team's estimates of company investments in hydrogen projects came from a database of publicly announced projects across the globe, validated by the members of the Hydrogen Council. Using public deployment information and internal projections, the team estimated required funding for these projects. It also classified projects by maturity level, depending on whether they were at an early stage, in the planning phase, or already had committed funding. By combining these insights with investment data from Hydrogen Council members that an independent third-party clean team collected, processed, and aggregated, the report team gained insights into the relevant investment trends in the market.

Government production targets and public funding. The report team reviewed announced government targets and compared them with the project pipeline to quantify the additional capacity required to reach the targets. This additional capacity was then costed and included in the investment total as ´announced´ investment. Countries such as China, Japan and Korea, which rely more heavily on announced public funding targets instead of capacity targets, were considered as a special case. In these countries, the report team reviewed announced government funding and compared it with announced private investment from the project pipeline. By assuming that the existing private projects received on average one-third of their total investment from the government (in most cases this information is not made public), the team could quantify the additional investment expected from these governments and include it in the ´announced´ investment category.

Upstream investment. Lastly, the team estimated the upstream investment required to realize direct private sector investments using industry revenue multipliers. It treated fuel cell and on-road vehicle platforms separately, with a bottom-up estimation of R&D and manufacturing costs.

Evaluating hydrogen cost-competitiveness: production, distribution and application

The cost competitiveness analysis in the report built on the Hydrogen Council Study 2020 report, “Path to hydrogen competitiveness: a cost perspective”. This year´s report focused on adding new technologies and applications (such as shipping and aviation) and revisited areas where technology, costs and underlying assumptions have changed.

Data for both perspectives were provided by Hydrogen Council members through an independent third party “clean team” who collected, aggregated and processed the data to preserve anonymity.

In addition to these data, the report builds upon McKinsey Energy Insights modelling of renewables costs and capacity factors, McKinsey Hydrogen Supply modelling, other proprietary assets, and numerous benchmarks from external data providers and databases. The report team also tested and validated the findings from these analyses via over 25 expert interviews before the results and key findings were presented to the Hydrogen Council study group. The study group, which consisted of 20 members of the Hydrogen Council, then validated, co-developed and tested these findings. The full steering group of the Hydrogen Council subsequently reviewed and approved the report.

Volume ramp ups. The study assumed several deployment scenarios for hydrogen technology. While not forecasts, these scenarios provided a way to analyze the effect of scale on cost competitiveness. Volume ramp up assumptions reflected the required low-carbon and renewable hydrogen production volume scales needed to meet 18% of global final energy demand by 2050 (in line with the 2°C goal).

Hydrogen production costs. Throughout this report, “low-carbon” and “renewable” hydrogen are used as shorthand to describe the production of hydrogen from natural gas through a reforming process with carbon capture (low-carbon hydrogen) and/or the production of hydrogen via water electrolysis from renewable electricity (renewable hydrogen). The focus on these two main pathways does not exclude other production pathways that can form part of a hydrogen economy, such as the reforming of biogas, pyrolysis, coal gasification, and others. Where the report mentions these alternative pathways, it describes them as such.

The report team analyzed hydrogen production costs using a specific production configuration that reflected the “base costs” of clean hydrogen production. This production configuration includes a dedicated renewable energy and electrolysis system (excluding grid connection fees or added transmission line infrastructure), and fully flexible production (zero minimum load requirements that require storage and oversizing of the generation capacity). Furthermore, it considered only raw production costs (distinct from supply prices that include services, redundancies and margins) for a scaled industry to support the cost-down (90 GW installed by 2030).

Carriers and application analysis. Carriers and applications with specific low-carbon and conventional alternatives underwent total cost of ownership (TCO) comparisons. For example, one analysis compared fuel-cell electric vehicles with battery electric vehicles (BEVs) with diesel vehicles. Likewise, fuels for aviation compared hydrogen versus synfuels versus kerosene (jet fuel).

The report team developed TCO trajectories for each hydrogen application and technology and its competing low carbon and conventional alternatives to identify relevant cost components. Moreover, the team pinpointed factors driving cost reductions and break-even points among competing solutions. Generally, it based hydrogen cost estimations on the average of low-carbon hydrogen (produced from natural gas reforming with carbon capture and storage) and renewable hydrogen (produced via renewable power and electrolysis).

Nevertheless, for some specific applications, a particular production method was assumed to reflect variations across regions and their respective settings.

CO_2 analysis. Throughout the report, CO_2 played two different roles. On one hand, it could function as feedstock for applications such as methanol (MeOH) shipping fuel. On the other, it represented greenhouse gas emissions that harm the environment. Although various ways exist to capture or obtain CO_2 feedstock (e.g., industrial capture or biogenic CO_2), this report assumed it was extracted from the atmosphere using direct air capture (DAC) technology. Hence, the report assumed the resulting product was produced in a carbon-neutral way.

The team conducted all analyses without assuming that implicit CO_2 emission costs penalized applications and technologies that emit CO_2. However, for some specific cases it did apply CO_2 costs. In those cases, the analysis clearly describes the implicit CO_2 emission costs.

Currency. All financial figures are in US dollars (USD) and refer to global averages unless otherwise indicated.

Investments into hydrogen are gathering momentum

>200

projects have been announced globally with

>80 bn

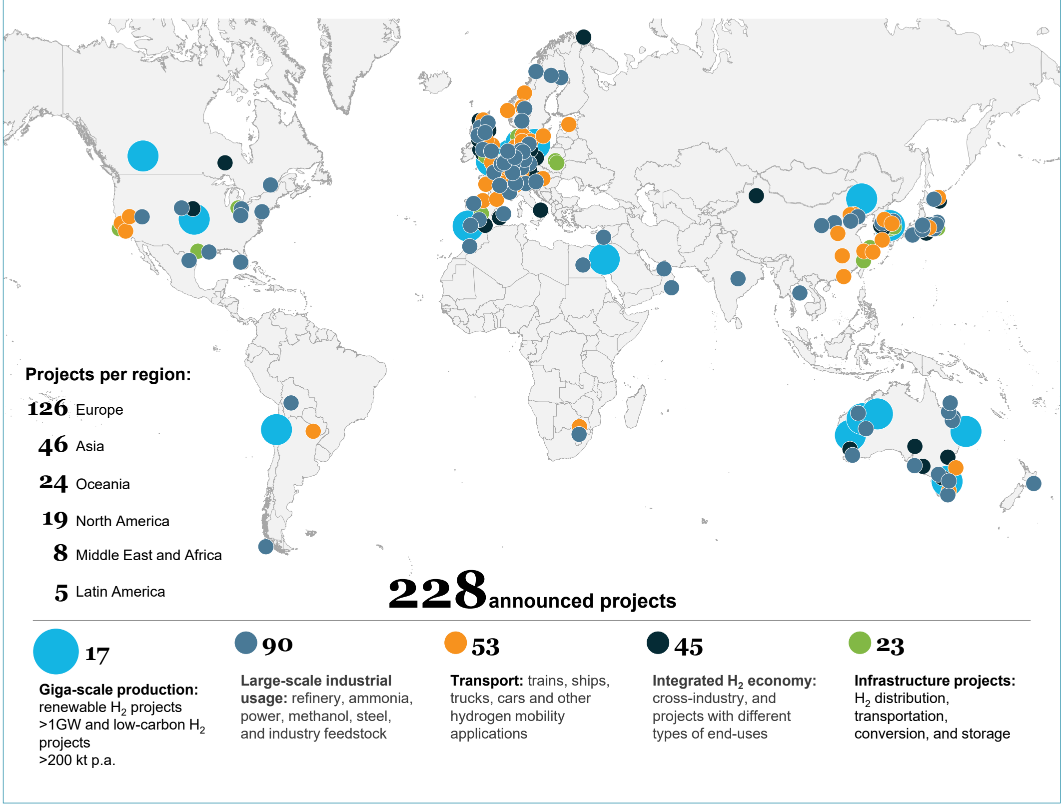
in mature hydrogen investment

II | Deployment and investment

Tremendous momentum exists, with over 200 H_2 projects announced worldwide

Globally, there are 228 hydrogen projects across the value chain (see Exhibit 2). Of these, 17 are already-announced giga-scale production projects (i.e. more than 1 GW[4] for renewable and over 200 thousand tons a year for low-carbon hydrogen), with the biggest in Europe, Australia, the Middle East and Chile.

Exhibit 2: Global hydrogen projects across the value chain



Europe leads globally in the number of announced hydrogen projects, with Australia, Japan, Korea, China and the USA following as additional hubs. Of all announced projects, 55% are located in Europe. While Europe is home to 105 production projects, the announced projects cover the entire hydrogen value chain including midstream and downstream.

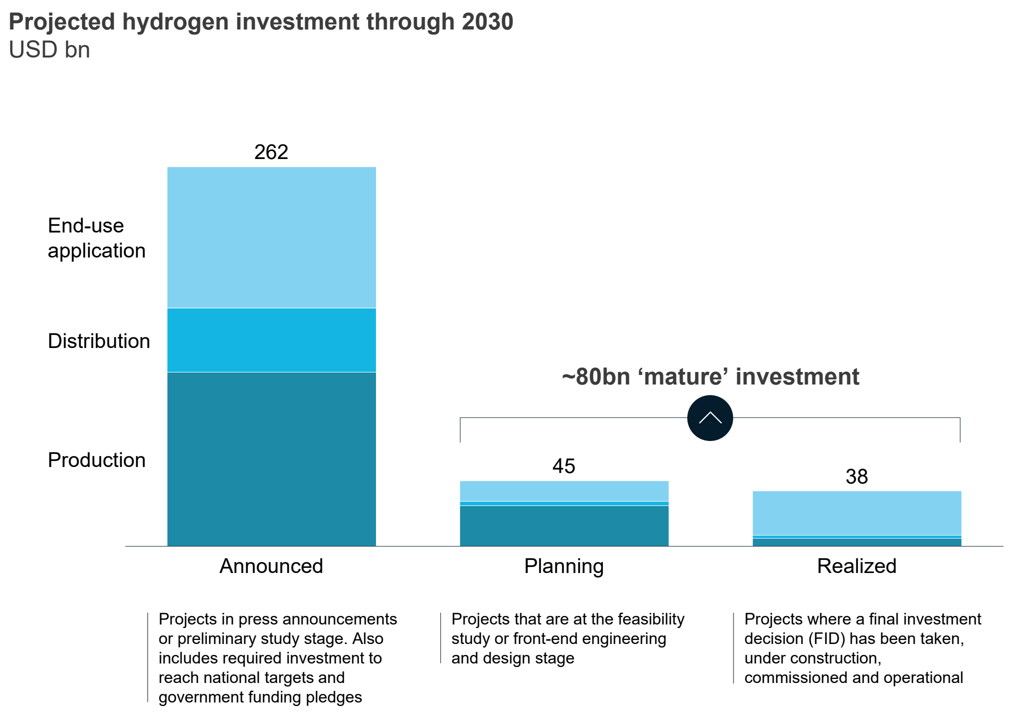
In expected major demand centers like Korea, Japan and Europe, the focus is on industrial usage and transport application projects. While Japan and Korea are strong in road transport applications, green ammonia, LH_2, and LOHC projects, Europe champions multiple integrated hydrogen economy projects. These latter initiatives often feature close cross-industry and policy cooperation (e.g., the Hydrogen Valley in the Northern Netherlands).

[4] Equivalent to 175 thousand tons at 100% load factor.

More than USD 300 billion in H_2 investments through 2030

A tally of project announcements, investments required to reach government production targets and spending projections across the value chain adds up to more than USD 300 billion through 2030. Given the industry's early stage, the vast majority (75%) of these investments involve announcements but not committed funding. To date, we estimate USD 80 billion of mature investments until 2030. These include USD 45 billion in the planning phase, which means companies are spending sizable budgets on project development. Another USD 38 billion involves either committed projects or those under construction, commissioned or already operational (see Exhibit 3).

Exhibit 3: Breakdown of announced investments by maturity



The largest share of investments is projected in Europe (about 45%), followed by Asia, where China is leading with around half of total investments.

Looking at the hydrogen value chain split, the production of hydrogen accounts for the largest share of investments. End-application investments have a higher share in mature projects due to funding for fuel cells and on-road vehicle platforms. In analyzing private investments among Hydrogen Council members, we see a clearly accelerating trend. Members expect to increase investments six times through 2025 and 16 times through 2030, compared with 2019 spending.

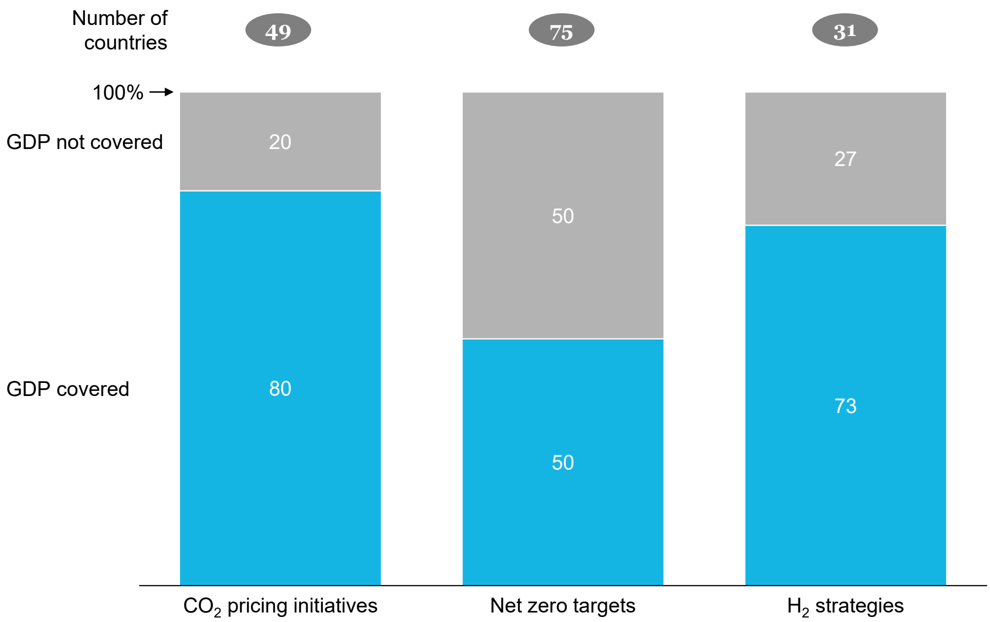
Companies tend to target their investments in the hydrogen space toward three specific areas: the capex of announced or planned projects, R&D, or M&A activities. The future investments of Hydrogen Council members trend heavily toward capex investments (80%) compared with spending on R&D or M&A activities.

Regulation and government support drive this momentum

Governments have plans to support strategies to transition to hydrogen, with USD 70 billion in play. The increasing governmental support stems from a global shift to decarbonization: 75 countries, representing half the world's GDP, have a net zero ambition and 80% of global GDP is covered by some level of CO_2 pricing mechanisms (see Exhibit 4).

Exhibit 4: Regulation supporting decarbonization and hydrogen

Share of global GDP covered by respective regulatory support mechanism
%, 100% = USD 88 Trillion



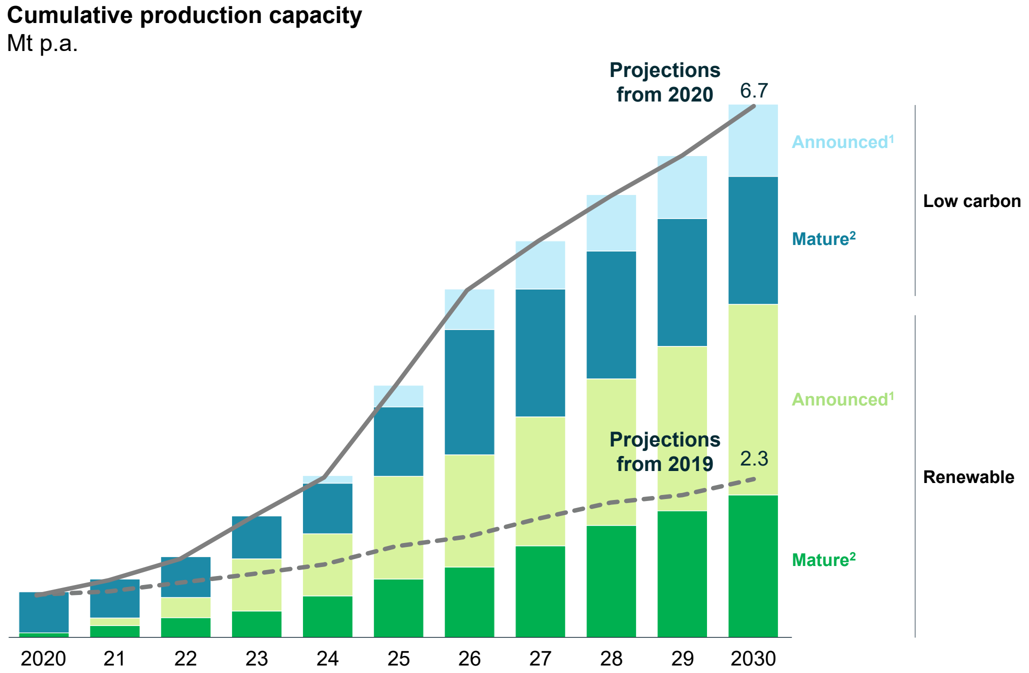
Hydrogen is a crucial element in most strategies to achieve net zero standing, and more countries are developing hydrogen plans. In fact, over 30 countries have created such strategies on a national level, and six are drafting them.

Besides the national hydrogen roadmaps, sector-level regulation and targets underpin the shift to hydrogen. In transport, more than 20 countries have announced sales bans on ICE vehicles before 2035. More than 35 cities covering over 100 million cars are setting new, stricter emission limits, and over 25 cities have pledged to buy only zero-emission buses from 2025 onwards. Globally, countries anticipate having 4.5 million FCEVs by 2030, with China, Japan and Korea leading the roll-out. In parallel, stakeholders are targeting 10,500 hydrogen refueling stations (HRS) by 2030 to fuel these vehicles.

For industry, the goalposts are also shifting. For example, the European Union has suggested that Member States incorporate low-carbon hydrogen production renewable fuel targets (REDII Directive), which could give a significant boost to hydrogen adoption in refining and by fuel retailers. In addition, four European countries (France, Germany, Portugal and Spain) have recently announced industry-specific clean hydrogen consumption targets in their national strategies. Likewise, quotas for aviation and shipping fuel are in advanced discussions among these four EU nations. Other countries have established incentives for low-carbon hydrogen by means of tax benefits, as in the case of the 45Q program in the United States. Similarly, in France, industrial users can avoid carbon costs by using renewable hydrogen, and in the Netherlands, investments into large-scale electrolyzer capacity connected to offshore wind power and the retrofitting of the natural gas grid are being made to replace fossil fuels by hydrogen.

Driven by a growing focus on hydrogen and increasing governmental support, the announced production capacity for clean hydrogen for 2030 increased to 6.7 million tons a year from 2.3 million tons previously. In other words, players have announced two-thirds of the clean hydrogen production capacity over the course of the past year (see Exhibit 5).

Exhibit 5: Announced clean hydrogen capacity through 2030



1. Includes projects at preliminary studies or at press announcement stage
2. Includes projects that are at the feasibility study or front-end engineering and design stage or where a final investment decision (FID) has been taken, under construction, commissioned or operational

Hydrogen production costs are declining faster than previously thought

60%

production cost reduction projected for renewable hydrogen by 2030 vs. 2020 baseline

III | Hydrogen supply

Renewable hydrogen could break even with gray H_2 before 2030 in optimal regions

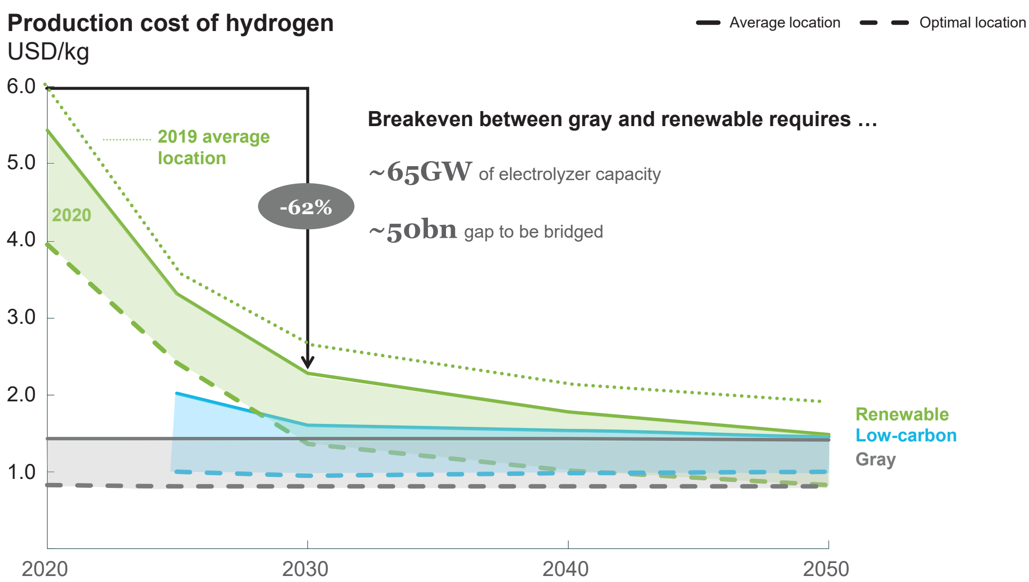
Renewable hydrogen production costs continue to fall more swiftly than previously expected. Compared with the Hydrogen Council Study 2020 report, “Path to hydrogen competitiveness: a cost perspective”, this year’s update resulted in even more aggressive cost-down expectations for renewable hydrogen production.

Three factors are driving this acceleration. First, capex requirements are dropping. We expect a significant electrolyzer capex decline by 2030 – to about USD 200-250/kW at the system-level (including electrolyzer stack, voltage supply and rectifier, drying/purification and compression to 30 bar). That is 30-50% lower than we anticipated last year, due to accelerated cost roadmaps and a faster scale-up of electrolyzer supply chains. For example, several electrolyzer manufacturers have announced near-term capacity scale-ups for a combined total of over approximately 3 GW per year.

Second, the levelized cost of energy (LCOE) is declining. Ongoing reductions in renewables cost to levels as much as 15% lower than previously expected result from the deployment of at-scale renewables, especially in regions with high solar irradiation (where renewables auctions continue to break record lows). The strongest reductions are expected in locations with optimal resources, including Spain, Chile, and the Middle East.

Third, utilization levels continue to increase. Large-scale, integrated renewable hydrogen projects are achieving higher electrolyzer utilization levels. This performance is driven largely by the centralization of production, a better mix of renewables (e.g., onshore wind and solar PV) and integrated design optimization (e.g., oversizing renewables capacity versus electrolyzer capacity for optimized utilization) (see Exhibit 6).

Exhibit 6: Hydrogen production costs by production pathway



Renewable hydrogen
- Dedicated renewable/electrolyzer system
- Fully flexible production
- Scale up of renewable hydrogen production
- Additional costs to reach end supply price

Low-carbon hydrogen
- Development of CO_2 pipelines and at-scale sites
- Scale-up of low-carbon hydrogen production
- Scale-up of CCS outside of hydrogen production

Key assumptions
- Gas price 2.6–6.8 USD/Mmbtu
- LCOE USD/MWh 25–73 (2020), 13–37 (2030) and 7–25 (2050)

Strong low-carbon hydrogen production momentum and more cost reductions

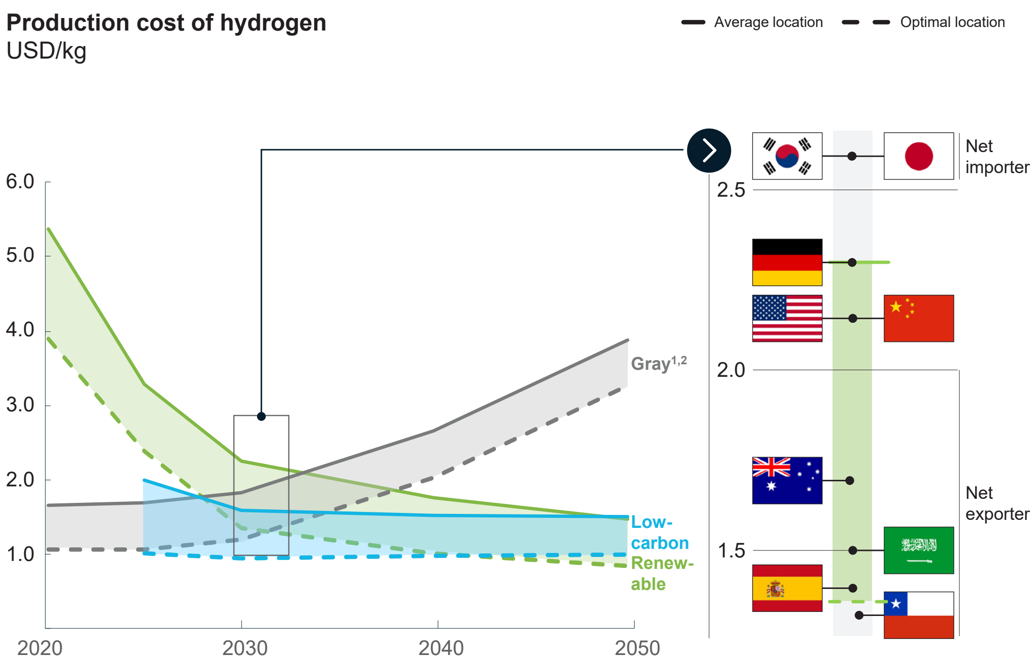
The production of low-carbon H_2 also continues to gain momentum. Improvements include increased CO_2 capture rates for autothermal reforming (ATR) from 95% in last year's report to 98%, coupled with potential capex reductions from smaller capture installations and lower compression requirements. Conducting ATR at higher temperatures can also increase methane-to-hydrogen conversion rates, resulting in lower methane content in the product gas, further reducing emissions (see Exhibit 6).

Introducing CO_2 costs can bring the earliest breakeven for clean hydrogen to 2028-2034

Including carbon costs for emissions related to gray and low-carbon hydrogen production greatly influences the breakeven dynamics between gray and renewable hydrogen. Assuming a carbon cost of about USD 50 per ton of CO_2e by 2030, USD 150 per ton CO_2e by 2040, and USD 300 per ton CO_2e by 2050, can bring the earliest breakeven for renewable hydrogen forward to a 2028 to 2034 timeframe. The exact year will depend on the availability of local resources.

In countries with optimal renewables but average cost natural gas (e.g., Chile) breakeven could occur as soon as 2028. In locations with average resources for both pathways (e.g., Germany), breakeven could come by 2032. At the same time, locations with abundant and optimal resources for both pathways (e.g., selected regions in the US) could see the breakeven of gray and renewable hydrogen by 2034. Low-carbon hydrogen could breakeven with gray by 2025-2030, subject to at-scale CO_2 storage and transport infrastructure, and an expected cost of about USD 35-50 per ton CO_2e (see Exhibit 7).

Exhibit 7: Hydrogen production pathways, including carbon costs



Key assumptions

- Gas price 2.6–6.8 USD/Mmbtu
- Cost USD/Ton CO_2 30 (2020), 50 (2030), 150 (2040) and 300 (2050)
- LCOE USD/MWh 25–73 (2020), 13–37 (2030) and 7–25 (2050)

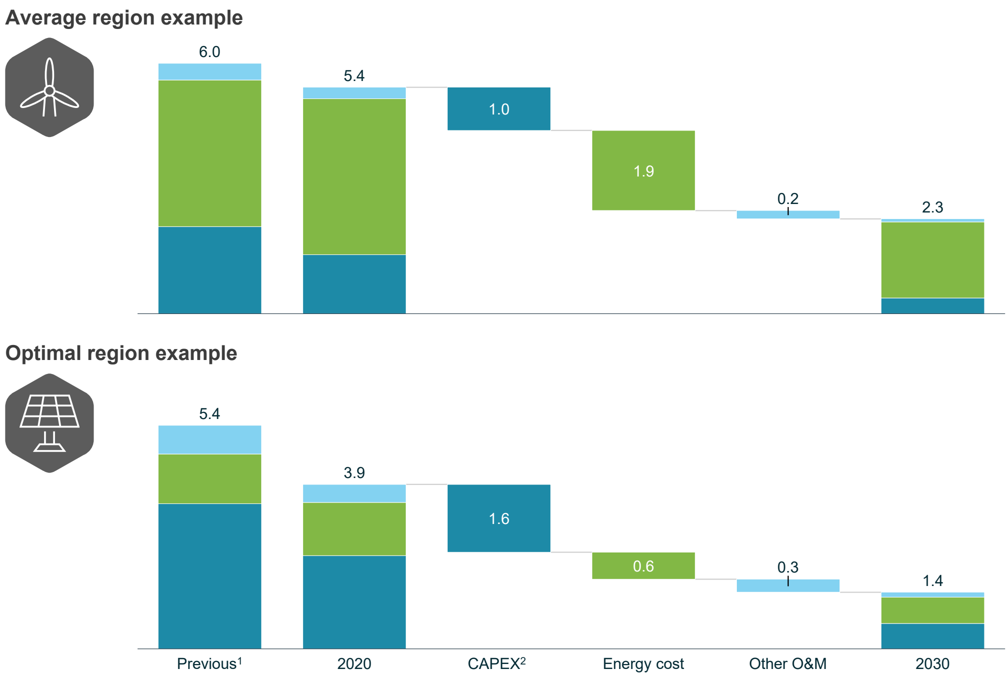
Together, these drivers are pushing down the cost curve for renewable hydrogen by as much as 20% for average locations and potentially 30% for optimal locations compared with the Hydrogen Council Study 2020 report, "Path to hydrogen competitiveness: a cost perspective".

For average projects such as offshore, wind-based electrolysis in Central Europe, renewable hydrogen production costs could decline from USD 5.4/kg in 2020 to USD 2.3/kg in 2030, with LCOE declines having the greatest cost-down impact. Due to the higher relevance of electricity cost, efficiency gains also have a slightly higher impact compared with locations using lower-cost renewables.

For projects using low-cost renewables like solar PV-based electrolysis in the Middle East, the cost of renewables-based hydrogen production could decline to USD 1.5/kg in 2030. In this case, declining capex costs will have the most impact in driving cost-down effects due to lower electrolyzer utilization rates compared with offshore wind setups. Both the Central Europe setup and the Middle East setup configurations can also benefit from integrated design optimization, striking a balance between higher utilization due to renewables capacity oversizing and a LCOE penalty due to curtailed electricity.

Truly optimal locations will likely include a combination of wind and solar resources for an additional upside. Countries like Australia, Chile or Saudi Arabia have the potential to benefit from such combined resources (see Exhibit 8).

Exhibit 8: Breakdown of renewable hydrogen production cost trajectory



1. 2020 Projection from 2020 Hydrogen Cost Roadmap Report
2. Includes learning rate on CAPEX and impact of larger electrolyzer size class (from ~2 MW to ~80 MW)

Electrolyzer capex savings can reduce costs quickly in a rapid global scale-up

Electrolyzer system costs could drop from about USD 1,120/kW in 2020 to an estimated USD 230/kW in 2030. This calculation includes the stack as well as the balance of plant (e.g., transformer and rectifier, drying/purification to 99.9% purity, compression to 30 bar). It excludes transportation of the electrolyzer to the site, installation, and assembly (including grid connection), the cost of the building (for indoor installations), and indirect costs such as project development, field services and "first fills." Depending on project specifics, these could double total costs by 2030.

Because electrolyzer system capex should decline sharply, other cost elements (including installation, assembly, and indirect costs) will take a larger share of costs over time. That's because learning curve effects regarding the engineering, procurement and construction (EPC) part of the value chain will be limited after the deployment of the first few large-scale projects.

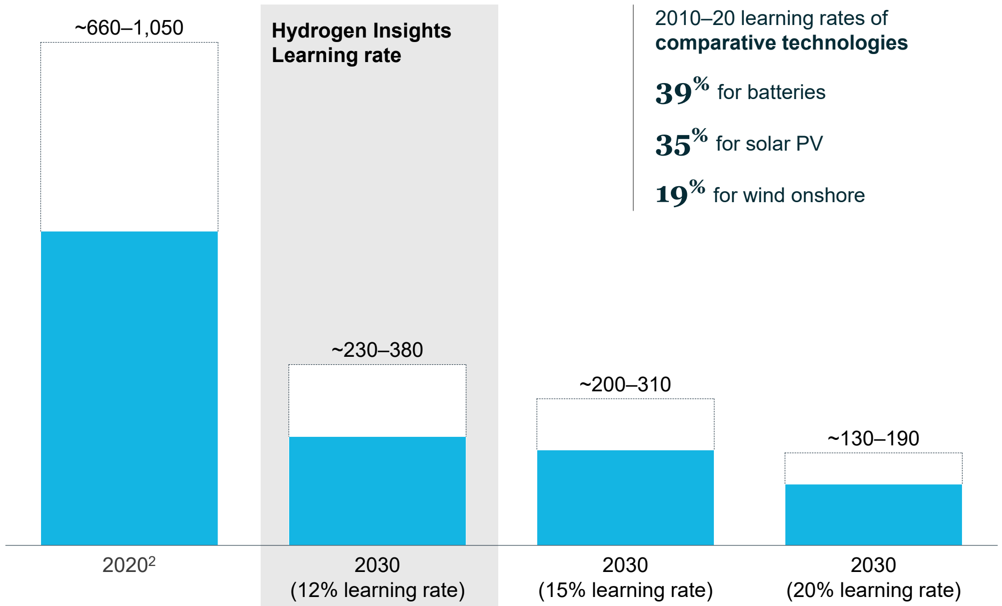
The total cost of an electrolyzer project also includes financing costs. A contribution margin in line with the project's weighted average cost of capital (WACC) requirements should scale with other capex elements. Financing thus becomes an important way to reduce hydrogen production costs. For instance, reducing WACC from 7% to 5% would reduce a project's overall capex commitment by almost 20%.

Expected electrolyzer learning curves could be too conservative

Current learning curve expectations for electrolyzer scale-ups range from 11-12% between 2020 and 2030 for polymer electrolyte membrane (PEM) and alkaline technologies. However, these learning curves appear conservative compared with the early development of other low-carbon technologies like batteries, solar PV or onshore wind, which saw learning rates of approximately 20-40% between 2010 and 2020. Potentially higher learning rates of 15%, 20% or 25% would drive additional cost reductions of 10-20%, 40-50% or 60-70%, respectively, by 2030 (see Exhibit 9).

Exhibit 9: Electrolyzer capex learning rate scenarios

Electrolyzer system capex[1] for different learning rates
USD/kW



1. Only includes stack and balance of plant. No installation and assembly, building, indirect cost or transportation site
2. Range based on different electrolyzer size classes of 2–20 MW

Low shipping costs from **major hydrogen supply centers** could unlock demand

USD

2-3 / kg

total shipping costs assuming at-scale production and transportation infrastructure

IV | Hydrogen distribution and global supply chains

With hydrogen production costs falling, costs for hydrogen distribution are becoming increasingly more important. For production and distribution, three types of value chains are emerging. Large-scale hydrogen offtakers that are in close proximity to favorable renewables or gas and carbon storage sites will use onsite production. Smaller offtakers, for example refueling stations or households, will require regional distribution. In regions without optimal resources, both large- and small offtakers may rely on hydrogen imports (see Exhibit 10).

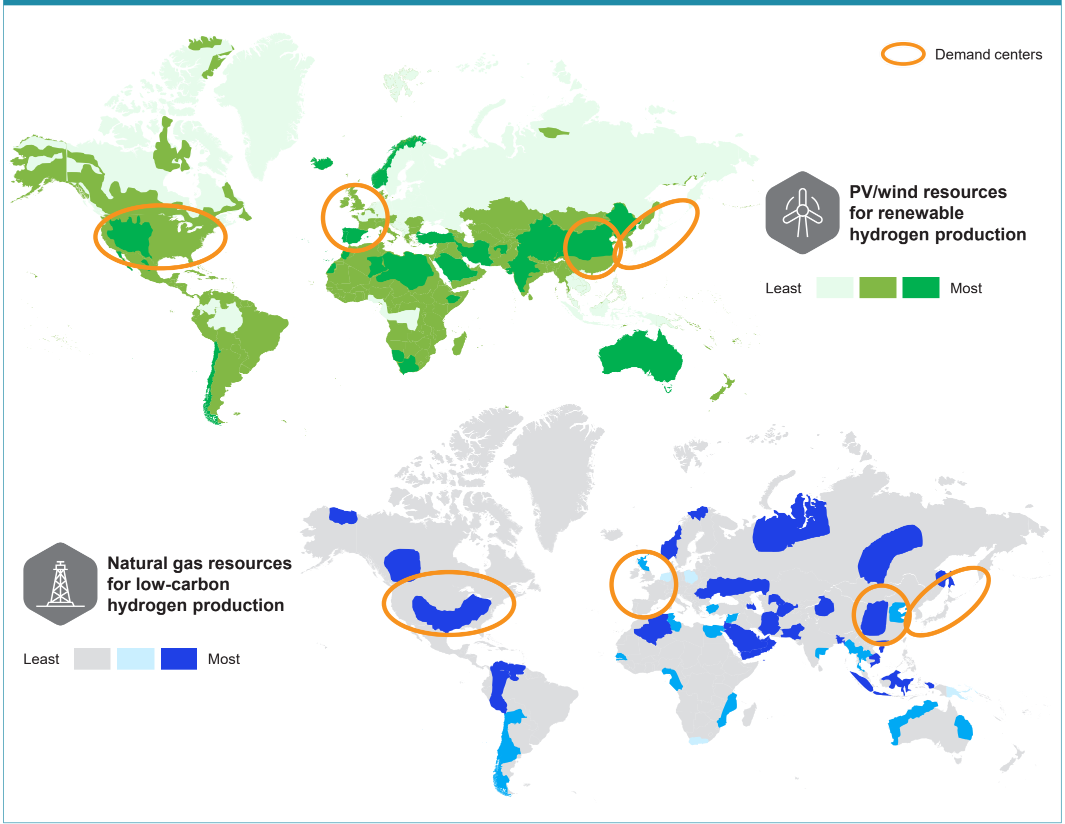
Exhibit 10: Emerging hydrogen distribution chains

H_2 value chain	Example end user (Europe, 2030)	Example value chain steps: Production	Conversion/ transmission	Distribution	Cost, USD/kg
Onsite	Industrial, large scale offtaker	• Renewable/low-carbon production **1.6–2.3 USD/kg**	• On-site storage for average of 1 day **0.5 USD/kg**		**~2–3**
Regional	H_2 refueling stations (HRS)	• Renewable/low-carbon production **1.6–2.3 USD/kg**	• Conversion to LH_2 and storage for average of 1 day *or* • Storage as GH_2 for average of 1 day and compression to 700 bar **0.7–1.0 USD/kg**	• Trucking as LH_2 for 300km + operating of 1,000kg LH_2 HRS *or* • Piping as GH_2 for 300km and operating of 1,000kg GH_2 HRS[1] **1.0–2.0 USD/kg**	**~3–5**
International	Industrial, large scale offtaker	• Renewable/ low-carbon production **1.0–1.4 USD/kg**	• International pipeline for ~9,000km and storage at port for average of 2 weeks *or* • Carrier conversion/ reconversion, shipping for ~9,000km and storage at port for average of 2 weeks **0.6–3.5 USD/kg**	• Trucking as LH_2/GH_2 for 300km and onsite storage for average of 1 day *or* • Piping as GH_2 for 300km and onsite storage for average of 1 day **0.1–2.0 USD/kg**	**~2–7**

1 Refers to usage of existing pipeline to industrial hub

The emergence of international distribution is driven by cost differences for hydrogen production stemming from renewables endowment, the availability of natural gas and carbon storage sites, existing infrastructure and the ease and time requirements for its build-out, land use constraints, and the assignment of local renewables capacity for direct electrification. Many expected hydrogen demand centers, including Europe, Korea, Japan, and parts of China, experience such constraints. In some of these cases, H_2 suppliers will meet this demand more effectively by importing hydrogen rather than producing it locally (see Exhibit 11).

Exhibit 11: Distribution of global hydrogen resources and demand centers



The optimal H_2 transport mode will vary by distance, terrain and end-use: no universal solution exists

Hydrogen can be transported globally using three forms of transportation – trucks, pipelines or ships – using a range of different carriers.[5] Currently, liquid hydrogen, liquid organic hydrogen carriers[6] and ammonia are the carbon-neutral solutions with the most traction.[7] While the optimal choice of transportation depends heavily on the targeted end-use and the terrain to be covered, some general rules on preferable solutions for different distances apply.

For short and medium range distances, retrofitted pipelines can achieve very low H_2 transportation costs (less than or equal to USD 0.1/kg for up to 500km). However, these costs are realizable only if existing pipeline networks are available and suitable for retrofitting (e.g., ensuring leakage prevention), and high volumes of H_2 are transported, guaranteeing high utilization rates. For lower or highly fluctuating demand, or to bridge the development to a full pipeline network roll-out, trucking hydrogen – in gaseous or liquid form – is the most attractive option. It can achieve costs of around USD 1.2/kg per 300km. End applications as well as demand size are decisive for choosing between liquid or gaseous hydrogen trucking options.

5 Gaseous hydrogen, liquid hydrogen LH_2, liquid organic hydrogen carriers (LOHC), ammonia (NH_3), methanol, LNG/LCO2 (dual-use vessels carrying liquefied natural gas on one trip and liquid CO_2 on the return trip) and solid hydrogen storage.
6 Various liquid organic hydrogen carrier materials are available, e.g. n-ethylcarbazole, methyl-cyclohexane, benzyltoluene – benzyltoluene used for analysis in this report
7 Synthetic methane produced from biogenic or air-captured CO_2 being a possible fourth candidate to be studied more in-depth

For longer distances, both new and retrofitted subsea transmission pipelines provide cheaper at scale transportation than shipping, but are not relevant for all regions. Where pipelines are not available, the transportation choice involves a range of different carriers. The three modeled here – LH_2, LOHC and NH_3 – are the most discussed. Since all three carriers fall into a comparable cost range, the optimal choice depends on the targeted end-use and requirements concerning hydrogen purification and pressure levels, as discussed in greater detail below (see Exhibit 12).

Exhibit 12: Overview of distribution options

<0.1 USD/kg | 0.1–1 USD/kg | 1–2 USD/kg | >2 USD/kg

		Costs				
		Distribution		Transmission		
		0–50 km	51–100 km	101–500 km	>1,000 km	>5,000 km
Pipelines[1]	Retrofitted	City grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
	New	City grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
Shipping	LH_2	N/A	N/A	N/A	LH_2 ship	LH_2 ship
	NH_3[2]	N/A	N/A	N/A	NH_3 ship	NH_3 ship
Trucking	LOHC[2]	N/A	N/A	N/A	LOHC ship	LOHC ship
	LH_2 trucking	Distribution truck LH_2	Distribution truck LH_2	Distribution truck LH_2	N/A	N/A
	Gaseous trucking	Distribution truck CH_2[3]	Distribution truck CH_2[3]	Distribution truck CH_2[3]	N/A	N/A

1. Assuming high utilization
2. Including reconversion to H_2; LOHC cost dependent on benefits for last mile distribution and storage
3. Compressed gaseous hydrogen

Hydrogen pipelines

Hydrogen pipelines are cheaper than electricity transmission lines

Hydrogen pipelines can effectively transport renewable hydrogen across long distances. They can transport 10 times the energy at one-eighth the cost associated with electricity transmission lines. Furthermore, hydrogen pipelines have a longer lifespan than electricity transmission lines and offer dual functionality, serving as both a transmission and storage medium for green energy.

Pipelines enable both international and regional/ last-mile transport, moving H_2 up to 5,000km at low cost…

While distribution networks cover regional and last-mile transport, onshore and subsea transmission pipelines could move hydrogen across distances that range from 500 to 5,000 or more kilometers. Pipelines can achieve extremely low-cost H_2 transport compared with alternative transportation modes, especially where retrofits of existing infrastructure are possible.[8] For example, retrofitting pipelines can save 60-90% of the cost of greenfield pipeline development.

[8] The option to retrofit depends on the existing pipeline (material, age, location), operating conditions, and availability, which might be limited due to long-term natural gas transmission agreements.

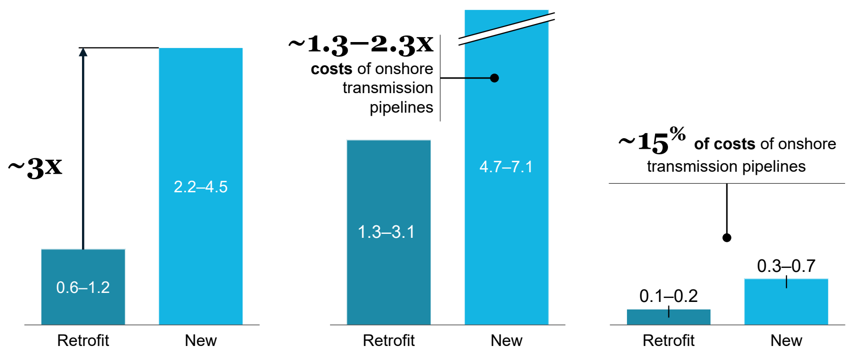
…but not all hydrogen pipelines are equal

While hydrogen pipelines provide cheaper transportation compared with many alternatives, the actual costs of hydrogen networks vary by type, length of network, and the condition of the retrofitted pipeline itself. Typical capex costs for onshore transmission networks including compression will range between USD 0.6 and 1.2 million per km for retrofit and USD 2.2 and 4.5 million per km for newly built H_2 pipelines, resulting in H_2 transport costs of USD 0.13-0.23/kg/1000km (see Exhibit 13).

Exhibit 13: Comparing hydrogen pipelines

	Onshore transmission pipelines	Subsea transmission pipelines	Distribution pipelines
Description	Large, high pressure transmission pipelines transporting gas on land	Large, high pressure transmission pipelines transporting gas through oceans	Smaller, lower pressure pipelines for last-mile gas delivery to end users
Ease of retrofitting	High	Low	Medium
	Potential availability constraints due to long-term natural gas commitments and capacity contracts	High compression requirements and subsea transmission network may be challenging	Distribution network location in densely populated areas could be problematic

Cost estimation
Capex in Million USD/km



For offshore/subsea transmission pipelines, costs are a factor 1.3 to 2.3 higher, given the specific challenges and conditions of subsea pipeline construction and operation for both new projects and retrofits. Distribution pipelines are substantially cheaper than transmission pipelines (roughly 15% of transmission pipeline costs), given their smaller diameter and lower pressures. However, distribution pipelines will likely become relevant only in the runup to 2040, when demand for hydrogen in residential and commercial buildings exceeds the threshold that the blending of up to 20% hydrogen into the natural gas grid can supply.

The costs of retrofitting versus building new pipelines depend on a variety of factors including diameter and pressure, the quality of the materials used, the pipeline's overall condition, the existence of cracks, the social costs of construction, and other considerations. Many of these factors are location-specific and thus give some regions and countries an advantage for retrofitting the natural gas grid. For example, in the Netherlands, parallel natural gas grid infrastructure allows companies to retrofit for hydrogen usage while gradually phasing out natural gas.

The costs of retrofitting can change based on pipeline upgrades and the presence of connected equipment such as metering stations, valves, and compressor stations.

Hydrogen carriers

Beyond pipelines, three carbon neutral H_2 carriers are competitive for long distance hydrogen transportation

As gaseous hydrogen is not suitable for long-distance shipping, suppliers can liquefy hydrogen, convert it to ammonia, or bind it to a liquid organic hydrogen carrier. If every step of the value chain uses green energy (fuel and/or electricity) and the hydrogen is produced from low-carbon sources, all three carriers can be considered low carbon.

The optimal carrier depends on the intended end-use, purity requirements and the need for long-term storage

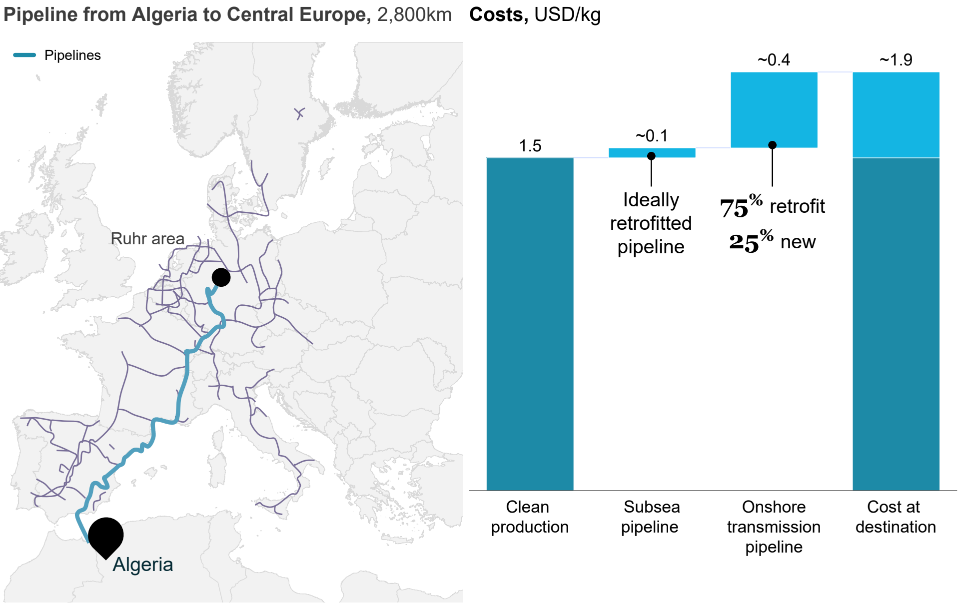
The long-term optimal choice of carrier depends on a range of factors. LH_2 is most efficient if the destination requires liquid or high-purity hydrogen, and has benefits if hydrogen needs to be distributed with trucks after landing at port. This is typically the case for hydrogen refueling stations for cars or trucks, for example. In contrast to NH_3 and LOHC, LH_2 does not require dehydrogenation or cracking to convert into gaseous hydrogen, which not only saves costs but also avoids purity

Case example: Low-cost H_2 pipeline transport can unlock hydrogen demand

By 2030, our projections indicate that clean hydrogen from North Africa could be piped to demand centers in Central Europe (e.g., the Ruhr area in Germany) at a cost of about USD 2 per kg of H_2. Of that, transport costs will constitute roughly USD 0.5 per kg of H_2. (see Exhibit 14).

Exhibit 14: Landed costs of renewable H_2 transported from Algeria to Central Europe using a pipeline

Costs for at scale production and pipeline transportation[1] in 2030



1. Assuming route will be built out by 2030; full rollout of backbone (2035–40) depicted here

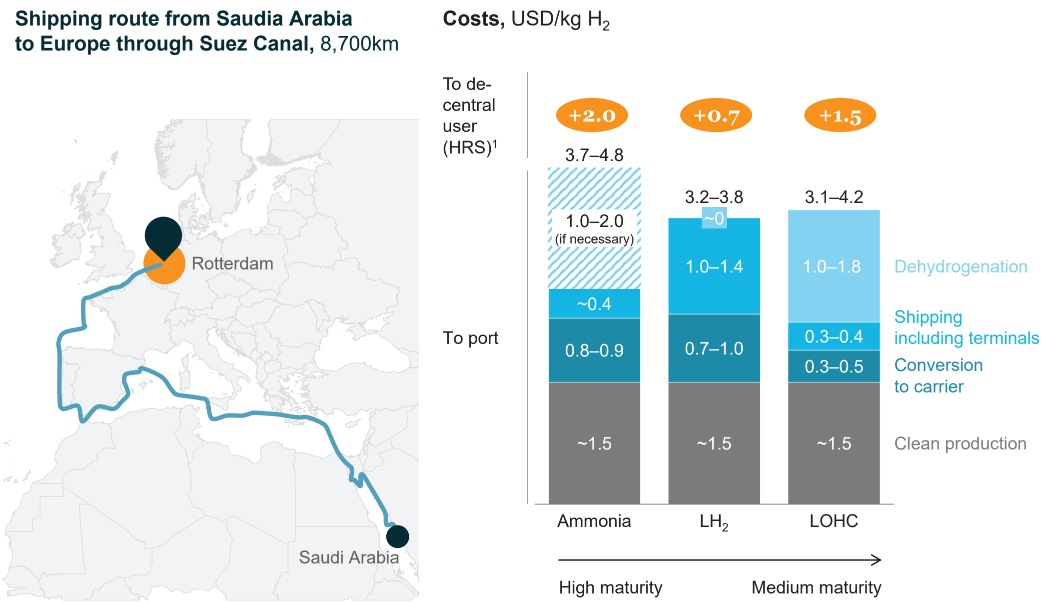
challenges caused by carrier residues. LH_2's main drawback is its relatively low volumetric energy density compared with ammonia, which limits the amount of hydrogen per ship, and the boil-off losses that occur with every day of storage. While liquefaction is a proven and commercialized technology, liquid hydrogen shipping and large-scale storage – which requires suppliers to manage the boil-off losses – remain in the early stages of deployment.

Ammonia is the straightforward answer for end-uses that need ammonia as a feedstock and can therefore avoid the need to crack NH_3 back into hydrogen (such as for fertilizer, shipping fuel, co-firing or ammonia combustion for power generation). However, suppliers are also considering this approach for other hydrogen use cases. Ammonia benefits from a higher volumetric energy density than does liquid hydrogen and thus suppliers can ship it more cost effectively than LH_2 using commercially available ammonia ships. However, the two drawbacks of using ammonia as a hydrogen carrier are the high costs of cracking it back into hydrogen and the achievable purity levels. Furthermore, because ammonia is toxic, it may face handling and storing restrictions in residential areas as well as limited options for in-land distribution.

Liquid organic hydrogen carriers can use existing diesel infrastructure and safely store hydrogen over long periods without loss. When using non-flammable and non-toxic carrier materials such as BT,[9] LOHC can use existing industry-scale diesel infrastructure without any additional safety regulations. The main drawbacks of LOHC are the novelty of the dehydrogenation process, which requires large amounts of heat to release the hydrogen from the carrier, and the limited hydrogen carrying capacity compared with LH_2 and NH_3. The ability to use cheaper storage tanks than those needed for other carriers partly outweighs these issues.

Exhibit 15: Landed costs at port of renewable H2 shipped from Saudi Arabia to Europe

Cost for at scale production and shipping transportation in 2030



1. Assumes liquid (for LH_2) or gaseous (for ammonia, LOHC) distribution with truck for 300km, also includes: purification to FCEV standard using a PSA for LOHC and NH_3, boil-off losses for LH_2, storage costs at port and HRS operating costs

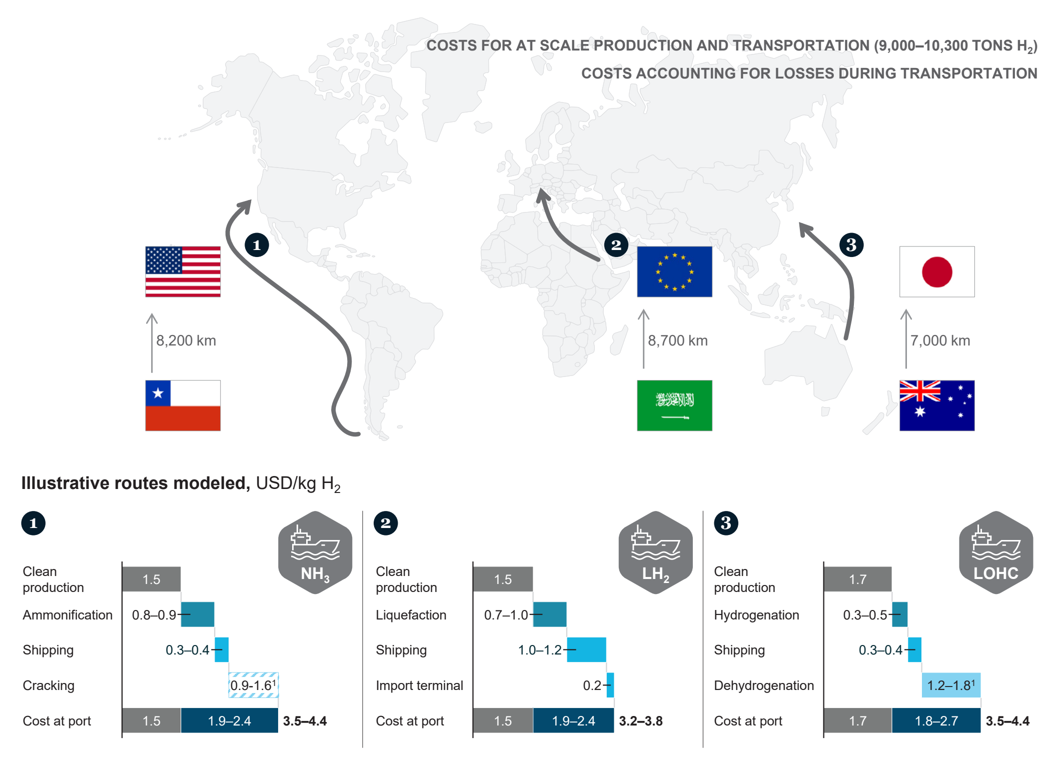
9 While BT includes toluene, it is does not fall under toxicity regulations given the limited toluene content per ton of BT.

Exhibit 15 shows a comparison of carriers for transporting renewable hydrogen from Saudi Arabia to Western Europe assuming at-scale hydrogen production and shipping infrastructure. If the end application requires ammonia, transporting hydrogen as ammonia could result in landed costs as low as USD 3 per kg of hydrogen. If hydrogen is required in the end application, landed costs are between 3 and 5. The optimal choice of a carrier for this example would thus ultimately depend on the targeted end-use, a resulting need for further overland transportation, and the projected storage time.

Hydrogen global transport can cost less than USD 2-3/kg

By 2030, assuming at-scale production and transportation infrastructure, hydrogen could be shipped from locations such as Australia, Chile or Middle East to projected demand centers at costs of USD 2-3/kg of hydrogen. This cost, coupled with very low hydrogen production costs, unlocks demand in many key sectors (e.g., in transportation, industry, feedstock and others) at the point of usage (see Exhibit 16).

Exhibit 16: Landed costs of hydrogen at port for selected global transport routes



1. Dependent on whether hydrogen feedstock or heat from grid is used for dehydrogenation heating requirement

Falling **clean hydrogen** and application specific costs will drive **greater cost-competitiveness** in hydrogen end applications

22

hydrogen end applications are projected to be the most competitive low-carbon solution by 2030 representing 36% of global emissions

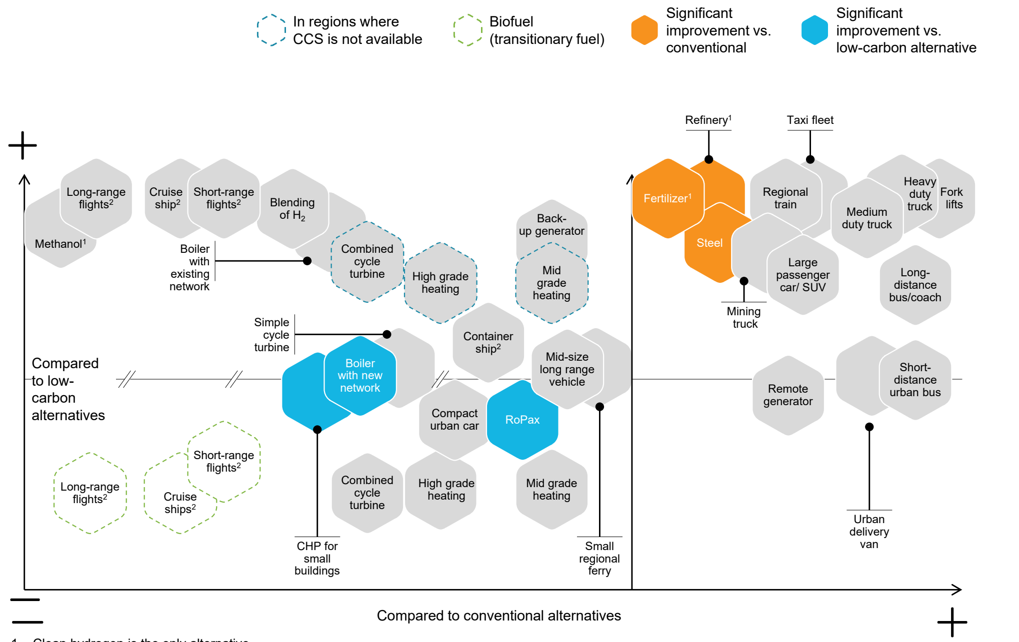
V | End applications

The cost competitiveness of hydrogen end applications

The *Hydrogen Insights* report analyzes the competitiveness of hydrogen applications across sectors through 2030 compared with conventional and low-carbon alternatives. Lower hydrogen production and distribution costs across all regions will improve the cost competitiveness of all end applications, as reflected in the shift to the right in the cost competitiveness matrix compared to Hydrogen Council Study 2020, “Path to hydrogen competitiveness: a cost perspective”.

In addition to hydrogen’s role as an overarching cost driver, the *Hydrogen Insights* report identifies three additional cost drivers with implications for individual end applications. They include optimized routes for green steel through the combination of DRI and scrap, which help green steel achieve cost competitiveness; improvements in battery technology that influence hydrogen breakeven with low-carbon alternatives in the transport sector; and new applications for hydrogen or hydrogen-based fuel usage (see Exhibit 17).

Exhibit 17: Hydrogen competitiveness per end application in 2030



1. Clean hydrogen is the only alternative
2. Carbon breakeven cost represents average cost over lifetime of asset
3. Biofuel is a complementary solution to hydrogen/ synfuels particularly used in heavy to decarbonize sectors such as shipping and aviation; usage will be subject to supply constraints

The updated cost outlook shows that 22 hydrogen applications can be the most competitive low-carbon solutions from a total cost of ownership perspective (including hydrogen production, distribution and retail costs). In addition to the applications that were previously competitive, including commercial vehicles, trains, long-range transport applications and boilers, today´s improved outlook adds fertilizer, refinery, steel, aviation, and shipping applications.

While this analysis focuses on the cost competitiveness of the end-use applications, other factors also drive the purchase decisions of companies and customers. Some of these include government targets, energy security, lower uncertainty regarding future energy costs, the premium placed by customers on carbon-free solutions, and investor preferences for ESG-compliant business models. For example, aviation, cruise ships, container shipping and steel are experiencing a push toward a greener restart post-COVID-19 from both customers and governments.

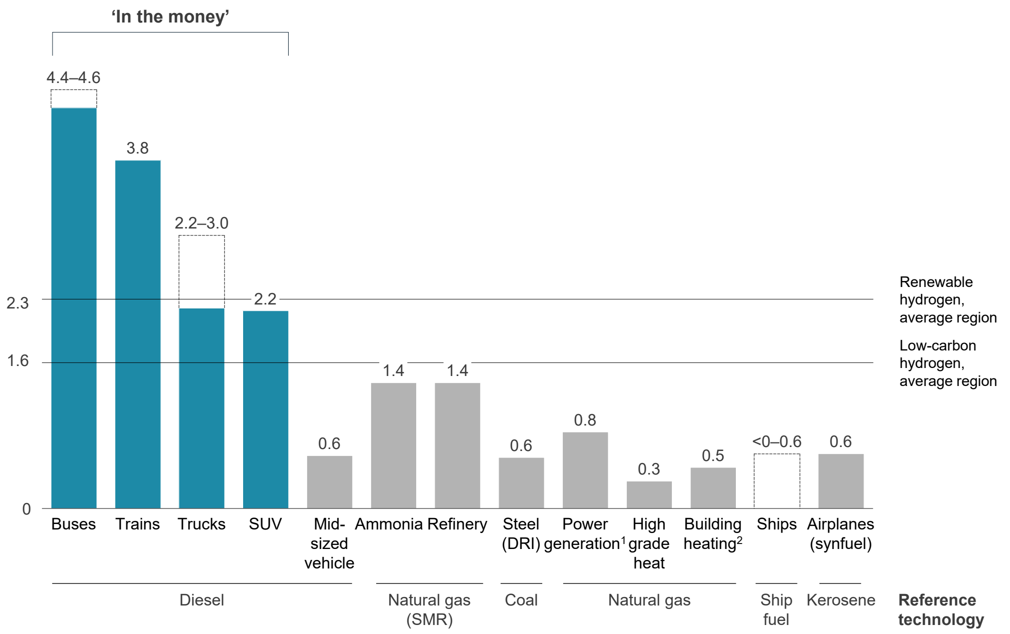
Hydrogen production cost breakeven

At a hydrogen production cost of USD 1.6-2.3/kg, most road transportation applications and hydrogen feedstock for industry are "in the money" (see Exhibit 18). With hydrogen costs between the blue and green hydrogen cost targets for 2030 and without any costs for carbon emissions, hydrogen is only competitive in heavier road transportation applications (not including passenger cars). A cost of carbon at USD 100/t of CO2e could push industry feedstocks for applications like steel, ammonia, and refining to breakeven and beyond. Other forms of transportation like shipping or aviation only break even at higher costs of carbon (> USD 70/tCo2e) but require hydrogen-based fuels as the only zero-carbon fuel possibility that can realize decarbonization ambitions.

While end applications in buildings and power require an even higher carbon (~200 USD/t CO2e) price to become cost competitive, we believe they will see strong momentum, nevertheless. For example, in the United Kingdom multiple landmark projects are blending hydrogen into natural gas grids for residential heating. They are also working with hydrogen for backup power solutions, especially for high power applications like data centers. The reason for this is that while hydrogen may not be able to outcompete conventional solutions, it can be the most cost-effective low-carbon option for many stationary use cases (see Exhibits 18, 19).

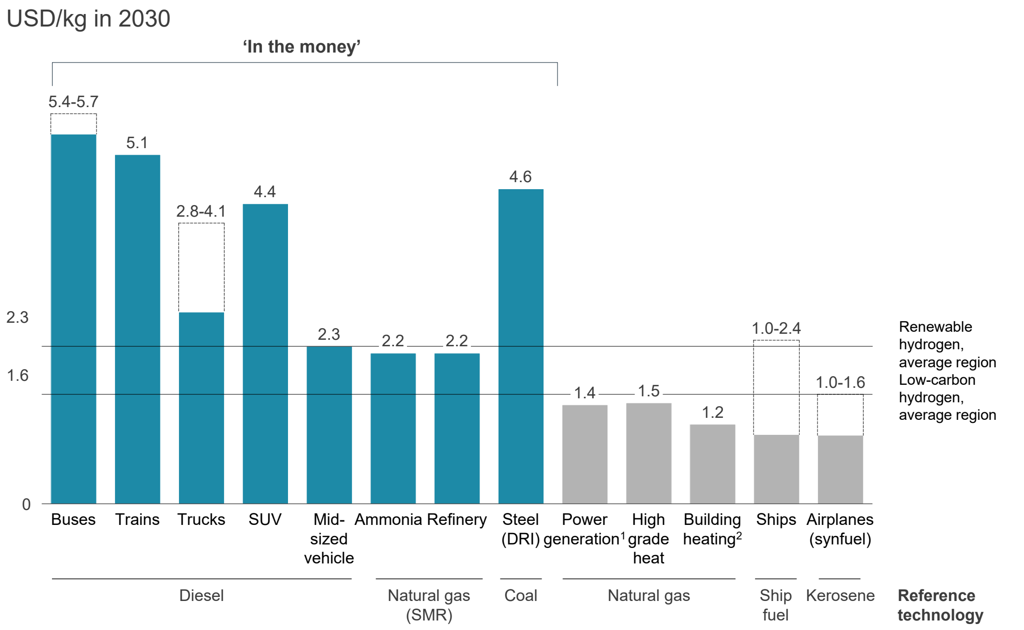
Exhibit 18: Required hydrogen production cost for breakeven with conventional solutions, without carbon costs

USD/kg in 2030



1. Average of combined cycle and single cycle turbine applications
2. Boiler with existing network

Exhibit 19: Required hydrogen production cost for breakeven with conventional solutions, with 100 USD/t CO_2e



1. Average of combined cycle and single cycle turbine applications
2. Boiler with existing network

A. Road transport and mining equipment

Global transportation generates 24% of global direct CO_2 emissions from gasoline and diesel combustion processes, with road vehicles like cars, trucks, buses, and motorcycles contributing roughly three-quarters of global transportation emissions. BEVs and FCEVs are both viable alternatives to decarbonize global transport. Use case-specific requirements such as range, payload and power requirements can determine the applicability and competitiveness of battery- or hydrogen-powered solutions.

On-road. In on-road trucking, BEVs remain the most competitive decarbonization option for lower- and mid-range use cases. FCEVs are best positioned to cover long-haul use cases, especially the upper spectrum cases with higher daily ranges. While most freight transport segments are not weight-constrained, FCEVs are the only alternative for weight-sensitive use cases of any driving range, including pulp and paper or iron and steel transport. That is because heavy batteries would reduce the potential payload of trucks to a larger extent than would fuel cells and hydrogen tanks.

For passenger cars, intended use and customer preferences will determine the choice of a fuel cell versus battery-electric powertrain. BEVs clearly outcompete FCEVs in lower-range use cases such as urban cars or mid-size vehicles (fewer than 500km). However, fuel cell vehicles are an option to power larger passenger cars, SUVs and vans with longer-range requirements and heavier use cycles, especially those used in commercial operations such as taxis or ridesharing.

Off-road. While zero-carbon powertrains for off-road segments such as mining trucks are less advanced than those for on-road use cases, fuel cell powertrains or even hydrogen combustion engines might represent the only alternative for decarbonizing very heavy equipment like dump trucks for mining operations. The high peak power requirements and harsh vibration and heat conditions experienced in the off-road environment make hydrogen combustion attractive as an alternative to fuel cells in off-road applications.

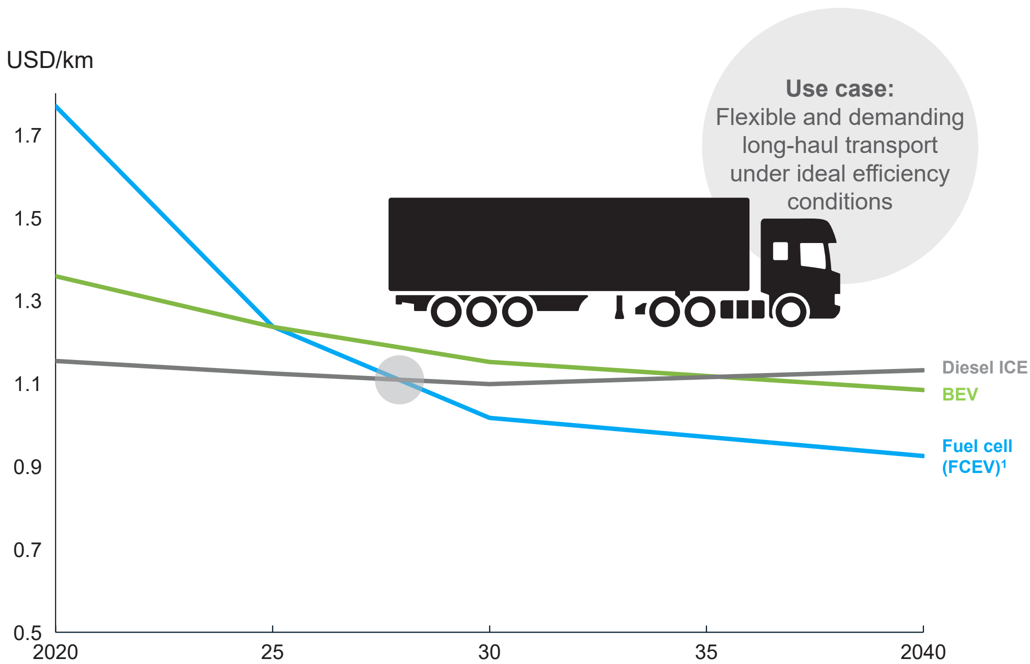
TCO use-case perspective: On-demand heavy-duty trucking for demanding long-haul transport

We modeled a long-haul heavy-duty class 8 truck for flexible and demanding long-haul transport with a vehicle lifetime of 10 years and a yearly distance of 150,000km. Our on-demand trucking use case requires a high fuel range of 800km. We assumed a hydrogen price at the dispenser of about USD 4/kg in 2030 and an underlying cost of roughly USD 50/t of CO_2e. In the model, we compared a heavy-duty truck (HDT) fuel cell electric vehicle (FCEV) with a battery-electric truck and a diesel truck.

We expect the on-demand HDT FCEV to become the cheapest option in terms of TCO by 2030. It should achieve break-even with battery-electric vehicles (BEVs) by around 2025, and with internal combustion engine (ICE) HDTs by 2028. Overall, the decrease in fuel cost (we expect H_2 cost to decline about 60% between 2020 and 2030) will drive an estimated 80% of the TCO change. The remaining 20% comes from falling equipment costs (powertrain costs are expected to decrease about 70% between 2020 and 2030). In the short-term, fuel costs make up about half of the TCO in this use case, while fuel cell powertrain costs account for approximately 12%, which breaks down as 45% fuel cell system costs, 40% tank cost and 15% other components. In the mid-term, fuel costs will account for 30% and the powertrain for 7% of total cost (see Exhibit 20).

In specific settings – e.g., where subsidies or other support mechanisms exist – the breakeven point can be shifted forward. Switzerland's toll exemptions or California's low carbon fuel standard (LCFS) credits are but examples for such policies.

Exhibit 20: Total cost of ownership of on-demand heavy-duty truck



1. Assuming renewable hydrogen, Europe

TCO use-case perspective: Open-pit dump truck for mining operations

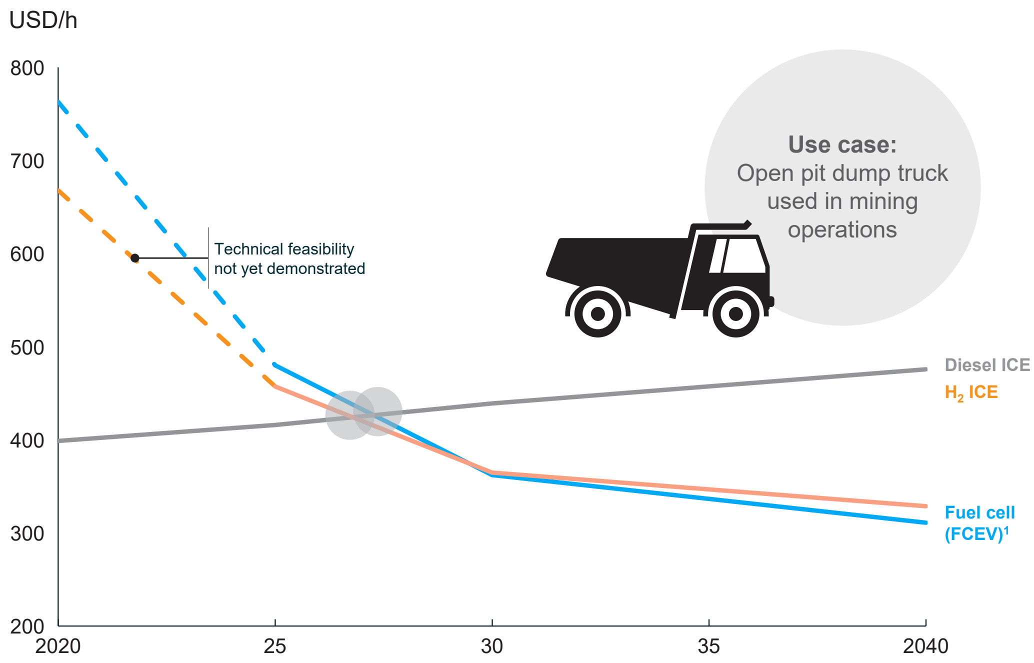
The TCO analysis modeled a 300t open-pit dump truck used in mining operations in Chile with 6,200 operational hours per year and a lifetime of 12 years. High power requirements (about 2,000 kW) made the mining truck an interesting application for hydrogen internal combustion engines, as fuel cell trucks with such high power requirements remain untested.

We assumed a hydrogen price at the dispenser of USD 1.4/kg in 2030 (with hydrogen production on-site) and an underlying cost of USD 50/t of CO_2e. We did not model a battery-electric mining truck, since its feasibility is challenging, especially in terms of charging. Because uptime is critical in mining operations, high-speed charging would be required to meet the required battery capacities. Moreover, many mines are off grid and battery swapping becomes difficult and expensive, given the extremely large batteries involved.

Both H_2 ICE vehicles and FCEVs should breakeven with conventional diesel trucks before 2030. We expect H_2 ICE trucks to breakeven before FCEVs do, because they need only minor adjustments compared with conventional diesel engines (with expected capex running at most 15-20% above diesel engine capex). Furthermore, local hydrogen production should enable relatively low hydrogen costs that offset the efficiency gap between fuel cells and internal combustion engines, which is 50-55% for FCs versus 40-45% for ICEs on a tank-to-wheels basis.[10]

For the FCEV truck, around 20% of the TCO change result from declining fuel cell powertrain costs, and another 60% because of lower hydrogen production costs. The H_2 ICE truck benefits from a decrease in hydrogen cost. More than 90% of this vehicle's TCO change results from the decline in fuel costs (76% by 2030), since powertrain technology is already mature (e.g., it contributes only 4% to the expected TCO decline though 2030) (see Exhibit 21).

Exhibit 21: Total cost of ownership of a 300 ton open-pit dump truck



1. Assuming production costs of renewable hydrogen in Chile

TCO use-case perspective: SUV for family usage

We also modeled an SUV for family usage with a required fuel range of 600km, a lifetime of 15 years and a yearly distance covered of 20,000 km. We compared a fuel-cell SUV, a battery-electric SUV and a diesel-powered one.

We expect the FCEV to break-even with the BEV in terms of TCO by 2028, while competitiveness versus diesel-powered SUVs takes one to two years longer. We assumed a hydrogen price at the dispenser of about USD 4/kg in 2030 and an underlying cost of USD 50/t of CO_2e.

The main drivers of FCEV TCO reductions are equipment costs (fuel cell system and hydrogen tank outlays) and decreasing cost of hydrogen at the pump. Hydrogen fuel costs account for 40% of the TCO through 2030, while almost 60% result from declining powertrain costs.

B. Ammonia

To date, industry produces 180 million tons of ammonia globally, with 80% used as feedstock for fertilizer and the remaining 20% for industrial chemicals production. Ammonia represents about 45% of global hydrogen offtake, making it the largest consumer of hydrogen today. Gray ammonia production contributes roughly 2% of global emissions, with approximately 0.5 gigatons (Gt) of CO_2 emitted because of its production.

With an increasing push toward decarbonization across sectors, new application fields will emerge for ammonia. Recognized as an effective sustainable shipping fuel in the freight shipping industry (as discussed in more detail in the chapter on sustainable shipping fuels), ammonia can also serve as a transport vector for hydrogen (especially for export projects in new geographies) and decarbonize power production when used for co-firing in existing thermal power plants.

Decarbonization alternatives

Ammonia is produced via the Haber-Bosch process, which combines hydrogen and nitrogen. As a highly feedstock-intensive process, a significant share of ammonia's carbon emissions result from the carbon intensity of the feedstock (30-40% of cradle-to-plant-gate greenhouse gas (GHG) emissions per ton of ammonia). Consequently, apart from using green electricity as an input for the conversion process, the only option for decarbonizing ammonia production involves the substitution of gray hydrogen from natural gas with renewable or low-carbon hydrogen.

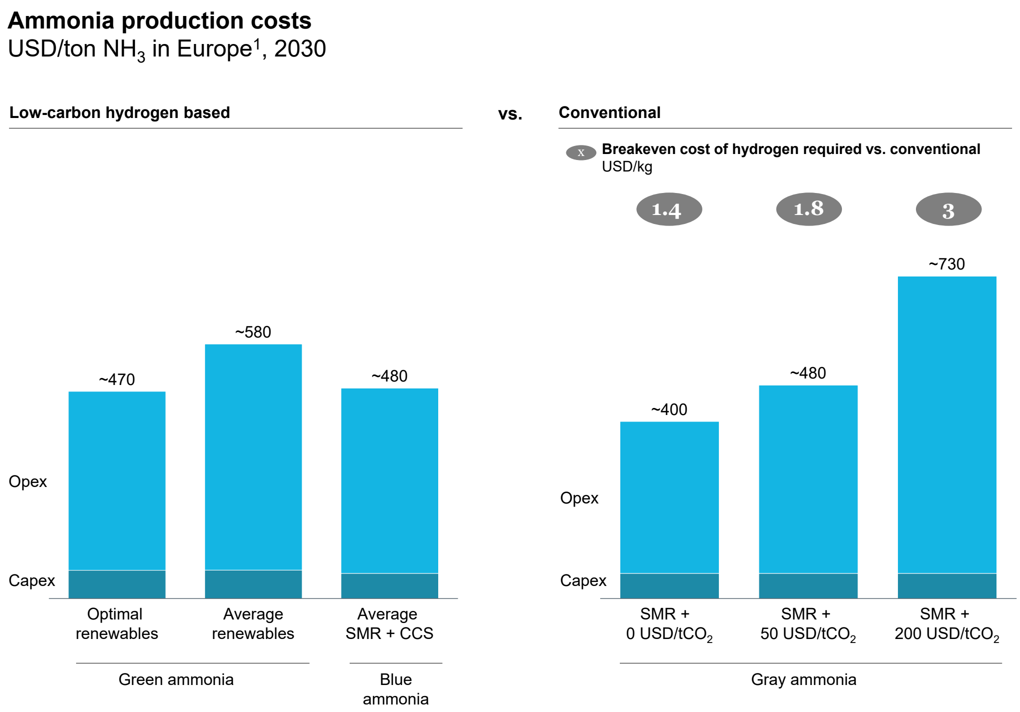
TCO Perspective

Given the feedstock intensity in the overall TCO (65-80%), ammonia production is highly sensitive to the production costs of clean hydrogen. As the cost of hydrogen production is region-specific and largely driven by renewable energy sources (RES) and carbon capture and storage (CCS) costs, the competitiveness of clean ammonia versus gray ammonia from natural gas varies by location.

Today, the production of clean ammonia in Northern Europe would cost at least USD 650-800/t and require a carbon price of USD 140-220/t of CO_2e to reach breakeven. As illustrated in Exhibit 22, the competitiveness of clean ammonia will change drastically by 2030. In Europe, the hydrogen price needed for clean ammonia to reach breakeven with its conventional counterpart by 2030 would be about USD 1.4/kg. With an optimal delivered cost of hydrogen of about USD 1.7/kg in Europe (from, for example, PV based electrolysis in Spain), green ammonia would require a carbon price of less than USD 50/t of CO_2e to break even. With average renewables in Northern Europe, breakeven would require a carbon price of approximately USD 100/t of CO_2e (see Exhibit 22).

In regions with lower-cost feedstock, such as North America and the Middle East, the breakeven cost would be even lower. In locations with constrained renewables and CCS, imported clean ammonia from optimal production locations could be an alternative to domestically produced ammonia.

Exhibit 22: Total cost of ownership of gray H_2 versus green and low-carbon for ammonia in Europe



1. Natural gas cost 6.9 USD/MMBtu, hydrogen 2030 cost 1.7/2.1/1.8 for optimal renewables (Spain solar)/average renewables (German offshore wind)/SMR with CCS

C. Steel

The steel industry is one of the three biggest producers of CO_2. Every ton of steel produced in 2018 emitted on average 1.85 tons of CO_2, amounting to about 8% of global emissions according to the World Steel Association. Increasing demand for low carbon steel products, changing customer requirements as well as tightening carbon emission regulations are only a few of the reasons decarbonization is a top priority for the steel industry. Consequently, the industry needs a drastic decrease in emissions to remain economically competitive (and in operation).

Decarbonization alternatives

Two main routes for steel production decarbonization exist: an integrated blast furnace (BF) and basic oxygen furnace (BOF) combination, or an electric arc furnace (EAF). The BF-BOF route produces steel from iron ore using coal as a reductant, while the main inputs for the EAF route are direct reduced iron (DRI) or steel scrap. While both production routes cause carbon emissions, the conventional BF-BOF route is 14 times more carbon intensive due to its dependency on coal.

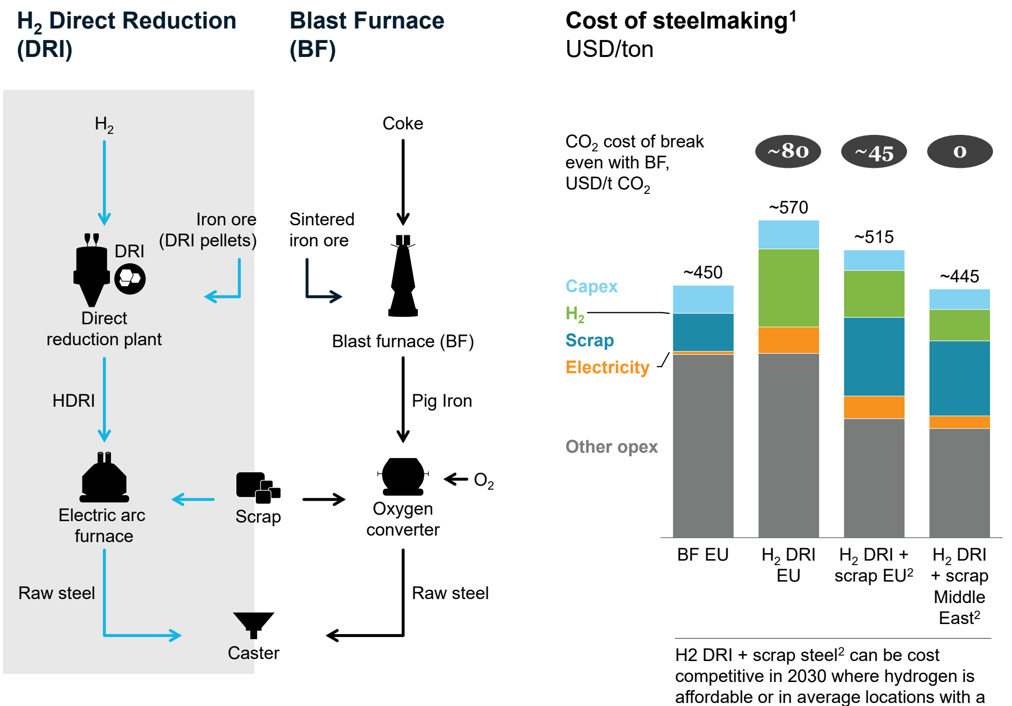
While there are strategies to decrease emissions on the BF/BOF route, including the reduction of production losses, efficiency increases, and CCU, these do not eliminate emissions fully, and have not been able to demonstrate cost-effectiveness. The DRI-EAF route in contrast can be fully decarbonized.[11] This requires steel makers to use renewable electricity to power the EAF, and then add clean

[11] Small amounts of natural gas are required that cause emissions of about 4kg CO_2 per ton crude steel – for full decarbonization these emissions would require abatement.

hydrogen or biomass as a reductant to produce the DRI. Since biomass will likely see constrained availability, we focus here on decarbonization using hydrogen.

The use of scrap in the EAF is an important driver of the total cost of production. The availability and quality of scrap largely depends on the region. Higher shares of scrap typically translate into lower costs, as DRI is usually more expensive. Higher amounts of scrap also typically reduce the quality of the steel, which implies a tradeoff between the quality of the steel produced and cost optimization from a higher share of scrap metal employed (see Exhibit 23).

Exhibit 23: Total cost of ownership of green steel versus alternative low-carbon and conventional pathways



1. End product is crude steel
2. 60% DRI, 40% scrap

TCO Perspective

In an optimized setup with 40% scrap and 60% DRI and accounting for a realistic expected cost of carbon, clean steel could become cost competitive with steel produced via the BF-BOF route by 2030. For example, clean steel production in Europe could cost as little as roughly USD 515 per ton of crude steel. This exceeds the estimated USD 450/ton of crude steel from the BF-BOF route without carbon costs, as – while capex costs are about 30% lower - H_2 feedstock costs and increased electricity requirements drive its operational costs significantly higher. This cost difference could be offset by a carbon cost of about USD 45/ton CO_2e, bringing BF-BOF produced steel to the same level as H_2-DRI and scrap steel. Using a "pure DRI" setup would increase costs significantly for the DRI-EAF route due to higher capex, higher electricity requirements, and, of course, higher DRI costs. In regions with more affordable renewables and H_2 costs, clean steel production costs could be even lower than the aforementioned USD 515/ton of crude steel from H_2-DRI + scrap in Europe.

For example, for an optimized plant in the Middle East that accesses renewable electricity at about USD 25/MWh and hydrogen at an estimated USD 1.4/kg, the cost of clean steel could be as low as approximately USD 445/ton. Interest from customers such as automotive OEMs to source green steel at a small premium creates additional momentum for clean steel alongside the favorable cost outlook in the future.

D. Sustainable shipping fuels

To date, international commercial shipping accounts for 0.9 Gt of CO_2e, equivalent to 2.6% of global GHG emissions. Assuming a business-as-usual scenario, commercial shipping emissions could increase up to 1.7 Gt of CO_2e by 2050.

To combat climate change, the International Maritime Organization (IMO) aims not only to reduce GHG emissions from shipping by at least 50% by 2050 (to 0.5 Gt of CO_2e) compared with a 2008 baseline, but to decarbonize the sector fully as soon as possible in the century.

Decreased energy demand resulting from technological advancements and targeted energy efficiency measures could save up to 0.5 to 0.9 Gt of CO_2e. However, alternative low-carbon shipping fuels are required to bridge the remaining gap of 0.3 to 0.7Gt of CO_2e for the industry to meet the IMO 2050 target of 0.5 Gt of CO_2e.

Decarbonization alternatives

To shift toward low- or zero carbon shipping, two innovations must happen in parallel: the production of decarbonized fuels and the development of new propulsion systems that enable the efficient use of these low-carbon fuels.

Phases of propulsion systems roll-out

The development of the propulsion systems will likely happen in overlapping phases: In a transitional period, dual-fuel engines running on a combination of conventional heavy fuel oil (HFO) and alternative fuels will allow a gradual shift towards decarbonized fuels with minimized retrofitting implications for established propulsion systems.

ICE propulsion systems running on low or zero carbon fuels represent the next step toward decarbonization as they – depending on the type of fuel – achieve vast emission reductions or even zero emissions at relatively low costs compared with those of alternative propulsion systems in the upcoming years.

The final phase will see the broader application of alternative propulsion systems such as electric or fuel cell systems that guarantee high fuel efficiency for hydrogen-based fuels.

Assessing different fuel choices

Industry players are discussing various fuel alternatives[12] to conventional liquid fossil fuels that differ in terms of feedstock availability and technology maturity. Moreover, depending on regulation-induced constraints, routes, and driving modes, the applicability of the alternative fuels for different ship types will also vary.

Liquified natural gas produces 30% lower CO_2 emissions compared with HFO. However, methane slippage in production processes and engines represents a real danger, as methane is 25x more potent than CO2 as a GHG measured over a 100-year period and thus detrimental to the climate. For this reason, the applicability of LNG as a low-carbon fuel is increasingly questioned. However, bio-methane and synthetic methane could be practical future options for the longer term.

[12] Liquefied natural gas, biofuels (e.g., hydrated vegetable oil), synthetic methane (not in the scope of this report), liquid clean hydrogen, green ammonia, and green methanol.

Liquid biofuel could serve as a transitionary fuel given its usability with conventional ICE propulsion systems without requiring significant retrofitting investments. However, feedstock availability constraints and growing demand from other decarbonizing sectors could result in rising prices and supply limitations. Moreover, depending on the feedstock, biofuels differ in CO_2 emission reduction potential, varying between 70% and 90% compared with HFO on a lifecycle basis.

Liquid clean hydrogen is producible in a carbon neutral way and – as a fuel – preferred over gaseous clean hydrogen due to its higher energy density. LH_2 reduces the climate impact substantially because it eliminates CO_2 and all non-CO_2 emissions (e.g., nitrogen oxide (NO_x) and sulfur oxide (SO_x)). Hence, LH_2 is a likely option for ship types that undergo stringent emission regulations such as small passenger ships sailing through natural reserves. However, the large volumes required for storage compared with other high density shipping fuels make LH_2 a less preferable option for long-haul shipping.

Ammonia is a compound of nitrogen and hydrogen featuring a high energy density (50% higher than LH_2). Companies can produce it carbon-neutrally via renewable hydrogen from electrolysis. NH_3 is easy to store and can use existing ammonia supply chains and infrastructure. Due to its toxicity, ammonia may prove challenging for some ship types (e.g., ships with passengers) due to safety concerns and potential future regulation around its storage onboard and in bunkering locations close to highly populated regions. To maximize the impact of ammonia as a sustainable shipping fuel, measures for strict control of NO_x and other non-CO_2 emissions must be in place.

Methanol results from combining CO_2 and hydrogen. Suppliers can produce it carbon-neutrally from renewable hydrogen and CO_2 from DAC, biogenic CO_2 or with reduced carbon emissions if CO_2 from industrial emissions serves as a feedstock. Regardless of the production route, fueling propulsion systems with methanol causes CO_2 emissions, partially offsetting the CO_2 savings from production. Like ammonia, methanol benefits from an existing global infrastructure and limited conversion costs for existing vessels.

TCO perspective

The most cost-effective decarbonization path differs per sub-segment of commercial shipping as each has distinct operating characteristics and economics. To account for such differences and investigate the role hydrogen-based fuels might play, we chose container ships and cruise ships for modeling.

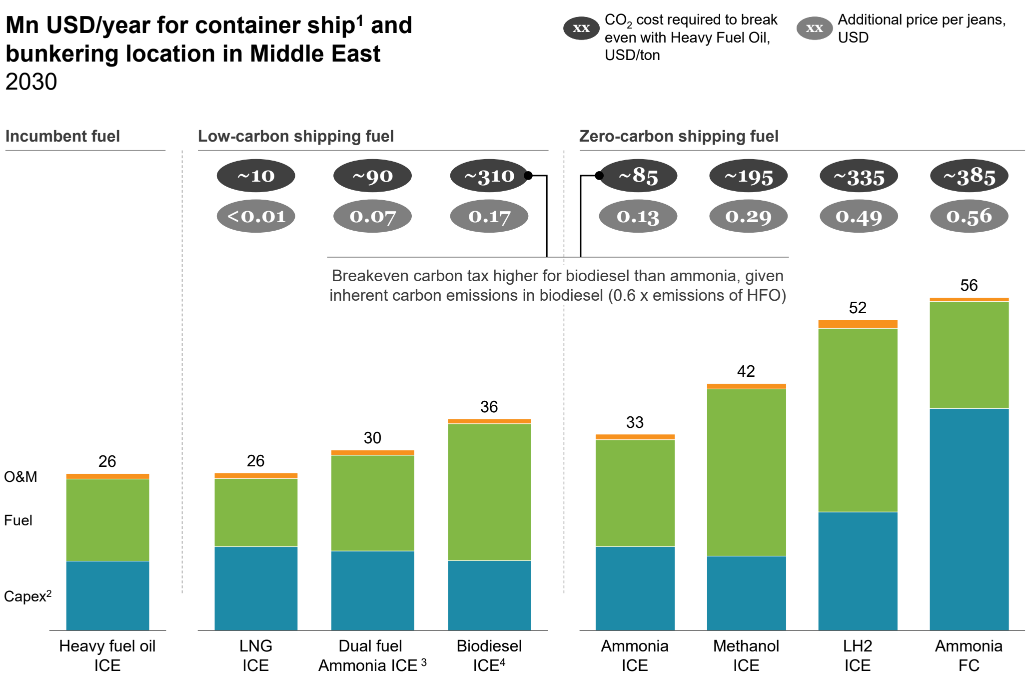
Both chosen sub-segments play a key role in the global shipping industry: container ships account for the largest share of global fleet emissions with 23%, and cruise ships represented the fastest growing segment before the COVID-19 pandemic. In addition, both segments are among the likely early-adopters of decarbonization strategies, given their proximity to end consumers that exhibit higher willingness to pay and face external regulatory pressures.

Container ships

In the long-term, green ammonia will be the cheapest zero carbon fuel for container ships, requiring USD 85/t of CO_2 to breakeven with HFO as illustrated in Exhibit 24. Dual-fuel ICE engines will accelerate decarbonization in the transitional period of the next 10 to 15 years before alternative fuels and propulsion systems reach scale. In the long-run, ammonia fuel cells should become the preferred propulsion system given their higher fuel efficiency compared with combustion engines and expected significant decrease in CAPEX over time.

Container ship operators should be able to allocate the additional costs associated with alternative fuels entirely to end customers as the cost increase only accounts for a fraction of the shipped product's final price. For example, a pair of jeans that retails at USD 60 and is transported from Southeast Asia to the US would become less than 1% (USD 0.13) more expensive if transported on a ship powered by an ammonia ICE engine compared with a ship running on heavy fuel oil (see Exhibit 24).

Exhibit 24: Competitiveness of alternative fuels in container shipping in 2030



1. 67 MW ship, TEU = 13,000–15,000, sailing distance of 84,200 sm/year
2. Including opportunity costs from increased space requirements compared to HFO ICE engine
3. Dual fuel engine powered by 50% HFO and 50% ammonia
4. 2nd generation biodiesel based on used cooking oil

Cruise ships

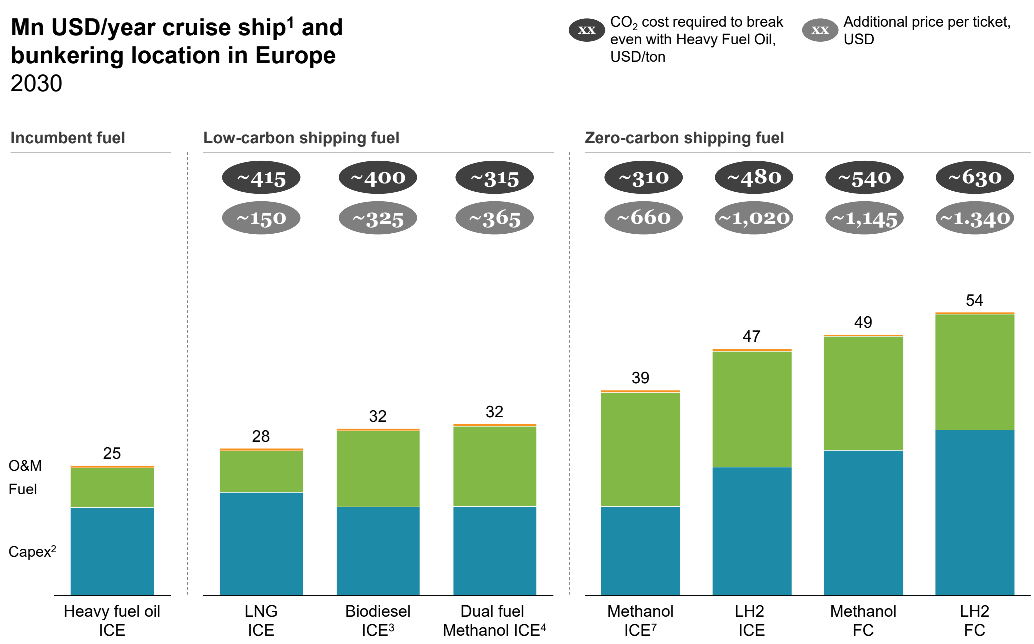
Compared with container ships, cruise ships exhibit a different route profile with shorter trip lengths, frequent stops, and more stringent safety regulations and risk considerations, all of which will likely rule out the use of ammonia due to its toxicity. Given this probability, carbon-neutral methanol and liquid hydrogen become the most viable fuel options, requiring about USD 300/t of CO_2 to break even with HFO, as illustrated in Exhibit 25.

As with container ships, dual-fuel ICE engines offer cruise ships a transitional technology until the full roll-out of methanol ICE and LH_2 fuel cells takes place. In the short run, this hybrid solution offers up to 25% lower costs compared with the fully decarbonized drive types.

Biodiesel and LNG – both discussed as transitional fuels – reduce but do not eliminate GHG emissions. LNG has the additional disadvantage of methane slippage, which has a stronger negative climate impact than CO_2. Thus, potential zero emission regulation will likely rule out the use of either fuel in some ships.

Comparable to container ships, cruise ship operators could also potentially pass the resulting cost increases of switching to green methanol or LH_2 to end consumers, as certain cruise ship passengers may have both the means and the willingness to pay for decarbonization. For example, a typical 10-day Baltic sea cruise of USD 1,400 would add about USD 660 to the average ticket price for methanol if all incremental costs were allocated entirely to customers (see Exhibit 25).

Exhibit 25: Competitiveness of alternative fuels in cruise ships in 2030



1. 18 MW ship, GT > 10,000, sailing distance of 138,200 sm/year
2. Including opportunity costs from increased space requirements compared to HFO ICE engine
3. 2nd generation biodiesel based on used cooking oil
4. Dual fuel engine powered by 50% HFO and 50% methanol

E. Aviation

The aviation sector emits more than 0.9 Gt of CO_2 per year, the equivalent of approximately 2% of the world's carbon emissions. In the past decade, the industry has shown an increased focus on decarbonization, leading to the International Air Transport Association's (IATA) target of halving CO_2 emissions by 2050 compared with a 2005 baseline.

The industry has a strong record on fuel efficiency improvement, cutting fuel burn per passenger-kilometer in half since 1990. However, operational efficiency improvements will not be enough to realize the decarbonization targets communicated by IATA.

Decarbonization options

As one of the hardest-to-abate sectors with high daily range requirements and weight constraints, aviation decarbonization options remain limited. Since batteries and electrification are currently impractical in aviation, the focus shifts to alternative fuels as substitutes for highly refined, fossil fuel-intensive jet fuel. A range of alternative fuels that vary in technological maturity and feedstock availability could substitute for traditional jet fuel.

Biofuel is the most mature and proven technology of those available. As for exact costs, the CO_2 reduction potential depends on the feedstock source chosen for biofuel production. Across feedstocks, a 70-90% reduction of CO_2 emissions compared with kerosene (jet fuel) is possible on a lifecycle basis with biofuels. Yet, contrary to other alternative fuels, biofuels emit particulate matter and other pollutants, which drive aviation's negative climate impact. Another challenge arises from potential feedstock shortages due to high demand from other segments (as discussed in the shipping fuels chapter).

Synthetic jet fuels (also called synfuels) represent another jet fuel alternative that suppliers can produce in a low-carbon way through the reaction of renewable hydrogen and CO_2. Unlike pure hydrogen solutions, synfuels can use existing jet fuel infrastructure and propulsion systems. The CO_2 decarbonization potential depends on the CO_2 feedstock source – direct air capture, in contrast to industry CO_2 emissions, creates a zero-carbon fuel. Even though synfuels do not eliminate emissions beyond CO_2 and thus reduce the overall climate impact to a lesser extent than pure hydrogen, they are one of the only viable options for the decarbonization of long-range flights from a cost perspective.

Liquid clean hydrogen is the most nascent technology in this group given its need for new propulsion systems (such as hydrogen combustion turbines or fuel cells) as well as storage and storage management systems. Hydrogen is the only alternative fuel that cuts all CO_2 emissions from flying. Furthermore, LH_2 can reduce a significant share of all non-CO_2 emissions like like NO_x and SO_x, leading to an overall reduction of 50-90% in climate impact which exceeds the reduction potential of all other alternative fuels. Contrary to other sustainable aviation fuels, LH_2 requires an overhaul of existing fuel infrastructure.

TCO perspective

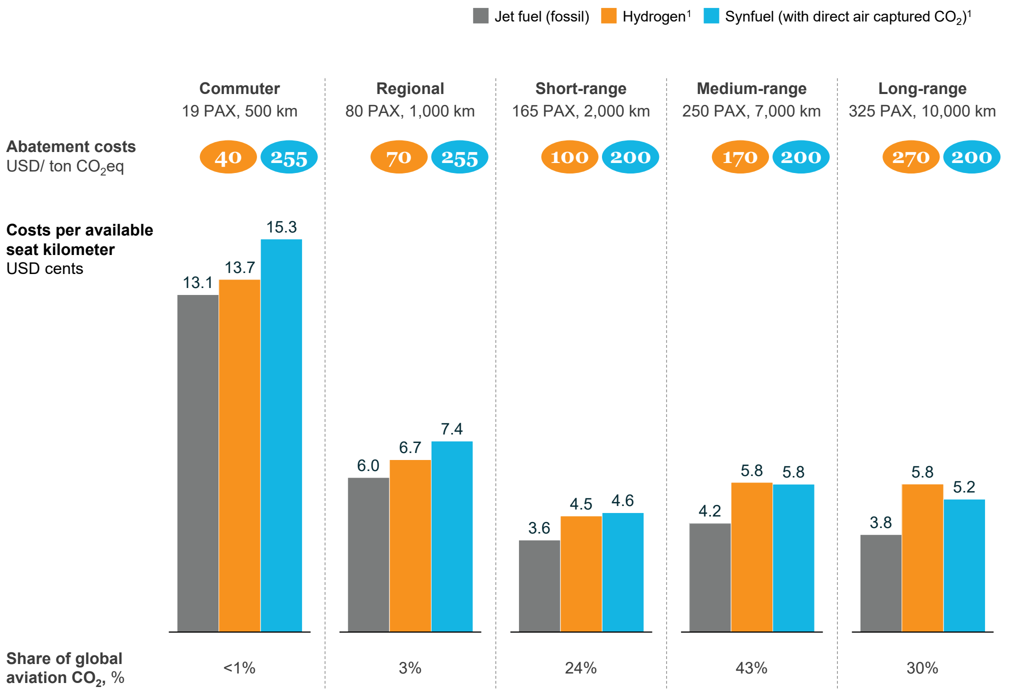
In aviation, the choice of the optimal low-carbon fuel depends on the size of the aircraft and the distance to be covered. To provide a perspective on the entire aviation industry, we modeled five different use cases: a commuter jet (19 PAX, 500km), a regional jet (80 PAX, 1,000km), a short-range aircraft (165 PAX, 2,000km), a medium range aircraft (250 PAX, 7,000km) and a long-range aircraft (325 PAX, over 10,000km). The costs modeled represent all direct and indirect costs, including CAPEX increases of the aircraft as well as infrastructure requirements.

Overall, the results show that hydrogen at scale can cost-effectively decarbonize flights up to the short and medium range categories, which account for 70% of global aviation CO_2e emissions. As highlighted in Exhibit 26, for the four use cases in this range, liquid hydrogen is the most competitive abatement option at a cost of USD 90-150/t of CO_2e by 2040. It also outperforms synfuel by 15-85% in terms cost per available seat-kilometer (CASK).

Beyond the 10,000km range, the storage space requirements make hydrogen unfeasible in terms of cost. Thus, for long-range flights, which account for 30% of global CO_2e emissions, synfuel is the most cost-competitive decarbonization option, at a cost of USD 200/t of CO_2e.

Note that, unlike in the rest of the report, we take a 2040 perspective here because an earlier entry-into-service and commercialization assumption for hydrogen-based aircraft remains unlikely (see Exhibit 26).

Exhibit 26: Total cost of ownership of aviation fuels for different use cases in 2040



1. Hydrogen propulsion assumed to be fuel cell-based for Commuter and Regional flights, and H_2 turbines for Short/Medium/Long-range aircrafts. Synfuel produced with Reverse Water Gas Shift reaction and Direct Air Capture (DAC). Production based in Europe

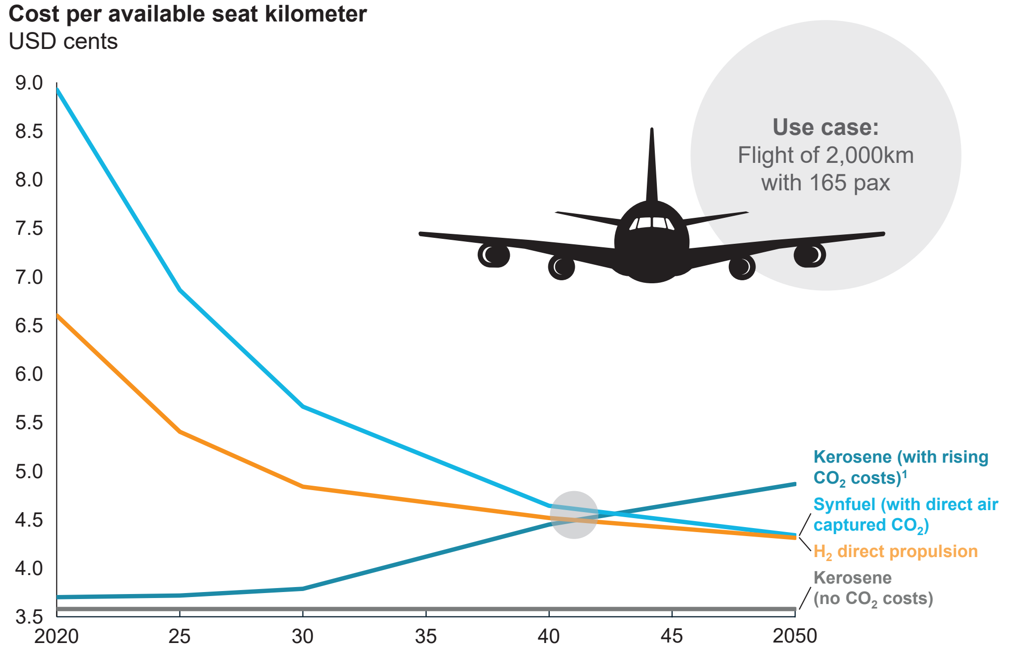
Zoom-in on short-range segment. Hydrogen is a more competitive decarbonization alternative for short-range flights than synfuel as it outperforms synfuels in both costs and climate impact. Over time, the cost advantage of hydrogen over synfuels will decrease as costs for the direct air capture technology required to produce carbon neutral synfuels fall.

Switching from kerosene to hydrogen implies a cost of about USD 100/t of CO_2e. If this additional cost were allocated entirely to the end consumer, it could raise the price of an airplane ticket by 30-35% in 2030 or USD 25 for a one-way flight from Frankfurt to London (see Exhibit 27).

Zoom-in on long-range segment. For the long-range flight segment synfuel is the most cost-competitive viable decarbonization option, as the required tank size would rule out hydrogen for distances of more than 10,000 km. While synfuel in the near future is still expensive, the costs of synfuel should drop significantly (by over 50% between 2020 and 2040), driven by the decreasing feedstock prices of hydrogen and CO_2. However, a high carbon cost of between USD 200 and 250/t of CO_2e is still needed to break even with kerosene. In a scenario with a USD 50/t of CO_2 cost of carbon in 2030 and a strong acceleration to USD 200/tCO_2 by 2040, synfuel could break even with conventional jet fuel between 2038 and 2043 for long-range flights, as shown in Exhibit 28.

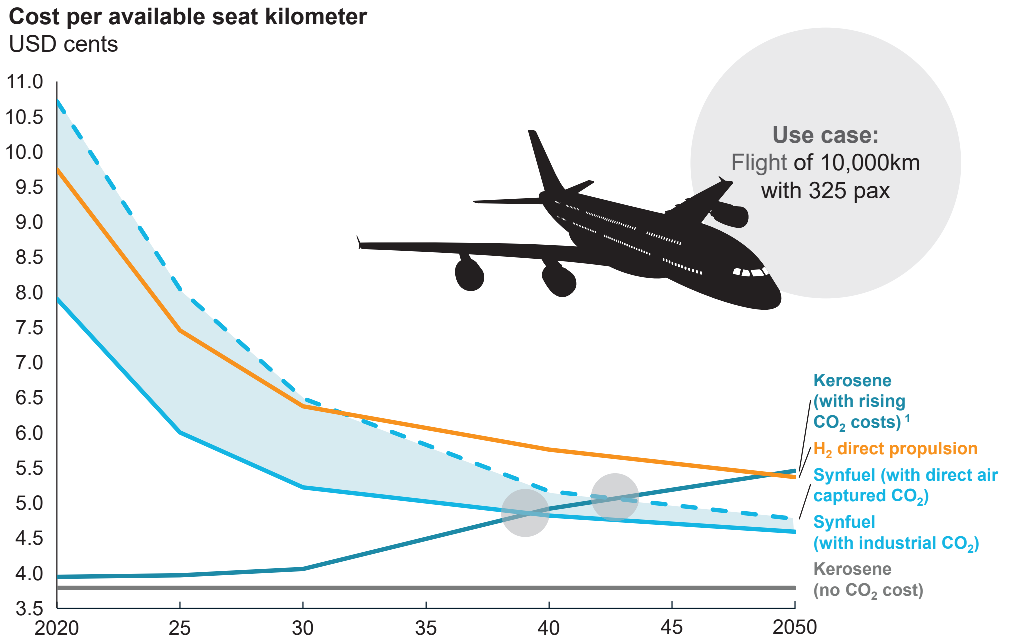
For the end customer, the ticket price for a long-range flight from London to Singapore (with an average ticket price of USD 600) might increase by up to USD 300 by 2040 if airlines allocate costs entirely to the end customer.

Exhibit 27: Total cost of ownership of a short-range flight over time



1. CO_2 cost growing from approx. 30 USD/t CO_2e in 2020 to 50 USD/t CO_2e in 2030, 200 USD/t CO_2e in 2040 and 300 USD/t CO_2e in 2050

Exhibit 28: Total cost of ownership of a long-range flight over time



1. CO_2 cost growing from approx. 30 USD/t CO_2e in 2020 to 50 USD/t CO_2e in 2030, 200 USD/t CO_2e in 2040 and 300 USD/t CO_2e in 2050

Hydrogen scale up will require capital and sector-level strategies

70bn

committed public funds by governments to support hydrogen transition strategies

VI | Implementation: bringing it all together to capture the promise of hydrogen

The strong commitment to deep decarbonization by governments worldwide has triggered an unprecedented wave of momentum in the hydrogen industry. Financial support, regulation and clear hydrogen strategies and targets in combination with the USD 70 billion committed public funds by governments to support the hydrogen transition have caused value chains to scale up, costs to come down and investments to climb to new heights.

The next chapter in the hydrogen story requires stakeholders to translate their ambitious strategies into concrete measures. Governments, businesses and investors should set sector-level strategies (e.g., for the decarbonization of steel), with long-term targets, short-term milestones, and the necessary regulatory frameworks. They must develop value chains for equipment, scale up manufacturing, attract talent, build capabilities, and accelerate product and solution development. This scale up will require capital, and investors have an outsized role to play in developing and pushing at-scale deployments. All this will require new partnerships and ecosystem building, with both businesses and governments playing important roles.

To get things started, strategies should aim at the critical unlocks, like reducing the cost of hydrogen production and distribution. We estimate that roughly 65 GW of electrolysis are required to bring costs down to a breakeven with gray hydrogen. This equals a funding gap of about USD 50 billion.

One place to support deployment is the development of clusters with large-scale hydrogen offtakers at their core. These will drive scale through the equipment value chain and reduce the costs of hydrogen production. By combining multiple offtakers, players can share investments and risks and begin to establish positively reinforcing collaborative loops. Other smaller hydrogen offtakers in the vicinity of such clusters can then piggy-back on the lower-cost hydrogen supply, making their operations breakeven faster.

Based on these core characteristics, we see several cluster types gaining traction, including:

- **Port areas** for fuel bunkering, port logistics, and transportation
- **Industrial centers** that support refining, power generation and the production of fertilizer or steel
- **Export hubs** in resource rich countries

To make clusters successful, they should include players along the whole value chain to optimize costs, tap into multiple revenue streams and maximize the utilization of shared assets. They should be open to additional players and infrastructure should allow easy access where possible.

The next few years will be decisive for the development of the hydrogen ecosystem, for achieving the energy transition and for attaining the decarbonization objective. As this report shows, progress over the past year has been impressive, with unprecedented momentum. But much lies ahead. The companies in the Hydrogen Council are committed to deploying hydrogen as a critical part of the solution to the climate challenge and Hydrogen Insights will provide a regularly updated, objective and global perspective on the progress achieved and the challenges ahead.

Glossary

ATR	Autothermal reforming
BEV	Battery electric vehicle
BF	Blast furnace
BOF	Blast oxygen furnace
BT	Benzyltoluene
CAPEX	Capital expenditure
CASK	Cost per available seat kilometer
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
DAC	Direct air capture
DRI	Direct reduced iron
EAF	Electric arc furnace
EPC	Engineering, procurement and construction
ESG	Environmental and social governance
EU	European Union
FC	Fuel cell
FCEV	Fuel cell electric vehicle, including light- and heavy-duty vehicles, and material-handling vehicles
FID	Final investment decision
GHG	Greenhouse gas
GDP	Gross domestic product
Gt	Gigaton
HDT	Heavy duty truck
HFO	Heavy fuel oil

HRS	Hydrogen refueling stations
H_2	Hydrogen
IATA	International air transport association
ICE	Internal combustion engine
IMO	International maritime organization
kg	Kilogram
km	Kilometer
LCFS	Low carbon fuel standard
LCO_2	Liquid carbon dioxide
LCOE	Levelized cost of electricity
LH_2	Liquid hydrogen
LNG	Liquefied natural gas
LOHC	Liquid organic hydrogen carrier
MENA	Middle East and North Africa
MeOH	Methanol
MMBTu	Million British thermal units (unit of energy, 1 MMBTU = 1.06 GJ)
Mt	Million tons
M&A	Merger and acquisition
NH_3	Ammonia
NO_x	Nitrogen oxides (type of tailpipe emission from ICE vehicles)
PAX	Persons approximately (number of passengers carried)
PEM	Polymer electrolyte membrane
PV	Photovoltaics
R&D	Research and development
RE	Renewable energy

RES	Renewable energy sources
SMR	Steam methane reforming
SO_x	Sulfur oxides (type of tailpipe emission from ICE vehicles)
SUV	Sport utility vehicle
t	Ton(s)
TCO	Total cost of ownership
TW/GW/MW/kW	Terawatt, gigawatt, megawatt, kilowatt (unit of power, 1 Watt = 1 J per s)
TWh/MWh/kWh	Terawatt hour, megawatt hour, kilowatt hour (unit of energy, 1 Watt-hour = 3600 J)
USD	United States Dollars
WACC	Weighted average cost of capital

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