For producing low-carbon hydrogen from natural gas with CCS, two technology options exist: steam methane reforming (SMR) and autothermal reforming (ATR). SMR combines natural gas and pressurised steam to produce syngas, which is a blend of carbon monoxide and hydrogen. Providers can easily capture about 60 per cent of the total carbon by separating the CO_2 from the hydrogen; the additional must be extracted from the exhaust gas, which is relatively expensive today, allowing for up to 90 per cent total capture rate.

ATR combines oxygen and natural gas to produce syngas. This process can easily capture up to 95 per cent of CO_2 emissions. ATR technology is typically used for larger plants compared with SMR technology.

Coal gasification produces hydrogen by reacting coal with oxygen and steam, which like the ATR plant, allows for a relatively easy capture of CO_2. However, the coal gasification plant emits about four times more CO_2 per kg of hydrogen produced than the ATR plant, increasing the amount of carbon that must be transported and stored.

Conditions for hydrogen production across regions and over time

The cost of hydrogen varies significantly across regions, as it depends heavily on the prices and availability of energy inputs. To produce low-carbon hydrogen from reforming plus CCS, companies require access to low-cost natural gas, such as in the US, where gas prices are below USD 3 per million British thermal units (MMBtu) and large-scale CO_2 storage (e.g. depleted gas fields, suitable rock formations). For renewable hydrogen from electrolysis, the crucial factor is access to low-cost renewables. For example, the levelised cost of energy (LCOE) for new solar power today can run as low as about USD 20 per MWh in regions such as North Africa.

When considering low-cost hydrogen's cost trajectory, the optimal cost of low-carbon hydrogen from reforming plus CCS could drop below USD 1.50 per kg in the short term in the most attractive geographic locations. In addition, the analysis shows that a carbon cost of about USD 50 per ton of CO_2e would allow low-carbon hydrogen to reach parity with grey hydrogen.

Low-carbon hydrogen production from reforming plus CCS is attractive in regions with natural gas, as it provides an option to leverage these resources. It is typically possible to store captured carbon in existing gas fields, and these countries often have the existing infrastructure and industry to handle gas. With enough scale, costs could drop to about USD 1.20 per kg in 2025 in regions like the US or the Middle East. For regions with higher average natural gas costs like Europe, low-carbon hydrogen from reforming plus CCS will cost around USD 2.10 per kg in 2020, declining to approximately USD 1.80 in 2030 due to the lower cost of carbon capture and carbon storage opportunities.

Regions such as Chile, Australia and Saudi Arabia have access to renewables from both wind and solar at low LCOE which enables high load factors for hydrogen production through electrolysis. They thus offer optimal potential for producing renewable hydrogen at minimum costs. Under these optimal conditions, hydrogen production could become available at costs of about USD 2.50 per kg by the early 2020s, declining to USD 1.90 per kg in 2025 and perhaps as low as USD 1.20 per kg in 2030. This is well below the average for grey hydrogen, and even close to parity with optimal grey hydrogen costs in 2030 if CO_2 costs are factored in.

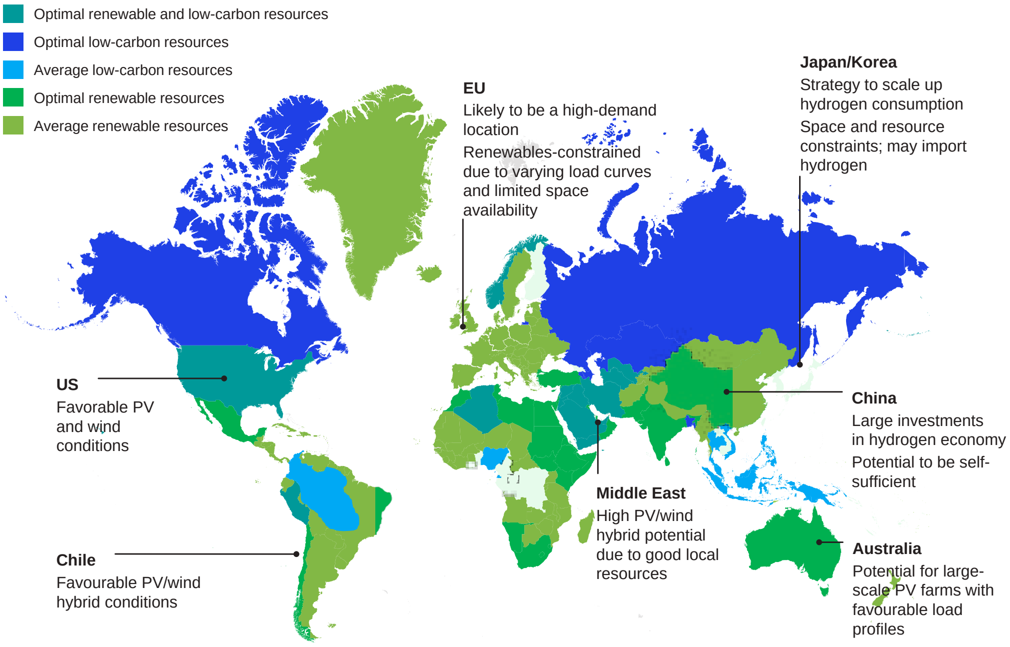
For regions where renewables cost are on average higher, e.g. Northern Europe, there are usually areas with favourable conditions for renewables. This makes it possible to produce hydrogen at lower-than-average costs and makes site selection for renewable hydrogen production of critical importance. The cost of renewable hydrogen produced from offshore wind in Europe starts at about USD 6 per kg in 2020. This rate is expected to decline by about 60 per cent by 2030 to approximately USD 2.50 per kg, driven by scale in electrolyser manufacturing, larger systems, and lower-cost renewables.

Other countries may have limited resources to produce low-carbon or renewable hydrogen at scale locally, such as Japan or Korea, and even parts of Europe. Some of these regions have ambitious decarbonisation policies that will require hydrogen; if local production cost is too high or unable to meet demand, they may become importers of hydrogen. Exhibit 12 shows where low-carbon hydrogen from reforming plus CCS and renewable hydrogen from electrolysis is projected to become cost competitive.

Grey hydrogen, the most competitive option today, should be fully phased out by 2050 to meet the 2-degree target. It is expected to become increasingly less competitive over time as the cost of CO_2 emissions increase, reaching cost levels higher than all low-carbon alternatives prior to 2040.

Exhibit 12 | Hydrogen production potential across regions

Best source of low-carbon hydrogen in different regions



EU
Likely to be a high-demand location
Renewables-constrained due to varying load curves and limited space availability

Japan/Korea
Strategy to scale up hydrogen consumption
Space and resource constraints; may import hydrogen

US
Favorable PV and wind conditions

China
Large investments in hydrogen economy
Potential to be self-sufficient

Middle East
High PV/wind hybrid potential due to good local resources

Chile
Favourable PV/wind hybrid conditions

Australia
Potential for large-scale PV farms with favourable load profiles

SOURCE: IEA; McKinsey

Demand centres, e.g. EU, North-east Asia, are often constrained for resources, and may not be able to self-supply hydrogen.

Countries with complementary load profiles of wind and PV can produce renewable hydrogen at very low prices.

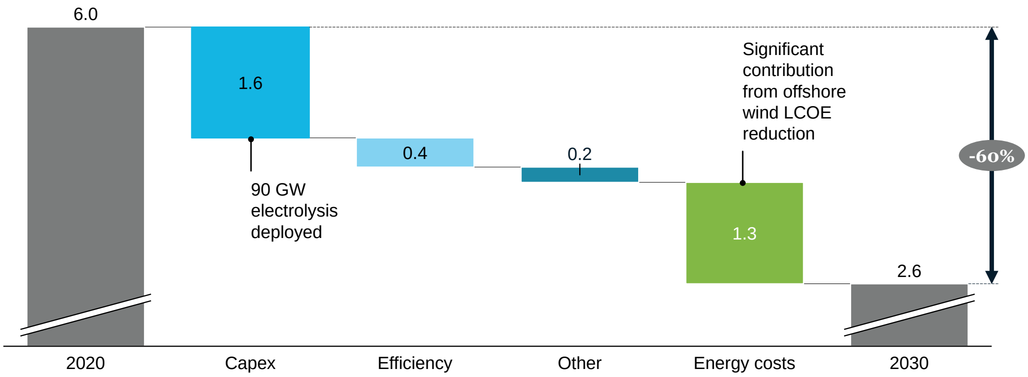
Regions like China and the US are both demand centres and have favourable RES.

Renewable hydrogen from electrolysis cost-reduction drivers

Since 2010, the cost of electrolysis has fallen by 60 per cent, from between USD 10 to 15 per kg hydrogen to as low as USD 4 to 6 today. The analysis shows that they will continue to fall: offshore wind-based electrolysis shows another 60 per cent cost reduction from now until 2030 (see Exhibit 13).

Exhibit 13 | Renewable hydrogen from electrolysis cost trajectory

Cost reduction lever for hydrogen for electrolysis[1] connected to dedicated offshore wind in Europe (average case)
USD/kg hydrogen



1. Assume 4,000 Nm3/h (~20 MW) PEM electrolysers connected to offshore wind, excludes compression and storage
2. Germany assumed

SOURCE: H21; McKinsey; Expert interview

Capex decreases ~60% for the full system driven by scale in production, learning rate, and technological improvements.

Increasing system size from ~2 MW to ~90MW.

Efficiency improves from ~65% to ~70% in 2030.

Other O&M costs go down following reduction in parts cost and learning to operate systems.

Additionally, storage may become cheaper (not included).

Energy costs[2] offshore wind LCOE decreases from 57 to 33 USD/MWh, and is assumed to be dedicated to hydrogen production.

Grid fees decrease from ~15 to 10 USD/MWh.

Load factor of 50%, i.e. ~4,400 full load hours equivalent.

Key drivers for continued cost reduction include the industrialisation of electrolyser manufacturing (-25 per cent), improvements in electrolyser efficiency and operations and maintenance (-10 per cent), and the use of low-cost renewable power (-20 per cent). The latter will be region specific and depend highly on access to renewable resources (sun and wind).

Regarding capex, a 60 to 80 per cent reduction from larger-scale manufacturing is expected by 2030. Important drivers of this drop include the shift from a largely manual production process to greater use of automation and 'roll-to-roll' streamlined production processes. Supporting factors include further technological improvements (like optimisation of catalyst loading), and increased system sizes, with associated scaling benefits. Moving from the 1 to 2 MW systems typically deployed today to, for instance, 80 to 100 MW systems can significantly decrease the cost contribution from auxiliary systems. In total, these improvements should reduce the capex from today's USD 2 per kg of hydrogen produced to USD 0.50 per kg by 2030. As mentioned in the previous chapter, this number might be conservative: the underlying learning rate is notably more conservative than in other 'new' technologies like solar photovoltaics (PV) and wind power. Thus, actual cost decline could happen even faster and accelerate the competitiveness of renewable hydrogen from electrolysis even more.

Higher efficiency results from incremental improvements in technology. The industry could increase lower heating value efficiency from around 64 to 68 per cent today for PEM/alkaline technology to about 70 per cent in 2030. Higher efficiency enables a smaller system using less electricity to produce the same amount of hydrogen, which would account for an approximate USD 0.40 per kg of hydrogen cost improvement. Additional O&M cost improvements should contribute another USD 0.20 per kg in cost cuts.

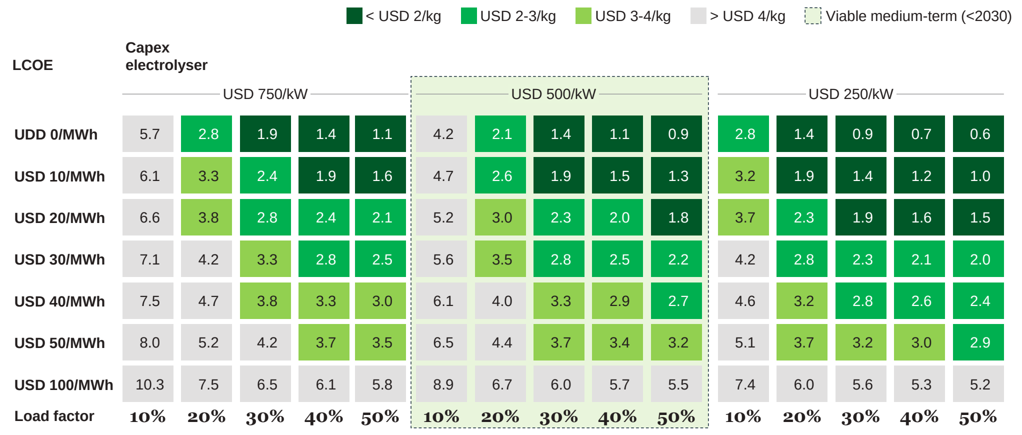
The lower cost of electricity from renewables will contribute the biggest share of reduction in operational cost. In the offshore wind example, a 40 per cent cost decline from approximately USD 70 to 40 per MWh could occur in 2030, accounting for lower costs of around USD 1.30 per kg.

Variations in renewables resources make renewable hydrogen from electrolysis production highly region specific. For example, solar paired with wind power in Chile should reduce hydrogen production cost to as low as USD 1.40 in 2030. Exhibit 14 shows the resulting production cost under different LCOE, utilisation, and electrolyser capex assumptions. The assessment also shows that even for a conservative assumption – an electrolyser capex of USD 500 per kW – access to renewables at USD 20 per MWh enables production of renewable hydrogen at about USD 2 per kg.

Exhibit 14 | Renewable hydrogen from electrolysis production cost scenarios[5], USD/kg hydrogen

Cost of renewable hydrogen with varying LCOE and load factors

USD/kg H_2



■ < USD 2/kg ■ USD 2-3/kg ■ USD 3-4/kg ■ > USD 4/kg ⬚ Viable medium-term (<2030)

LCOE / Capex electrolyser	USD 750/kW					USD 500/kW					USD 250/kW				
UDD 0/MWh	5.7	2.8	1.9	1.4	1.1	4.2	2.1	1.4	1.1	0.9	2.8	1.4	0.9	0.7	0.6
USD 10/MWh	6.1	3.3	2.4	1.9	1.6	4.7	2.6	1.9	1.5	1.3	3.2	1.9	1.4	1.2	1.0
USD 20/MWh	6.6	3.8	2.8	2.4	2.1	5.2	3.0	2.3	2.0	1.8	3.7	2.3	1.9	1.6	1.5
USD 30/MWh	7.1	4.2	3.3	2.8	2.5	5.6	3.5	2.8	2.5	2.2	4.2	2.8	2.3	2.1	2.0
USD 40/MWh	7.5	4.7	3.8	3.3	3.0	6.1	4.0	3.3	2.9	2.7	4.6	3.2	2.8	2.6	2.4
USD 50/MWh	8.0	5.2	4.2	3.7	3.5	6.5	4.4	3.7	3.4	3.2	5.1	3.7	3.2	3.0	2.9
USD 100/MWh	10.3	7.5	6.5	6.1	5.8	8.9	6.7	6.0	5.7	5.5	7.4	6.0	5.6	5.3	5.2
Load factor	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%

SOURCE: McKinsey

Low-carbon hydrogen production cost-reduction drivers

Low-carbon hydrogen from natural gas has the potential to enter the market with costs only about 10 to 20 per cent higher than those of conventional grey hydrogen, providing low-carbon hydrogen at scale. In addition to the cost of the natural gas feedstock itself, the other key cost components of low-carbon hydrogen from reforming plus CCS are CO_2 capture, transportation and storage.

The cost of the CO_2 capture process itself is estimated to be roughly USD 0.20 to 0.30 per kg for an SMR plant, and less than USD 0.10 per kg for an ATR plant where the process design leads to more concentrated CO_2 streams.

The second important factor is the cost and availability of CO_2 transport and storage. CO_2 storage is typically available in natural-gas-rich regions, as depleted oil and gas fields make good storage areas. However, this strategy requires significant upfront investments – often hundreds of millions[6] of dollars and several years – to finalise development. That is why projects expected to happen between 2025 and 2030, such as Northern Lights[7], require action and investment today. These projects generally seek to transport and store large amounts of CO_2, and thus they will depend on several industrial scale emitters to co-invest and share the cost burden. This is similar to conventional O&G investments, underlining the importance of developing high downstream demand for low-carbon hydrogen.

In addition to low-carbon hydrogen production from natural gas, it is also possible to produce hydrogen from coal gasification with CCS. The gasification of coal emits roughly four times more CO_2 per kg of hydrogen produced and consequently has higher required sequestration volumes. In addition, residual CO_2 emissions per kg of hydrogen are higher than for SMR/ATR. Thus, the tradeoff is between feedstock cost, which can be very low for regions that are rich in coal and have already established relevant infrastructure, such as China or Australia, and CO_2 sequestration and residual emissions cost. Overall, costs should amount to USD 2.10 per kg of hydrogen for a coal cost of about USD 60 per ton.

---

[5] The specified capex includes BoP. The assessment assumes additional 25 per cent for assembly/EPC and USD 65/kW for grid connection and building construction.

[6] Press reports on Northern Lights mention the requirement for over USD 1 billion in public funding.

[7] Equinor (2019).

Global hydrogen shipping

Since the costs of hydrogen production differ significantly between regions, long-distance transmission and international trade in hydrogen can be attractive. This is particularly true for countries like Japan or South Korea, which are expected to have large hydrogen demand but lack suitable locations to deploy power generation from wind and solar.

A global supply chain will likely consist of long-distance pipelines as well as shipping routes. Even existing natural gas pipelines can transport hydrogen, often with only modest upgrades. This could be an option, for example, to transport low-carbon hydrogen derived from natural gas from Russia or Norway into Central Europe; or renewable hydrogen from electrolysis from Northern Africa into Southern Europe.

For hydrogen shipping to become economically feasible, the industry needs to scale up its infrastructure, targeting to reach similar levels that liquid natural gas (LNG) has today in the mid to long term. Since ship-based imports will always directly compete with domestic production, domestic hydrogen cost levels and their potential to reduce will be decisive. In the case of Japan, the analysis shows that ship-based imports are economically competitive versus locally produced renewable hydrogen from electrolysis as long as local renewables' LCOE are above USD 60 per MWh or not available at a scale that could meet the full domestic power demand.

There are several technology options for shipping hydrogen globally. The three major archetypes are liquid hydrogen (LH2), ammonia (NH3), and a set of different technologies based on liquid organic hydrogen carriers (LOHCs).

LH2 shipping delivers hydrogen in pure form at the location of import. Today LH2 shipping costs are high (e.g. for the route from Saudi Arabia to Japan about USD 15 per kg in 2020), but with enough scale, they could fall to USD 1.7 per kg in 2030. Indeed, the technology is similar to that used for LNG, which supports quick scale-up given similar conditions as for LNG – namely large enough demand in demand centres to warrant investment into hydrogen production and transmission. This would require a scale-up of typical vessel capacity from 160 tons to about 10,000 tons, and liquefaction capacity from 10 to 50 tons per day to as much as 500 tons per day. In addition, if further transportation with trucks or storage in liquid form is required or direct use of hydrogen, e.g. for industry or fuel cell vehicles, LH2 shipping benefits this next step in the value chain as no further conversion to hydrogen is required.

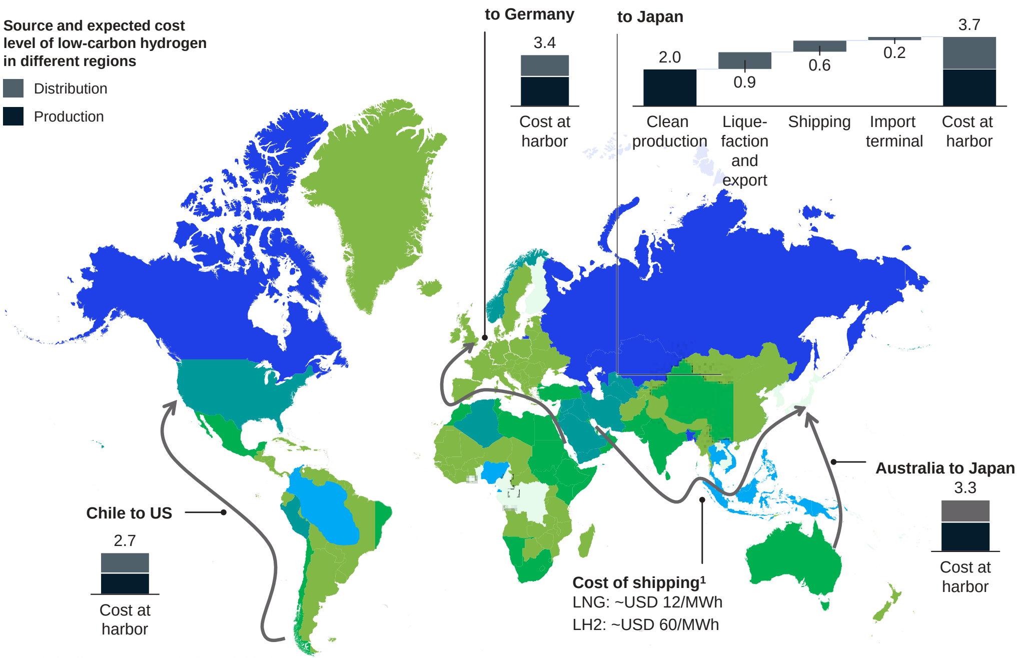
Exhibit 15 shows examples of potential shipping routes and end-to-end costs for LH2 shipping. It should be noted that these values are highly sensitive to scale-up and uncertainty around the opportunities for cost reductions remains.

Using ammonia as the hydrogen carrier has the benefit of leveraging existing infrastructure for global distribution. Additionally, the conversion from hydrogen to ammonia is a well-established technology. In cases where the end use is ammonia, shipping ammonia is the preferred option (but requires careful handling by certified operators due to its toxicity). However, if the end use requires pure hydrogen, an additional reconversion step is required, which is currently at an early stage of development. In addition, reconversion would require access to low-cost clean energy at the arrival port if the desire is to have a low-carbon or renewable hydrogen product: the absence of which is exactly why hydrogen was being shipped into the demand centre in the first place. Depending on the technology evolution and local conditions, this reconversion step could add another USD 1 to 2 per kg on top of conversion and shipping costs.

Exhibit 15 | Global shipping of hydrogen

Cost of shipping liquid hydrogen across regions, 2030

USD/kg



1. Includes liquefaction, terminals, and shipping

SOURCE: McKinsey Energy Insights

LOHC shipping based on a range of different chemical compounds, such as toluene or methyl-cyclohexane, has the benefit of leveraging existing shipping infrastructure and allows hydrogen to be transported and stored as a liquid. Like ammonia, a challenge lies in the dehydrogenation step, which requires scale-level development as well as significant energy input at the import destination. In contrast to ammonia, it also requires the return of the carrier to the port of origin. Further, there are several different LOHC technologies, hindering economies of scale unless global standardization is achieved. Given the low maturity of the technology, cost estimates for LOHC, as well as cycling rates, are still highly uncertain and require additional research and development. Therefore, a conclusive cost analysis was not undertaken in this study.

Which shipping technology will become the least cost option depends on the end uses, the required onshore transportation, scale up and technological development. If hydrogen is the end use, LH2 seems to be the closest to maturity across the value chain and the lowest-cost alternative by 2030, although significant scale-up will be a critical prerequisite for cost reductions.

Local hydrogen distribution

To reach sufficiently low hydrogen costs at the point of consumption, production (or delivery to a major centralised facility such as a port) is only part of the story. Often, hydrogen must also undergo local distribution to the end user.

Central, large-scale applications like ammonia production or refining will typically produce hydrogen either on-site or nearby (in the case of an industry complex with several hydrogen consumers) and then distribute it via pipelines. Since such infrastructure already exists today at scale, the cost contribution is minor, with limited cost-reduction potential.

For decentralised users of hydrogen, the situation is different. Here, last-mile distribution is a major cost driver – often responsible for more than 50 per cent of the total hydrogen cost. That being said, The analysis suggests that hydrogen distribution can become highly competitive once the industry achieves scale and high levels of utilisation throughout the value chain.

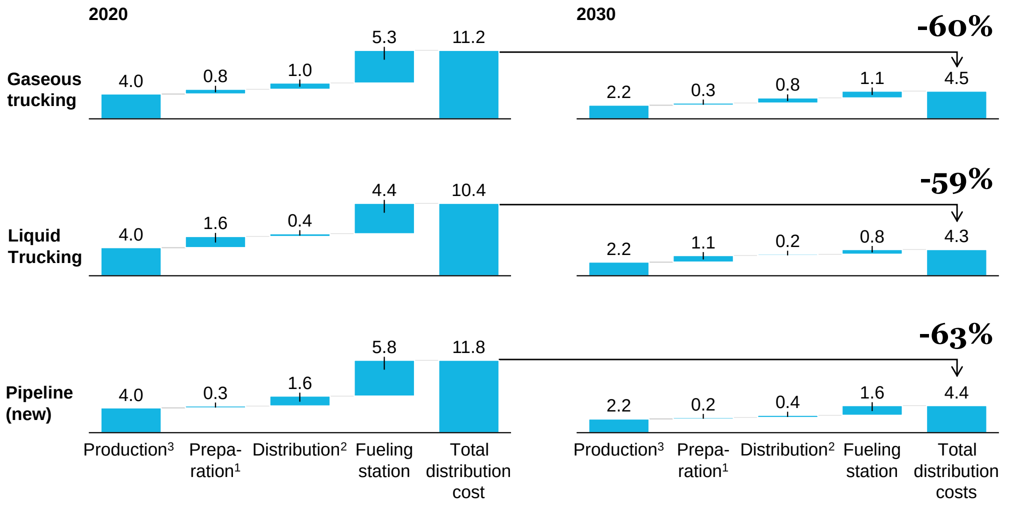
Three main options exist for hydrogen distribution: 1) trucking of compressed hydrogen, 2) trucking of liquefied hydrogen, and 3) the use of pipelines. The decision of which distribution option to pursue will differ from case to case, based on the demand profile and the distance from supply. For shorter distances, compressed gaseous hydrogen (GH2) offers the lowest cost. Liquid trucking is most economical for distances above 300 to 400 km. If hydrogen is already available in liquid form at the production or delivery site, even shorter distances are economical.

Building a new hydrogen distribution pipeline network is a significant investment over multiple years but can become economical in cases that involve large volumes. However, companies could also use existing natural gas pipelines. Here, either hydrogen blending or – if the current network configuration allows for it – upgrades to pure hydrogen distribution, may make sense.

Analyses suggest that all the pathways for hydrogen distribution should decline significantly in cost over the next decade – by about 60 per cent including production, and by as much as approximately 70 per cent when only considering distribution and retail – bringing the cost of hydrogen at the pump to less than USD 5 per kg by 2030. Exhibit 16 shows the evolution of hydrogen cost including distribution for the three different options.

Exhibit 16 | Evolution of hydrogen cost for transportation

Cost of hydrogen
USD/kg dispensed



1. Compression for gaseous trucking, liquefaction for liquid trucking or storage for pipelines
2. Gaseous trucking, liquid trucking or pipelines
3. Assumes average blue and green production cost in Europe (Germany offshore wind)

SOURCE: McKinsey Hydrogen Supply Model

Scaling up distribution channels and refuelling stations is key for achieving cost reductions.

Pipelines are the lowest-cost alternative when there is a network to leverage and high hydrogen volumes.

Energy consumption for the liquid and high-pressure routes is centralised; pipelines and low-pressure trucking require more higher-cost energy on-site.

Achieving this level of cost improvement depends on the scale-up of demand and the associated increase in utilisation of distribution infrastructure. For example, the main cost drivers in the trucking distribution pathway are as follows:

Increase in trucking capacity. Costs for gaseous and liquid hydrogen trucking should decrease by USD 0.10 to 0.20 per kg for typical distances of 300 to 500 km, due mainly to improved utilisation and lower equipment costs with rising scale.

Increasing scale and density of filling centres. Increasing utilisation and scaling up capacity of truck filling centers and liquefaction plants should reduce costs further by about USD 0.50 per kg for both liquid and gaseous trucking. A further cost decline is expected from the increasing density of filling centres: a reduction of trucking distance by 100 km on average will reduce trucking costs by another USD 0.10 per kg.

Scaling up demand and HRS size. Hydrogen refuelling stations are currently the highest cost element in the cost at the pump, accounting for about 70 per cent of total distribution and retail costs. Today's high cost primarily results from the low utilisation of even small stations due to the limited uptake of fuel cell vehicles. A cost decline of about 80 per cent is possible, from roughly USD 5 to 6 per kg in 2020 to about USD 1 to 1.50 per kg in 2030. The savings consist of higher utilisation (USD -2 per kg), increasing station size (USD -1 per kg) and industrialisation of equipment manufacturing (roughly USD -0.80 per kg).