Guidehouse

Covering Germany's green hydrogen demand: Transport options for enabling imports

Imprint

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Executive Summary

Green hydrogen will play an important role in the energy transition. In Europe, Germany is expected to become the biggest importer of green hydrogen and its derivatives, accounting for more than half of the combined hydrogen import demand across European countries. Transport of hydrogen and its derivatives will be a crucial step for meeting local demand.

Hydrogen demand. Germany's demand for hydrogen[1] is expected to grow immensely in the coming years. To reach the 2030 decarbonisation target and achieve climate neutrality by 2045, the National Hydrogen Strategy foresees hydrogen demand to be between 90 terawatt-hours (TWh) and 110 TWh per year in 2030 and reach 110 TWh-380 TWh by 2050. Other studies forecasting Germany's future green hydrogen needs suggest demand could be two to three times as high.[2]

Import demand. Given the high expected demand levels and limited potential for green hydrogen production in Germany, most of the green hydrogen demand will have to be met by imports. Countries in Europe and outside Europe will be needed as partners for covering demand. Spain, the UK, and Scandinavia have the highest production potential for green hydrogen in Europe, while the largest potential for exports is expected in Spain, and in Scandinavia. Outside of Europe, studies identify the highest hydrogen export potential in Australia, Argentina, Brazil, Canada, Chile, Morocco, Oman, Saudi Arabia, and the United Arab Emirates, among others. Green hydrogen production in Germany and in Europe will likely be focused on hydrogen. Derivatives such as ammonia and methanol are expected to be almost exclusively imported, mainly from countries not connected via pipelines removed.

Hydrogen transport. Several options exist to transport hydrogen and its derivatives to Germany. The availability and economics of hydrogen transport routes have important implications on the form and origin of hydrogen imports.

- **Pipelines**, especially those with large diameters, offer the most economical way of transporting large volumes of hydrogen. Repurposing existing natural gas pipelines can reduce infrastructure investment cost to as low as one-third of new pipelines. Pipeline transport is particularly well-suited for inner-European transport and transport from neighbouring regions with pre-existing infrastructure, e.g. North Africa.

- For import routes across long distances (3,500 km or more), **maritime shipping** is the preferred option. Particularly for routes where hydrogen pipelines are not possible and for hydrogen derivatives, shipping can be the only transport option. However, given that converting hydrogen into derivatives (and reconversion) is the single biggest driver of transport cost, hydrogen and its derivatives should be transported in the form required by the end use to minimise conversion losses.

- While at low volumes and across short distances, **importing renewable electricity** to produce hydrogen in Germany can be cheaper than pipelines, over distances of 500 kilometres and above, pipelines are better suited for hydrogen imports from an economic point of view. However, electricity imports for use in the power sector will still play an important role for ensuring Germany's energy security.

Sustainability of transport. Decarbonised pipeline operation and ship fuelling will be key for assuring the green quality of hydrogen, from a full-lifecycle emissions perspective. This requires pipeline compressors to be operated using electricity with high renewable energy shares in all transit countries. For shipping, decarbonized fuels such as green hydrogen, ammonia or methanol can greatly reduce the emission intensity of the final product delivered compared to conventional shipping fuels.

Infrastructure. Importing large quantities of hydrogen and transporting them across Germany will require suitable pipeline and port infrastructure, and adequate storage reservoirs within the country to ensure a functioning hydrogen market with flexible supply and stable pipeline utilisation. Of the available options, salt caverns are considered the most promising storage solution. Existing caverns, gas reservoirs, and aquifers could satisfy Germany’s 2030 storage needs and over 80% of the needs in 2050. However, further research into storage options, cost factors, and associated investment needs will be necessary.

Domestic use. The use of hydrogen should be limited to sectors where direct electrification is difficult, i.e. in energy intensive industries, for long-distance transport (including aviation and maritime shipping), and as a flexibility and storage resource in the power sector, including in (dispatchable plants for) district heating.

Regulation. Regulation will be key for a fast run-up of global hydrogen markets. The sustainability criteria set out by the EU will determine the economics of green hydrogen projects. While clear and stringent criteria for green hydrogen are crucial to ensure sustainability, more lenient requirements could be applied for a limited transition period to allow for a faster market development. For hydrogen grid infrastructure, which is considered a natural monopoly that should be fully regulated in the long run, a two-staged approach starting with a more flexible regulatory framework in the beginning should be considered to ensure timely build-up of the grid.

Recommendations. Germany will likely become a major importer of green hydrogen in the future. Being a major market player, Germany has the potential to shape the global run-up of hydrogen supply chains and trade routes. A German import strategy should consider the following key aspects:

- Set up **European and international hydrogen partnerships** to secure sufficient hydrogen supply and build up the international hydrogen economy.

- Increase security of supply by **diversifying hydrogen supply countries and transport routes**, sourcing imports both via maritime and pipeline transport.

- **Build up and finance the transport infrastructure** for short- and long-term hydrogen imports to accelerate the hydrogen market run-up.

- **Set and align standards and regulation** for hydrogen production and transport to ensure sustainability and provide the necessary certainty for investors.

- **Continue and expand hydrogen support instruments** whilst simplifying access to funding to close the financing gap of early hydrogen projects and ensure bankability.

- Continue to **support international research and development** on technology and innovation along the hydrogen value chain to realise rapid cost reductions.

- **Support joint flagship projects** and export German technology solutions to promote innovation and enable scaling of hydrogen production.

Germany’s network of Energy Partnerships and Energy Dialogues offers an ideal foundation for reinforced international cooperation on the creation of a global green hydrogen economy.

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1 Introduction and purpose of this study

As part of its obligations under the Paris Agreement on Climate Change, Germany has adopted ambitious emissions reduction targets including the goal of reaching climate neutrality by 2045. To achieve its decarbonisation targets, Germany will not only require a massive expansion of renewable electricity use across all sectors but also rely on the timely deployment of fuels based on renewable energy in areas that are difficult to electrify.

Green hydrogen, produced from renewable electricity, and its derivatives will play a key role for implementing Germany's climate objectives. Over the next two decades, demand for green hydrogen and its derivatives is expected to increase substantially. Domestic production potential in Germany is, however, limited, while more favourable conditions and ample potential for green hydrogen supply exists in some other (European and non-European) countries. As a result, imports of green hydrogen and its derivatives will be an important pillar for meeting Germany's future hydrogen demand.

To connect green hydrogen demand with supply, hydrogen can be transported via pipelines, by ship, or alternatively, renewable electricity can be imported for hydrogen production in the destination country. The question where to source hydrogen imports from and in which form (i.e. as pure hydrogen or in the form of hydrogen derivatives) is closely linked to the availability and cost of the different transport routes. Understanding the different transport options, their advantages, challenges, and associated costs is crucial for developing viable green hydrogen supply chains to Germany.

This study seeks to provide an informational basis for decision makers in the German government regarding the choice between different options for transporting green hydrogen and its derivatives to Europe and to Germany. It gives an overview of Germany's expected hydrogen demand (Chapter 2), and the domestic supply potential and resulting import needs up to 2050 (Chapter 3). This is followed by an economic assessment of the different transport options including discussions of the major cost drivers and possible geopolitical considerations regarding the choice of transport routes (Chapter 4). In addition, the study touches upon options for hydrogen storage in Germany (Chapter 5), and requirements for regulation and standards regarding hydrogen transport in Germany and Europe (Chapter 6).

In the framework of its Energy Partnerships and Dialogues the German Federal Ministry for Economic Affairs and Climate Action (BMWK) is cooperating with partner countries around the globe on the production, offtake, trade, transport, and certification of green hydrogen and its derivatives. Against this backdrop, the study also intends to inform partner countries with respect to Germany's future demand for imports of green hydrogen and provide an overview of potential transport routes and their implications on hydrogen trade with Germany. Finally, it also highlights cooperation potential with German businesses on green hydrogen projects, technology and innovation.

2 Hydrogen demand

Key takeaways

- In Germany, green hydrogen will play an **important role in reaching climate neutrality** by 2045.
- Although German hydrogen demand forecasts are subject to large **uncertainties** in the short (2030) and long term (2050), the different studies agree that Germany will **depend on green hydrogen** imports to cover its demand (according to studies, between 12 TWh-70 TWh in 2030 and 170 TWh-750 TWh in 2050).
- To cover its import demand, Germany should **cooperate with exporters** of green hydrogen (e.g. countries in the MENA region).
- Germany should pursue **alliances with other net importers** of (green) hydrogen, align standards (e.g. on sustainability criteria), and identify collaboration opportunities (e.g. on transport routes).

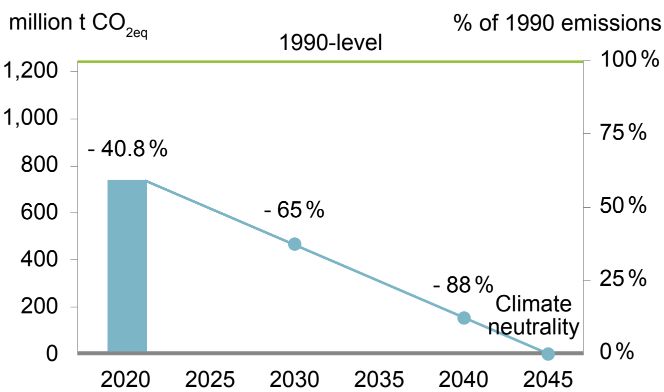
2.1 Germany's hydrogen demand

Germany's 2021 climate protection law targets emissions reductions of 65% by 2030, 88% by 2040, and net-zero emissions by 2045 compared to the 1990 level.[3] These reductions will require a substantial economic transformation including the power, industry, transport, buildings, and agriculture sectors.

To achieve its emission reduction targets, Germany must increase energy efficiency significantly and rapidly expand the production and use of renewable energy. For sectors difficult to electrify, green hydrogen is expected to play an important role in reaching emission reductions. In 2020, the German government published the National Hydrogen Strategy[4] (NWS). It expects the demand for hydrogen and its derivatives (hydrogen-based energy carriers such as ammonia, synthetic methane, methanol, and synthetic fuels) to reach between 90 TWh and 110 TWh in 2030 and 110 TWh-380 TWh by 2050.[5] The strategy, that will be updated in 2022, currently targets a domestic electrolysis capacity of at least 5 gigawatts (GW) to be installed by 2030 and another 5 GW by 2035, or 2040 at the latest. The coalition treaty of the German government elected in 2021 has increased this ambition targeting 10 GW electrolysis capacity by 2030.[6] Domestic hydrogen production alone will not be sufficient to cover Germany's hydrogen demand; the majority will need to be imported.

Besides the NWS, several studies estimate the expected demand for green hydrogen and its derivatives and the resulting import needs over time.[7] This section compares three prominent studies and their different scenarios and assumptions.[8]

Figure 2.1 **Germany's emission reduction targets through 2045**



Source: Guidehouse (2022) based on BMU (2021)

- **Climate-Neutral Germany 2045 (KNDE)** by Prognos/Agora Energiewende (2021)[9] is the only study that reflects the German federal government's updated 2030, 2040, and 2045 climate targets and shows a path to reaching these targets. Th is study assumes an earlier coal exit (by 2030) than scheduled per the German coal phase-out act; this assumption is supported by a more stringent EU emissions trading system (ETS) than currently in place. With growing electrification, power demand is expected to increase significantly, covered by a fast and strong expansion of renewable energy. Green hydrogen demand will mainly stem from the industry and the power sectors; synthetic fuels will be used in the transport sector and in industry. The study also assumes declining ammonia demand due to reduced consumption of animal products.

- The **Long-Term Scenarios (LFS)** by Fraunhofer ISI et al. (2021)[10] model three scenarios: 1) power, 2) hydrogen, and 3) a power-to-gas/power-to-liquid scenario. All three scenarios align with Germany's old 2050 climate targets (i.e. those before increasing the targets' ambition in June 2021). The intermediate targets (2030 and 2040) are only reached in the power scenario; in the other scenarios, reaching these targets would require considerable additional green hydrogen volumes.

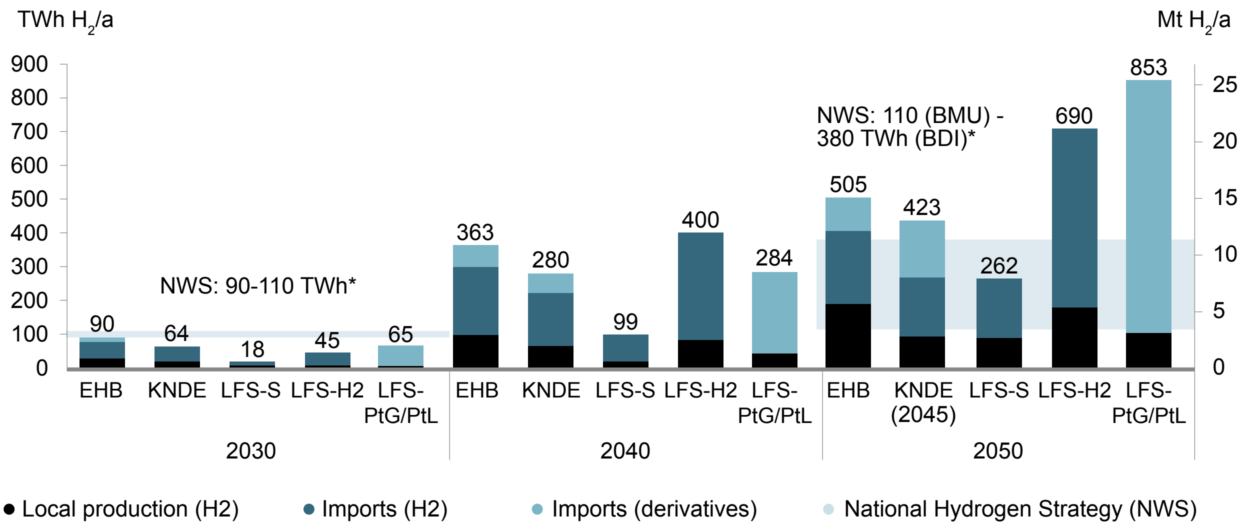
In the electricity scenario (LFS-S), widespread electrification and considerable use of green hydrogen in industry and transport are assumed. Some green hydrogen will also be used as a backup for power generation. This scenario is the most cost-efficient of the three. In the hydrogen scenario (LFS-H2), green hydrogen is the preferred energy carrier for energy and material use in the industry, transport, and building sectors. It assumes widespread availability of a hydrogen infrastructure by 2050. The power-to-gas/-liquid scenario (LFS-PtG/PtL) assumes strong utilisation of green hydrogen derivatives across all energy end uses and some green hydrogen demand covered by domestic production. Given these specific assumptions, it is considered a peripheral scenario.

- The **European Hydrogen Backbone (EHB)** by Guidehouse (2022)[11] models sector-specific green hydrogen demand and the realisable renewable energy and green hydrogen production potential across European countries. In the industry sector, green hydrogen is primarily used for steelmaking and as a feedstock for ammonia and high value chemicals production but also as an energy carrier for medium- and high temperature processes. In the transport sector, green hydrogen-based synthetic fuels and green hydrogen used for fuel cell electric vehicles spur demand. Buildings use green hydrogen and other low-carbon renewable gas like biomethane in hybrid heat pumps and district heating where hydrogen-based solutions are introduced over time. Substantial green hydrogen demand will also accrue from use for dispatchable power generation.

Figure 2.2 contrasts the green hydrogen demand forecasts until 2050 as presented in the three studies against the national strategy and shows the expected share of domestic production in relation to imports for each scenario. By 2030, annual demand for green hydrogen and its derivatives is expected to be 18 TWh-90 TWh. Because the studies analysed focus on green hydrogen only, all scenarios predict a hydrogen demand lower than the NWS which considers total hydrogen demand (90 TWh-110 TWh in 2030).

Between 2030 and 2040, a period of fast-growing hydrogen uptake is expected, resulting in demand between 100 TWh and 400 TWh—four to nine times the respective 2030 levels. In the long run (up to 2045/2050), demand increases to around 260 TWh-850 TWh per year, with the majority of scenarios expecting a higher demand than the NWS range of 110 TWh-380 TWh (the exception being the LFS-S scenario, which falls within the range).

Figure 2.2 **Green hydrogen demand in Germany: local production and imports, 2030–2050**



Projections: NWS: National Hydrogen Strategy, EHB: European Hydrogen Backbone, KNDE: Climate-Neutral Germany 2045, LFS: Langfristszenarien (-S: electricity scenario, -H2: hydrogen scenario, -PtG/PtL: power-to-liquid/power-to-gas scenario).
* Includes both hydrogen and PtG/PtL demand.

Source: Guidehouse (2022) based on Guidehouse/EHB (2022), Climate-Neutral Germany 2045 (2021), LFS (2021), National Hydrogen Strategy (2020)

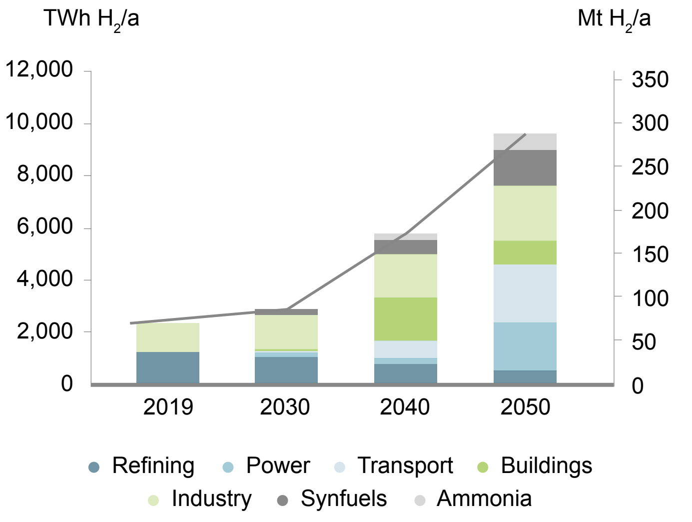
In all scenarios, imports are expected to cover around two-thirds of green hydrogen demand. While all studies project some domestic production of pure green hydrogen, there is agreement that demand for derivatives will be exclusively served by imports because of cost advantages in exporting countries.

Within Germany, the bulk of hydrogen demand will stem from industrial clusters located in western and central Germany, the North Sea region, and in Bavaria. In North Rhine-Westphalia (NRW), key hubs are expected to develop along the Rhine River where major chemical and petrochemical installations and steel plants are located.[12] Hydrogen demand in this region is projected to be 18 TWh in 2030 and around 25 TWh in 2040 and after.[13] Additional need for hydrogen is expected to emerge from industrial clusters in central Germany (Ludwigshafen, Leuna), in the Bremen and Hamburg area (mostly for the steel industry), the North Sea region and in southern Bavaria (mostly in the chemical industry).

2.2 Global hydrogen demand and competition for imports

Strategies to cover Germany's future import demand for green hydrogen and its derivatives must consider other importers within Europe and globally. The International Energy Agency (IEA) forecasts hydrogen demand across the globe to grow rather modestly over the current decade (see Figure 2.3). After 2030, the global hydrogen economy is expected to pick up speed with demand almost doubling over ten years. By 2050, annual hydrogen demand could reach 290 million tonnes or 9,600 TWh, exceeding current global renewable energy production levels.[14]

Figure 2.3 **Global hydrogen demand by end use over time**



Source: Guidehouse (2022) based on *IEA Energy Technology Perspectives (2020)*

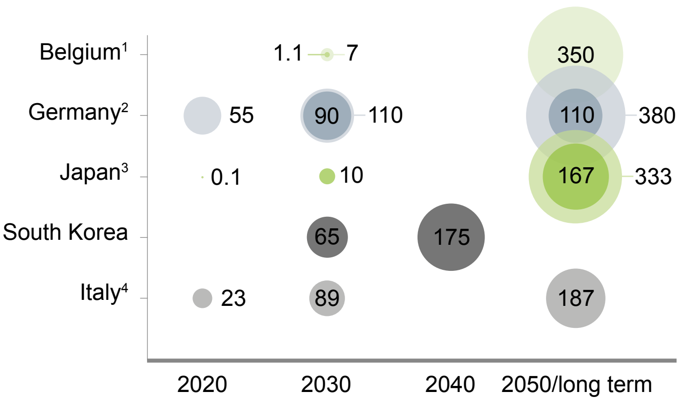
While most hydrogen demand will arise in industry and refining in the 2020s, demand growth between 2030 and 2040 will be driven by applications in buildings and transport. Synthetic fuels production and the power sector will create additional demand towards 2050.

According to the EHB analysis, the largest demand for green hydrogen and derivatives in Europe is expected to arise in Germany (around 500 TWh in 2050), followed by Spain, the UK, and Italy with expected demand levels roughly half the German volumes. Other countries with significant expected green hydrogen demand are France, Poland, and the Netherlands (in descending order).[15]

Some countries with high expected green hydrogen demand will likely be able to cover their needs through domestic production (Spain, the UK, France, and the Netherlands). Other European countries including Germany, Belgium, Italy, and Austria are expected to become importers of green hydrogen. Germany is expected to have the highest demand for imports of green hydrogen and its derivatives across the EU and UK, with over 70% of the combined hydrogen import needs of European countries in 2040, and around 60% in 2050.[16]

Between 2017 and November 2021, around 20 countries across the globe and the European Commission have published hydrogen strategies. Another dozen is preparing a strategy while several countries have entered into initial policy discussions on hydrogen.[17] Only a few countries have quantified their expected future hydrogen demand levels and import needs. Among those countries, the main importers are Belgium, Japan, and South Korea, which are all expecting similar long-term hydrogen demand levels as Germany (see Figure 2.4).[18]

Figure 2.4 **Projected annual hydrogen demand in selected net importing countries (in TWh/a)**



Bubble size and corresponding labels show the targeted lower (inside bubble) and upper (outside bubble) range of annual demand for hydrogen and derivatives in TWh per year.

Sources: Guidehouse (2022) adapted from *LBST (2020)*, based on: [1] *Trinomics & LBST (2020)* and *FPS Economie (2021)*, [2] *NWS (2020)*, [3] *METI (2017)*, [4] estimate based on *Guidehouse/EHB (2022)*

In Belgium, domestic demand for green hydrogen and its derivatives is expected to reach around 350 TWh in 2050.[19] Major demand is expected to emerge in industrial applications, in transport and, to a lesser extent, in decentralized applications like in buildings. The domestic potential for green hydrogen production is however limited by resource and land availability for renewable energy. The hydrogen strategy of the Belgian federal government expects 3 TWh-6 TWh of hydrogen and its derivatives to be imported from other (European and mainly non-European) countries in 2030 and 100 TWh-165 TWh in 2050.[20] According to the Belgian Hydrogen Import Coalition, by 2050 another 400 TWh of green hydrogen and its derivatives could be imported for transit to other European countries by using existing harbour and pipeline infrastructures.[21] The Belgian Government is forging partnerships with potential hydrogen exporters, e.g. with Oman, and actively promotes projects for the production and export of green hydrogen and its derivates.

Japan and South Korea have a larger emphasis on blue and grey hydrogen. In Japan, hydrogen demand for power generation is expected to amount to 10 TWh by 2030.[22] In the long term, this demand is expected to rise to 167 TWh-333 TWh. No clear preference is given as to whether this should be grey, blue, or green hydrogen. Given Japan's strong dependence on energy imports and the limited land availability for additional large-scale renewable power plants, it will likely also rely on hydrogen imports from other countries. Japan is focusing on agreements and demonstration projects with Australia, Argentina, Brunei, New Zealand, Saudi Arabia, and the United Arab Emirates (UAE).[23]

South Korea expects its domestic hydrogen demand to reach 65 TWh in 2030 and 175 TWh in 2040. The current strategy prioritises using the existing natural gas capacities for grey hydrogen production; in the long term, however, a shift to green and low-carbon hydrogen (including carbon capture and storage) is planned. Given the low share of renewables and high electricity prices, any future green hydrogen demand will likely need to be imported. South Korea is focusing on cooperation with Saudi Arabia, Australia, Israel, and Norway in the areas of liquified hydrogen, liquid organic hydrogen carriers (LOHCs), and ammonia imports.[24]

Given the limited green hydrogen supply volume – at least in the early years – Germany will likely compete with other countries for imports. This competitive situation can also be leveraged to accelerate the global scale-up of hydrogen production and trade. A surging need for imports across the globe offers opportunities for resource pooling to finance transport routes, among others. Aligning standards and regulations on hydrogen and its derivatives with other major importers can enhance offtake certainty for investors in exporting countries.

Not all countries have committed to a green hydrogen agenda (e.g. Japan, South Korea). The alliances and trade routes these countries forge may affect the attractiveness and competitiveness of green hydrogen production in potential export markets. This could be exacerbated if importing countries introduce subsidies indiscriminate of the type of hydrogen to accommodate for an initially higher cost and kickstart the hydrogen economy. For potential hydrogen exporters with vast natural gas resources, investing in green hydrogen production could be less attractive. As a result, it may take longer to achieve a scale-up of green hydrogen supply and cost declines.

Within the framework of its Energy Partnerships and Energy Dialogues and its energy diplomacy, Germany should pursue alliances with other net importers of (green) hydrogen, both inside and outside of Europe, align standards (e.g. on sustainability certification), and identify common interests and opportunities to collaborate on transport routes.

2.3 Conclusion

Green hydrogen demand in Germany is expected to increase considerably by 2030 (around 18 TWh-70 TWh) per year and accelerate further until 2050 (260TWh-850 TWh). Major demand centres will develop around the industrial clusters in NRW, in the North Sea region, Bavaria, and central Germany. Domestic green hydrogen production will likely play a minor role in supplying the quantities needed. Imports of green hydrogen or its derivatives will be key for covering demand.

The decarbonization task at hand will likely lead to changes in Germany's industrial landscape. When only looking at the cost of energy, relocating (parts of) highly energy-intensive production processes (e.g. primary steel production) to regions with abundant renewable energy potential may look more appealing than converting and transporting green hydrogen to Europe for use in industrial processes. However, the competitive advantage of Germany's industry is based on highly integrated clusters. The synergies and cost advantages realised in these clusters would be at risk if a part of the value chain is offshored. The lengthy downtimes in the German manufacturing industries during the Covid-19 crisis revealed how vulnerable global value chains can be. Hence, all things considered, relocation may eventually result in increased cost.

Many countries in Europe and across the globe view green hydrogen as a cornerstone of decarbonizing their economies. While some countries will be able to cover a significant share of hydrogen demand through domestic production, others will depend strongly on imports (Belgium, Italy, Japan, and South Korea).

With the global scale-up of the hydrogen economy, more and more countries are competing for limited green hydrogen supply volume—at least in the early years. Germany should leverage this competitive situation by forming alliances with other net importers of (green) hydrogen within and outside of Europe to jointly build up transport routes and set standards to ensure the sustainability of the hydrogen supply chain.

3 Hydrogen supply

Key takeaways

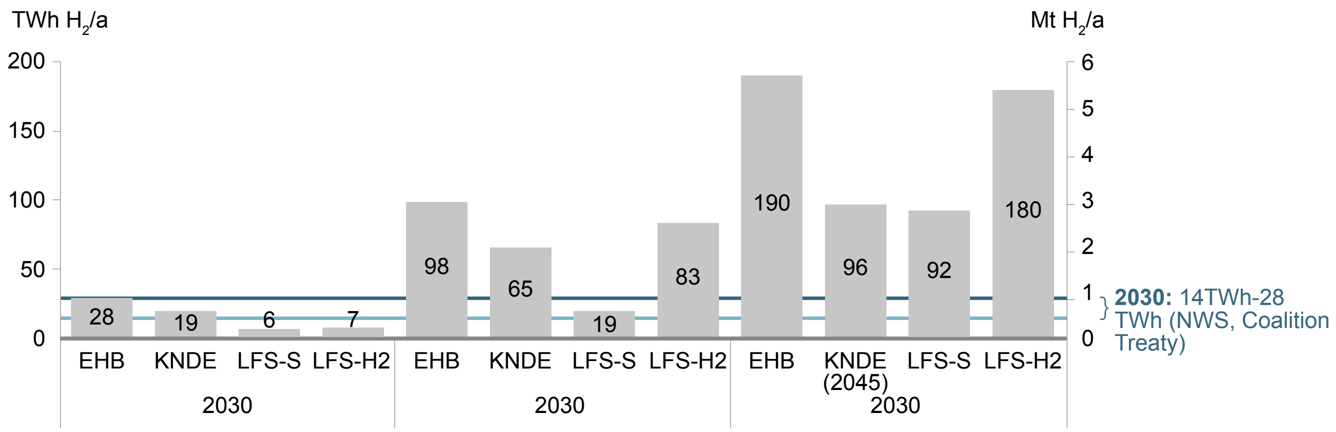
- **Domestic** green hydrogen production in Germany is expected to be focused on **pure hydrogen**. According to forecasts, hydrogen **derivatives** (methanol, ammonia, etc.) **will be almost exclusively imported.**
- Major European hydrogen production potential is located in Spain, the UK, Scandinavia and Germany.
- By 2030, green hydrogen production cost is expected to fall to **€2-€3.5/kg**. High natural gas prices make green hydrogen **cost-competitive** with blue hydrogen already in the short term.
- **Cooperation** with potential exporting countries of green hydrogen offers ample **potential** to introduce German expertise and technology solutions.

3.1 Supply volumes by region

3.1.1. Domestic supply (Germany)

According to the NWS, domestic hydrogen production should reach 14 TWh[25] in 2030 and 28 TWh in 2035, or 2040 at the latest (see dashed lines in Figure 3.1).[26] Studies expect green hydrogen production of between 6 TWh and 28 TWh to be feasible in the short term (2030). In 2040, supply could reach 19 TWh-98 TWh and between 92 TWh and 190 TWh by 2045/2050. In these forecasts, domestic supply covers between 26% and 36% of total power-to-X (PtX) demand. Green hydrogen production in Germany is expected to focus on pure hydrogen while derivatives (methanol, ammonia etc.) will be almost exclusively imported. Green hydrogen and its derivatives are expected to be imported from countries with better resource availability.

Figure 3.1 **Green hydrogen production in Germany (in TWh), 2030–2050**



Projections shown: NWS: National Hydrogen Strategy, KNDE: Klimaneutrales Deutschland 2045, LFS: Langfristszenarien (-S: electricity scenario, -H2: hydrogen scenario).

Source: Guidehouse (2022) based on *Climate-Neutral Germany 2045 (2021), LFS (2021), National Hydrogen Strategy (2020), Coalition Treaty 2021-2025*

The projected hydrogen production volumes are difficult to compare because they are based on different assumptions on electrolyser operating hours (expressed in full load hours).[27] The NWS implies much higher output levels per GW of electrolysis capacity than the studies assessed. It assumes electrolysers to run at 4,000 full load hours per year and to operate with an efficiency of 70%. Thus, 1 GW of electrolyser capacity is expected to produce 2.8 TWh of hydrogen per year. According to the forecasts by KNDE and LFS, the annual output per GW of electrolyser capacity in Germany is expected to be at least one third lower (see second column in Table 31 below).

Table 3.1 **Electrolysis full load hours and efficiency assumptions by study**

Study/Source	Output ratio (TWh/a H_2 per GW of electrolyser capacity)	Full load hours	Electrolysis efficiency
NWS	2.8	4,000	70%
KNDE	1.76-1.92*	2,500-2,750**	70%
LFS	1.2-1.9*	1,700-2,700**	70%

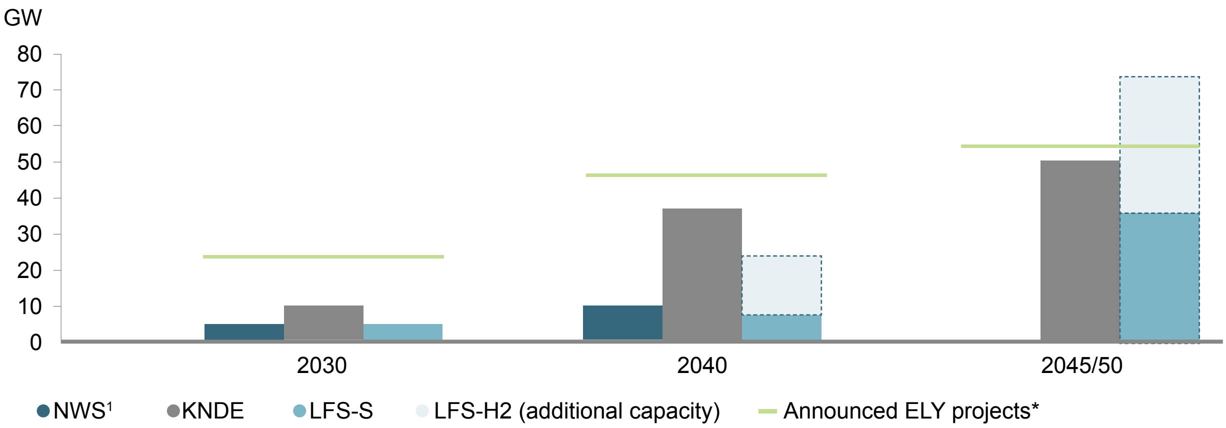
NWS: National Hydrogen Strategy; KNDE: Klimaneutrales Deutschland 2045, LFS: Langfristszenarien
*Implicit assumption calculated based on the expected demand in the forecast years between 2030 and 2050 and the assumed electrolyser capacity in the study.
**Full load hours required to achieve implicit output-capacity ratio given an electrolysis efficiency of 70%.

Given the resource potential in Europe and the variability of solar PV and wind, electrolysers can operate at around 2,000-5,000 full load hours per year; if connected to the grid or to large-scale electricity storage, full load hours exceeding 5,000 can be achieved.[28] To reach the output levels targeted by the NWS, electrolysers would have to source some energy from the grid to increase operating hours. The actual permissible operating hours will largely depend on the criteria regarding renewable electricity input for green hydrogen that are to be formulated by the European Commission in a Delegated Act (DA) on Article 27 of the Renewable Energy Directive (RED II). This DA is expected to be published early 2022. The NWS capacity factor assumption should then be reviewed based on the DA.

To reach the targeted production levels, the NWS targets an electrolyser capacity of 5 GW in 2030, with an additional 5 GW to be installed by 2035 or 2040 at the latest (see Figure 3.2). Given the most recent 2030 capacity target of 10 GW stated in the coalition treaty of the new German government domestic hydrogen production could be as high as 28 TWh at the end of this decade. Studies indicate that a far higher domestic green hydrogen production could be possible in the long-term. KNDE projects renewable electrolysis capacity in Germany to reach 37 GW in 2040, and around 50 GW in 2045.[29] Based on the expected hydrogen production levels in the Fraunhofer ISI projections (LFS-S and LFS-H2), electrolysis capacity could reach 48 GW-95 GW by 2050.

A recent survey by the German transmission system operators indicates that these projections could even be surpassed. By April 2021, around 500 announced projects had been reported with a combined electrolyser capacity much higher than projected in studies.[30] However, not all announced projects are expected to be completed.

Figure 3.2 **Electrolysis capacity forecasts for Germany (in GW), 2030–2050**



Projections shown: NWS: National Hydrogen Strategy, KNDE: Klimaneutrales Deutschland 2045, LFS: Langfristszenarien (-S: electricity scenario, -H2: hydrogen scenario).
Areas with dashed outlines show theoretically needed electrolysis (ELY) capacity assuming an electrolysis efficiency of 70% and 3,500 full load hours.
[1] The coalition contract (24.11.2021) of the new German government targets 10 GW in 2030 already.
* Projects announced by April 2021 according to Netzentwicklungsplan Gas 2022–2032 (consultation).

Source: Guidehouse (2022) based on *Climate-Neutral Germany 2045 (2021), LFS (2021), National Hydrogen Strategy (2020), Netzentwicklungsplan Gas 2022-2032 (consultation document)*

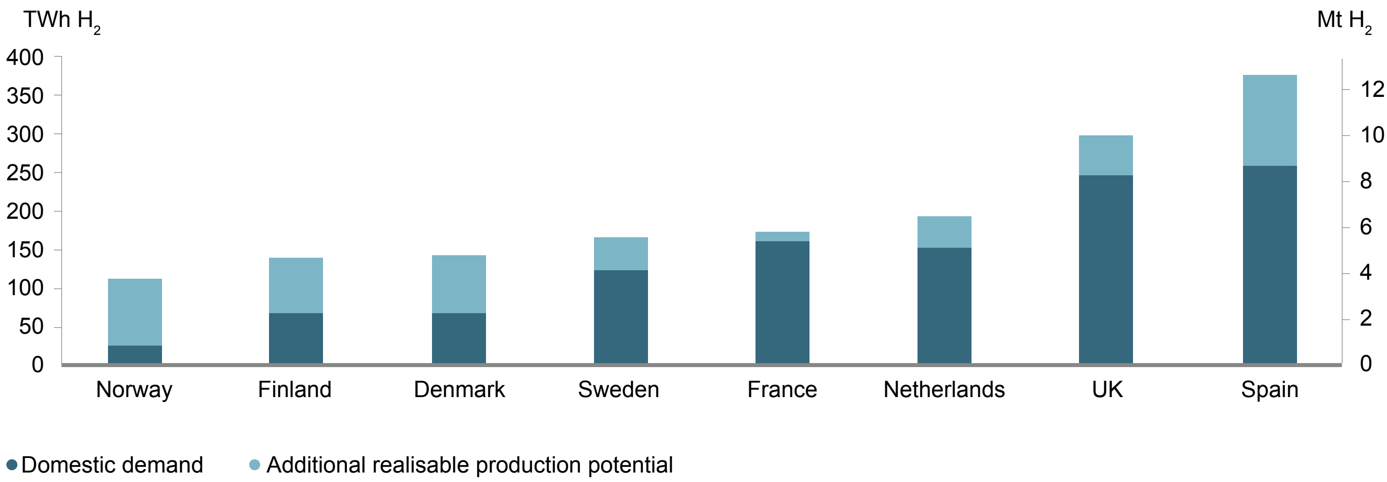
Major challenges to fully using the domestic hydrogen production potential include the availability of land for renewable power generation and public acceptance. Yet, the numbers provided by the studies assessed only give an indication of the levels of domestic supply that would be feasible if land availability and acceptance were not limiting factors. A more realistic assessment of the hydrogen supply potential in Germany and in Europe would need to factor in these challenges.

3.1.2. Supply across Europe

Within Europe, there is significant potential for green hydrogen production on the Iberian Peninsula and in the UK, and Scandinavia.[31] This potential can be harnessed if land availability is not restricted (e.g. by social acceptance issues), such that economically and technically feasible sites can be used for renewable energy production.

In the EU, Spain is expected to have the highest realisable potential for green hydrogen supply with close to 400 TWh in 2050 (see Figure 3.3). Other countries with production potentials above 150 TWh are the UK, the Netherlands, Germany, France and Sweden (in descending order). Overall, production in Europe is expected to primarily cater to European demand for green hydrogen. While countries like Spain, Norway, Denmark, and Finland could become major green hydrogen exporters within Europe, other countries like Germany, Italy, France and the UK are expected to use most of their potential to cover domestic demand.

Figure 3.3 **Realisable green hydrogen production potential and domestic demand in 2050, projections for selected countries of the EU and UK**



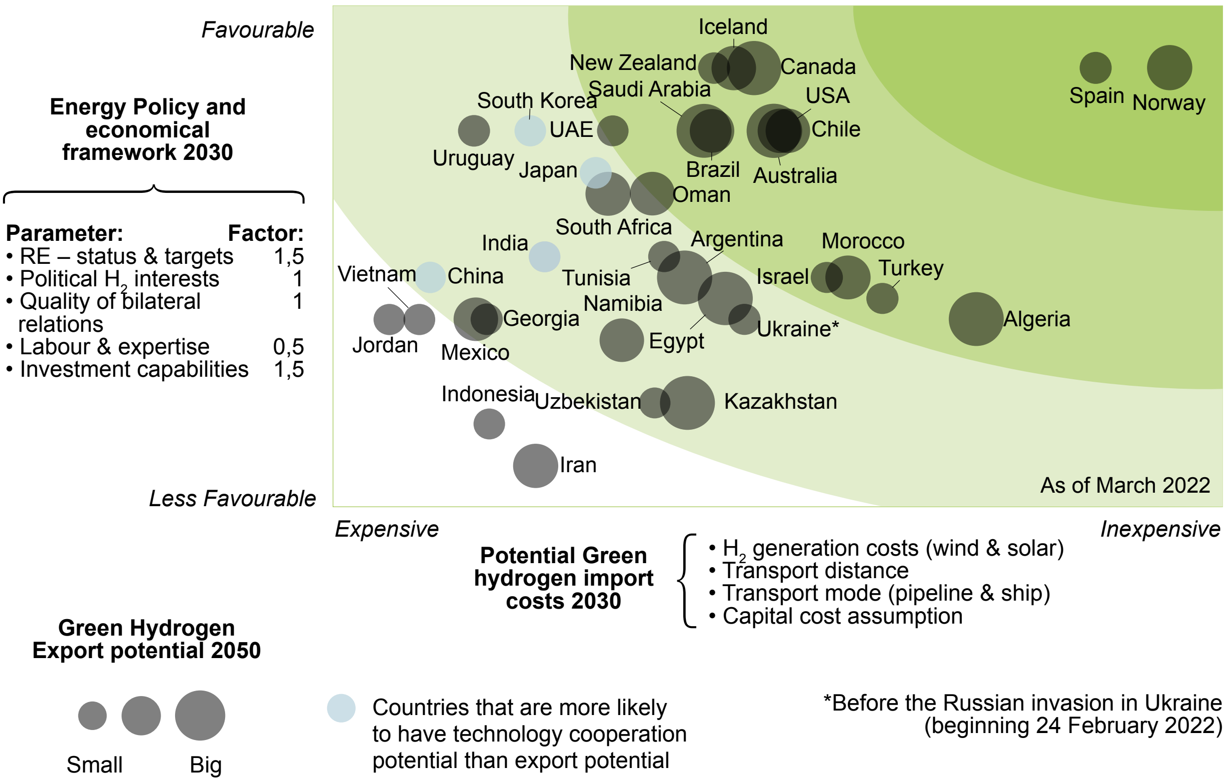
Source: Guidehouse (2022) based on *Guidehouse/EHB (2022)*

3.1.3. International supply beyond Europe

While proximity to Europe naturally leads to a competitive advantage for exports because of the lower transport costs, this factor becomes significantly less influential when relying on shipping and converting hydrogen.[32] Therefore, supply from outside of Europe is not regionally limited. Other factors such as infrastructure and costs of renewable energy production must be considered to evaluate the potential of a region. The Middle East and North Africa (MENA) region and countries on the eastern EU border have an advantage from a transportation cost perspective. The MENA region also benefits from favourable conditions for renewable energy, which already led to low electricity production costs.[33] However, the consideration of political, economic, and geographical factors can narrow down the potential.

An analysis conducted by Guidehouse, Gesellschaft für Internationale Zusammenarbeit (giz), adelphi, and Deutsche Energie-Agentur (dena)[34] in 2019 reflected these additional factors. The country analysis was updated in 2022 under consideration of recent political and economic developments and updated assumptions for the transportation costs. Further, a new parameter reflecting the capability of a country to invest in hydrogen was included in the energy-politico-economic axis and the weighting of all parameters was revised. The updated resulting graph can be seen in Figure 3.4. In this analysis, countries outside of the EU[35] were ranked by their energy-politico-economic framework conditions, the production potential for green hydrogen, and their exporting cost to Germany. Some countries in Europe's neighbouring regions (Algeria, Morocco, Turkey, Iceland, Israel) show great potential for hydrogen exports to Germany. More distanced countries (Australia, Brazil, Canada, Chile, Saudi Arabia, Oman, New Zealand, UAE, USA) are also well-suited for exports. Among the overall highest-ranking countries with high export potential are Algeria, Australia, Canada, and Saudi Arabia.

Figure 3.4 **International cooperation and export potential on green hydrogen with Germany**



Source: Guidehouse (2022) Updated chart based on *Guidehouse, giz, adelphi, dena (2020)*

In a comparative assessment, dena contrasted this analysis[36] to other hydrogen and PtX mappings.[37] One of these mappings conducted by Fraunhofer IEE[38] concludes that 80% of the area potential for PtX production is concentrated in 10 countries, three of them in the MENA region (Egypt, Libya, Saudi Arabia) and one being Russia. In another mapping, the authors confirm the European neighbouring regions as well-suited for hydrogen exports to Europe because of the mentioned cost advantages related to transport. However, more distanced regions can reduce their transportation costs by exporting derivates instead of hydrogen.[39] This opens the door to other promising regions such as North America and Australia, which, according to Fraunhofer IEE, include some of the remaining top ten countries[40] for area potential.

Based on a simulation of a fully renewable global system for 2050, LUT University and dena concluded that Africa and South America will become exporters of synthetic fuels and Europe will become an importer in the long term.[41] Another publication mapping the potential in Africa points out problematic restrictions to electrolysis, connected to groundwater reserves, which strongly affect some African countries such as Niger and Mali.[42] dena underlines the strong differences in some assumptions made in the selected mappings, notably with regard to water availability and capital costs.

Although a direct comparison of results is not possible due to the methodological differences, dena points out that all selected studies agree that the global hydrogen and PtX demand can be covered in the long term. There is a basic understanding of where hydrogen imports could come from, however more analysis is needed, e.g. to establish a detailed global PtX atlas that shows regionalised hydrogen production potentials including cost estimates.

The assessment of hydrogen production potential indicates which countries could become major hydrogen producers. Yet, the realisation also depends on the availability of funding for green hydrogen projects. The needed investment security is still lacking in some regions.[43] Compared to technical assumptions, the consideration of socio-economic aspects is connected to a high degree of uncertainty because of their volatile nature. While these aspects need to be considered, they should not be overestimated to realise a high share of the global hydrogen potential. Country-specific assessments can help to identify those risks more clearly and explore solutions to them.[44] To further support international hydrogen projects, the German government has devised several support mechanisms focusing on hydrogen production, research and development, and trade, (e.g. German International Funding Guideline, H2Global, H2UPP) next to the existing instruments of foreign trade promotion.

3.2 Cost of green hydrogen production

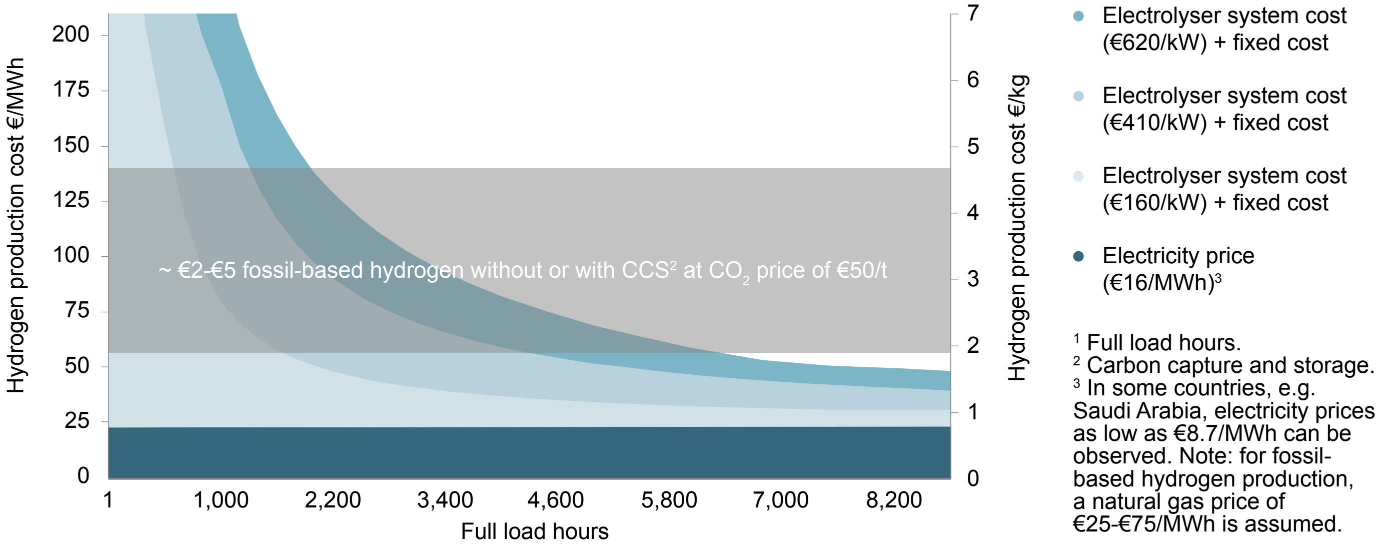
The cost of hydrogen from renewable energy is determined by several key factors: cost of renewable electricity, electrolyser system cost, electrolyser operating hours, local investment conditions, and cost of transport.

The **cost of renewable electricity** is the single largest cost factor in hydrogen production (see green area in Figure 3.5). Auctions for renewable energy across the globe have recorded dramatic cost declines over the past decade. This trend is expected to continue in the future.[45] In countries with good resource potential like Saudi Arabia, prices as low as $0.0104/kilowatt-hour (kWh) (€0.0087/kWh) for solar PV have been reached in 2021.[46] In contrast, auctions for solar PV in Germany were between four to ten times as high with prices between €0.039/kWh-€0.084/kWh.

Electrolyser system cost represents the main capital cost (capital expenditure, CAPEX) in hydrogen production. The cost for electrolysers is expected to fall in the future given steep technological learning curves. A doubling of cumulative electrolyser production is estimated to lead to an 18% reduction in cost. By 2025, the cost could fall as low as €200-€300/kilowatt (kW) from around €500-€600/kW.[47] As larger electrolysers are built, economies of scale can reduce the impact of system cost on hydrogen cost per unit. Risk is a major factor for the cost at which lenders and banks are willing to provide finance to projects, impacting overall CAPEX. Political, economic, and regulatory stability or offtake agreements can reduce the risk of not achieving the required rates of return and can reduce project cost.

Electrolyser operating hours (Full Load Hours) are a key determinant of hydrogen cost. Hydrogen production facilities feature high fixed cost (investment cost of electrolyser system) but low operation and maintenance cost (electricity and other system cost). Next to decreasing prices of the electricity feedstock and decreasing electrolyser system cost, longer runtimes can drastically reduce the cost for green hydrogen on a kilogram (or kWh) basis (see Figure 3.5).[48] In regions with less favourable renewable energy conditions, lower full load hours can be offset by connecting electrolysers to electricity storage.

Figure 3.5 **Renewable hydrogen production cost depending on operating hours**



[1] Full load hours.
[2] Carbon capture and storage.
[3] In some countries, e.g. Saudi Arabia, electricity prices as low as €8.7/MWh can be observed. Note: for fossil-based hydrogen production, a natural gas price of €25-€75/MWh is assumed.

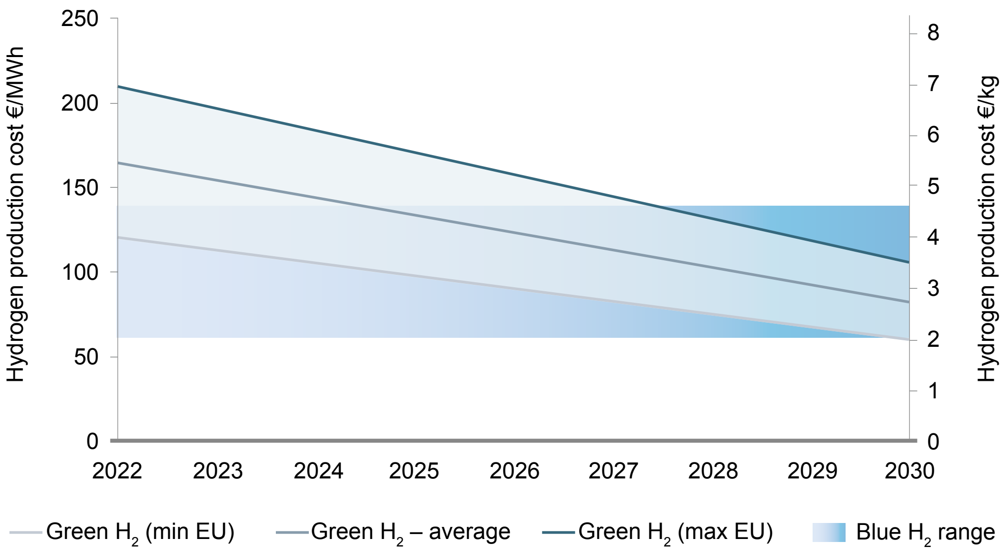
Source: Guidehouse (2022) based on Guidehouse/Agora Energiewende (2021)

Local investment conditions affect the cost of capital for hydrogen production facilities and the total investment cost. Learning-by-doing effects including increased standardisation, higher specialisation, and improved manufacturing processes are expected to lower the risk perception of lenders and banks and improve the financing conditions.[49]

Finally, the **cost of transport** is a critical driver of the final cost of hydrogen delivery (see Chapter 4 for detailed discussion).

The cost of green hydrogen supply is expected to decline over the next 10 years, driven by falling electrolyser cost and cheaper renewable energy supply (see Figure 3.6). Subject to the natural gas price hikes to €100/MWh and above in early 2022, green hydrogen prices have momentarily fallen below those of blue hydrogen. Durable cost-competitiveness of green hydrogen with blue is expected to be reached at the end of this decade. In countries outside of Europe with more favourable resource potential (e.g. in the MENA region) such low cost levels are already reached today. However, the full cost of hydrogen delivery from those regions depends on the cost of transport, which is still high. For fossil-based hydrogen transport cost plays a minor role given that it can be produced locally.

Figure 3.6 **Hydrogen production cost in Europe over time: green versus blue hydrogen**



Note: For blue hydrogen production in Europe, a natural gas price of €25-€75/MWh, a carbon price of €50/ton of CO_2 and CCS capture rate of 90%-95% are assumed.

Source: Guidehouse (2022) based on *Guidehouse/Agora Energiewende (2021)*

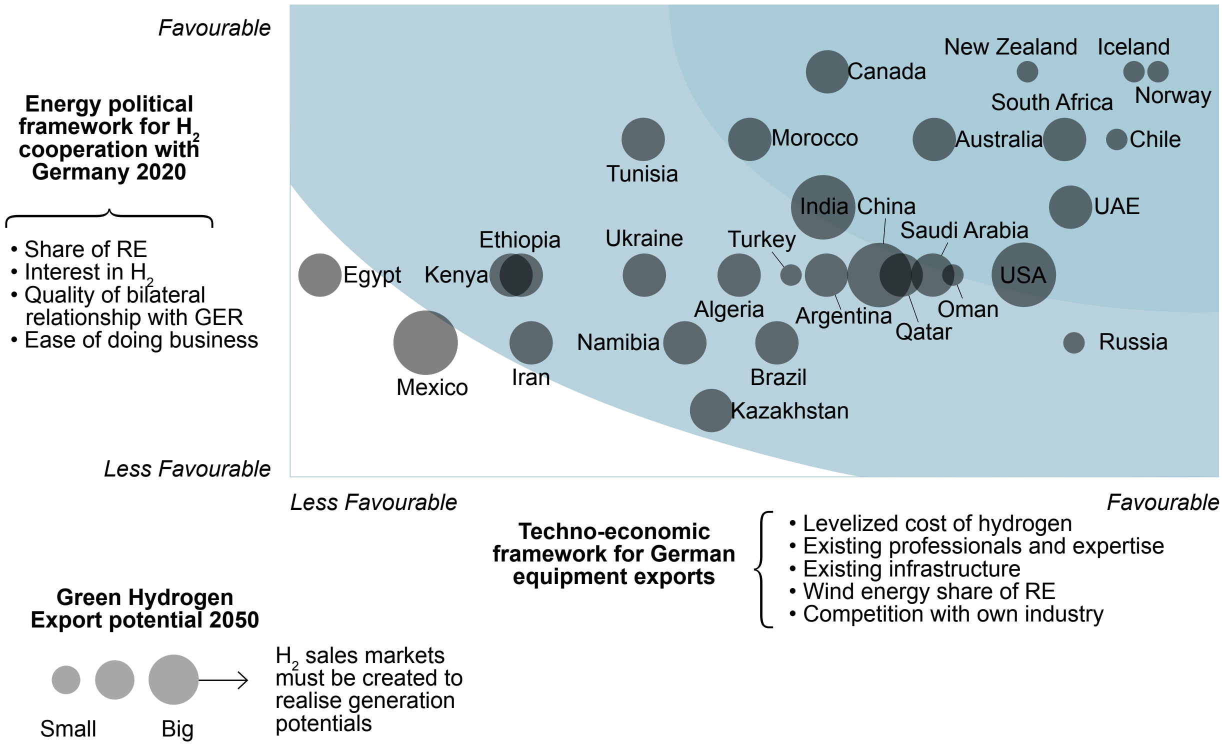
By 2050, the cost for green hydrogen production in Europe is expected to decrease to levels well below €3/kg.[50] According to the EHB, of the estimated total production potential of around 4,000 TWh in 2050, 2,500 TWh could be produced at costs below €1.5/kg while another 600 TWh could be as cheap as €1/kg or less.[51] Whether these quantities can be produced will be subject to social acceptance and the speed and extent of renewable energy expansion in Europe including questions around land availability for additional renewable energy capacity and the required expansion of the power grid. While many countries outside of Europe have favourable conditions regarding renewable energy potential and site availability, the low cost of gas supply in major gas producing countries (e.g. in the MENA region) can widen the cost gap between green and blue hydrogen production in those countries.

3.3 Technology export potential for German companies

The emergence of a global hydrogen economy as an integral part of countries' energy transition strategies offers ample opportunities for German technology manufacturers. The German share of the global turnover of water electrolysis manufacturers was 19% in 2018, making Germany the world market leader.[52] By 2025, German electrolyser manufacturing capacity is expected to reach a market share of around 36%.[53] Besides electrolyser production, over 100 German companies[54] are well-positioned along the value chain for green hydrogen—from electrolysis to end use but excluding electricity generation from renewable energy. This includes large companies such as car manufacturers (e.g. BMW, Daimler), corporations in the mechanical and plant engineering sector (e.g. Siemens, Robert Bosch), electrolyser manufacturers (e.g. Enapter, Siemens Energy, Sunfire, and ThyssenKrupp), and companies in the industrial gas sector (e.g. Linde). In addition, numerous small and medium-sized enterprises (SMEs) are active along the hydrogen value chain.

Besides the European market, there is significant potential for exports to countries outside the EU. Figure 3.7 (developed in a short study by Guidehouse, giz, adelphi, and dena in 2020[55]) provides an initial overview of countries outside the EU27 that have a particularly high export potential for German green hydrogen technology in the medium and long term. In this framework, countries were ranked by their techno-economic potential, political situation, and generation potential.

Figure 3.7 **Export conditions for German hydrogen technology**



Source: Guidehouse (2022) based on *Guidehouse, giz, adelphi, dena (2020)*

The techno-economic criteria[56] assess the extent to which the geographical, industrial, and infrastructural conditions in a country could favour German hydrogen technology exports. Energy political criteria[57] assess whether the energy political framework in a country favours possible imports of German technologies along the green hydrogen value chain. The absolute generation potential[58] indicates the theoretical market potential for green hydrogen plants, which is limited by the absolute green hydrogen generation potential.

From an energy political and techno-economic point of view, the countries with the most favourable conditions for German technology exports are New Zealand, Iceland, Norway, and Chile (Figure 3.7). However, these countries have a small overall generation potential for green hydrogen. Countries with slightly less favourable conditions but higher generation potential—meaning potentially bigger markets—include Australia, Canada, India, Morocco, the UAE, the US, and South Africa.

The expected green hydrogen market growth opens opportunities for German industry, especially with regard to facilitate exports to countries with particularly good production potential. The NWS acknowledges this opportunity and aims at preparing new markets for German technology exports, among other things.[59] It also provides a budget of two billion euros to support international activities in the field of hydrogen, particularly in the context of Energy Partnerships and Energy Dialogues: To promote international technology cooperation and innovation on green hydrogen and its derivatives, the **German International Funding Guideline** supports the establishment of production facilities, and for storage, transport and integrated application of green hydrogen outside the EU and European Free Trade Association (EFTA) countries. Additionally, the guideline contains a module for accompanying research projects and academic and vocational training. The **H2UPPP** programme provides targeted support for European and German SMEs in the development of pilot projects for the production and use of green hydrogen and its derivatives with a focus on project implementation in developing and emerging countries. The establishment of **global and bilateral innovation funds** (PtX growth funds) should mobilise investments in green hydrogen technologies through dedicated financing instruments. Moreover, to increase investment security and accelerate the ramp-up of international trade of green hydrogen and its derivatives, the **H2Global** program offers producers a compensation of differential costs between purchase and sales prices.

3.4 Conclusion

To satisfy its future green hydrogen demand, Germany will rely on domestic production and imports from in and outside of Europe. While the NWS expects 14 TWh-28 TWh of hydrogen production per year by 2030 and 2035/2040, respectively, domestic production will likely be higher as already indicated by the new 10 GW target in the coalition treaty. Given the high interest in hydrogen projects expressed by German industry stakeholders, studies estimate that the domestic green hydrogen production potential could reach 65 TWh-83 TWh in 2040 and at least 92 TWh by 2050. Nevertheless, supply is limited by resource potential and growing demand for renewable electricity across sectors and will likely not be sufficient to cover demand.

In Europe, the largest potential for green hydrogen production and exports is expected on the Iberian Peninsula (Spain) and in Central and Eastern Europe (Romania, Poland, Greece). These countries will likely be able to produce excess hydrogen to serve demand in other European countries. However, land availability for and public acceptance of the required additional volumes of renewable energy installations are major factors of uncertainty not sufficiently addressed by existing studies.

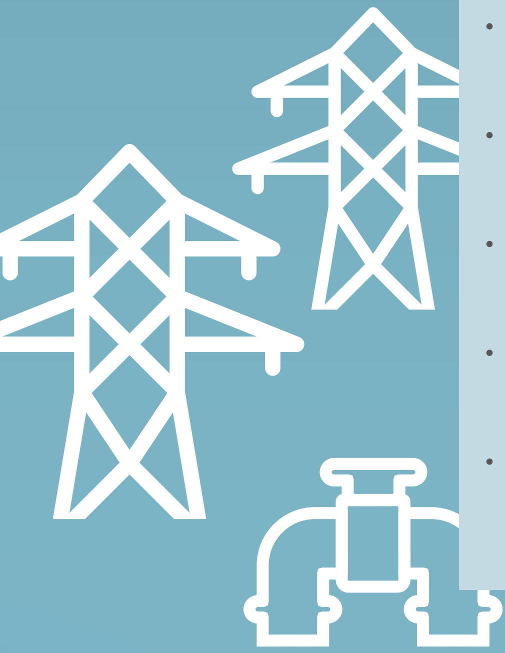
The cost of green hydrogen supply is expected to decrease over time. By mid-decade, hydrogen from renewable sources produced in Europe is expected to be as cheap as – become cost-competitive with – fossil-based hydrogen. Regions with very low cost of renewable electricity, e.g., the Gulf region, will likely achieve these cost levels much sooner. However, the total cost of delivery of green hydrogen produced outside of Europe strongly depends on the cost of transport from those regions.

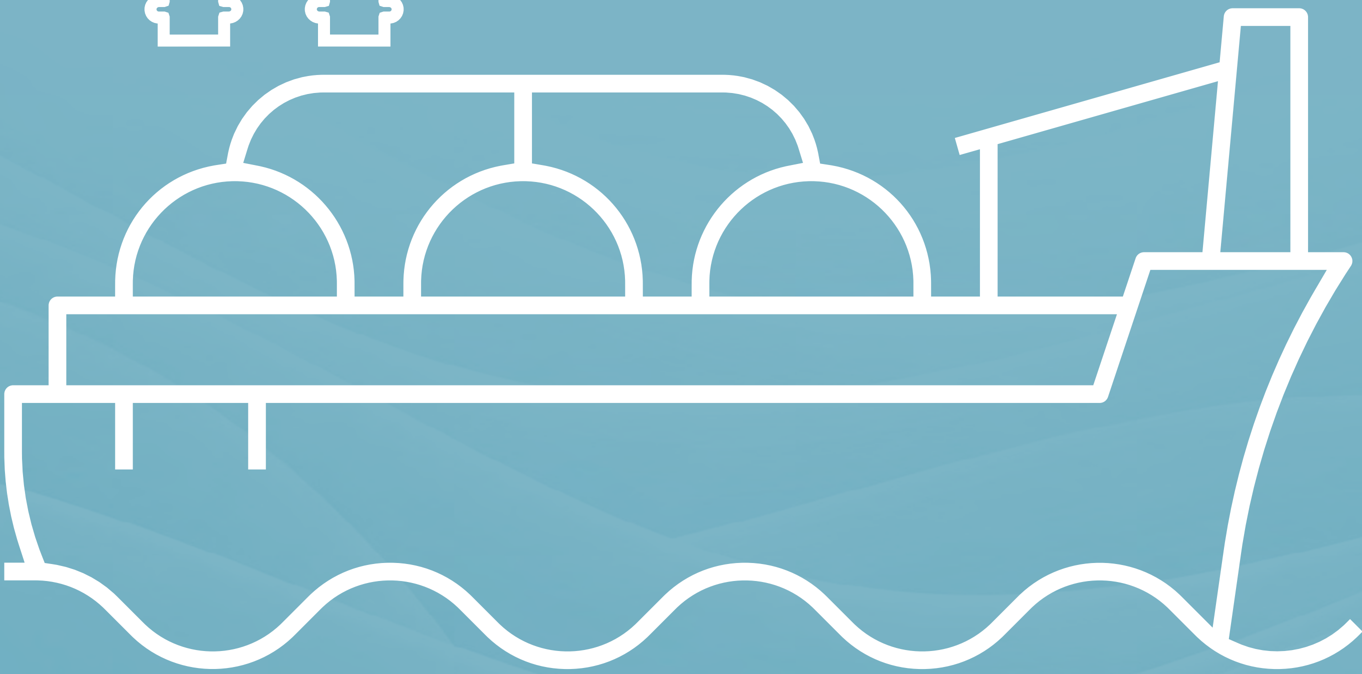
Despite being a future green hydrogen importer, Germany is a leader in hydrogen technologies and the nascent global hydrogen economy offers ample potential for German firms through technology exports. Local value creation in partner countries should be considered as an important goal of technology exports in the areas of electrolysis, hydrogen end use, and renewable energy technologies to countries with more favourable resource potential in and outside of Europe.

4 Hydrogen transport

Key takeaways

- **Where feasible, pipelines** are the most economical way to transport **large volumes of hydrogen.**
- The cost of **repurposed pipelines** can be as low as one-third the cost of new pipelines.
- Shipping can be an option **where no pipeline routes are possible and to transport hydrogen derivatives.**
- Imports of **electricity** for local hydrogen production are only competitive for **low volumes and across short distances.**
- **Conversion** is the single biggest driver of cost. Hydrogen and its derivatives should be transported in the form required by the end use to minimise conversion losses.





4.1 Hydrogen pipelines

Hydrogen can be transported via pipelines, introducing the opportunity to use existing natural gas pipelines by blending hydrogen into these pipelines. Hydrogen can currently be blended at up to 2% in terms of volume. Blending ratios of up to 10% are also possible without major effects on distribution networks or end users.[60] Blending would reduce the value of hydrogen, which is no longer provided in its pure, carbon-neutral form; instead, it would serve to decarbonise the natural gas transported. Furthermore, some off-takers cannot flexibly adjust to varying shares of hydrogen in the gas mix. Therefore, it is not an option to linearly ramp up hydrogen in the grid.

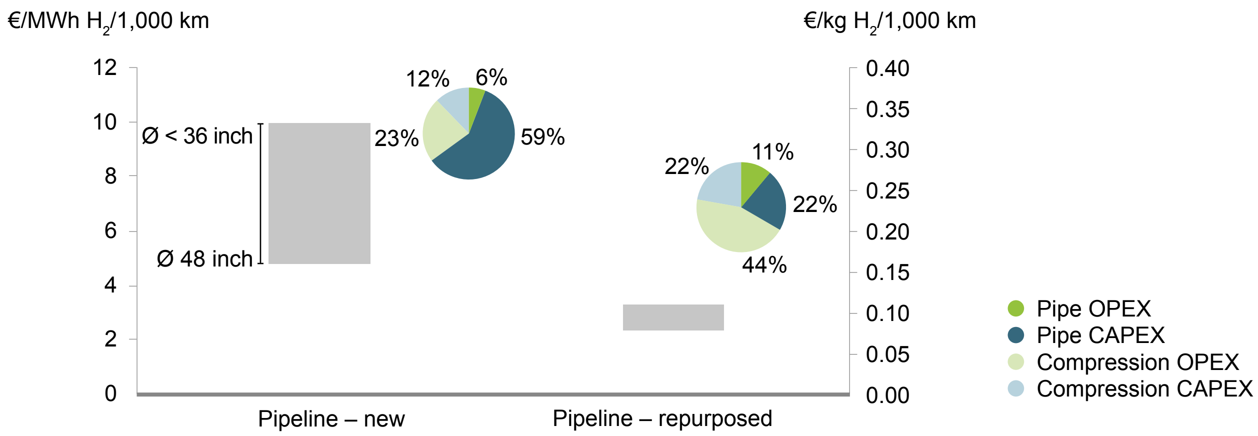
To transport more valuable pure hydrogen, dedicated pipelines would be needed. New, dedicated pipelines could be constructed with an investment cost between 10% (for pipelines with larger diameters) and 50% (for smaller distribution pipelines) higher than natural gas pipelines.[61] Alternatively, existing natural gas pipelines could be repurposed. There are several options to mitigate hydrogen embrittlement of the pipeline materials, such as more rigorous inspection protocols to ensure no defects form or applying internal coatings. Valves and fittings also need to be tightened because hydrogen is a much smaller molecule and can escape more easily than methane.

Compressors would need to be replaced because of different physical characteristics between hydrogen and methane. HyWay27 estimates the cost of repurposed pipes to be 12%-26% of the cost of new pipes on a per kilometre CAPEX basis.[62] The exact costs of repurposing are subject to more detailed engineering studies.

The cost of pipeline transport per tonne (or per kWh) decreases strongly with the transported volume as energy flow through a pipe is proportionate to the square of its radius.[63] Pipelines are usually constructed only for large capacities. The Nord Stream 1 pipeline between Germany and Russia, for example, has a capacity of 55 billion cubic metres (bcm) per year (for comparison: natural gas consumption in Germany in 2017 was 106 bcm).[64] Hydrogen pipelines would only be feasible if the partners commit to large trade volumes upfront.

When transporting pure hydrogen, safety needs to be considered. Hydrogen is highly flammable and explosive. Although it is not classified as toxic, it can be harmful when exposed to high concentrations. Thus, the safe handling of hydrogen pipelines and storage facilities, including periodic inspections and maintenance, is important.

Figure 4.1 **Cost comparison of new and retrofitted hydrogen pipelines**



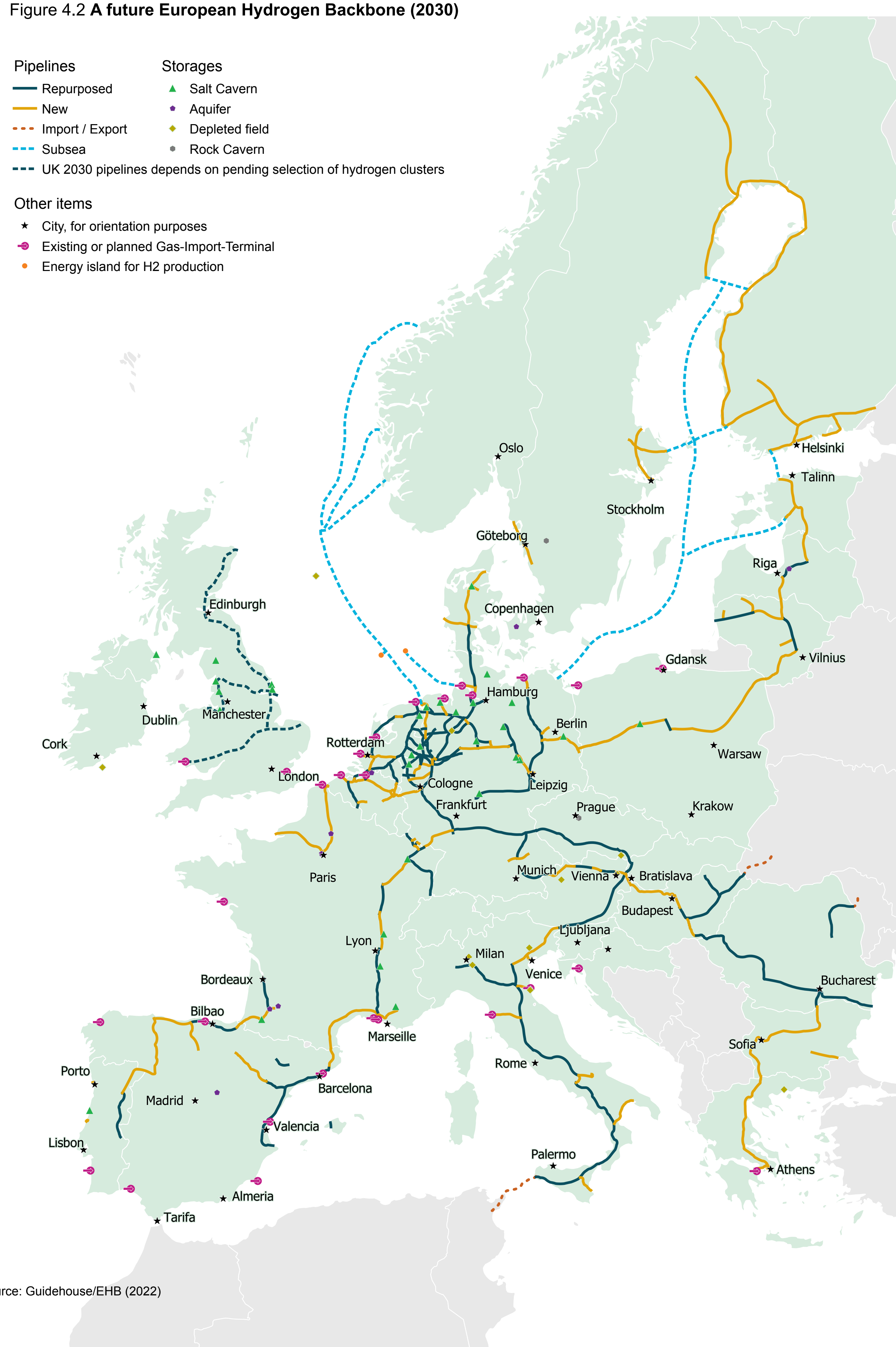
Source: Guidehouse (2022) based on Guidehouse/EHB (2021), BNEF (2021), Guidehouse/Agora Energiewende (2021), IEA (2019)

Repurposed natural gas pipelines offer the most cost-effective solution for hydrogen transport via pipelines, especially when using large diameters (48 inches, or 121 centimetres). This makes them especially suitable for intra-European transport and imports from neighbouring countries with existing gas infrastructure (e.g. Morocco, Algeria, Ukraine, or even the Gulf region). Another advantage of repurposing gas pipelines for hydrogen transport is the higher social acceptance of already existing infrastructure compared to new pipelines.

Because pipelines are competitive only at large volumes and based on high upfront investment, they tend to create supply oligopolies. For example, the EU covers 82% of its natural gas imports from just three countries that it has pipeline connections with: Russia, Norway, and Algeria.[65] This leads to a lack of market liquidity and creates geostrategic dependencies which should be avoided in the setup of future international hydrogen markets.[66]

The European Hydrogen Backbone (EHB) project has developed maps that illustrate which hydrogen pipeline infrastructure will be available at what point in time.[67] Based on input from gas transmission system operators, the EHB outlines a possible future hydrogen network across Europe. The EHB analyses that up to five supply corridors could emerge by 2030. These cross-border corridors can integrate large volumes of renewable and low-carbon hydrogen using solar resources in southern and eastern European countries, and wind resources around the North, Baltic, and Mediterranean Seas.

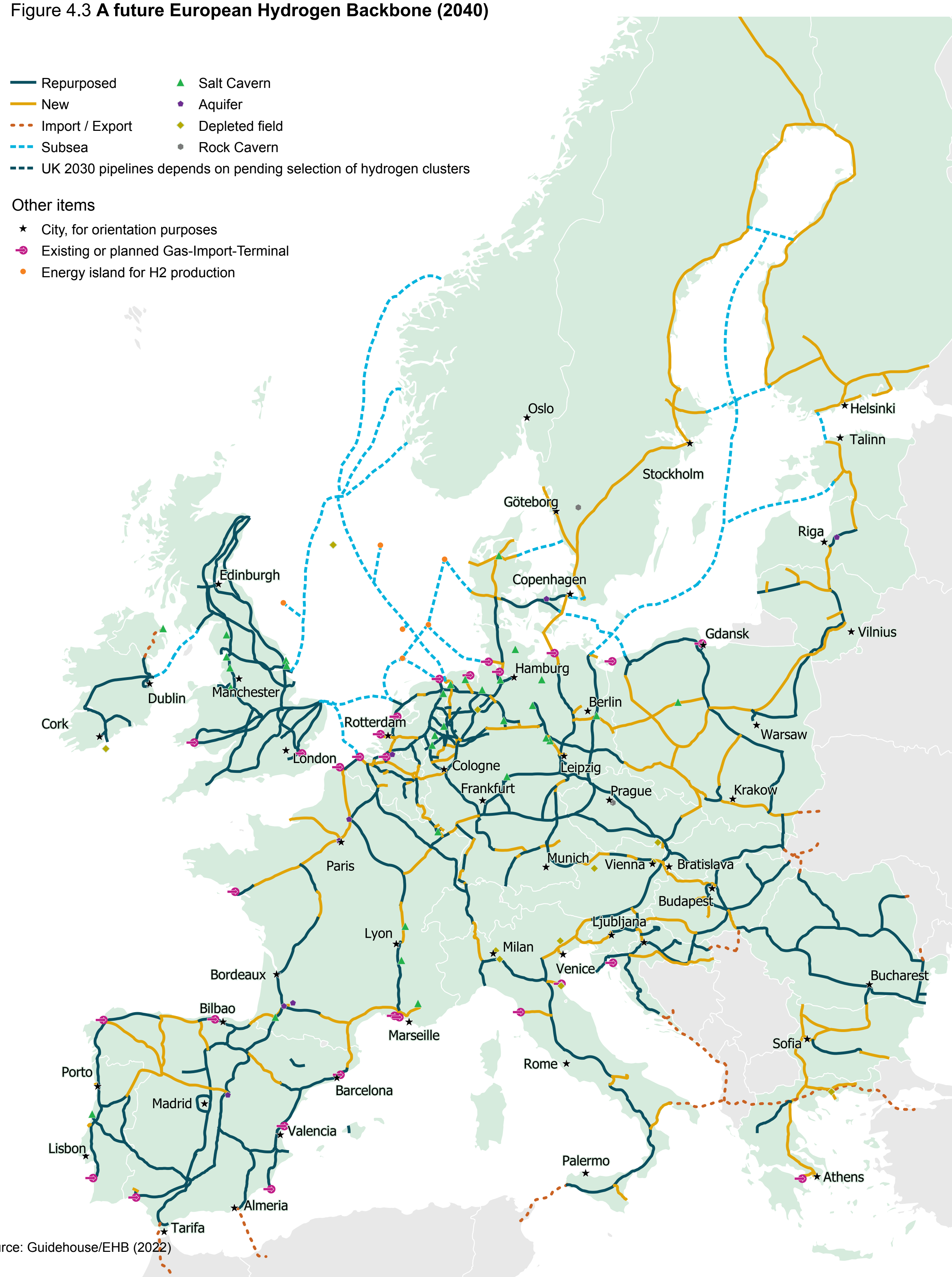
Figure 4.2 **A future European Hydrogen Backbone (2030)**



Source: Guidehouse/EHB (2022)

In 2030, the European hydrogen infrastructure could have a total length of around 28,000 km (see Figure 4.2). Between 2030 and 2040, the European Hydrogen Backbone will continue to grow, covering more regions and developing new interconnections across Member States. By 2040, the proposed backbone can have a total length of almost 53,000 kilometres[1], consisting of approximately 60% repurposed existing infrastructure and 40% of new hydrogen pipelines (see Figure 4.3).

Figure 4.3 **A future European Hydrogen Backbone (2040)**



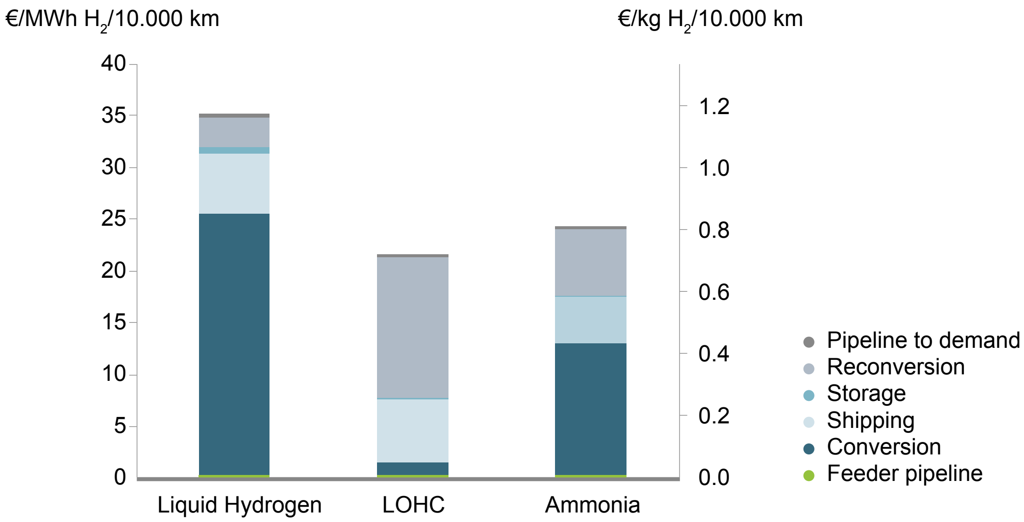
Source: Guidehouse/EHB (2022)

4.2 Hydrogen shipping

Hydrogen can also be transported over long distances by ship. Depending on the provisions of the yet-to-be-published DA on Article 27 from the RED II, the transport of hydrogen will likely have to be carbon-neutral for the green hydrogen to count towards the RED targets. Given the significant precedent that this will set, fuelling international hydrogen transport with conventional fuels will likely not be an option.

Several options for shipping hydrogen exist. It can be transported in its pure form, in a compound with a carrier molecule (LOHCs), or in the form of hydrogen derivatives like ammonia. Figure 44 shows expected cost components of different shipping options in the long run, assuming fully decarbonized transport. While shipping ammonia is the cheapest way to transport hydrogen via ship, the cost of shipping LOHC is expected to drop below that of ammonia in the long run.

Figure 4.4 **Estimated long-term cost components of hydrogen shipping options**



Source: Guidehouse (2022) based on Guidehouse/EHB (2021)

4.2.1. Shipping liquid hydrogen

Because space demand is a key driver of shipping cost, energy density is an important parameter. Gaseous hydrogen could be transported at a pressure of 700 bar, which is similar to the pressure needed for fuel cell mobility applications. Liquefied hydrogen would yield an energy density twice as high at atmospheric pressure, making it a more suitable option for shipping. It can also be used as a fuel to power ships.

The downside of liquid hydrogen is that the boiling temperature of hydrogen is -253°C, much lower than that of natural gas (-162°C). Consequently, liquefication consumes approximately one-third of the hydrogen's energy content.[68] For shipping at 10,000 km, the cost of conversion constitutes around 80% of the total cost. Economically, the cost to ship hydrogen is driven by the one-time energy loss rather than the shipping distance.

Shipping enables importers to maintain a higher diversity of suppliers than pipelines. As for liquefied natural gas (LNG), once an importing terminal is installed, any exporting country with liquefication capacities can supply hydrogen. The relatively small effect of distance on shipping cost further increases flexibility when choosing suppliers of liquid hydrogen.

4.2.2. Shipping LOHCs

LOHCs have the potential to significantly reduce the cost of hydrogen shipping and can–depending on the carrier molecule–represent a safe alternative to ammonia shipping. This option can use existing bunkering facilities on board and at the ports. For LOHC-transport, hydrogen is reacted with organic molecules like toluene to form an oil-like liquid that is easier to transport than hydrogen itself. This reaction releases thermal energy which can be used for heating in the exporting region. At the destination, hydrogen is removed from the carrier molecule, which can be shipped back and reused.

As a downside, removing hydrogen from the LOHC after shipping it requires an energy input of around one-third of its energy content.[69] The importing region is likely energy-constrained, so the energy consumed in this step may be more expensive than in other shipping methods such as liquefaction, where most of the energy needed for liquefaction is spent in the exporting country.

The upside is that large shares of the energy needed for unloading are thermal energy, meaning that waste heat sources in the importing country can improve the economics and environmental footprint of the method. Hydrogen can also be used as carbon-neutral fuel in a fuel cell. In this case, the waste heat produced by the fuel cell can be used directly as thermal energy input for unloading the hydrogen from the LOHC carrier before it is used as fuel.

While some LOHCs (e.g. toluene) are highly toxic compounds, also alternative, less-hazardous carrier molecules are being explored. Currently, the most commercially successful non-toxic candidate is dibenzyl toluene. [70] It can store the same amount of hydrogen relative to weight and the conditions for hydrogen loading and unloading are similar to those for toluene.

4.2.3. Shipping hydrogen derivatives

It makes sense to produce hydrogen derivatives close to hydrogen production facilities. First, this is due to the high energy losses that occur in the conversion process. Producing liquid carbon-based fuels typically entails energy losses of around 50%,[71] the largest cost contributor being electricity with 40%-70% of the production cost.[72,73] Large-scale hydrogen production facilities will be located where cheap electricity is available, so these locations will also allow for cost-competitive production of hydrogen derivatives such as ammonia or methanol.

Second, hydrogen derivatives are easier and cheaper to transport than hydrogen because they have a higher energy density and are less volatile and easier to contain than hydrogen. Liquid ammonia, for example, can be transported at -33℃ under atmospheric pressure, or at 25°C under pressure of 10 bar. Coupling the production of derivatives like ammonia and methanol to hydrogen production facilities rather than transporting hydrogen to produce derivatives in the importing country saves cost and effort.

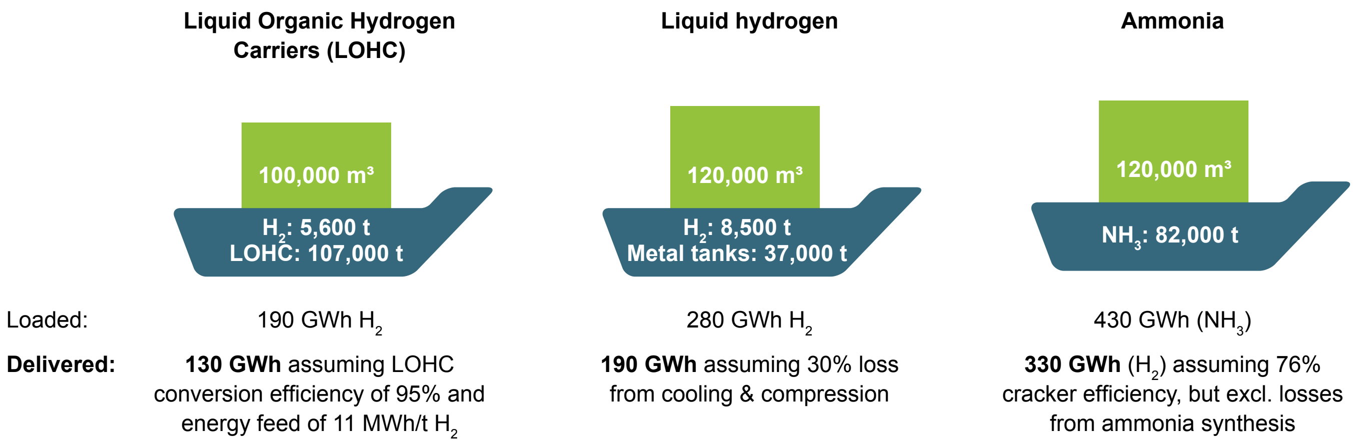
Hydrogen derivatives may also be used as hydrogen carriers, similar to LOHCs. For long distances, the lower transport cost per kilometre outweighs the higher energy loss incurred by the conversion and reconversion. Methanol and ammonia can also be used as shipping fuels. However, methanol combustion releases carbon dioxide while burning ammonia produces nitrogen oxide like diesel fuels. Unlike for methanol, ammonia-powered vessels must also carry heavy fuel oil or diesel to ensure quick start-up of engines in case of emergency.

When shipping derivatives, safety should be considered. Because methanol and ammonia are highly toxic, flammable (especially methanol) and explosive under certain conditions, transport and storage tanks represent an enhanced security risk. Next to exogenous impacts (attacks, natural disasters, ship accidents), metal ageing and fatigue under stress (changes in temperature and pressure) can cause corrosion and cracks. This can produce leaks or spillage with extremely harmful health and environmental implications. Compared to an oil spill, the consequences of an ammonia spill can be more dire because it dissolves in water contaminating it. On land, storage and bunkering must be in less populated regions and undergo regular safety inspections.

4.2.4. Shipping volumes

Liquid hydrogen, ammonia and LOHC-hydrogen compounds have very different energy densities. While liquid hydrogen has a very low density by weight and volume, ammonia and LOHC are rather heavy. The maximum load capacity is thus limited by the tanker volume and maximum weight of the freight (deadweight tons). For example, a ship with the dimensions of a typical LNG-tanker vessel cold theoretically bunker 8,500 tons of hydrogen in its liquid form (see Figure 4.5). When using LOHC-based carriers, even at full load, only around 5,600 tons of hydrogen would be transported because of the high weight of the carrier molecule of around one ton per cubic metre. While in terms of weight, ammonia shipping clearly outperforms hydrogen (around 82,000 tons), the advantage becomes smaller when considering the energy content delivered. When reconverted to hydrogen, the advantage of ammonia over liquid hydrogen is further diminished. If parts of the cargo are used as shipping fuel, the delivered energy is reduced for all three options.

Figure 4.5 **Energy and volumes transported in an exemplary large long-range tanker***



Note: all numbers rounded. Weight, volume or energy delivered does not consider energy consumed as shipping fuel
* Ship and tank dimensions based on a large tanker vessel with a maximum cargo carrying capacity of 120,324 m³ or 107,115 Deadweight Tons. In reality, the vessel type may differ depending on the cargo transported.

Sources: Guidehouse (2022) based on *Minervamarine.com: Aframax tanker* and *Alkhaledi et al. (2021) A hydrogen fueled LH_2 tanker ship design.*

The above comparison in Figure 4.5 serves as a stylized example. The actual vessel types, sizes and tanker designs are likely to differ depending on the cargo transported. While for LOHC-based transport, existing oil vessels can be cleaned and repurposed, and ammonia can be carried in LPG vessels, liquid hydrogen transport requires highly insulated metal tanks to keep temperatures below boiling point (-253°C). The world's first liquid hydrogen tanker pioneered currently only holds 75 tons,[74] while commercial availability of vessels for largescale transport of liquid hydrogen is expected in the 2030s. Existing LPG vessels currently available for ammonia transport have capacities of up 20,000 tons while internationally up to 60,000 tons are being shipped.[75] In Germany, larger transport volumes are currently restricted by the port handling and storage capacities, and safety concerns.

4.2.5. Import terminals

In Germany, the utility RWE plans to construct a terminal for green ammonia imports in Brunsbüttel by 2026.[76] Additional dedicated hydrogen import terminals are planned by in the city of Hamburg with a view on becoming a large hydrogen import hub. These terminals would be able to import ammonia, liquid hydrogen or LOHC.

A more flexible and possibly faster enabler of future energy imports are Floating Storage and Regasification Units (FSRU). Such terminals could be available in Germany for LNG imports by winter 2022/2023, provided an accelerated permitting and construction of pipelines to shore. While the four FSRU terminals planned in the North Sea and Baltic Sea (Wilhelmhaven, Brunsbüttel, and two more in Stade, Hamburg-Moorburg or Rostock) will focus on LNG imports, studies for ammonia FSRU are currently underway in Japan.[77]

As of March 2022, there are 26 fixed LNG terminals across the EU. Germany currently has none although plans to establish such terminals have existed for several years. Against the backdrop of the Russian war in Ukraine, on 27 February 2022, German Chancellor Olaf Scholz announced the construction of two LNG terminals in the North of Germany (possible locations are Brunsbüttel and Wilhelmshaven).[78] Another LNG terminal is planned by utility EnBW in Stade.[79] These new LNG terminals are designed to be convertible for handling future hydrogen and derivatives.

At the moment, it is assumed that hydrogen imports to Germany will primarily come in the form of ammonia. While LNG terminals can in principle be converted handling ammonia, the following points must be considered:

- LNG and ammonia have very different chemical properties that would make it necessary to rework the inner lining and the weld seams of bunker tanks.
- Ammonia is a highly toxic substance, which is why landfall in inhabited areas (unlike for LNG) currently seems out of the question.
- LNG import facilities are equipped with boil-off gas (BOG) compressor packages and a BOG re-condenser.[80] The BOG compressor configuration plays the key role in identifying the required modification to operate the facility with ammonia. The BOG compressor typically operates at near LNG temperature at the suction. The higher ammonia boil-off temperature may inhibit compressor or downstream equipment re-use due to the high discharge temperature. However, the compressors can potentially be re-used for ammonia service with upgrading such as seal gas system, if applicable, but this option needs to be evaluated in detail on a case-by-case basis.

The conversion of LNG import terminals to ammonia terminals requires additional investment in engineering, equipment, materials, and civil works to dismantle and remove items and install new materials and equipment. These modification costs are estimated to constitute up to 20% of the LNG import facility CAPEX.

If the ammonia imported at a terminal is re-converted to hydrogen before further use, hydrogen crackers are needed. In the hydrogen value chain for imported green ammonia, reconversion is the most expensive step. This is due to the high temperatures of up to 600°C 800°C needed to crack ammonia gas. Therefore, reconversion near energy-intensive industries with excess heat, such as steel, copper or cement production, could offer cost advantages. At the same time, centralised conversion of ammonia to hydrogen at the landfall can be 30% cheaper than decentralised conversion due to greater scale and efficiency. First largescale ammonia crackers will enable hydrogen imports of 1 Mt/a (33.33 TWh/a) through Rotterdam from 2026 while direct imports via Wilhelmshaven are expected by 2028.

4.2.6. The last mile to demand

While in the long run hydrogen transport and distribution would ideally resemble current natural gas infrastructure, i.e. a fully-fledged hydrogen grid, this option will not be available in the short to medium term. In absence of a hydrogen grid, the "last mile" can be traversed using be cargo trucks, trains, or inland vessels.

Liquid hydrogen is currently transported by rail or road in liquid hydrogen trailers containing an insulated tank held within a frame. These containers have the same dimensions as ship containers.

Like liquid hydrogen, ammonia is transported in pressurized tanks via inland waterways or via rail. These tanks represent a safety hazard when transported across inhabited areas. If ammonia is not the end use but hydrogen is, ammonia should be cracked into hydrogen at the port and transported in pipelines. While ammonia itself can also be transported in dedicated pipelines, such infrastructure is currently not available in Germany and would be more expensive to build than ship or rail transport.

Hydrogen that is imported using LOHCs can, in principle, be transported safely across Germany just like fossil oils. Before it can be used as an energy carrier, hydrogen must first be removed from the LOHC (dehydrogenisation). This process can take place at the importing port, at distribution points such as near dedicated hydrogen pipelines, or the place of final consumption. While centralized dehydrogenization allows for economies of scale, decentralized conversion can be more flexible and enable supplying many different locations especially early on when hydrogen pipelines for onward transport are not yet available.

The first test cargo shipments are expected to be low in volume and may already come in sealed ship containers, that can be loaded on existing trucks, trains, or cargo barges using existing infrastructure. For larger volumes arriving in tanker ships additional handling and storage infrastructure at the importing port will be needed depending on the form of imports.

Like with long-distance transportation, trucks, trains, or vessels used for inland distribution must run on renewable fuels like green hydrogen, green methanol, or renewable electricity. However, open questions remain as to when decarbonized transport options and handling infrastructure at ports will become commercially available.

4.3 Transporting power to produce hydrogen domestically

While large-scale renewable energy production is most cost-effective in regions with good resource potential, hydrogen can be produced either near a renewable energy site or close to final demand clusters. Electricity can either be imported directly for use in the power sector, or it can be transported to Europe via high voltage direct current (HVDC) or high voltage alternating current (HVAC) power lines and converted in electrolysis plants. Given the extensive existing power grid across Europe, this option is often discussed for imports from neighbouring regions such as North Africa.

Using existing HVDC transmission assets can imply significant cost savings compared to other transport routes. While repurposing existing natural gas pipelines would imply additional capital investment for retrofitting, the capital cost of using existing infrastructure is zero for electricity transmission. However, pipelines generally allow to import much larger quantities of hydrogen than power lines (see stylized example in Table 4.1). Considering the limited existing trans-Mediterranean electricity lines, electricity imports will not be able to sufficiently supply projected long-term import demand for green hydrogen.

Table 4.1 **Volumes transported via pipeline and power lines (illustrative example)**

Transport options		Hydrogen transported (per year)	
		Energy*	Mass*
Pipeline	48-inch (1,200 mm), 12.9 GW, 80 bar	64 TWh	1,900 tons
	20 inch (510 mm), 0.9 GW, 50 bar	4.5 TWh	130 tons
Power line	HVAC (800 kV), 2.8 GW	14 TWh	400 tons

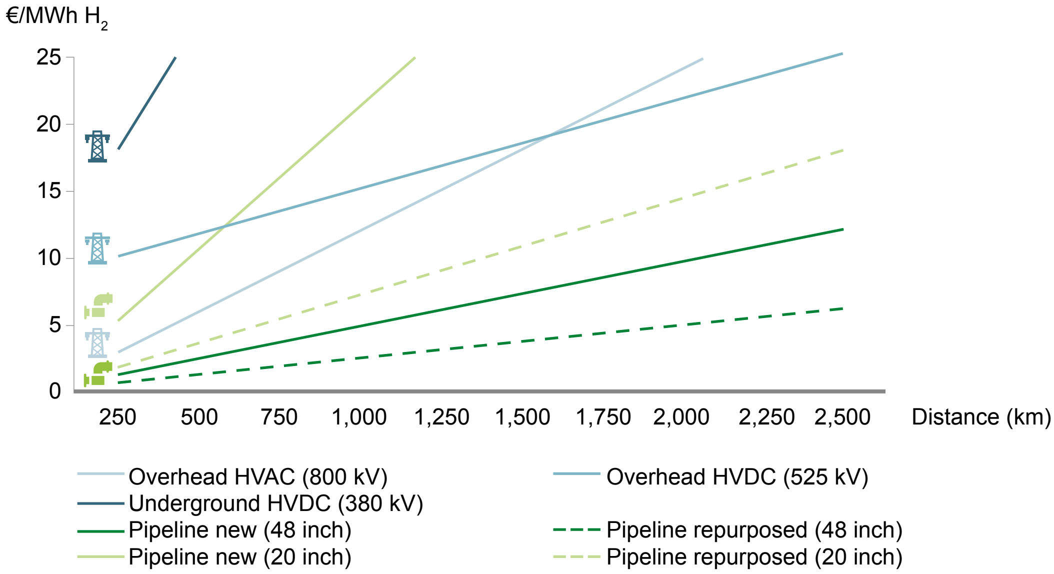
* For both pipelines and power lines, 5,000 full load hours are assumed. The figures shown are based on an illustrative direct point-to-point connection and exclude pipeline and transmission losses.

Source: Guidehouse (2022) based on *Guidehouse/EHB (2021)*

The absolute potential of this HVDC cost advantage is small though—the only existing electricity transmission lines between Europe and non-European countries are between Morocco and Spain, while an interconnector between Italy and Tunisia is planned. This connection is already in use, which means its capacity for additional power transmission is limited, especially for the scale of the energy import demand discussed in Chapter 2. Moreover, given that electrolyser losses occur at the import destination, grid infrastructure capacity would need to be oversized to compensate for the losses. The use of existing gas infrastructure in this region would enable much larger quantities of energy (13 GW via pipelines vs. 2 GW via HVDC) to be transmitted due to the well-developed pipeline infrastructure built primarily for gas imports from Algeria.

If no suitable transmission infrastructure is available, newly built power lines can be used to import renewable electricity to produce hydrogen to be used in industry (not for generating electricity). However, given the high investment cost of new HVAC and HVDC lines, in Europe, for the large volumes expected in the long run, it is always cheaper to import hydrogen via large pipelines rather than importing electricity and converting it to hydrogen (see Figure 4.6). Additionally, the lowest cost transmission option, 800 kV overhead HVAC, does not exist in Europe and faces considerable regulatory hurdles, especially in densely populated areas. Nevertheless, for small volumes that may be required in the short term, even new power lines can play an important role for distances of 400 km and above. This holds for volumes up to 5 TWh per year transported in small 20-inch (510 mm) pipelines.[81]

Figure 4.6 **Cost comparison of hydrogen transport routes: electricity and pipelines**



Source: Guidehouse (2022) based on *Guidehouse/EHB (2021)*

If the desired end use is baseload electricity generation, no conversion or reconversion is required. This results in electricity imports being significantly cheaper than importing hydrogen for power generation. If the final use is hydrogen (including hydrogen used for power generation as a flexibility option), largescale imports via pipelines will always be most cost-efficient.

The sustainability criteria on electricity supply for green hydrogen production, expected to be published by the European Commission early 2022 (see information box in Chapter 4.6), are likely to prescribe a geographical correlation between electricity and hydrogen production. Long-distance transport of electricity for hydrogen production would be inadmissible if the green hydrogen is to be accounted under the EU RED. Even assuming that the criteria on geographical correlation are going to be soft, the economics indicate that transporting electricity to produce hydrogen at the destination will not be a feasible option for the large import amounts required.

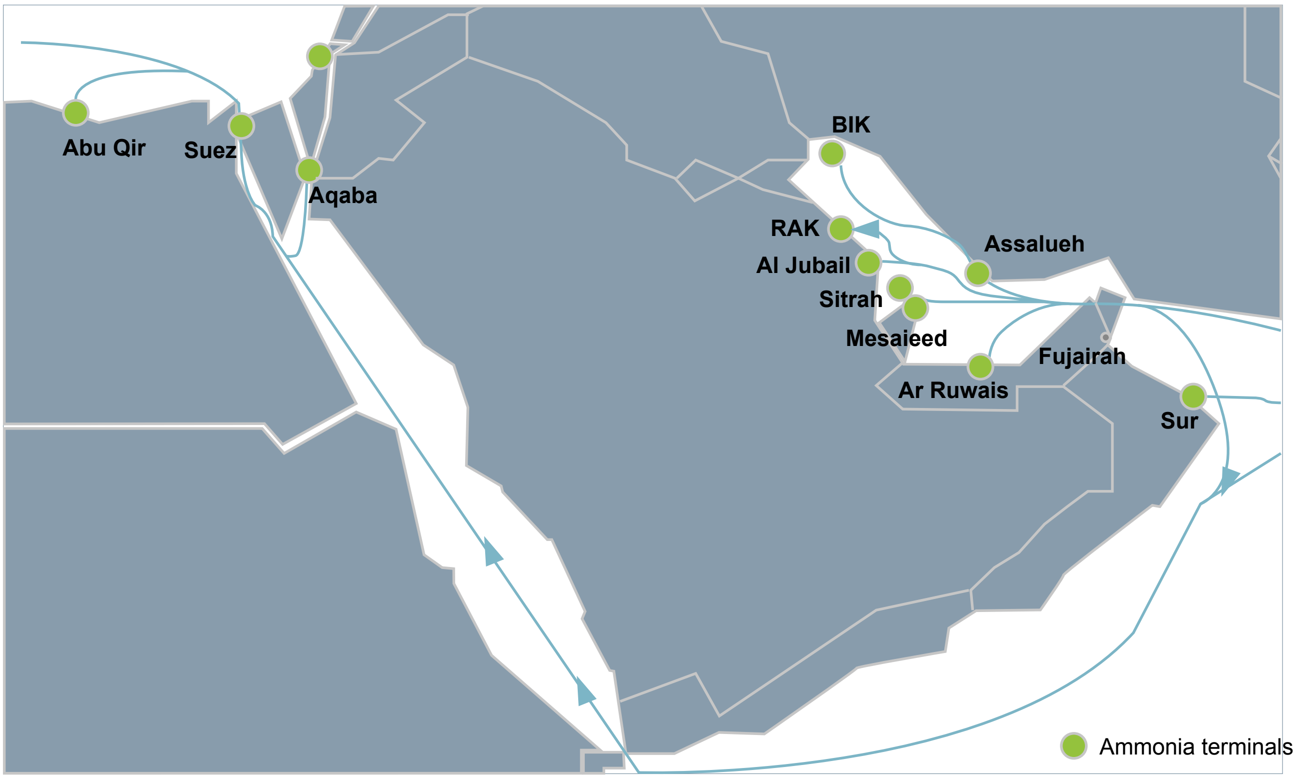
Assessment of possible hydrogen export routes:
Example of existing hydrogen transport options on the Arabian Peninsula

No pipelines or power transmission lines connect the Arabian Peninsula to Europe. The region itself has several large-scale LNG pipelines, but they only cover a small geographic area, primarily connecting extraction sites with demand centres along the coast of the Arabian Gulf and ports at the Red Sea. To export natural gas to locations in Europe, several countries have built LNG terminals and four large-scale liquefication plants are in operation.

All Gulf Cooperation Council countries host major ports where petroleum products can be shipped from. The large-scale oil tankers with capacities of up to 2 million barrels of oil can also be used to transport synthetic liquid fuels (e.g. kerosene).

Ammonia terminals exist throughout the region, in particular along the coast of the Arabian Gulf. From there, ammonia can be transported in its liquid form (either compressed or cooled) using special vessels. Most commonly, ammonia is further processed to urea or fertiliser before being exported.

Figure 4.7 **Ammonia terminals on the Arabian Peninsula**

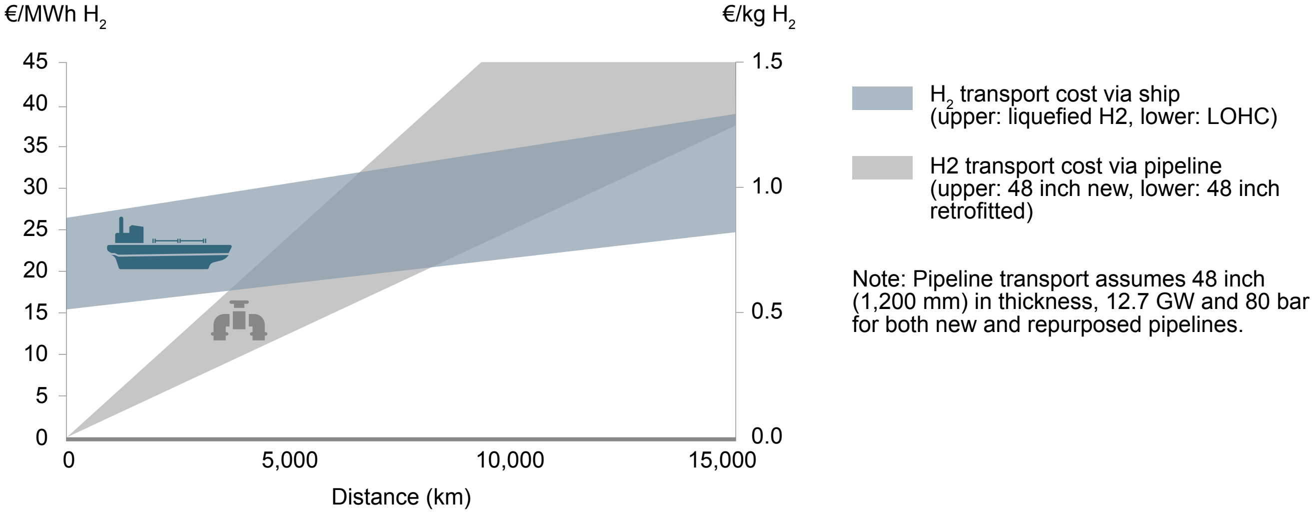


Source: Guidehouse (2022) based on Conference presentation by Georgy Eliseev (IHS Markit) at GPCA Agri-Nutrients Conference 2019 (day 2), *https://gpcafertilizers.com/wp-content/uploads/2019/10/Day-2-05-Georgy-Eliseev-IHS-Markit.pdf.*

4.4 Cost comparison

The cost to ship hydrogen is driven by one-time energy losses from conversion and reconversion. For pipeline transport, cost correlates with distance in a quasi-linear fashion as for each kilometre in distance, one kilometre of pipeline needs to be built. At a certain distance, the cumulated costs for pipeline construction exceed the cost induced by energy losses for liquefication or (re)conversion (see Figure 4.8). The exact location of this breakeven point between pipelines and shipping is still under debate—the IEA claims it is around 3,500 km.[82] Regardless, pipelines are more economical for short- to medium distance transport while shipping is cheaper at long distances only.

Figure 4.8 **Cost comparison of shipping and pipeline hydrogen transport routes**



Source: Guidehouse (2022) based on *Guidehouse/EHB (2021)*

Shipping is more suitable for low volume imports than pipeline transport because shipping is less dependent on economies of scale. The LNG example shows this (see): the largest current LNG terminal in Europe (Grain, UK) has an import capacity of 27.5 bcm per year, significantly less than the existing Nord Stream 1 pipeline capacity of 55 bcm per year.[83] Furthermore, shipping import terminals require less upfront investment than pipelines. While the investment cost of Nord Stream 1 was $390 million per bcm of capacity,[84] LNG import terminals require an investment cost of around $100 million per bcm capacity.[85] The lower upfront cost implies that an import terminal is economically less dependent on a maximised utilisation than a pipeline. However, this cost does not include investments in liquefaction facilities in the exporting country and the development cost of vessels fuelled with hydrogen or its derivatives.

Table 4.2 **European gas supply capacity: LNG terminals and pipelines**

Supply source	Capacity (TWh/a)
Regasification (LNG)	**2,400**
Pipelines	**6,000**
Russia	3,400
Norway	1,800
Algeria, Libya	800
Total supply	8,400
Consumption	4,000

Source: Guidehouse (2022) based on *Teslo et al. (2022)*

Overall, pipelines offer the more cost-efficient transport option for high volume and medium- to-long distance hydrogen imports from countries within Europe and neighbouring regions such as North Africa or Ukraine. However, ship transport can work well for low volumes and imports from outside of Europe (e.g. the Gulf region) and countries where no pipeline infrastructure is possible (e.g. Australia or Chile). Given the high cost impact of conversion and space constraints, the shipping route is most economic to import derivatives when these are desired as the final product (i.e. do not require reconversion).

The cost of different transport routes also affects the relative profitability of producing versus importing different hydrogen products. Given that ammonia can be shipped more easily and at lower cost across long distances, producing ammonia in Central Europe may not be economically viable in the long run.[86] Conversely, pure hydrogen can easily be transported via pipelines. Repurposing and extending the existing transnational gas grid will allow hydrogen to be transported from supply to demand centres across Europe.

4.5 Emission intensity

The full lifecycle emissions of green hydrogen and its derivatives are crucial, not only from a sustainability perspective but also for designing viable green hydrogen projects. For green hydrogen consumed in the European Union, the upcoming DA on Article 29 on the greenhouse gas emission criteria for synthetic fuels will determine which emissions in the production and delivery process will be counted into the threshold for green hydrogen (see Chapter 6). It is likely that emissions from the transport to the final end use (e.g. pipeline operation, shipping and trucking) will be included into this threshold–at least in the long run. This makes the development of decarbonized hydrogen transport options a key priority.

Pipelines: When transporting pure hydrogen via pipelines, the key greenhouse gas emission potential stems from the electricity used for powering compressors along the pipelines. For example, an illustrative large pipeline (48 inch) transporting 64 TWh of green hydrogen per year over a 5,000 km distance would require 4.6 TWh of electricity, or 7% of the energy transported (see Table 4.3).[87] For a medium sized pipeline (36 inch) transporting 18 TWh of hydrogen per year over 1,000 km, compressor energy demand would be 1 TWh, or 6% of the energy transported.[88] If the energy is sourced from the grid[89], this would increase the greenhouse gas content of hydrogen transported in larger pipelines across greater distances by 26 g CO_2/kWh and 21 g CO_2/kWh for medium sized pipelines across shorter distances.

Table 4.3 **Energy consumption and emission intensity of pipeline operation (illustrative examples)**

Pipeline	Hydrogen transported (per year)	Pipeline compression energy (per year)	Hydrogen emission intensity using grid electricity	Renewable energy capacity for fully decarbonized pipeline operation
5,000 km pipeline 48-inch (1200 mm), 12.9 GW, 80 bar	64 TWh (1.9 Mt)	4.6 TWh	26 g CO_2/kWh (880 g CO_2/kg)	2.6 GW
1,000 km pipeline 36 inch (900 mm), 3.6 GW, 50 bar	18 TWh (0.5 Mt)	1 TWh	4.1 g CO_2/kWh (137 g CO_2/kg)	0.1 GW

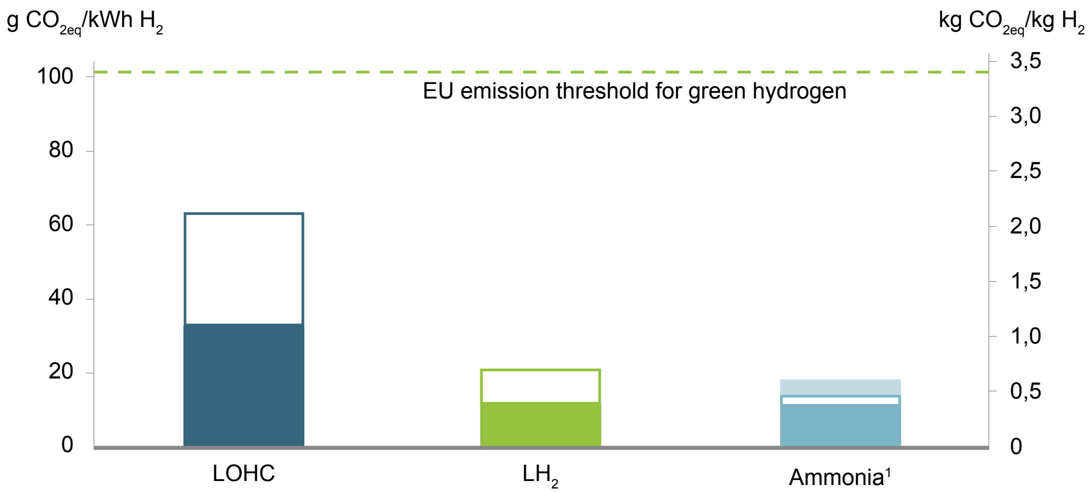
Notes: Pipelines are assumed to operate at 75% capacity and at 5,000 full load hours. For simplification, the example considers direct point-to-point connections while pipeline losses are disregarded. For grid electricity, an emission intensity of 366 g CO_2/kWh is used; for renewable energy plants, a capacity factor of 20% (1,752 full load hours) is assumed.

Source: Guidehouse (2022) based on *Guidehouse/EHB (2021)*

The emission intensity for hydrogen transported via pipelines depends crucially on the electricity mix used to power compressor stations. To fully decarbonize the pipeline transport process, additional renewable electricity capacity will be needed in pipeline transit countries. While it seems unlikely that renewable energy plants will be installed exclusively for the purpose of powering the future hydrogen grid, gas TSOs can contract new renewable energy via power purchase agreements to decarbonize their operations. With the emergence of dedicated hydrogen infrastructure this will create an additional push for renewable energy expansion.

Shipping: In 2020, international shipping accounted for around 2% of global greenhouse gas emissions.[90] On a per ton of cargo transported and kilometre basis, conventional shipping produces 6.5 grams of CO_2.[91] Thus, for an exemplary vessel transporting 100,000 t of hydrogen across 10,000 km, a total of 6,500 t of CO_2 would be emitted. If liquid hydrogen is transported, this would result in a roundtrip emission intensity of 21 g CO_2/kWh. If hydrogen is transported using LOHC-carriers, the emission intensity would be much higher at 32 g CO_2/kWh given the high weight of the carrier molecule for a one-way trip, and up to 63 g CO_2/kWh if LOHC-carrier molecules are transported back to the exporting port. For ammonia, the roundtrip emission intensity would be 14 g CO_2/kWh, or 18 g CO_2/kWh if ammonia is converted back to hydrogen.

Figure 4.9 **Emission intensity of different shipping options over 10,000 km using conventional maritime fuels**



White area: additional emissions from shipping LOHC-carrier molecules or metal tanks back to the port of origin.
[1] Shaded area: additional emissions if the final product is green hydrogen.

Note: To account for the different densities of these fuels transported and the limited tanker volume, fuel-specific emission intensity factors were calculated based on an exemplary long-range vessel with a light disposal (weight of empty vessel) of 18,000 t and a capacity of 107,000 t (DWT) or 120,324 m³ tanker capacity, and assuming a tank weight of 37,000 t for liquid hydrogen. In reality, the vessel type may differ depending on the cargo transported.

Source: Guidehouse (2022) based on Guidehouse/EHB (2021), IMO (2021) and Alkhaledi et al. (2021)

Against the EU's threshold of 3.4 kg CO_{2eq}/kg (102 g CO_{2eq}/kWh) for green hydrogen and its derivatives must not exceed, especially in the case of LOHC, conventional shipping leaves little room for additional emissions along the supply chain. This highlights the importance of developing solutions for decarbonized shipping. First vessels powered by green hydrogen, or its derivatives are currently under development with commercial products expected between 2023-25. Maersk, Hyundai and European energy are working on green e-methanol container vessels with dual-fuel systems (methanol or HFO).[92] Ammonia ships using fuel cell technology are under development by Fraunhofer IMM and the ShipFC consortium[93] while MAN wants to launch first ammonia-fueled engines in container ships by 2025-26,[94] both of which will likely require backup fuels aboard. Hydrogenious and Østensjø are cooperating on the development of LOHC shipping with fuel cell propulsion.[95] First large hydrogen-fueled LOHC ships are expected to become available by 2026. The HySHIP consortium is working on tanker barges, ferries and deep-sea vessels powered by liquid hydrogen.[96]

Additional momentum for decarbonised maritime transport is expected to come from the EU Commission's legislative proposals regarding the extension of the EU Emission Trading Scheme to maritime shipping and the FuelEU Maritime Initiative that limits the energy intensity of ship transport.

4.6 Geopolitical considerations

The German government has made it clear that it expects a continued dependency on energy imports including from outside Europe, and scenarios confirm this will be necessary. A shift from importing fossil fuels to renewable fuels such as green hydrogen can also lead to a geographical shift in energy dependency because major exporters of green hydrogen may be different from major fossil fuel exporters. For Europe, a switch in energy carriers toward green hydrogen could importantly also reduce its dependency on natural gas imports from Russia.

The geopolitical dynamic of a future global hydrogen market could resemble a gas market. Countries are likely to adopt exporter or importer roles based on their cost competitiveness and their access to large markets. Countries with favourable export conditions could dominate the global market. As in existing energy carrier markets, this opens the doors for market influence based on national interests by producing countries.[97] However, the fundamental difference to current oil & gas markets being that hydrogen can be produced anywhere where there is electricity and water. Resilience against possible supply disruptions is typically achieved by storing strategic reserves. Another way to strengthen the resilience of importing countries is to increase the diversity of exporters and transportation options. Relying solely on pipelines for transport (which, because of the immense infrastructure investment, only a limited number are likely to be built in the short or medium term) means the markets would become less diversified and more vulnerable to disruptions. Some of the regions accessible by pipeline are also connected to uncertainties, such as the political instability in some parts of the MENA region. Hence, shipping green hydrogen or its derivatives could be a reasonable addition to pipelines or power lines, even if costs are higher.[98] However, shipping routes, while adding to the diversification, can also become vulnerable on straits because of territorial conflicts.[99]

To hedge geopolitical risks, the German government could consider a few strategic options. Diversifying sources of supply requires cooperating with multiple potential exporters from around the globe. This approach is being implemented in the context of Germany's Energy Partnerships and Energy Dialogues, many of which have already taken up hydrogen in their activities. Depending on few exporters could also be reduced by promoting shipping routes in addition to pipelines. To build resilience against potential shortages due to disruptions to international trade, Germany should develop suitable storage capacities for hydrogen and hydrogen-based energy carriers.

4.7 Conclusion

Hydrogen can be transported via pipelines, ships, or transmission lines in the form of electricity. Which option is most suitable depends on the distance and geographical conditions, the existing infrastructure, and geopolitical considerations. In general, hydrogen and derivatives should be transported in the form required by the end use to minimise conversion losses.

Due to their high investment cost in relation to distance, pipelines are the most economical solution across short and medium distances (up to 3,500 km for new pipelines, 6,000 km if existing pipelines are retrofitted) and when large volumes (up to 12.7 GW per pipeline) are transported. In regions with an existing gas grid, repurposed pipelines are a least-cost option, with costs as low as one-third compared to new pipelines.

For shipping, the single biggest driver of cost is conversion and reconversion. This cost is highest for less dense pure hydrogen that is imported in its liquid form and lower–although still substantial–for derivatives like ammonia and for LOHC-based transport options.

Importing renewable electricity over long distances from outside Europe to produce green hydrogen is not considered an economically viable option. Although using existing power lines has a cost advantage over pipeline transport, the existing interconnector capacity with potential exporting regions is limited. While transport of hydrogen via new power lines is not cost-competitive compared against either shipping or pipelines, power imports using existing infrastructure can be an option for initial low volumes of hydrogen demand.

Overall, all transport options offer advantages that can come to play at different stages: In a first phase where volumes needed are low and the availability of pipeline infrastructure is limited, shipping or electricity imports can be viable alternatives for the import of hydrogen and its derivatives. As pipeline infrastructure develops, combining ship and pipeline routes can allow for greater cost savings, even across far distances. In the long run, a fully-fledged pipeline network across Europe and with connections to neighbouring regions will be the most cost-efficient solution for large-scale imports of hydrogen. Shipping can remain an option for export regions where no pipeline routes are possible (due to geography or political instability) as well as for very long distances–especially when combined with pipelines.

Both the shipping and pipeline route consume energy when moving hydrogen or its derivatives from one place to another. To assure a sustainable hydrogen supply along the entire supply chain, it is crucial to decarbonise the transport process itself. For pipelines, the electricity needed to operate compressors should be sourced from renewable sources. Ships can run on hydrogen derivatives (e.g. green ammonia or methanol) or liquid hydrogen instead of heavy fuel oil, which is associated with high CO_2 emissions compromising the sustainability of green hydrogen particularly for LOHC and ammonia transport.

As a major component of the total cost of green hydrogen delivery, transport cost plays a decisive role in the development of the future hydrogen economy in Germany, Europe, and across the globe. The lowest cost transport routes available determine not only where hydrogen will be produced but also which products (pure hydrogen or derivatives) will be imported. Given the cost challenges (conversion, reconversion) associated with shipping pure hydrogen across long distances and the benefits of existing pipeline infrastructure, it is likely that pure hydrogen will be produced in Europe and neighbouring countries while demand for derivatives will be served by imports from other regions.

5 Hydrogen storage

Key takeaways

- **Salt caverns** are the most suitable option for hydrogen storage. Alternatives include depleted gas reservoirs, aquifers, and hard rock caverns.
- **Existing** caverns, gas reservoirs, and aquifers could **satisfy all the storage needs by 2030** and over 80% of the 2050 needs.

5.1 Why storage is important for hydrogen transport

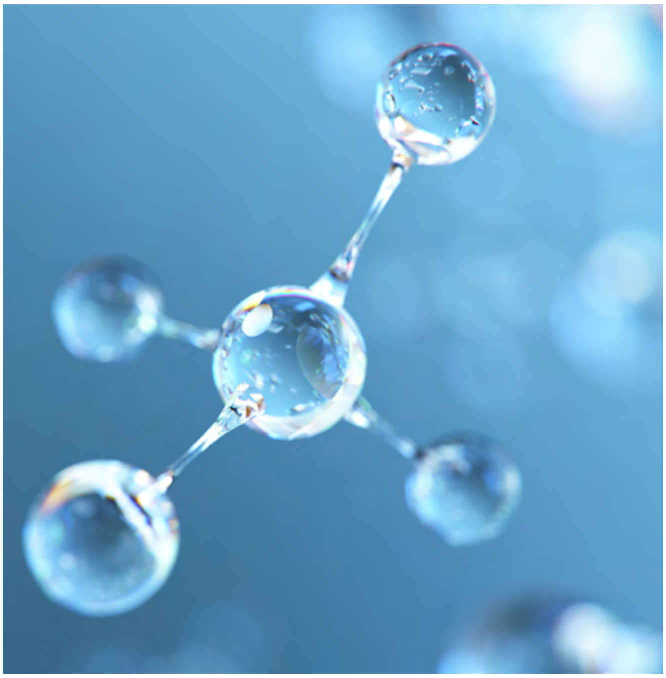
Due to the intermittency of wind and solar resources, green hydrogen supply will be subject to hourly and weekly variability and seasonal patterns in renewable energy production. On the demand side, hydrogen will be used primarily in industry processes that require uninterrupted energy supply. In the power sector, hydrogen can serve as a dispatchable power source to meet residual load as the penetration of intermittent renewables increases. Towards 2040 and 2050, applications in the buildings sector will lead to additional seasonal and diurnal variability.

Against this backdrop, hydrogen storage provides major values in three areas:[100]

Market flexibility	Storage can be filled during periods of lower hydrogen demand and depleted when demand is high or supply is low. It allows for hedging against supply and price risk and stabilises consumer prices. It also helps ensure a high pipeline utilisation to keep relative transport cost per kilogram transported stable.
System flexibility	As the penetration of intermittent renewables increases, hydrogen storage can provide system integration services. Excess power can be converted and stored in the form of hydrogen and reconverted into electrical energy later when needed, balancing power supply and demand. Efficiency and losses should be considered in this use case.
Security of supply	Like gas storage, storing hydrogen allows for building reserves that ensure against interruption of supply or failure in another part of the energy system. It also enables consistent and steady hydrogen throughput in pipelines in times of lower production.

5.2 Options for hydrogen storage

Hydrogen can be stored as a gas or liquid, using LOHCs, in the form of other substances (e.g. ammonia, methanol), in surfaces, or as a hybrid. Given the specific characteristics of hydrogen, gas storage is the only viable long-term and large-scale storage option.[101] Compared to natural gas, hydrogen has a low density (around 24%), and it only liquefies at low temperatures (-253°C vs. -160°C for natural gas). Aboveground storage would be energy-intensive or immensely space consuming.[102]



Gas can be stored underground in depleted gas reservoirs, aquifers, salt caverns, and hard rock caverns. Except for rock caverns, appropriate geological structures are available in Germany for all underground storage types. Storage in porous structures such as aquifers is still in early stages of development. In contrast, salt caverns have a proven suitability for hydrogen storage, and are considered the most promising solution due to the high level of flexibility they provide and their widespread availability across Germany. Of the estimated 16 TWh and 111 TWh storage facilities required by 2030 and 2050, respectively, salt caverns could cover around 40 TWh; another 61 TWh would be available from all other storage types.[103]

In the near term, storage is expected to be located near demand centres (in the form of liquid or compressed hydrogen or ammonia) to stabilise supply to end users.[104] However, this is not cost-optimal from a system perspective; aside from stable supply, most other advantages storage offers will likely not be available due to its relative location in the overall system. In the mid- to long term, as a European hydrogen backbone emerges, dedicated underground storage sites will be needed close to supply to stabilise production, feed point-to-point pipelines with high capacity factors, and deliver baseload hydrogen to customers.[105] Once a fully-fledged hydrogen supply grid is in place, the pipeline network will likely be vast enough to stabilise production across regions (i.e. from solar energy in Spain and wind in the North Sea region).

The investment cost of underground storage is composed of cost for cushion gas, site exploration and development, and surface and sub-surface infrastructure. Other factors affecting the final cost of hydrogen storage on a per-unit basis are the size of the reservoir, operating conditions, and the number of injection and withdrawal cycles. Unlike natural gas storage, which is primarily used for strategic reserves and to cover seasonal demand peaks, hydrogen storage will likely be needed to firm the daily and monthly variability of renewables. This has implications on technology, cost, and system operation.

Early estimations indicate that the levelised cost of hydrogen storage could be between €0.18 and €1.3/kg of hydrogen for salt caverns, at around €1/kg for depleted gas fields and aquifers, and around €2.3/kg for hard rock caverns.[106] Given its crucial importance for a functioning hydrogen supply chain (stable supply, high pipeline utilisation, and cost), further research on storage options for hydrogen is greatly needed.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6 Certification and regulation

Key takeaways

- **Clear** and **stringent** sustainability criteria for green hydrogen are crucial. To accelerate the market run-up, more **lenient criteria** should be considered for a limited a **transitory** period.
- Hydrogen grid infrastructure is considered a **natural monopoly** and should be fully regulated in the long run. To promote timely infrastructure investments, a **two-staged approach** with an initial regulatory framework should be considered.
- Regulation will need to be **harmonised** across the EU to foster market integration while still allowing countries the flexibility to adjust to reflect domestic specificities.

Green hydrogen will be key for reaching the global climate targets and for mastering the energy transition. However, it can only deliver on the expected emission abatement effects if produced from renewable energy – and without taking away renewable energy from other, more efficient uses. The specific criteria hydrogen producers need to comply with for hydrogen to be counted as fully renewable will be specified in the DA on Article 27 of the RED, to be published by the European Commission in 2022 (see box below).[107]

While stringent sustainability criteria for green hydrogen production are essential, uncertainty about the specific requirements and overly onerous criteria can stifle project development. On the one hand, regulatory certainty is needed to enable planning of and investment in large-scale hydrogen projects, needed to achieve cost-reductions. On the other hand, in the short-term, a more flexible and lenient regulatory framework can help accelerate the run-up of hydrogen markets and accommodate for faster technological learning effects. Such initial regulations should, however, only be implemented for a transitory period of 5-10 years and do not substitute for clear and stringent long-term criteria that must be set out from the start.

As global hydrogen markets emerge, also regulatory aspects for hydrogen infrastructure need to be addressed. Because gas grid infrastructure features high upfront cost with significant potential for economies of scale, the future hydrogen grid infrastructure is bound to be a natural monopoly. Adding to the likeliness of natural monopoly formation are the lower transaction cost for natural gas incumbents compared to new market entrants.

To establish a hydrogen economy in Germany and to enable a working hydrogen market throughout the EU, an adequate regulatory framework will be required. This can provide much needed regulatory certainty for investors and market actors, both from the within and outside the EU. Such a framework needs to be aligned across member states to promote integrated network planning, facilitate the integration of the future hydrogen market, and reduce the risk of distortion between member states. To that end, European Commission has published its Hydrogen and Decarbonised Gas Package in December 2021. The package aims at establishing a market for hydrogen, creating a suitable investment environment, and enabling the development of dedicated infrastructure, including for trade with third countries. The market rules will be applied in two phases, before and after 2030, and will notably determine access rules to hydrogen infrastructure, separation of hydrogen production and transport activities, and tariff setting. A new governance structure in the form of the European Network of Network Operators for Hydrogen (ENNOH) will be created to promote the establishment of a dedicated hydrogen infrastructure, coordinate cross-border and interconnector network construction, and elaborate on specific technical rules.

EU sustainability criteria for green hydrogen production

For green hydrogen to fulfill its crucial role in the energy transition puzzle, its production must follow stringent sustainability criteria. For hydrogen consumed in the European Union, the soon-to-be-published Delegated Acts (DA) on Article 27 and Article 29 of the Renewable Energy Directive (RED II) will be specifying the criteria under which green hydrogen to be counted as fully renewable.

The DA on Article 27 will outline the conditions for electricity supply for electrolysers. For hydrogen produced with grid-sourced electricity, the following criteria are expected: additionality of renewable energy (i.e. new, unsubsidized installations), temporal correlation of renewable energy and hydrogen production (likely on an hourly basis), and geographic correlation between renewable energy and hydrogen production to reduce strain on the grid.

As a renewable fuel of non-organic origin (RFNBO) green hydrogen green hydrogen must achieve at least 70% emissions reductions compared to a fossil fuel comparator (defined at 94 g CO_{2eq}/megajoule or 338 g CO_{2eq}/kWh), resulting in 3.4 kg CO_{2eq}/kg of hydrogen. From the greenhouse gas emissions reduction methodology that will be outlined in the DA on Article 29 it is expected that this threshold applies to the full life-cycle emissions of green hydrogen, including the production and transport up until the final point of consumption.

7 Conclusions and recommendations

Reaching Germany's decarbonisation targets will require a complete overhaul of the energy system. Next to the urgently needed expansion of renewable energy, electrification and energy efficiency increases, hydrogen will become a cornerstone of Germany's decarbonisation strategy. Nevertheless, Germany will remain reliant on energy imports.

Hydrogen demand in Germany is expected to increase massively to up to 170 TWh-750 TWh in 2050. Most of this demand will need to be served by imports. Like Germany, other countries such as Belgium, Italy, Japan, or South Korea will also rely on hydrogen imports. In Europe, Germany will account for almost half of the total import demand.

While blue hydrogen can play a role in the short term for testing und building up supply chains, green hydrogen will prevail in the medium to long term due to better economics and sustainability. Unlike green hydrogen, blue hydrogen is still associated with significant greenhouse gas–in particular methane–emissions from the natural gas production process, non-captured CO_2 emissions from methane reforming and leakage from carbon storage. Therefore, blue hydrogen can only serve as a transition technology, and lock-in effects regarding infrastructure and production facilities should be avoided.

To comply with its ambitious energy and climate targets and to meet the associated rapidly increasing green hydrogen demand, Germany must develop a strategy for securing adequate quantities of hydrogen imports, while using synergies with both hydrogen producers and other major importers.

A German import strategy should consider the following key aspects:

- Set up **European and international hydrogen partnerships** to secure sufficient hydrogen supply. Such partnerships could be bilateral or multilateral, e.g. teaming up with other potential importers of hydrogen. Establishing a hydrogen industry can also support exporting countries in diversifying their economies and creates new revenue streams and jobs.

- Increase security of supply by **diversifying hydrogen supply countries and transport routes.** While for large volumes of molecular hydrogen pipeline transport is the most economic option, maritime shipping is particularly relevant in the short-term when hydrogen pipeline infrastructure is still limited, and for derivatives such as ammonia or methanol.

- **Build up and finance the transport infrastructure** for short- and long-term hydrogen imports. Offtake and delivery are key factors for the realization of hydrogen projects. To prevent infrastructure bottlenecks slowing down the hydrogen market run-up, the necessary pipeline and port infrastructure in Germany and Europe must be developed and expanded rapidly.

- **Set and align standards and regulation** for hydrogen production and transport. Uncertainty around standardisation and regulation can be a major roadblock delaying the implementation of projects. While the criteria for green hydrogen production will be determined at the European level, Germany should align with other importers in the EU and in Asia to establish viable regulatory approaches and certification schemes for green of hydrogen imports and also develop safety standards. To accelerate the market run-up, regulation should provide flexibility in the initial market phase while also giving a long-term outlook to provide certainty for investors.

- **Continue and expand hydrogen support instruments.** Funding support is critical to close the financing gap of early hydrogen projects and ensure bankability. Existing funding instruments such as Germany's International Funding Guideline, H2 Global, H2UPPP, and the upcoming innovation funds (see Chapter 3.3) should be continued, expanded. Next to trade credit insurance schemes (Euler Hermes) a PtX-Growth Fund should be established to secure the bankability of projects. Creating a one-stop-shop for support instruments could further simplify access to funding.

- Continue to **support research and development** on technology and innovation along the hydrogen value chain to realise rapid **cost reductions**. Many of the technologies required to enable the hydrogen economy are made in Germany. Technology cooperation with partner countries in R&D hubs and laboratories, "living labs", (e.g. on solar-powered electrolysers, operation under in ambient temperatures, hydrogen storage, carbon sourcing for derivatives, etc.) can benefit the quick rollout of international hydrogen trade.

- **Support international flagship projects.** Support for joint projects with partner countries will be essential to enable flagship projects that can create learning effects, promote innovation and enable scaling of hydrogen production.

Germany's network of Energy Partnerships and Energy Dialogues offers an ideal vehicle to address many of the aforementioned points

List of abbreviations

bcm	Billion cubic metres
CAPEX	Capital expenditure
CO2(eq)	Carbon dioxide (equivalent)
DA	Delegated Act
dena	Deutsche Energie-Agentur
DWT	Deadweight ton
EHB	European Hydrogen Backbone
EFTA	European Free Trade Association
ETS	Emissions trading system
EU	European Union
giz	Gesellschaft für Internationale Zusammenarbeit
GW	Gigawatt
HVAC	High voltage alternating current
HVDC	High voltage direct current
IEA	International Energy Agency
KNDE	Climate-Neutral Germany (Klimaneutrales Deutschland)
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LFS	Long-term scenarios (Langfristszenarien)
LNG	Liquefied natural gas
LOHCs	Liquid organic hydrogen carriers
MENA	Middle East and North Africa
Mt(/a)	Megatons (per year)
MWh	Megawatt hour
NRW	North Rhine-Westphalia (Nordrhein-Westphalen)
NWS	National Hydrogen Strategy
PtG/PtL	Power-to-gas/-liquid
PtX	Power-to-X
RED II	Renewable Energy Directive II
SME	Small and medium-sized enterprise
TWh(/a)	Terawatt-hours (per year)
UAE	United Arab Emirates

Germany's future hydrogen demand in studies

The future hydrogen demand projections given in the studies analysed differ for several reasons:

- First and most importantly, Germany's new climate targets are only reflected in the KNDE projections. This implies that an even faster ramp-up of green hydrogen than considered in NWS and LFS could be necessary to meet the new targets.
- Secondly, the LFS scenarios each reflect the pronounced use of a particular decarbonisation pathway (electrification, hydrogen, and PtG/PtL). In reality, a mix between the different pathways may be more likely.
- Finally, uncertainty remains over transport cost, land use, and availability for renewable energy plants in Germany and Europe and over capacity factors for electrolysis. The different assumptions used here affect what share of domestic green hydrogen production can be expected and which countries and regions will be suitable for sourcing imports (see Chapters 3 and 4).

Moreover, the estimates are subject to caveats:

- Most studies estimate supply and demand volumes based on the cost of green hydrogen supply instead of using hydrogen prices, which may contain profit margins or risk premiums. Therefore, cost may be underestimated.
- Limited consideration is given to the infrastructure requirements across sectors (including gas grid retrofits, exchange/retrofits of end-use appliances, hydrogen-based heat distribution system).
- Studies use a simplified version of the integrated value chains in industrial clusters.
- The sourcing of CO_2 demand required to produce hydrogen derivatives is often not fully considered.

Overall, demand projections can provide a useful frame of reference for the conceivable orders of magnitude of future green hydrogen demand in Germany. However, the large range between scenarios reflects the high uncertainty about hydrogen market uptake. This uncertainty is a challenge for policy development. The German National Hydrogen Strategy, originally from 2020, is revised in 2022 to reflect the latest developments on expected hydrogen demand and supply.

Hydrogen definitions

Table C1. Hydrogen colours

Color	Definition
Green	Hydrogen produced from renewable electricity.
Blue	Hydrogen produced from natural gas with carbon capture and storage.
Gray	Hydrogen produced from natural gas without carbon capture and storage.

Table C2. Hydrogen conversion factors (lower heating value)

Megatons (Mt)	Terawatt hours (TWh)	Gigajoules (GJ) (million)	Billion cubic metres (bcm)*
1	33.3	120	11.126

* Assumption: normal cubic metre gas measured at 1 atmosphere and 0ºC.

End notes

1 In this report, unless specifically labelled as green (produced from renewable electricity), blue (from natural gas with carbon capture and storage) or gray (from natural gas), hydrogen refers to hydrogen produced from energy sources not further specified.

2 Germany's National Hydrogen Strategy is currently under revision to reflect the higher expected demand.

3 The new climate targets increase the level of ambition compared to the previous target of reaching 55% emission reductions by 2030 and climate neutrality by 2050. (Source: German Federal Government (2021). Climate Change Act. Available online: *https://www.bundesregierung.de/breg-de/themen/klimaschutz/climate-change-act-2021-1936846*.)

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7 Existing hydrogen demand covered by hydrogen from natural gas via steam methane reforming (SMR) is considered natural gas demand (in line with the energy balance methodology) and is not included here.

8 See Appendix B for a more detailed discussion on the assumptions.

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18 While its official hydrogen strategy is yet to be published, Italy is likely to have similarly high hydrogen demand and associated import needs as those countries.

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24 LBST (2020): International Hydrogen Strategies.

25 Given the 10 GW of domestic electrolysis capacity by 2030 targeted in the coalition treaty (24.11.2021), production could reach 28 TWh in 2030. Available online: *https://www.bundesregierung.de/breg-de/service/gesetzesvorhaben/koalitionsvertrag-2021-1990800.*

26 Current hydrogen production (55 TWh/a, mainly grey hydrogen in SMR plants and 3.85 TWh via electrolysis) and plans to install blue hydrogen production facilities with an annual output of 9 TWh are excluded here.

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28 Guidehouse/EHB (2022): European Hydrogen Backbone. A European Hydrogen Infrastructure Vision Covering 28 Countries. Forthcoming.

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