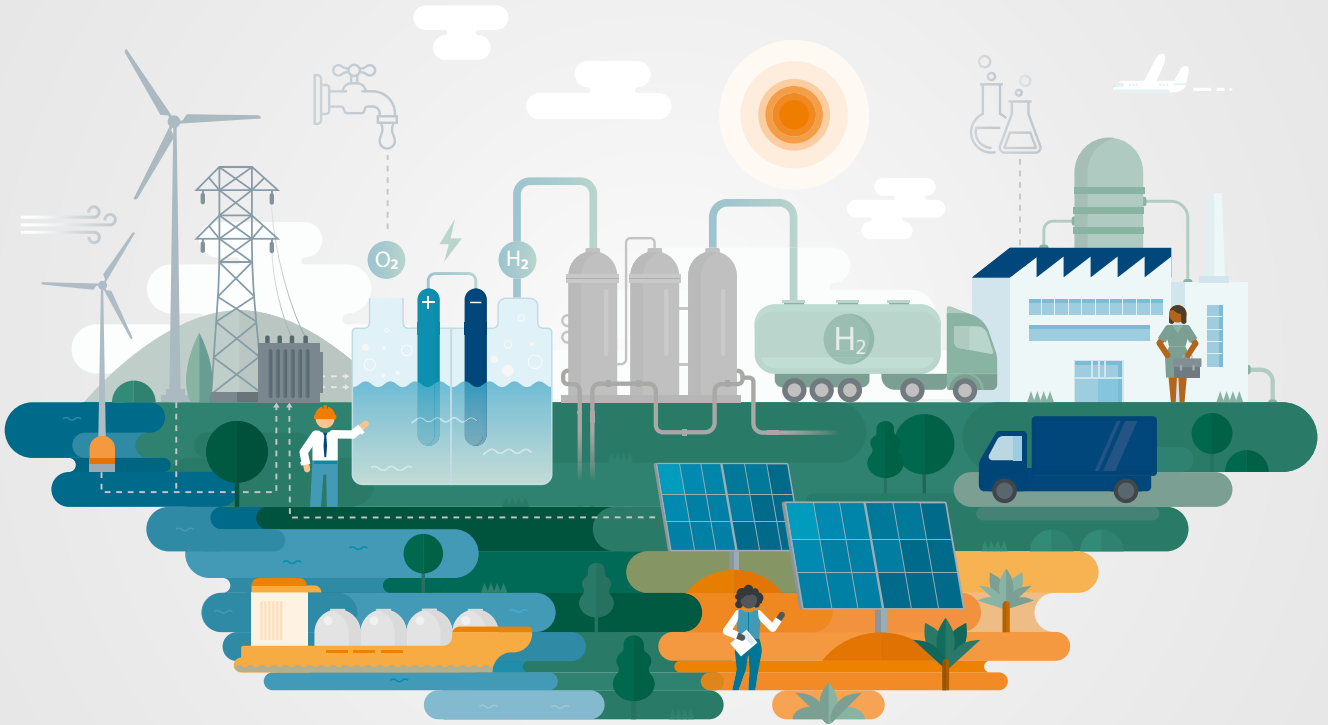




Turkish-German • Türk-Alman
Energy Partnership
Enerji Ortaklığı

Options for Transporting Green Hydrogen from Türkiye to Germany

*Carried out under the bilateral energy partnership on behalf of the
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Imprint

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Energy Partnership
Enerji Ortaklığı



Deutsch-Türkische
Industrie- und Handelskammer
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Executive summary

This paper analyses the feasibility of different options for transporting green hydrogen from Türkiye to Germany. It discusses the options of pipeline and ship-based transport and highlights the respective techno-economic, financial and regulatory determinants of both modes of transport.

As for the pipeline solution, two corridors are explored, namely the South-East European Corridor (SEEHyC) via Greece, Bulgaria, Romania, Hungary, Slovakia, Czechia and Hungary, and the Southern Corridor (SouthH₂) via Greece, Italy and Austria. Depending on the degree of repurposing, estimated investment in pipelines ranges from EUR 6 billion (SouthH₂) to 11.2 billion (SEEHyC). In terms of transportation costs, pipelines offer long-term advantages over shipping if a minimum capacity booking of over 50 TWh per year is reached. Prevailing regulatory risks and the lack of long-term purchases have a deterrent effect on private investors. Additionally, complex geopolitical coordination between the transit countries is needed.

By contrast, the transport of green hydrogen via ship as ammonia is more flexibly scalable and could make use of established logistics chains in both Türkiye (e.g., Gemlik, Bursa province) and Germany (e.g., Brunsbüttel, Schleswig-Holstein). However, efficiency losses in the

case of ammonia cracking for final use as molecular hydrogen at the destination significantly impair the overall levelised cost. Our techno-economic assessment shows the following diverging cost profiles:

In 2050, the shipping costs of ammonia as a derivative without cracking are estimated at 0.4 EUR/kg H₂.

While pipeline transport is estimated to be cost-effective at high volumes with transportation costs of approximately 0.3–1.2 EUR/kg H₂, transportation costs for molecular hydrogen to be borne by the end user rise to up to 3 EUR/kg H₂ after ammonia cracking. The financing of large-scale infrastructure projects remains a key hurdle. The ship-based transportation of hydrogen in the form of ammonia, on the other hand, is associated with much lower capital costs on the infrastructure side, as both Türkiye and Germany can draw on existing port facilities that are required for loading and unloading. However, ammonia should preferably be used directly. Existing funding programmes such as the Connecting Europe Facility as well as instruments that are currently being conceptualised such as intertemporal cost allocation are being discussed as possible solutions to address the specific risks associated to hydrogen infrastructure.

Key messages

Türkiye is a promising location for the production of green hydrogen.

Türkiye provides a competitive business case for the production of green hydrogen due to its vast potential for electricity generation based on renewables. With its existing advanced industrial base, the country is well positioned for trade in hydrogen and derivatives.

Pipeline-based transport is the most efficient transport option to meet the demand of molecular hydrogen in Germany.

Pipeline-based transport is best suited for the end use of molecular hydrogen in sectors such as steel and chemicals. Depending on the assumptions surrounding technological developments, projected pipeline-based transport costs range between 0.3–1.2 EUR/kg H₂.

The economic case for routing Turkish hydrogen exports to Germany via the southern hydrogen corridor SouthH₂ (Greece – Italy – Austria – Germany) is superior due to a higher potential for the retrofitting of existing assets and higher projected capacity utilisation.

The two most important factors for determining the economic feasibility of a hydrogen pipeline are the degree to which existing infrastructure for natural gas can be retrofitted for transport hydrogen and the projected utilisation of the pipeline. The routing of Turkish hydrogen exports to Germany via SouthH₂ performs better than an alternative connection via the South-East European Hydrogen Corridor SEEHyC (Greece – Bulgaria – Romania – Hungary – Slovakia – Czechia – Germany), due to a higher degree of possible retrofitting for existing assets and projected utilisation.

Crucial questions surrounding financing and regulation remain unanswered in hydrogen pipeline corridors within the EU and with non-EU countries.

Existing financing measures for hydrogen infrastructure in the EU are limited to direct subsidies, e.g., for Projects of Mutual Interest (PMI) under the Connecting Europe Facility. However, none of these instruments are suitable for spreading the high initial capital costs over the lifecycle of an asset or for hedging the long-term uncertainty of a lack of capacity bookings. Intertemporal cost allocation mechanisms are necessary, for example in the form of amortisation accounts in which governments act as guarantors.

Türkiye's specialisation as a supplier of green ammonia and other low-carbon hydrogen-based products represents a tangible short-term opportunity.

Given the many hurdles to establishing pipeline-based hydrogen transport from Türkiye to Germany, the immediate focus in the coming years should be on using and expanding existing ammonia infrastructure. As Türkiye is already an exporter of ammonia and fertilisers, the EU's phase-in of the Carbon Border Adjustment Mechanism (CBAM) allows the Turkish economy to establish itself as a supplier of green products to the European Union.

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1 Introduction

The global energy landscape is undergoing significant transformation, as nations strive to decarbonise their economies and meet ambitious climate targets. In this context, green hydrogen has emerged as a promising solution for sectors that are difficult to electrify directly. Türkiye, with its abundant renewable energy resources, is well positioned to become an important player in the production and export of green hydrogen. As Europe seeks to diversify its energy sources and reduce dependence on fossil fuels, the idea of importing green hydrogen from Türkiye has gained traction. This scoping report will identify the key determinants for policymakers and industry when considering possible Options for transporting green hydrogen from Türkiye to Germany. It will focus primarily on two primary means of transport, namely transport via pipeline, and via ship in the form of ammonia.

For the transport of hydrogen via pipeline, two options seem relevant – transport via the South-East European Hydrogen Corridor (SEEHyC) or the Southern Corridor (SouthH₂) via Italy. These corridors could leverage existing natural gas infrastructure, with necessary modifications to accommodate hydrogen transport. SEEHyC would traverse southeastern Europe, potentially passing through countries such as Bulgaria, Romania and Hungary before reaching Germany. The SouthH₂ corridor, on the other hand, would involve transporting hydrogen from Türkiye to Italy, likely via Greece and the Adriatic Sea, before continuing northward to Germany. Both pipeline options present unique challenges and opportunities. Factors such as infrastructure readiness, geopolitical considerations and the willingness of transit countries to participate in the hydrogen economy will play a crucial role in determining the feasibility and attractiveness of each route. An alternative to pipeline transport is the shipping of hydrogen in the form of ammonia. This method involves converting hydrogen to ammonia at the point of production in Türkiye, shipping it to Germany and then reconverting it back to hydrogen through a process called ammonia cracking. Ammonia (NH₃) is an attractive hydrogen carrier due to its higher energy density compared to pure hydrogen and the existing infrastructure for its transport and storage. Türkiye's strategic location, with access to both the Mediterranean Sea and the Black Sea, provides multiple options for retrofitting existing infrastructure and establishing export terminals.

Comprehensive analysis of these transport options must consider not only the direct costs of infrastructure development and operation but also factors such as energy efficiency, scalability and alignment with the long-term energy strategies of both the exporting and importing countries. For instance, pipeline infrastructure, once established, could potentially serve multiple countries along its route, fostering a more integrated European hydrogen market. On the other hand, maritime ammonia transport could offer Türkiye the flexibility to trade hydrogen derivatives on a smaller scale as the ramp-up for molecular hydrogen transport remains nascent. Financing infrastructure plays a key role in the realisation of hydrogen transport projects. The substantial capital requirements for developing hydrogen pipelines or ammonia shipping facilities necessitate innovative financing models. Public-private partnerships, green bonds and multilateral development bank funding could be potential sources. Additionally, government guarantees and long-term offtake agreements are currently necessary to attract private investment, given the early stage of the hydrogen market. The financing strategy would need to account for the long-term nature of these infrastructure investments and the evolving regulatory landscape around hydrogen.

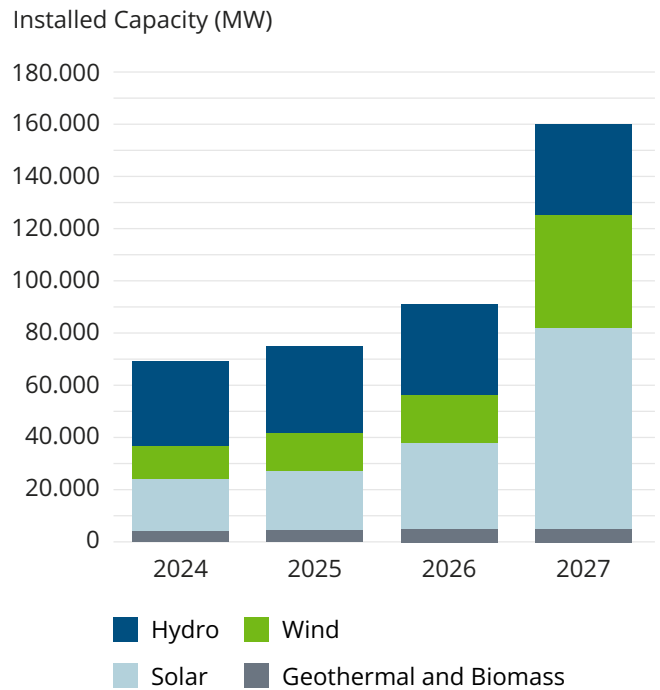
By thoroughly examining these factors, this scoping report aims to provide a comprehensive comparison of pipeline and ship transport options for hydrogen from Türkiye to Germany. The findings will contribute to the ongoing dialogue on the future of Europe's energy landscape and the role of green hydrogen in achieving climate neutrality. As Türkiye positions itself as a potential major exporter of green hydrogen, with projections suggesting an export capacity of 1.5 to 1.9 million tonnes by 2050, the choice of transport method will be critical in realising this potential. The outcomes of this analysis within the Turkish-German Energy Partnership shall provide information for future decision-making processes for energy infrastructure investments in Türkiye and Germany.

2 Türkiye's potential for green hydrogen production

Türkiye has set an ambitious target to become carbon-neutral by 2053. Since ratifying the Paris Climate Agreement in 2021, the country has been actively working towards transitioning to a sustainable and climate-friendly economy. A significant step in this direction was the updating of its Nationally Determined Contribution (NDC) in 2022, which outlines the roadmap for emission reductions. The goal is to reduce greenhouse gas emissions by 41% by 2030, compared to a business-as-usual scenario. The strategy for achieving climate neutrality encompasses the entire economy, involving both mitigation and adaptation measures, with detailed analyses on implementation feasibility. Special attention is given to the energy sector, as it holds the greatest potential for defossilisation. The energy sector is the largest source of emissions in Türkiye, according to the Directorate of Climate Change (DCC). In 2022, this sector accounted for 71.8% of the country's total greenhouse gas emissions, five times more than the second largest emitting sector, agriculture (12.8%).¹ The Turkish government recognises that a swift transition to renewable energy is not only crucial for climate protection but also significantly enhances the country's economic opportunities and resilience. In 2023, Türkiye's electricity production reached 319.8 TWh/a, with about 134.34 TWh/a (42%) coming from renewable energy sources.² As of 2024, installed renewable energy capacity was 66.68 GW, representing a record year for total capacity growth.^{3,4} At the end of 2024, installed renewable production capacity equalled 58% of total installed production capacity (116 GW).⁵ For 2025, the government projects a significant increase in renewable energy capacity, anticipating record-breaking total installed capacity of 74.7 GW (see Figure 1).

The share of renewable energy in electricity generation has significantly increased in recent years, reaching 42.7% in 2023 and 45% in 2024. This upward trend is

Figure 1: Installed renewable energy capacity in 2024 and outlook from 2025 (in GW)



Source: Own illustration, based on Fichtner (2024) and MENR (2025)

projected to continue, with one forecast for 2025 also expecting 47.8%, according to Anadolu Agency.⁶ Türkiye possesses significant wind resources in the western regions and abundant solar energy potential nationwide, along with hydropower and geothermal capabilities. These renewable energy sources are primarily used to meet electricity demand across sectors such as buildings, industry and transport. However, with hydropower already largely maximised as of today, the future energy strategy will depend on expanding wind and solar capacity. The short-term goal is to achieve a 50% share of renewable energy in electricity generation by 2030.⁷

1 cf. Republic of Türkiye Ministry of Environment, Urbanisation and Climate Change (2024).

2 cf. Ember Energy Institute (2024).

3 cf. Republic of Türkiye Ministry of Energy and Natural Resources (2025).

4 cf. Fichtner (2024).

5 cf. Republic of Türkiye Ministry of Energy and Natural Resources (2025).

6 cf. IANS (2024).

7 cf. Yalçın (2024).

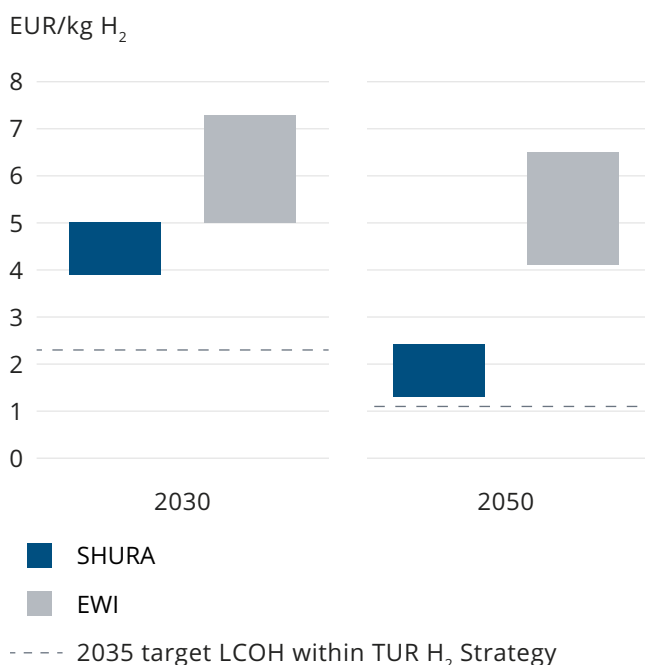
Deriving from Türkiye's endowment with renewable energy resources, there are different estimates of the production and export potential for green hydrogen in the country, which suggest a similar export surplus of green hydrogen. In a 2021 study, SHURA predicted that under optimal conditions, up to 3.4 million tonnes (Mt)/year of green hydrogen could be produced by 2050, for which 35.3 GW of electrolysis capacity would be needed. The institute estimates maximum domestic hydrogen demand at 1.9 Mt per year, which results in a hydrogen export potential for Türkiye of about 1.5 Mt per year.⁸ The Istanbul International Center for Energy and Climate at Sabanci University, on the other hand, assumes an electrolysis capacity of 50 GW by 2050 and hydrogen production of up to 5.5 Mt. With domestic demand at 3.8 Mt, however, the export surplus is in a similar range, with 1.7 Mt of export potential in 2050.⁹ The Turkish Hydrogen Technologies Strategy and Roadmap envisages an expansion target for electrolyser capacities of 2 GW by 2030, 5 GW by 2035 and 70 GW by 2053. Taking into account Sabanci's optimistic assumptions (75% electrolyser efficiency and approx. 5,000 full-load hours), an installed electrolysis capacity of 70 GW would result in a production volume of up to 7.9 Mt of hydrogen. Applied to the potential demand estimated by SHURA, this would result in an export surplus of about 5 Mt of green hydrogen per year. This figure, however, is not based on a dedicated simulation and would require further analysis.

According to the hydrogen strategy adopted by the Turkish Ministry of Energy and Natural Resources (MENR), the levelised cost for the production of renewable hydrogen being aimed for is USD 2.4/kg H₂ by 2035 and just half of this level, i.e., USD 1.2/kg H₂ by 2053. SHURA envisions that, depending on the electrolysis technology and subject to scaling and efficiency improvements, production costs will be between 3.9 and 5.0 EUR/kg H₂ for alkaline and PEM electrolyzers in 2030 and expects a cost range of 1.3 to 2.4 EUR/kg H₂ with ideal grid planning in 2050.¹⁰

For comparison, the Institute of Energy Economics at the University of Cologne (EWI) modelled the levelised cost of hydrogen (LCOH) worldwide based on a rather broader and general set of assumptions for most of the countries worldwide. This does not necessarily reflect the specific

set of parameters impacting Turkish LCOH but provides a source for the basis of comparative analyses in a global context. EWI thus assumes production costs between EUR 5.0/kg H₂ (based on PV-only) and EUR 7.3/kg H₂ (based on wind-only) in 2035. By 2050, the assumed costs fall to 4.1 EUR/kg H₂ and 6.5 EUR/kg H₂, respectively. This puts Türkiye at a comparable LCOH to Italy, Tunisia or Bulgaria.¹¹ It should be noted that the EWI assumptions are relatively recent and based on updated assumptions regarding the degression of electrolysis costs and capital costs (for a detailed list of assumptions see Annex 1).

Figure 2: Projected LCOH according to different sources (EUR/kg H₂)



Source: Own illustration, based on SHURA (2021), MENR (2023), EWI (2024)

The study by SHURA also offers strategic insights for prioritising hydrogen production efforts for both domestic use and export opportunities. According to the authors, Türkiye's potential for the export of renewable hydrogen is particularly pronounced in the western

8 In a centralised scenario for the energy system, the maximum export volume increases to 1.9 Mt, as hydrogen consumption is distributed across six designated regions and not the entire country.

9 cf. Istanbul International Center for Energy and Climate (2023).

10 Please note that the following currency exchange rate was used: EUR 1.0 = USD 1.05.

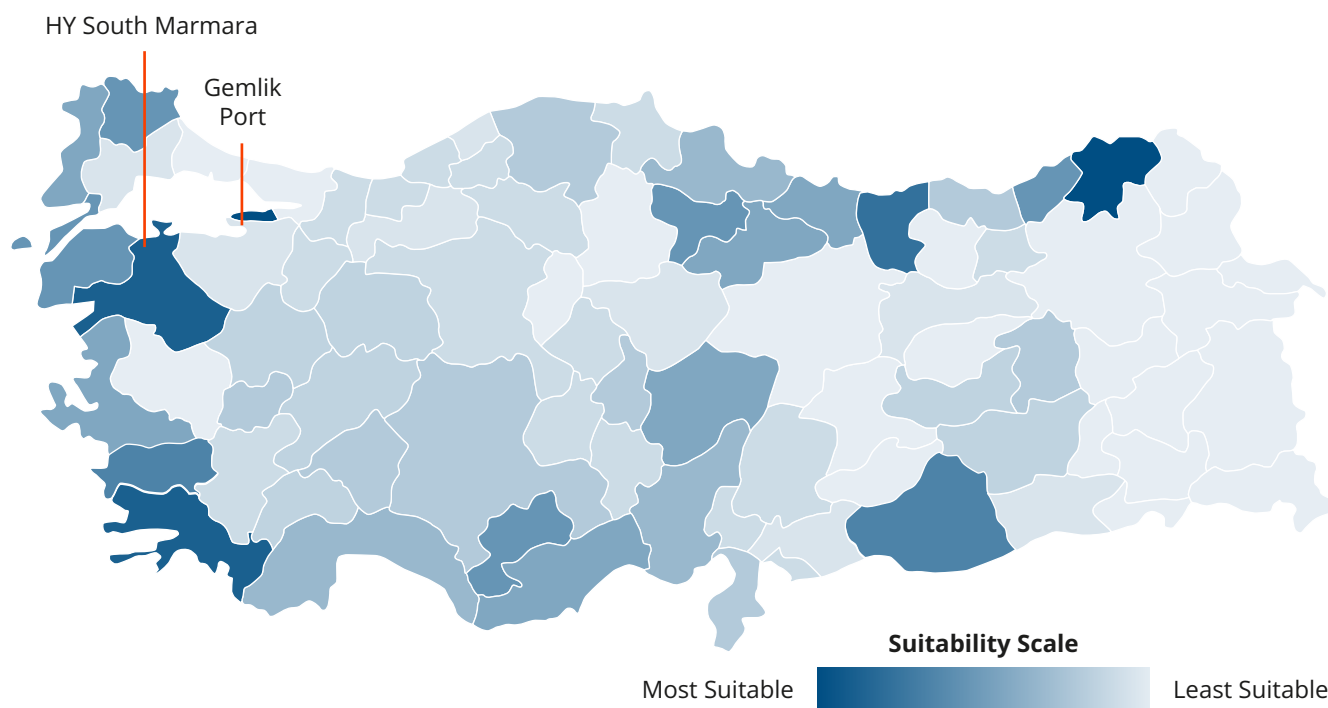
11 cf. Klaas et al. (2024).

provinces like Yalova, Balıkesir, Aydın and Muğla (see Figure 3). While the market ramp-up of green hydrogen often encounters demand-side challenges, a robust industrial base – especially in the petrochemical sector in industrial hubs like Istanbul and Izmir – could ensure consistent demand during the early ramp-up phase. Coastal locations offer sea water access which, if desalinated, represents an alternative water source for electrolysis-based hydrogen in dry regions.¹²

The relative proximity to the Greek border further positions the regions well for potential linkage to the European hydrogen pipeline-based network, while at the same

time, port facilities with capacities for handling derivatives like ammonia already exist, for example in the port of Gemlik, in Bursa province. This offers room for exploration of a dual strategy to leverage both local and global hydrogen market opportunities. A good example of institutional recognition of the strategic potential in the region is the funding of the HYSouth Marmara project as part of the Hydrogen Valley initiative by the Clean Hydrogen Partnership, which is co-financed by the European Union. The European Commission has provided EUR 7.4 million for the 14 consortium partners under the Horizon Europe funding programme.¹³ South Marmara consists of the provinces Balıkesir and Çanakkale.

Figure 3: Evaluation of green hydrogen export potential, including South Marmara Hydrogen Valley



Source: SHURA (2021), adapted

¹² Türkiye is considered a mostly arid to semi-arid country with average available water per capita per year of 1350 m3 as of today. (cf. Kibaroglu (2022)) Therefore, responsible use of water should be assessed on a case-by-case basis so as to prevent competing use with civilian demand for water.

¹³ cf. European Commission (2023).

Although the two provinces account for only 3% of Türkiye's total area, the sub-region has 3 GW of installed renewable energy production capacity. This represented almost 10% of the installed new renewable energy capacity in 2021, excluding hydropower, for which the development potential in Türkiye is already stagnant. The majority of this generation came from onshore wind, with a share of 21%, making South Marmara the leading region in Türkiye in terms of installed wind capacity. In addition, it is assumed that Türkiye's first offshore wind farms are likely to be built in the zones adjacent to the South Marmara region. Some of the South Marmara region's near-

coastal and offshore zones have the highest potential for wind energy compared to other regions.^{14,15} Potential for the production of green hydrogen in Türkiye therefore certainly exists, thanks to the country's favourable endowment with renewable resources. The extent to which this potential can be translated into an export-oriented national hydrogen economy depends on the circumstances associated with different transport options. The following section will therefore deal in more detail with the different technical options and routes for hydrogen transport from Türkiye to Germany and address various techno-economic aspects.

Info box 1: Projected German hydrogen demand

Today, Germany consumes about 42 terawatt hours per year (TWh/a) of grey hydrogen. The country's projected total demand for hydrogen and derivatives amounts to 95 to 130 TWh/a by 2030 as per Germany's National Hydrogen Strategy (NHS), first introduced in June 2020 and updated in July 2023.

Around 50% to 70% of this demand (45 to 90 TWh/a) is expected to be met by imports, due to limits of domestic production. The share of imports is expected to increase further in the years beyond 2030 as demand for hydrogen and hydrogen derivatives is expected to increase further as well, reaching 360–500 TWh/a by 2045 for hydrogen alone and an additional 200 TWh/a for hydrogen derivatives. While at present it is difficult to predict the exact level of demand in 2030, the BMWK assumes that a swift ramp-up will take hold by the mid-2030s. To mitigate associated market risks faced by project developers and offtakers, the German government has approved the construction of a state-backed 9,040 km hydrogen core pipeline network, ensuring efficient distribution by connecting domestic demand, production and import sources.

The primary consumers of hydrogen in Germany will be sectors where demand is already established, particularly in the industrial and chemical domains (e.g., steel production, chemicals production and refineries). Additionally, demand will be significant in aviation, shipping and the power generation sector, both through the substitution of demand currently covered by fossil fuels and through new production processes.

The outlined demand projections are in line with long-term scenarios the German government is developing to achieve climate neutrality by 2045. It should be pointed out that the actual transposition of this projection into actual economic demand for hydrogen will depend on the upcoming regulatory and market framework conditions. These include, for example, the development of ETS prices, the revision of the CBAM (e.g., for exporters), the electricity market design (including policies for power plants), as well new support regimes such as lead markets and CCfD (e.g., under the Clean Industrial Deal).



14 cf. Duman (2022).

15 It should be noted that other regions are also possible candidates for the hybrid production (PV and wind) of green hydrogen. For reasons of rigour, the South Marmara region is presented here as a proxy for the general Turkish production potential. For reasons of stringency in the context of the transport cost analysis, we do not cover an in-depth analysis of the production potential of all regions.

3 Options for hydrogen transport from Türkiye to Germany

The following section will shed light on the techno-economic relationships between pipeline and ship-borne hydrogen. The technical status quo of the respective technology paths will first be examined before an eco-

nomical assessment of different transport routes is carried out based on parameters such as derivative, distance and brownfield use. Figure 4 shows the different routing options geographically.

Figure 4: Routing options for hydrogen transport from Türkiye to Germany



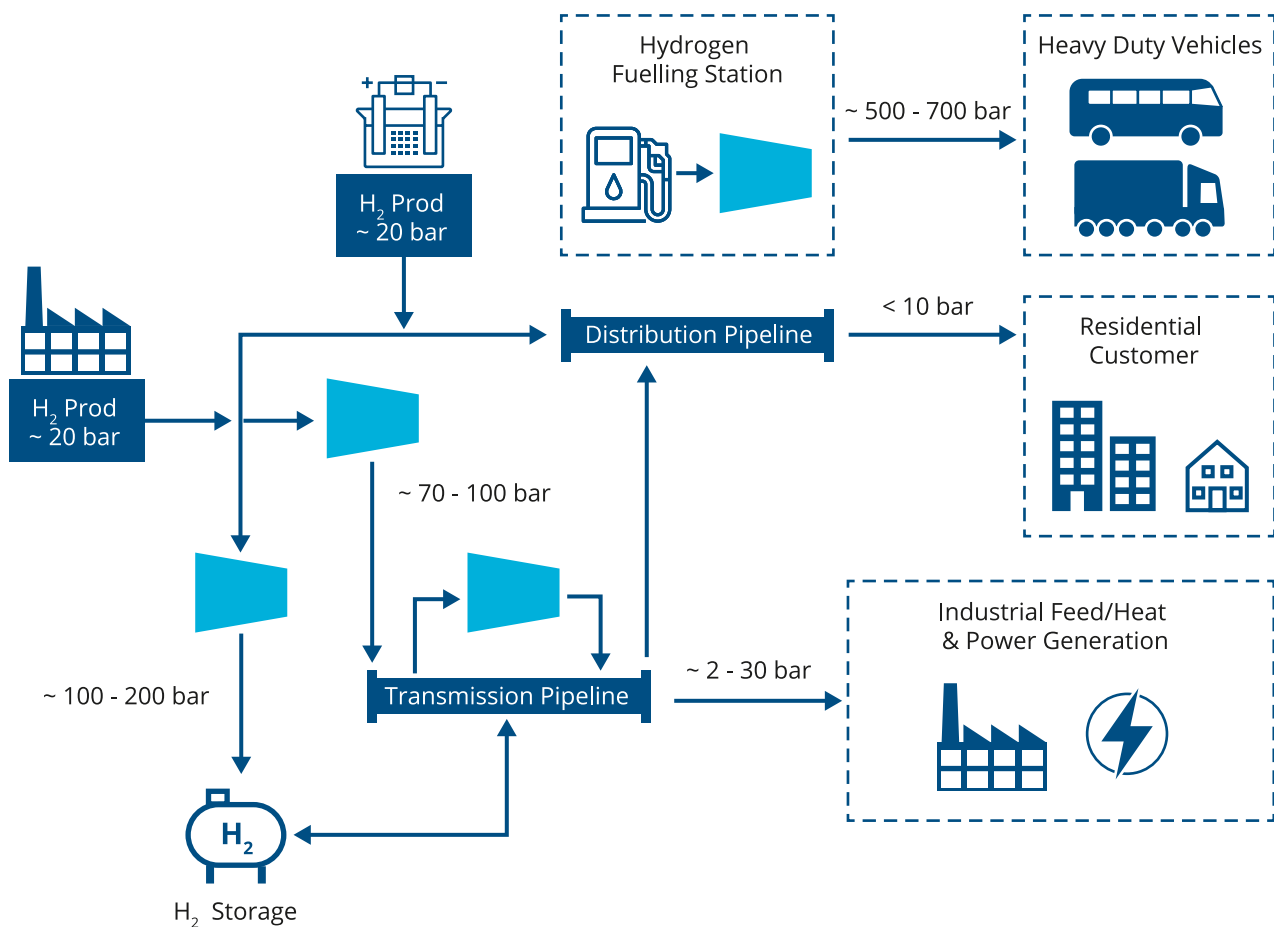
Source: Own illustration (2025)

3.1 Transport via pipeline

Transport of hydrogen via pipeline is a mature technology, which allows continuous, secure and economically favourable delivery of hydrogen from the hydrogen production location to the location with hydrogen demand. Hydrogen pipelines are used to transport compressed, gaseous hydrogen, which is transported by means of pressure differences in pipelines, i.e., the gas flows from a high pressure at the pipeline entry point to a lower pressure at the pipeline exit point. Transport via pipeline requires additional infrastructure elements, including compressors, valves, regulators and measuring equipment. Pipelines can vary in size, design pressure and pipeline material depending on the required transport capacity. The size of the pipeline is determined by its nominal diameter (DN), which is specified in mm or inches. The design pressure (DP) is the highest gas pres-

sure at which a pipeline can safely operate and is given in bar. Pipelines are usually laid underground and are made of steel or plastic. In supra-regional, high-capacity transport networks, this usually means steel pipelines with a design pressure from 16 to several hundred bar. The required pipeline inlet pressure is achieved at the production site and maintained by means of compressor stations along the transport route.¹⁶ Compressor stations must be installed at appropriate intervals to compensate for a pressure drop in the pipeline. The average distance at which a compressor must be placed is between 250 and 300 km.¹⁷ The actual distance depends on operational conditions, characteristics of the pipeline and the quantities of transported hydrogen. An example of a future hydrogen supply chain with pipeline infrastructure for transport and distribution – including indicative operational conditions for hydrogen pressure – for connecting all parts of the supply chain, is shown in Figure 5.

Figure 5: Example hydrogen supply chain, with pipeline infrastructure for transport and distribution



Source: Own illustration, based on Khan, et al. (2021)

¹⁶ cf. Khan, Layzell and Young (2021).

¹⁷ cf. Solomon et al. (2024).

Retrofitting existing natural gas pipelines offers favourable investment costs in comparison to construction of new hydrogen pipelines. It can significantly shorten typically long lead times (planning, licensing and construction) and can reduce environmental impact.¹⁸ Retrofitting is an interesting option where the existing and future natural gas supply can be secured via other parts of a gas network. In principle, a retrofitted hydrogen pipeline functions similarly to a gas transport pipeline but specific challenges need to be borne in mind. Since the volumetric energy density of hydrogen (10.78 MJ/m³) is about 3.3 times lower than that of natural gas (35.5 MJ/m³) and the increase in flow rate to the erosion rate of hydrogen is about 2.9 times higher than of natural gas, the capacity of a hydrogen transport pipeline is limited to approximately 88% of the energy content (capacity) of a natural gas pipeline.¹⁹ To achieve this capacity, hydrogen compressors require at least three times as much energy compared to compressors for natural gas transport. Also, there are issues relating to pipeline material and gas network equipment. In the case of steel natural gas pipelines, in particular those made of high-yield strength steels, exposure to molecular hydrogen combined with cyclic stress can increase the growth rate of cracks in material²⁰ which could ultimately lead to leakage or mechanical failure.²¹ Remedies are being proposed and tested to tackle the issue, such as more rigorous monitoring and maintenance, appropriate pressure management, e.g., lower operating pressure, usage of liners (pipe in pipe), application of pipeline wall coatings and, as a measure of last resort, replacement of pipeline sections. For compressors, valves and measuring devices, replacement of the equipment is necessary.

Approximately 5,000 km of hydrogen pipelines are in operation worldwide, around 2,000 km of which are in Europe.²² This figure is still modest in contrast to methane networks, which have a total pipeline length of approximately 1 million km, largely because hydrogen pipelines have so far been limited to the petrochemical industry. In comparison to natural gas pipelines, existing hydrogen pipelines are also smaller in size and transport capacity, operate under static load and there are no operational offshore (subsea) hydrogen pipelines to date.²³ Following ambitious policy strategies and targets technology deployment targets for green and low-emission hydrogen markets worldwide, there are currently many initiatives and plans for the development of regional, national and transnational hydrogen networks.²⁴ Those plans envisage construction of new pipelines as well as retrofitting of existing natural gas networks. According to the IEA Hydrogen production and infrastructure projects database, there are around 150 ongoing hydrogen pipeline infrastructure projects worldwide, 20 of which are for offshore hydrogen pipelines. The majority of these projects are still in the concept or feasibility study phase. Most advanced projects that have reached the final investment decision phase or that are already in the construction phase are in the Netherlands, Germany, Spain, France, Denmark, Italy, Australia and China. The size of the pipelines (DN) in the ongoing projects varies between 16 and 36 inches and design pressure (DP) varies between 24 and 84 bar for the onshore pipelines and up to 210 bar for the offshore (subsea) pipelines. Figure 6 shows hydrogen transport infrastructure projects in Europe as depicted in the Hydrogen Infrastructure Map, a visualising platform set up by a joint initiative of gas infrastructure operators.

18 cf. IEA 2024.

19 cf. Khan, Layzell and Young (2021).

20 The process, known as Hydrogen accelerated fatigue cracking (HAFC).

21 cf. Martin et al. (2024).

22 cf. IEA (2023).

23 *ibid.*

24 cf. IEA.

Figure 6: Hydrogen transport infrastructure projects, as at Q4 2024

Source: Hydrogen Infrastructure Map (2024)²⁵

25 cf. H₂inframap (2024). Please note that the platform is intended for informative and indicative purposes only and not for providing any guarantee of the realisation of projects.

In the case of Germany, ambitious policy goals²⁶ include use of hydrogen and its derivatives by 2030, in particular in the industrial sector, in air and maritime transport and in the electricity sector, with around 50% to 70% of demand expected to be covered by imports. The German transmission system operators (TSOs) submitted applications for what is known as the hydrogen core network and these were approved by the Federal Network Agency (BNetzA) in October 2024. The core network will be constructed in phases between 2025 and 2032. With a total length of 9,040 km by 2032, 60% of it will consist of retrofitted natural gas pipelines.²⁷ Thus, the German hydrogen core network integrates into the further vision of the European Hydrogen Backbone (EHB), not least due to its location in Europe as a central node. The European Hydrogen Backbone is an initiative of 33 European TSOs for the integrated planning and coordination of a European hydrogen network. The members are currently planning for a joint hydrogen network with a total length of 53,000 km by 2040. The initiative seeks to foster market competition, security of supply, security of demand and cross-border collaboration between European countries and their neighbours.²⁸

For the potential import of hydrogen from Türkiye to Germany via pipeline, several interconnection points in the southern parts of the German hydrogen core network can be considered. The first option for pipeline-based transport is to be found in the South-East European Hydrogen Corridor (SEEHyC) initiative. This was

launched in early 2024 by seven infrastructure operators: DESFA (Greece), Bulgartransgaz (Bulgaria), Transgaz (Romania), FGSZ (Hungary), Eustream (Slovakia), NET-4GAS (Czech Republic) and OGE (Germany). The common goal is to establish a hydrogen corridor to supply Central and Eastern Europe with green hydrogen. In addition, the initiative aims to increase the diversity of supply sources and thus strengthen future security of supply. Furthermore, according to the project consortium, not only will European hydrogen production be improved, but in particular the import of hydrogen from the Middle East will be facilitated. This vision is also based on the retrofitting of existing gas infrastructure, with simultaneous strategic investments in new hydrogen pipelines and compressor stations. The project, in total consisting of a pipeline length of approx. 3,000 km, is currently under review for inclusion in the Projects of Common/Mutual Interest (PCI/PMI) list of the European Commission.²⁹ Only the Greek-Bulgarian Hydrogen Interconnector is already listed in the PCI list according to the current status. DESFA's contribution to the SEEHyC initiative is a new 570 km hydrogen pipeline that will be able to transport pure hydrogen mainly from the southern part of Greece to the connection point with Bulgaria. Preliminary analysis shows that a 36-inch pipeline will enable capacity of 80 GWh per day. Bulgartransgaz EAD's infrastructure contribution to the SEEHyC consists of 580 km of new bidirectional H₂ transmission infrastructure, which will be developed in two phases. FID is currently still pending for the Greek-Bulgarian Hydrogen Interconnector.³⁰

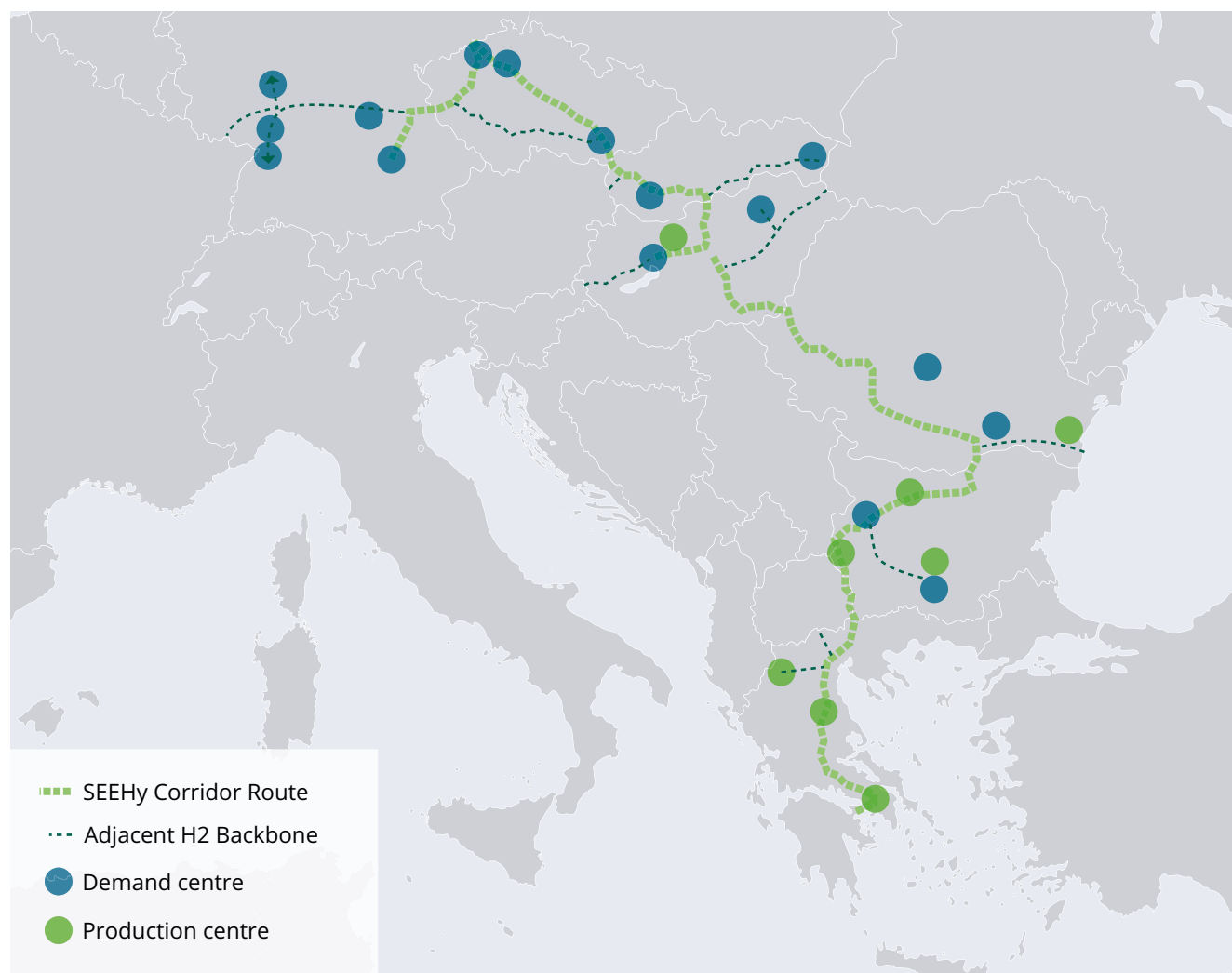
26 Goals have been set in the National Hydrogen Strategy from 2020 and its update from 2023, as well as in the Import strategy for hydrogen and hydrogen derivatives from 2024, cf. Bundesministerium für Wirtschaft und Klimaschutz (BMWK) (2024b).

27 cf. Bundesministerium für Wirtschaft und Klimaschutz (BMWK) (2024a).

28 European Hydrogen Backbone (2025).

29 Listing as a PCI enables projects to be eligible for direct funding from the Connecting Europe Facility (for more information see section 4.2).

30 Phase 1 of the project (about 250 km of 40-inch hydrogen transmission pipeline between the Bulgarian-Greek border and the Sofia region) is scheduled to be operational by the end of 2029 and is part of the mentioned PCI listing. Phase 2 of the project concerns the remaining Bulgarian segment and is scheduled to be commissioned by the end of 2029 and will be submitted for PCI status, along with further pipeline sections of the other consortium partners (cf. Southeast European Hydrogen Corridor Initiative (2024)).

Figure 7: Routing of the South-East European Hydrogen Corridor (SEEHyC)

Source: SEEHyC Consortium (2025)

A second alternative to be considered is the Southern Hydrogen Corridor (South_{H₂}), a 3,300 km dedicated hydrogen pipeline corridor project managed by the Italian, Austrian and German transmission system operators Snam, TAG, GCA and bayernets. The individual projects have been granted PCI status by being included in the 1st PCI/PMI list under the revised TEN-E Regulation published by the European Commission on 8 April 2024. The corridor connects North Africa, Italy, Austria and Germany and enables the supply of low-cost renewable hydrogen produced in the South to major European demand clusters. The development of the South_{H₂} corridor is part of the European Hydrogen Backbone and envisages hydrogen import capacity of 4 Mt/year, which would

represent more than 40% of the REPowerEU import target by 2030. The initiative focuses on the use of existing retrofitted midstream gas infrastructure for hydrogen transport, with some new dedicated infrastructure included where necessary. A high proportion of retrofitted pipelines can enable cost-effective transport. The corridor has received institutional support as well as strong support from companies along the entire value chain and along the entire route from Italy via Austria to Germany. The renewable hydrogen would be largely produced in North Africa, for which the partners have collected signed letters of support from producers intending to produce around 2.5 Mt/a of renewable hydrogen.³¹ Türkiye could only be connected to the South_{H₂} pipeline via a

31 cf. The South_{H₂} Corridor (2025).

link with Greece. Within the current process for the 7th PCI list, an application has been submitted by the project developer IGI Poseidon for an offshore pipeline between Taranto (GRC) and Otranto (ITA). The commissioning of

South₂ is planned for the early to mid-2030s, while the PCI application for IGI Poseidon envisages commissioning of the offshore segment between Greece and Italy in 2035.

Figure 8: Routing of the South₂ Corridor with possible interconnection to Greece



Source: South₂ Consortium (2025), adapted

As things stand today, it seems more likely that South₂ will be realised sooner than SEEHyC, as the South₂ project 1) already has PCI status, 2) has political momentum, 3) has multiple sources of hydrogen production and 4) involves fewer players that need to be aligned. As a PCI project, the individual pipeline segments are eligible for funding from the Connecting Europe Facility (see section 5 on financing). In fact, both SNAM and TAG received

grants of EUR 24 million and 1.4 million for conceptual engineering and Front End Engineering Design (FEED) preparation in the last call for proposals under the Connecting Europe Facility in 2025.³² SEEHyC has also been granted Global Gateway Status, which could facilitate future financial support from the EU. The corridor has an established governance structure, with the relevant ministries of the partner countries Germany, Austria, Italy,

32 cf. European Commission (2025b).

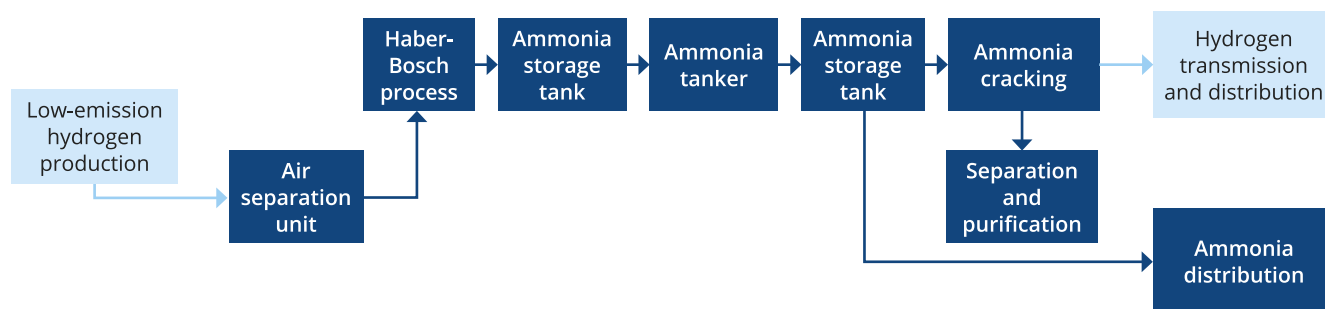
Tunisia and Algeria signing a JDoI in January 2025 to support the development of the Southern Hydrogen Corridor. Two countries, namely Algeria and Tunisia, are ready to act as potential exporters, and the lower number of project countries simplifies network planning for the TSOs involved.³³

3.2 Transport via ship

Alongside transport via pipeline, a viable alternative for large scale, long-distance transport of hydrogen is by ship. For this purpose, hydrogen must be converted to a denser form, by compression, liquefaction or conversion

into a chemical carrier. Technological options for hydrogen transport by ship include compressed or liquefied hydrogen (LH_2), ammonia (NH_3), liquid organic hydrogen carriers (LOHC), methanol (MeOH), liquefied synthetic methane (LCH_4) and Fischer-Tropsch diesel (FTD). Each option requires specialised ships and port infrastructure capable of handling the given hydrogen form or carrier, as well as conversion plants for the conversion at the exporting port. Also, reconversion facilities may be necessary at the importing port for the processing of shipped hydrogen carrier back into pure hydrogen. Required technological processes for ship transport via ammonia are shown in Figure 9.

Figure 9: Technological pathways for the long-distance transport of hydrogen and ammonia by ship



Source: Own illustration, based on IEA (2023)

Only a few of the options for transporting hydrogen by ship are possible using existing infrastructure. For example, shipping hydrogen in the form of ammonia could be the least challenging option given that supply chains are already well established.³⁴ Ammonia can be transported in liquid form, cooled to -33°C or at ambient temperature by pressurising it to 8 bar, with a volumetric energy density lower than marine gas oil (MGO), liquefied natural gas (LNG) or methanol (MeOH), but still higher than other hydrogen transport options making it practical for transport by ship.³⁵ In comparison to methanol, ammonia offers potential cost benefits, as its production does not require a source of CO_2 and no CO_2 is

emitted when combusted. Using ammonia, there is a smaller fire hazard risk, due to the higher minimum ignition energy and smaller flammability range compared to hydrogen.³⁶

There are approximately 150 ports with ammonia terminals globally, around 30 of which are located in the EU-27 countries, with some of these terminals being used for export, some for import and some for both.³⁷ Additionally, LNG terminals are currently seen as likely candidates for future retrofitting for green ammonia imports, as the existing superstructure may facilitate the geographical correlation for reconversion and intake for

33 cf. The South H_2 Corridor (2025).

34 Ammonia usage is currently limited to fertiliser production and industrial applications for which 20 Mt/a is traded annually, around 17-18 Mt by ship, cf. Bonnet-Cantalloube et al. (2023).

35 cf. Riemer, Schreiner and Wachsmuth (2022).

36 cf. Alibas et al. (2024).

37 cf. Bonnet-Cantalloube et al. (2023).

hydrogen networks for further distribution with the hinterland. This also holds true for Türkiye. The retrofitting of LNG infrastructure for green ammonia is considered feasible but nevertheless represents a complex technical overhaul. Also, when using LNG tanks, the storage capacity of the tanks will be reduced to two thirds of their original energy capacity.³⁸ According to Global Energy Moni-

tor, twelve projects have currently been announced for the import of hydrogen via LNG terminals in Europe, either as liquefied hydrogen (LH_2), as ammonia (NH_3) or as liquefied synthetic methane (LCH_4), with ammonia being the most common derivative of choice in seven projects, four of which are in Germany, see Table 1.³⁹

Table 1: Plans for hydrogen import by European LNG terminals

Pipeline utilisation	County	Status	Fuel
Zeebrugge LNG Terminal	Belgium	Operating	Ammonia, liquid hydrogen
Dunkirk LNG Terminal	France	Operating	Ammonia
Fos Tonkin LNG Terminal	France	Operating	Ammonia
Brunsbüttel FSRU	Germany	Operating	Ammonia
Lubmin FSRU	Germany	Retired	Ammonia
Wilhelmshaven FSRU	Germany	Operating	Ammonia
Wilhelmshaven TES LNG Terminal	Germany	Proposed	eLNG
Eemshaven FSRU	Netherlands	Operating	Liquid hydrogen
Brunsbüttel LNG Terminal	Germany	Construction	Liquid hydrogen
Stade LNG Terminal	Germany	Construction	Ammonia, liquid hydrogen
Dioriga FSRU	Greece	Proposed	Liquid hydrogen
Zeeland Energy FSRU	Netherlands	Proposed	Liquid hydrogen

Source: GEM (2025)

For further use of hydrogen, ammonia needs to be reconverted using ammonia crackers, which is energy-intensive process, requiring 15–33% of the energy content of the fuel.⁴⁰ In addition, further purification and pressurisation of hydrogen is needed for most hydrogen applications. Large-scale crackers are not yet commercially available but the potential scale-up of the technology is seen as feasible. In this sense, initial pilot projects have been announced.⁴¹ For the potential import of

ammonia as a hydrogen carrier from Türkiye to Germany by ship, several existing ports can be considered. As an example case for this analysis, the export facility of Gemlik port in Türkiye and the import hub of Brunsbüttel port in Germany have been chosen for this option. The Gemlik port facility run by Gübre Sanayii A.S. is located around 125 kilometres south of Istanbul and has an existing ecosystem of ammonia and fertiliser producers that work with the terminal's handling capacity and

38 cf. Riemer, Schreiner and Wachsmuth (2022).

39 cf. Global Energy Monitor (2025).

40 Due to the high temperature requirements of 500-550°C using a catalyst or even 950-1050°C without an optimised catalyst (cf. Riemer, et al. 2022).

41 Air Liquide announced the construction of an industrial-scale ammonia cracking pilot plant in the port of Antwerp: cf. Air Liquide (2023).

serve both the domestic and international markets.⁴² This creates excellent conditions for exploring the potential for large-scale export of ammonia as a transport vector for green hydrogen. The port facilitates ammonia storage and shipping, with an annual handling capacity of 0.2 Mt NH₃/a and two liquid ammonia storage tanks with capacity of 30,654 m³.⁴³

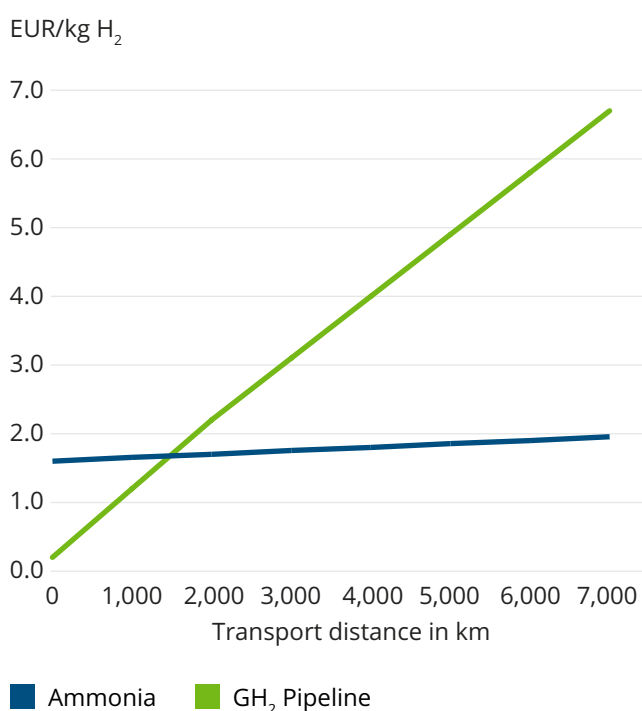
In Brunsbüttel, Germany, two ammonia import terminals can be considered. The Yara terminal was put into operation in October 2024. It has an import capacity of 3 Mt NH₃/a.⁴⁴ RWE is also developing an ammonia import terminal in Brunsbüttel with import capacity of 0.3 Mt NH₃/a by 2026 and, at a later stage, expansion to 2 Mt NH₃/a capacity and development of a large industrial-scale cracking facility.⁴⁵ The costs for the RWE project are estimated to be in the ‘mid three-digit million range’.⁴⁶ The project envisages the construction of an ammonia cracker in the final phase.

3.3 Techno-economic aspects of hydrogen transport options from Türkiye to Germany

Realising hydrogen transport from Türkiye to Germany in practice depends on implementing a feasible transport option. The choice of the transport option strongly depends on investment cost aspects. To map indicative investments and costs for the pipeline and ship transport option, desktop research has been carried out. As a rule of thumb, pipelines are the most cost-effective transport option, particularly for large hydrogen volumes, while shipping becomes more economical over longer distances.⁴⁷ The costs of different transport options can be compared on the basis of unit or specific transport costs, i.e., the cost of transporting a unit of energy (MWh) or mass (kg) of hydrogen. Figure 10 shows a comparison of transport costs⁴⁸ for GH₂ via pipeline and ammonia shipping analysed in the TransHyDE project.⁴⁹ In this analysis, the specific transport cost of GH₂ via pipeline is

favourable for transport distances up to approximately 1,600 km. The levelised cost of transportation for ammonia shipping is more favourable than the pipeline option for transport distances longer than 1,600 km, with a specific transport cost of approximately 1.7 EUR/kg. The reason for this is that the transport costs for ammonia are not significantly dependent on the distance, as they do not include additional investment costs (no additional ship is needed for longer distance) and mostly arise from operating shipping costs. It should be noted that such general assessments are based on a certain set of assumptions⁵⁰ and can serve only as guidance.⁵¹

Figure 10: Indicative transport costs for LOHC, LH₂, GH₂ and ammonia via pipeline or shipping



Source: GEM (2025)

42 cf. Gemlik Gübre (2023).

43 cf. Gemlik Gübre (2025).

44 cf. Yara (2024).

45 cf. Global Energy Monitor (2025).

46 cf. RWE (2022).

47 cf. IEA (10/2024).

48 Based on current cost parameters and including costs of reconversion into gaseous hydrogen.

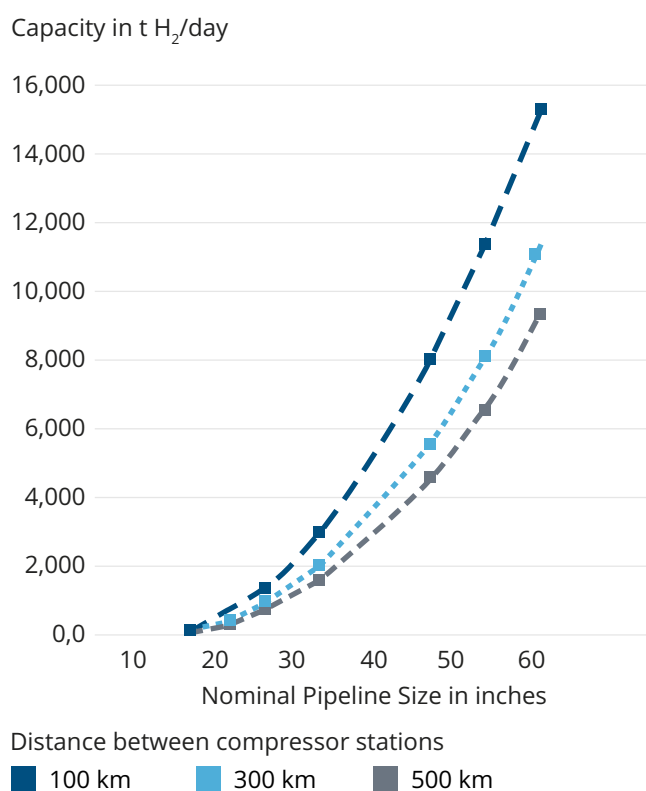
49 cf. Alibas et al. (2024), TransHyDe is a project funded by the German Federal Ministry of Education and Research (BMBF), in which over 100 project partners researched various technical possibilities and framework conditions for hydrogen transport from 2021 to 2025.

50 Based on calculations of Forschungsstelle für Energiewirtschaft e.V., cf. Wendlinger et al. (2022).

51 Transport cost estimations vary substantially between literature sources. For example, in the JRC Assessment of Hydrogen Delivery Options from 2021, compressed hydrogen gas via pipeline appears to be the cheapest option for distances up to 3,000 km, cf. Joint Research Centre of the European Union (2021).

In this sense, for a robust estimation of specific transport cost for large-scale volumes by pipeline, more comprehensive analysis is required. Such analysis needs to include flow calculations, projected demand and other factors, followed by detailed engineering of the system set-up to find an optimised trade-off between pipeline size, number and capacity of compressor units, flow rates and operating pressures.⁵² Figure 11 shows an example of estimated pipeline capacity based on pipe size and distance between compressor stations. For instance, a 1,500 km pipeline with a nominal pipeline size of 36 inches (") and a distance between compressors of 300 km would achieve transport capacity of almost 6,000 tonnes of hydrogen per day. With the assumed 75% pipeline utilisation in the applied cost tool, a hydrogen throughput of approximately 1.5 Mt (or 50 TWh) per year would be required. It is obvious that securing capacity pipeline utilisation on such a scale, especially in the early stage of hydrogen market development, is one of the major hurdles to realisation of the pipeline option.

Figure 11: Example of estimated variation in pipeline capacity based on pipe size (NPS - Nominal pipeline size in inches) and distance between compressor stations

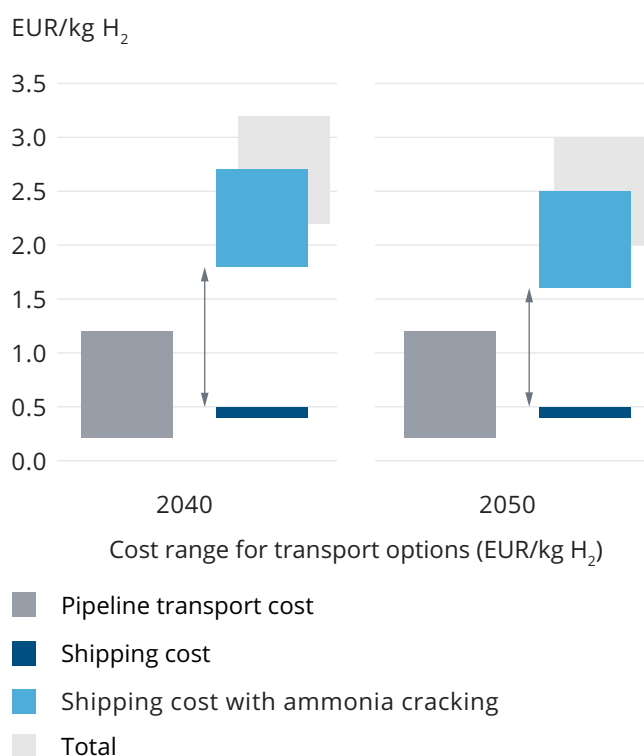


Source: Khan et al. (2021)

To better understand the cost drivers behind the transport options for exporting hydrogen from Türkiye to Germany, the EWI Global PtX Cost Tool was examined for the scope of this report.⁵³ Developed by the Institute of Energy Economics at the University of Cologne (EWI), the tool can estimate the transport cost for transporting hydrogen and hydrogen derivatives from a chosen origin country to a chosen destination country. For this analysis, the transport options of shipping (ammonia) and pipeline (H₂) were applied.

The tool makes simplified assumptions on transport routes, e.g., predefined start and end points and pipeline or shipping routes. However, it is possible to cover various cost uncertainties by varying several scenario settings.⁵⁴ In that way, cost ranges for transporting hydrogen from Türkiye to Germany, for a timeframe between 2040 and 2050, were attained, as shown in Figure 12. For pipeline transport, unit cost varies between 0.3 and 1.2 EUR/kg H₂. For the shipping option via ammonia, unit

Figure 12: Estimated transport cost to be borne by end user in 2040 and 2050 to import hydrogen from Türkiye to Germany via pipeline and ammonia shipping (EUR/kg H₂)



Source: Own elaboration, based on EWI Global PtX Cost Tool (2024)

⁵² cf. Khan, Layzell and Young (2021).

⁵³ cf. Klaas et al. (2024).

⁵⁴ Varied scenario settings include shipping charter rate (low rate or high rate), infrastructure scenario (brownfield or greenfield) and hydrogen pipeline costs (retrofit, low-cost new or high-cost new).

cost varies between 0.4 and 0.5 EUR/kg H₂. However, the subsequent cracking of ammonia back into hydrogen leads to a multiplication of the transport price to be borne by the end user by a factor of 4–5. The calculated price according to EWI assumptions is 2.2–3.2 EUR/kg H₂ and 2.0–3.0 EUR/kg H₂ for the years 2040 and 2050 respectively, after cracking. Following this estimation, it can be concluded that, based on transports costs alone, ammonia shipping is a highly competitive option where no reconversion to gaseous hydrogen is required in the destination country. To transport the assumed hydrogen quantity of 50 TWh or 1.5 Mt per year via ammonia shipping, around 44 TWh or 8.5 million tonnes of ammonia⁵⁵ and around 150 voyages per year would be required.⁵⁶

Transport via pipeline seems to be the more favourable option where molecular hydrogen is to be applied directly in the end-use sector. At the same time, estimated unit costs for the pipeline transport option are less certain. They depend on assumptions around investment costs for newly constructed or retrofitted pipelines with different diameters (e.g., 28" or 36"). The assumption of greenfield investment considers both capital expenditures (CAPEX) and operating expenses (OPEX), while brownfield investment considers only OPEX as the infrastructure in this case is considered fully depreciated. If the utilisation of the pipeline is assumed to be less than 75%, the estimated unit transport cost is much higher.

It can be noted that the degree of retrofitting has significant implications for the estimated investment costs of both transport routes. According to the European Hydrogen Backbone, new onshore pipelines with a diameter of 36" can be expected to cost 3.2 million EUR/km. In comparison, the cost for retrofitted pipelines of the same diameter is just under a fifth at 0.64 million EUR/km.⁵⁷ However, investment volume alone cannot indicate a transport cost advantage of one of the options, in the sense of a lower transport unit cost. Such comparison

also requires a projection of hydrogen intakes and offtakes along each route to estimate the pipeline utilisation. To get an initial idea about the effects on the unit transport costs, different degrees of retrofitting and capacity utilisation for a 36" pipeline were analysed, based on data published by the EHB initiative.⁵⁸ Where pipeline utilisation is similar, with load factors of either 25% or 75%, the SouthH₂ route would offer an approximately 75% lower transport cost per kg H₂, due to a higher degree of retrofitting. Additionally, lower utilisation of one route and higher utilisation of another route has been compared. With low utilisation (load factor 25%) of the SouthH₂ route and higher utilisation (load factor 75%) of the SEEHyC route, the SEEHyC route would offer an approximately 40% lower transport cost. With higher utilisation of the SouthH₂ route and lower utilisation of the SEEHyC route, the SEEHyC route would offer a transport cost that is approximately three times as high (325%) (cf. Annex 2).⁵⁹

Based on the latest scenarios in what is known as the Ten-Year Network Development Plan (TYNDP) set out by the European Network of Transmission System Operators for Gas (ENTSO-G), countries along both routes have a high hydrogen deficit, in a similar order of magnitude, i.e., approx. 400 TWh in 2040.⁶⁰ Yet, another qualitative difference between the two route options is the consideration of other import sources for green hydrogen. In the case of the southern corridor, the feed-in of hydrogen through Algeria and Tunisia, as envisaged in the pentilateral high-level political process, can reduce the delta.⁶¹ The prospect of being able to meet the demand reported in market enquiries will be a decisive criterion in the acquisition of project financing. From a technical and economic point of view, for large-scale export of hydrogen from Türkiye to Germany for further use, the SouthH₂ route appears to be more favourable, both from the perspective of lower capital investment and due to infrastructure and market dynamics.

55 Calculation was carried out by an online conversion tool, cf. Clean Air Task Force (2025).

56 EWI Global PtX Cost Tool assumes a vessel capacity of 57,120 t, cf. Klaas et al. (2024).

57 cf. European Hydrogen Backbone Initiative (2023).

58 cf. Jens et al. (2021).

59 Based on weighted average unit costs provided by the EHB and applied for the given degree of retrofitting. The EHB has updated infrastructure costs in the meantime. Therefore, the absolute unit cost values, e.g., 0.18 and 0.32 €/kg/1,000 km for SouthH₂ and SEEHyC respectively, in the case of higher utilisation, are not applicable anymore. However, the updated costs for the new 36" onshore pipelines include an almost proportional increase in costs for new and retrofitted pipelines (45% increase of CAPEX for new pipeline and 60% increase for retrofitted pipeline), meaning the relative difference is still applicable.

60 cf. ENTSO-E and ENTSOG (2024).

61 cf. Bundesministerium für Wirtschaft und Klimaschutz (BMWK) (21/01/2025).

Table 2: Techno-economic parameters of different transport options

	1) Pipeline via SEEHyC	2) Pipeline via SouthH ₂	3) Ammonia shipping from Gemlik to Brunsbüttel port incl. cracking
Distance	Approx. 3,000 km (from Greek-Turkish border to possible German interconnector)	Approx. 3,000 km, approx. 100 km of which offshore (from Greek-Turkish border to possible German interconnector)	7,450 km
Transport parameters	36" pipeline	36" pipeline	Ship capacity 57,120 t 150 voyages per year for 1.5 Mt
Estimated degree of retrofitting	20%	70%	n/a
Estimated CAPEX	EUR 11.2 billion (bn)	EUR 6 bn	Reuse of existing infrastructure in Türkiye possible. Estimated cost for upgrading one German ammonia import terminal: EUR 500 million for Yara Rostock and RWE Brunsbüttel
Countries along the transport route	Greece, Bulgaria, Romania, Hungary, Slovakia, Czechia	Greece, Italy, Austria	n/a
Hydrogen import-export balance within corridor	High hydrogen deficit (approx. 300 or 400 TWh in 2040)	High hydrogen deficit (approx. 270 or 420 TWh in 2040*)	n/a
Hydrogen import possibilities additional to EU-production within corridor	Other import options (not analysed)	Algeria and Tunisia (approx. 210 or 250 TWh in 2040*) Other import options (not analysed)	n/a
Decisive factors for transport costs	Pipeline utilisation (load factor) – highly uncertain Lower degree of retrofitting	Pipeline utilisation (load factor) – moderately uncertain Higher degree of retrofitting	Ammonia cracking scale-up and decrease in costs

*according to the Distributed Energy and Global Ambition scenarios in TYNDP 2024

4 Financing mechanisms

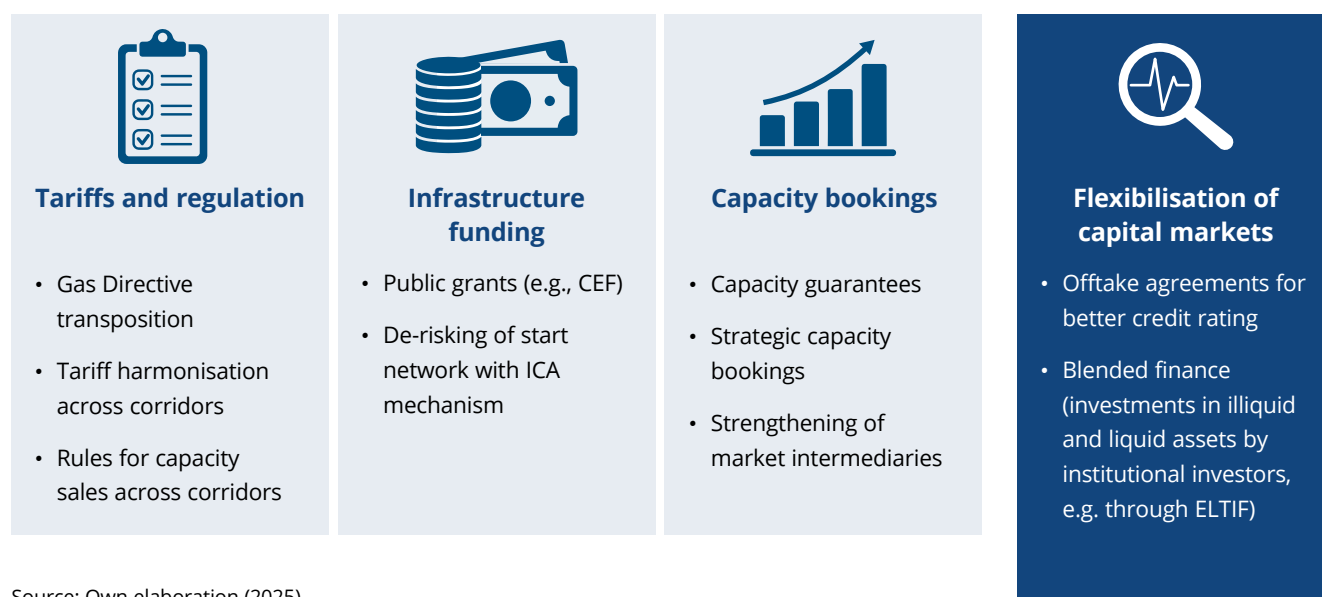
The financing of hydrogen infrastructure is subject to significant market and technology risks, even more so than established energy infrastructure. As a result, private sector investment decisions must often be made in an uncertain environment. According to the International Energy Agency (IEA), annual global investment in clean energy reached USD 2 trillion in 2024, yet only 0.1% was allocated to clean hydrogen.⁶² This reflects the high perceived risks associated with hydrogen infrastructure projects.

Infrastructure projects, particularly those that face the risk of becoming stranded assets if not utilised, often exhibit a poor risk–return ratio. While infrastructure investments typically offer low returns, their initial high

CAPEX requirements and market uncertainties heighten the investment risk. This holds particularly true for the nascent green hydrogen market.⁶³

Few hydrogen users will connect to the network during the early market phase. Their number will gradually increase. The limited number of users would render cost-reflective tariffs prohibitively high and inhibit infrastructure expansion and usage. Capping tariffs over a multiannual ramp-up phase could facilitate network usage for first movers but would place significant financial burden and risk on the TSO or port operator. In this context, a set of basic principles for hydrogen infrastructure financing can be outlined (see Figure 13).

Figure 13: General principles and potential instruments for funding hydrogen pipeline networks



Source: Own elaboration (2025)

⁶² cf. IEA (2024).

⁶³ cf. Reul and Graul (2024).

The following sections are intended to address the infrastructure-specific points 1) Tariffs and regulation, 2) Infrastructure funding, 3) Capacity bookings and 4) Flexibilisation of capital markets in particular. The discussion of offtake subsidies is essential, as offtake is a vital element in the value chain when it comes to financing projects over their entire life cycle, as it is only through the business case that private investments can be sustained. However, this is a larger debate that plays out over all the

different technology paths, which is deliberately not part of this study of infrastructure funding feasibility. While upstream subsidies are also not directly applicable to financing hydrogen infrastructure, they are nonetheless indirectly conducive to achieving critical quantities of hydrogen volumes for possible pipeline capacity utilisation. Info box 2 provides a brief overview of funding instruments from German or EU funding programmes and multilateral development banks.

Info box 2: Entities and programmes providing grants for upstream hydrogen projects

H2Global is an instrument funded by the **German Ministry of Economic Affairs and Climate Action (BMWK)**. It operates as a double auction model, balancing purchase and resale prices with government subsidies. In the first round, Germany allocated EUR 717 million for hydrogen imports. Initial contracts have secured at least 259,000 t of green ammonia for delivery to Germany between 2027 and 2033 at an estimated production cost of EUR 4.50 per kg of green hydrogen. A second H2Global auction round announced in February 2025, including a joint auction with the Netherlands, focuses on four regional lots and one global auction with a total budget of EUR 2.5 bn of funding. Türkiye would be eligible for the upcoming global lot with a budget of EUR 567 million as of February 2025.⁶⁴

Other types of grant from the **European Union** could also kick off initial investment in projects. For instance, funding from the Clean Hydrogen Partnership can be regarded as a concrete example. This is a public-private partnership that was launched as part of the **Horizon Europe** programme. EUR 1 trillion is available for the 2021–2027 funding period. HYSouthMarmara, the first hydrogen valley project from Türkiye, received EUR 7.4 million from the Clean Hydrogen Partnership in 2022, which was the highest EU grant received from Türkiye so far.⁶⁵ However, much larger subsidies for energy and infrastructure projects are to be provided as part of the Global Gateway Initiative by 2027. One possible vehicle for this is the **European Investment Bank's** Global Gateway Fund of EUR 300 million.⁶⁶ Also noteworthy is the process of establishing a Green Hydrogen Fund worth EUR 434 million, which explicitly provides funding for production, processing, storage and transport infrastructure.⁶⁷

The European Bank for Reconstruction and Development (EBRD) is also an important financier in Türkiye with a portfolio of just under EUR 8 billion. 42% of the portfolio consists of investments in sustainable infrastructure. EBRD loans are characterised by a flexible structure that is tailored to the circumstances of the project and the country, region and sector. A key feature is the financing ratio of up to 35% of total project costs for new projects or the long-term capitalisation of established companies. The loan amount for private sector projects typically ranges between EUR 3 million and EUR 250 million, with an average of EUR 25 million. An important requirement is that at least one third of the financing must be covered by equity, with significant equity contributions expected from sponsors, including contributions in kind.⁶⁸

In March 2024, the **World Bank** announced a new **Country Partnership Framework (CPF)** for Türkiye for the period of 2024–2028. The new CPF will be delivering USD 18 billion in total and when this is added to the current country portfolio of USD 17 billion, it constitutes the third largest country programme of the World Bank. USD 6 billion of this comes from the International Bank for Reconstruction and Development, USD 9 billion from the World Bank International Finance Corporation, depending on market developments and customer demand (combination of long-term and short-term financing), and up to USD 3 billion from the Multilateral Investment Guarantee Agency (MIGA).⁶⁹ Also worth mentioning in the World Bank context is the **10 GW Lighthouse Initiative**. As part of this initiative, the World Bank plans to specifically promote renewable hydrogen projects in developing countries in the coming years by streamlining MDB financing and uniting financial support.⁷⁰

64 cf. Hintco (2025).

65 cf. Ufuk Avrupa (2021).

66 cf. European Investment Bank (2022).

67 cf. Collins (2022).

68 cf. European Bank for Reconstruction and Development (2025).

69 cf. World Bank Group (2023).

70 cf. World Bank (2024).

4.1 Regulatory framework conditions

Under the EU's Gas Package, hydrogen infrastructure is classified as a Regulated Asset Base (RAB). Accordingly, tariff structures are determined by the public sector to ensure non-discriminatory access to infrastructure. The Gas Package gives Member States the flexibility to apply negotiated third-party access (nTPA) to dedicated hydrogen networks up until the end of 2032. After this date, the default rule shall be regulator-set, i.e., non-discriminatory and objectively regulated third-party access (rTPA). Access to hydrogen storage is based on similar TPA rules as for hydrogen networks, with more flexibility until the end of 2032. For hydrogen terminals, however, the default rule is negotiated TPA Tariffs.⁷¹ Under the Gas Package, financial transfers between gas and hydrogen networks are permitted if a project is otherwise non-viable and subject to approval by the respective National Regulatory Authority (NRA) for a limited time (approximately one-third of the depreciation period). The levying of charges for the existing gas infrastructure could therefore be included in the financing considerations for hydrogen infrastructure.⁷² However, the effects of partial cross-financing should be carefully examined before deploying this option, as gas network users already face considerable costs due to shortened depreciation periods.

In addition, interoperability between the networks must be ensured, particularly in cooperation with non-EU countries. Within the EU, the European Network of Network Operators for Hydrogen (ENNOH) will in future be responsible for guidelines on network codes, the adoption and publication of ten-year plans for the expansion of hydrogen networks as well as annual work programmes and supply forecasts. However, additional cooperation is required in these areas if Turkish hydrogen exports are to be connected to the European network.

4.2 Infrastructure funding

The considerable investment needed for cross-border hydrogen networks will require a combination of private capital in equity and debt as well as public funds/de-risking through grants or guarantees. Especially during the development phase, projects face high risks and therefore high financing costs, e.g., for feasibility stud-

ies. Direct public support measures, such as grants, will be especially important to support this high-risk segment of the project cycle. Certain EU Member States have already provided state aid to hydrogen networks with cross-border relevance (e.g., under the IPCEI Hy2Infra). However, to advance the trans-European hydrogen network in a coherent manner, EU-level coordination and financial support will be key.

The Trans-European Energy Networks (TEN-E) policy provides CAPEX subsidies and has significantly contributed to the modernisation of the EU's cross-border energy infrastructure since 2013. It also makes available CAPEX subsidies via the Connecting Europe Facility (CEF). To meet energy infrastructure needs at regional and European level, the TEN-E policy identifies priority corridors and thematic areas. Furthermore, it establishes a biennial list of Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs) to support the EU's energy and climate goals. These are priority infrastructure projects of the European Union to strengthen the internal energy market. They address gaps in the European energy network and must demonstrate economic, social or environmental benefits for at least two EU Member States. PMIs connect EU energy networks with third countries.⁷³ For the 2021–2027 period, the EU allocated an energy budget of EUR 5.84 billion to support the transition to clean energy.⁷⁴ CEF is often used to finance feasibility studies, a crucial hurdle for securing long-term financing.

Intertemporal cost allocation (ICA) mechanisms may provide an effective approach in this regard. ICA can be used to stretch the CAPEX investments over a prolonged time frame, while mitigating some of the market risks faced by hydrogen infrastructure. In the early market phase, there will be only a small number of hydrogen network users, which will gradually increase as the market ramp-up progresses. The limited number of users and the resulting high tariffs may discourage network expansion and use. Capping tariffs over a multiannual ramp-up period to facilitate the use of the network by first movers may place significant financial burden and risk on infrastructure operators. There are a number of public instruments which could be used to support and de-risk hydrogen networks under ICA regimes. One approach to ensure a viable business case under an ICA regime may be an amortisation account. While the network operators invest in the pipelines, the state reduces

71 cf. European Parliament and European Council (13/06/2024).

72 cf. Hancher and Suci (2024).

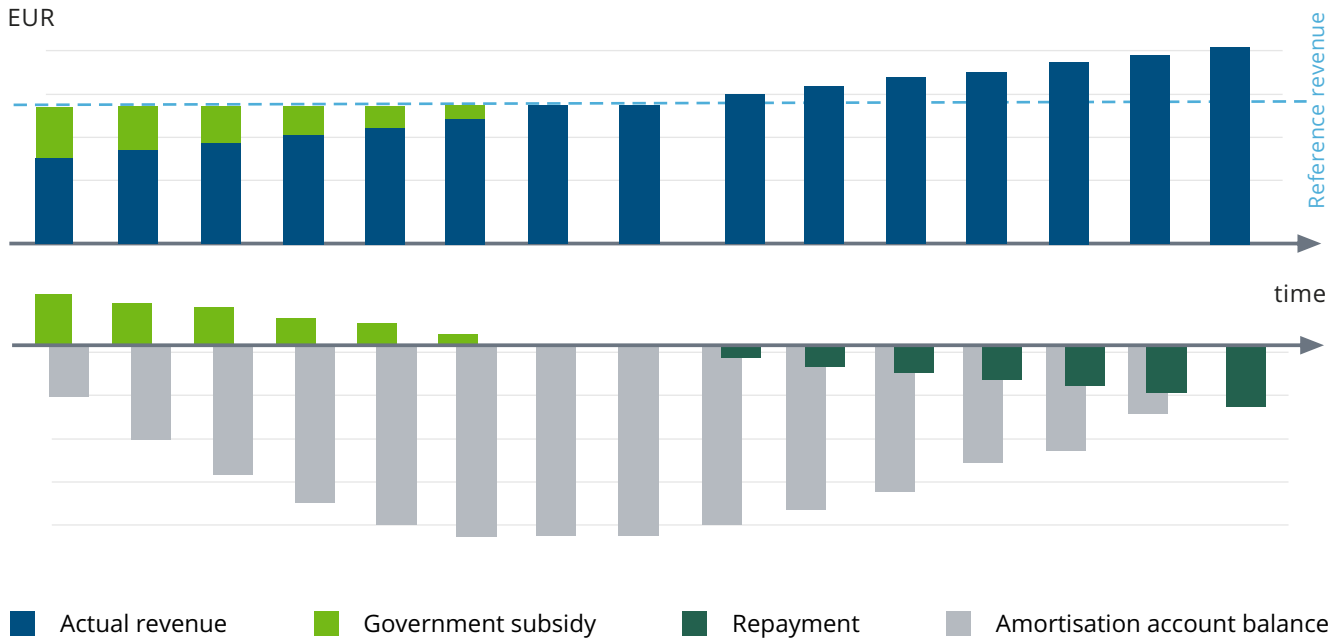
73 cf. Bundesnetzagentur (2022).

74 cf. European Commission (2025a).

the risks of these investments via what is known as an amortisation account, in which the early revenue shortfalls, consisting of the difference between capped tariffs and investment costs, are booked with interest. As the

number of network users rises, the total revenue increases as more and more shippers book capacities in the network and repayments to the account gradually balance the intertemporal cost allocation out (see Figure 14).

Figure 14: Operative principle of amortisation accounts



Source: German Energy Agency (2025)

Early revenue shortfalls (investment costs minus capped network tariffs) would be recorded in the depreciation account. As the market ramps up, tariffs will gradually exceed costs as more and more shippers book capacity. The resulting additional revenues of the TSOs will be credited to the depreciation account, offsetting the start-up deficits. Network regulators should ensure a balanced level of tariffs.⁷⁵ The state partially assumes liability for a potential remaining negative balance at the end of the term.⁷⁶ The account could be used to maintain network tariffs at a level conducive to the nascent market, which would be continuously ensured by the National Regulatory Authority. For the time being, therefore, it seems more likely that intertemporal cost allocation mechanisms will be used mainly at national

level, especially for infrastructure including sections in non-EU countries. For cross-border hydrogen transport corridors, this means that, in most cases, each national ICA will only be able to cover pipeline segments passing through the respective state. It should be noted that at the time of publication of this report, a consultation process is underway by the European Agency for the Cooperation of Energy Regulators (ACER).⁷⁷

4.3 Capacity bookings

Bookings of transport capacity ensure cashflows within investments in regulated energy networks. As described above, an insufficient numbers of network users will

⁷⁵ cf. Bothe et al. (30/08/2024).

⁷⁶ In the case of the German hydrogen core network, TSOs have to bear a deductible of up to 24%, while the state would cover the remaining balance with a subsidy.

⁷⁷ According to Regulation (EU) 2024/1789 on the market for hydrogen and decarbonised gas, ACER is required to issue a recommendation on methodologies for determining the intertemporal cost allocation by 5 August 2025. ACER's recommendation will serve as guidance for transmission system operators (TSOs), distribution system operators (DSOs), hydrogen network operators and national regulatory authorities on how to develop and implement these mechanisms effectively. (cf. European Union Agency for the Cooperation of Energy Regulators (2025)).

book capacities during the ramp-up phase, so the TSOs and their investors carry a significant amount of risk. Capacity guarantees can help address this issue and provide a level of certainty during the ramp-up phase, especially under an ICA regime. There are two main options for the state to intervene here. One option would be that the state guarantees the revenues for a certain network capacity, e.g., 30% of network capacity over 15–20 years. The government guarantee ends when the actual bookings in the network exceed the minimum capacity.

Alternatively, a government can act as an intermediary and book pipeline capacities itself via a state-owned entity, creating 'anchor capacity bookings'. For the duration of the asset's life, the asset owner would be encouraged to resell this capacity. However, if they fail to secure buyers, the government would act as a capacity buyer of last resort. Alternatively, public authorities resell the capacity on the secondary market.⁷⁸

4.4 Leveraging private capital in the EU

Hydrogen infrastructure will need upfront access to capital markets (e.g., debt financing, green bonds) and solid investment ratings, which beyond direct public support can also be facilitated by binding supply and offtake agreements.⁷⁹ Given the extensive CAPEX requirements of hydrogen infrastructure projects, a stable upfront financing framework is essential. Due to the considerable uncertainties in the hydrogen market, state-backed risk-sharing mechanisms are necessary to achieve investment-grade ratings and make projects viable for commercial banks. A combination of equity, debt and public funding or guarantees can enhance overall financing conditions. Institutional investors, who hold 71% of investment fund capital in the EU, prioritise

long-term predictability and prudent risk management. Many such investors, including insurance companies and pension funds, require quick access to liquidity to meet their financial commitments. Consequently, blending illiquid infrastructure investments with liquid assets is crucial for risk management.

One noteworthy regulation in this context is the creation of European Long-Term Investment Funds (ELTIFs) in 2015. ELTIFs were designed as a collective investment framework allowing investors across Europe to put money into companies and projects that need long-term capital. However, the fund type has not yet had the desired effect, due to a lack of pragmatism in the selection of possible assets, narrow diversification rules and limited opportunities for marketing to retail investors. While ELTIFs held assets worth almost EUR 13.6 billion in their portfolios until 2023, the Alternative Investment Association (AIMA) expects that assets worth up to EUR 100 billion could be included soon.⁸⁰ This is due to reform of the ELTIF, which was adopted through Commission Delegated Regulation (EU) 2024/2759 and came into force on 1 January 2024. This extended the scope of application and relaxed the criteria of the instrument. ELTIFs can now invest in a mix of liquid and non-liquid assets, making them a more widely applicable financial product. What plays a particularly important role in the European-Turkish context is the geographical applicability of ELTIFs. It is only since the reform that long-term investments can be made in non-EU countries. The majority of an ELTIF's revenues may now also be generated in non-EU countries. This recognises the fact that investments in non-EU countries can also strengthen the European economy, particularly in the immediate neighbourhood. This includes the development of border regions and the improvement of commercial, financial and technical cooperation in the energy sector.

78 cf. Reul and Graul (2024).

79 cf. Bundesanstalt für Finanzdienstleistungsaufsicht (2024).

80 cf. Arthur, Allright and Halmagi (2023).

5 Regulatory framework for the implementation of effective hydrogen trade

Implementation of the European legal framework will be crucial for realising effective hydrogen trade between Türkiye and the EU. This requires an approximation of laws, regulations and administrative provisions. The most important parts of EU legislation and regulation are briefly mentioned below. A more detailed description can be found in the dena factsheet on the regulatory aspects of hydrogen imports into the EU (Stüwe et al. 2025).

The Renewable Energy Directive (RED) is a crucial aspect of the regulatory framework around hydrogen and its derivatives. It was adopted as part of the EU's 'Fit for 55' package, which aims to reduce greenhouse gas emissions by 55% by 2030. RED II, first adopted in 2018, provides a foundational framework for the production of RFNBOs. The European Commission has further specified these basic rules through two key Delegated Acts adopted in 2023:

- Regulation (EU) 2023/1184 defines electricity sourcing criteria for the production of Renewable Fuels of Non-Biological Origin (RFNBO)
- Regulation (EU) 2023/1185 outlines greenhouse gas (GHG) accounting rules for RFNBOs

In 2023, RED III introduced stricter requirements for sustainability and greenhouse gas (GHG) reduction, in line with more ambitious RFNBO integration targets. The EU co-legislators formally adopted RED III on 19 September

2023. Other forms of hydrogen, such as blue hydrogen produced by steam methane reforming (SMR) or auto-thermal reforming (ATR) of natural gas with carbon capture and storage (CCS), can be categorised as low-carbon fuels, for which a separate delegated act, Directive (EU) 2024/1788, is expected to be adopted soon. However, the EU's quota targets for the use of renewable energies explicitly apply to RFNBOs. This means that only green hydrogen and its derivatives can be counted towards the RED III quotas, which aim for 42% renewable hydrogen in the industrial sector by 2030, 60% by 2035; 5.5% renewable fuels in the transport sector by 2030. At the same time, the implementation gap in EU-internal hydrogen production projects could increase the need for import sources outside the EU.

Another important element of EU legislation that must be considered for hydrogen exports to Germany and the EU is the Carbon Border Adjustment Mechanism (CBAM), a tool for pricing CO₂ emissions generated by the production of goods that use carbon-intensive production processes posing a risk of carbon leakage. The goods covered by this labelling include cement, iron, steel, aluminium, fertilisers, electricity and hydrogen. The emphasis is on major importers with the highest share in emissions, while 80% of EU companies are to be exempt under the CBAM. The CBAM will be introduced gradually, with a transition period from 2023 to 2025, and is expected to be fully in place from 2026. It is aligned with the phase-out plans under the EU Emissions Trading System (ETS).

6 Conclusion and recommendations

After a thorough examination of the various aspects of Turkish hydrogen production and pertinent transportation options to Germany, a range of concluding observations can be made. The following general observations should be emphasised.

Türkiye can become a competitive supplier of green hydrogen and its downstream products due to the country's high potential for renewable energy, established industries and geographical proximity to the EU. However, as in other regions, the speed and scale of the hydrogen ramp-up is still uncertain, leading to challenges for infrastructure planning and financing.

In principle, **pipeline transportation is the most cost-effective option for transporting molecular hydrogen**. However, this decisively depends on the utilisation of the pipeline – regardless of which route it ultimately takes. For the assumed 75% pipeline utilisation in the applied cost tool on which this study is based, **a minimum hydrogen throughput of approximately 50 TWh H₂/a would be required**. Securing pipeline capacity utilisation by such an order of magnitude, especially in the early stage of hydrogen market development, is one of the major hurdles for realising the pipeline path and will require public financial incentives.

Different route options were examined for their technical and market feasibility and viability: 1) the South-East European Hydrogen Corridor, 2) the SouthH₂ Corridor and 3) transport via ship from Gemlik to Brunsbüttel. A comparison of the two pipeline options shows that the SEEHyC route enables a lower degree of retrofitting (approx. 20%) compared to the SouthH₂ route (approx. 70%). **The estimated investment needed for SEEHyC (approx. EUR 11.2 bn) is almost double the expenditure required for the SouthH₂ route (approx. EUR 6 bn)**, even disregarding the cost for pipeline infrastructure to connect these projects to the hydrogen intake point in Türkiye.

However, investment volume alone is not sufficient to indicate a transport cost advantage of one of the pipeline options. For such a comparison, a detailed projection of

hydrogen intakes and offtakes along each route is necessary, following the optimisation of pipeline design. Based on the latest TYNDP scenarios, countries along both the SouthH₂ and SEEHyC routes have a **projected net deficit for hydrogen in a similar order of magnitude – roughly from 300 to 400 TWh in 2040**. For the pipeline option via SouthH₂, additional hydrogen import possibilities (approximately 210 to 250 TWh in 2040 from Algeria and Tunisia) could materialise, making this option more feasible in terms of realising the high utilisation rates required for economic hydrogen transport via pipeline, as shown in section 3.3.

To establish critical minimum utilisation for a Turkish hydrogen pipeline section, a volume of 1.5 Mt or 50 TWh of green hydrogen is required. In view of these high volumes, option 3) of shipping hydrogen as ammonia could be a viable solution in the ramp-up phase. In this case, synergies in the use of existing port infrastructure and superstructure (like from Gemlik port to Brunsbüttel port) could be feasible in the short-term. With respect to large-scale hydrogen export for end use of molecular hydrogen, **deploying ammonia cracking technology at scale causes additional costs for the end user of molecular hydrogen (2–3 EUR/kg H₂ transport cost for end user compared to 0.4 EUR/kg H₂ transport via pipeline without cracking)**. It therefore remains open whether this business case will materialise for hydrogen transport from Türkiye to Germany. Sectors that process ammonia as feedstock provide a particularly promising business case for ammonia exports from Türkiye.

Regarding the financing of hydrogen infrastructure, the complex interplay of **regulated tariffs and high investment risk inherent in regulated asset bases** was examined. Possible financing mechanisms were analysed in terms of their effectiveness. In particular, means of **inter-temporal cost allocation** such as amortisation accounts are being discussed as possible measures for financing hydrogen infrastructure, but require further legislative initiative. **A joint PMI application** for a Greek-Turkish hydrogen interconnector would represent an opportunity to apply for EU-funding under the Connecting Europe Facility.

The following policy recommendations were drawn from this process:

- To establish **planning security for infrastructure operators, regulatory authorities along the respective corridors must implement** the EU's Gas Package. This includes, for example, the timely definition of network codes and regulated network tariffs. This is a prerequisite for project developers to be able to determine the specific financing gaps and for financial plans to be drawn up.
- In addition, a financing mechanism is needed in the short term to **co-finance/de-risk possible infrastructure investments**. If possible, this should also be applicable to countries in the EU neighbourhood. The current PMI process also envisages the direct funding of infrastructure between EU and non-EU countries. A joint application of Turkish infrastructure developers with EU TSOs should thus be considered. However, with a regulated tariff regime, guarantee instruments such as intertemporal cost allocations may be more effective than direct subsidies in improving the attractiveness of hydrogen infrastructure investments over its lifetime.
- Given the complexity and financial challenges associated with hydrogen infrastructure, a **hybrid financing approach combining regulatory incentives, risk-sharing mechanisms and long-term refinancing strategies** will be crucial for ensuring a sustainable hydrogen transport corridor from Türkiye to Germany. Commercial banks can provide the capital for infrastructure developers during the initial ramp-up phase of infrastructure assets over the span of 6–7 years. Afterwards, private investments could be refinanced through long-term institutional investors for longer periods of 20–30 years. Commercial financing should be combined with public instruments, depending on budget availability, to achieve an optimal allocation of costs and risks and minimise the financial burden for project developers.
- In addition to the strategic planning of pipelines, it is advisable in the short term to **develop supply chains by using existing ports and their topside facilities that need little to no modification for the processing and distribution of ammonia**. An examination of the need for any upgrades to transshipment and storage capacities seems sensible.
- However, until plans for possible pipeline use are firmed up, it is advisable to **identify further product classes under the CBAM for which green hydrogen must be used to decarbonise the process chain**. Türkiye has a competitive profile for green hydrogen production and could establish itself as an exporter of these products by decarbonising further product classes relevant to the EU's CBAM, such as steel and chemicals.

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Annexes

Annex 1: Assumptions behind the techno-economic analysis, reference year 2040, based on EWI (2024)

	Assumption	Scenario	Value	Unit
General	Currency exchange	all	1.05	1 EUR = 1.05 USD
Electrolysis	Economic lifetime	all	25	Years
	CAPEX	baseline	485.32	\$/kW _{el}
	FOM	baseline	9.17	\$/kW _{el}
	Electricity demand	all	46.57	kW _{el} /kg H ₂
	Conversion efficiency	all	0.70	kW _{H₂} /kW _{el}
	Electricity price	all	69.84	\$/kW _{el}
	Labour cost parameter	all	0.65	%
	WACC	all	18.07	%
Hydrogen pipeline	Specific investment costs	high-cost new	0.72	\$/ (kW H ₂)/km
	Specific investment costs	retrofitted	0.14	\$/ (kW H ₂)/km
	FOM	all	0.02	\$/ (kW H ₂)/km/a
	Utilisation	all	75	%
	Lifetime	all	42	years
	Losses	all	0.30	%
	WACC	all	10	%
	Annuity	all	10	%
Ship (ammonia)	Charter rate	low charter rate	33,000	\$/d
	Charter rate	high charter rate	67,000	\$/d
	Fuel consumption	all	150.00	t CH ₃ OH/day
	Fuelling cost	all	20,000.00	\$
	Port cost	all	850,000.00	\$
	Vessel capacity	all	57,120.00	t NH ₃
	Speed	all	25.00	km/h
	Berthing time	all	48.00	hours
	Waiting time	all	96.00	hours
	Boil-off	all	0.02	% per day

	Assumption	Scenario	Value	Unit
Hydrogen-to-ammonia (Haber-Bosch process)	Economic lifetime	all	25.00	years
	CAPEX	baseline	1,433.31	\$/kWNH ₃
	CAPEX	optimistic	1,003.51	\$/kWNH ₃
	FOM	baseline	57.33	\$/kWNH ₃
	FOM	optimistic	40.14	\$/kWNH ₃
	Hydrogen feed-in	all	0.18	kg H ₂ / kg NH ₃
	Electricity demand	all	0.81	kWhel/kgNH ₃
	Conversion efficiency	all	0.87	kWNH ₃ /kWH ₂
Ammonia-to-hydrogen (hydrogen ammonia cracking)	Lifetime	all	25.00	years
	Specific investment costs	baseline	428.10	\$/kWH ₂
	Specific investment costs	optimistic	305.35	\$/kWH ₂
	FOM	baseline	12.84	\$/kWH ₂
	FOM	optimistic	9.16	\$/kWH ₂
	Ammonia feed-in	all	5.74	kgNH ₃ /kgH ₂
	Electricity demand	all	4.06	kWel/kgH ₂
	Heating demand	all	7.69	kWth/kg H ₂
	Conversion efficiency	all	1.11	kWH ₂ /kWNH ₃
	Utilisation	all	0.90	-

Annex 2: Relative difference in transport costs based on capacity utilisation and degree of retrofitting

Pipeline utilisation	75%	25%
EHB 2021 transport cost New pipeline*	0.37 (EUR/kg)/1,000 km	0.90 (EUR/kg)/1,000 km
EHB 2021, transport cost Retrofitted pipeline*	0.10 (EUR/kg)/1,000 km	0.25 (EUR/kg)/1,000 km
Transport cost 20% retrofitted pipeline*	0.32 (EUR/kg)/1,000 km	0.77 (EUR/kg)/1,000 km
Transport cost 70% retrofitted pipeline*	0.18 (EUR/kg)/1,000 km	0.45 (EUR/kg)/1,000 km
Same utilisation, Retrofitting 70% vs 20%	-75% lower unit cost South ₂	
SEEHyC utilisation 75%, retrofitting 20% vs South₂ utilisation 25%, retrofitting 70%	-41% lower unit cost SEEHyC	
SEEHyC utilisation 75%, retrofitting 70% vs South₂ utilisation 25%, retrofitting 20%	-325% lower unit cost South ₂	

Source: Own elaboration, based on EHB (2021)

* The figures are based on weighted average unit costs provided by the EHB and applied for the given degree of retrofitting. The EHB has updated infrastructure costs in the meantime. Therefore, the absolute unit cost values, e.g., 0.18 and 0.32 €/kg/1,000 km for South₂ and SEEHyC respectively, in the case of higher utilisation, are not applicable anymore. However, the updated costs for the new 36" onshore pipelines include an almost proportional increase in costs for the new and retrofitted pipelines (45% increase of CAPEX for the new pipeline and 60% increase for the retrofitted pipeline), meaning the relative difference is still applicable.

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List of abbreviations

ACER	European Agency for the Cooperation of Energy Regulators	JDoI	Joint Declaration of Intent
AIMA	Alternative Investment Association	LCH₄	Liquefied synthetic methane
ATR	Autothermal reforming	LCOH	Levelised cost of hydrogen
BMWK	German Ministry of Economic Affairs and Climate Action	LH₂	Liquefied hydrogen
CAPEX	Capital expenditure	LNG	Liquefied natural gas
CBAM	Carbon Border Adjustment Mechanism	LOHC	Liquid organic hydrogen carriers
CCS	Carbon capture and storage	MDB	Multilateral development bank
CEF	Connecting Europe Facility	MENR	Turkish Ministry of Energy and Natural Resources
CO₂	Carbon dioxide	MeOH	Methanol
CPF	Country Partnership Framework	MGO	Marine gas oil
DAC	Direct air capture	MIGA	Multilateral Investment Guarantee Agency
DCC	Directorate of Climate Change	MJ	Megajoule
DN	Nominal diameter	Mt	Million tonnes
DP	Design pressure	MWh	Megawatt-hour
DSO	Distribution system operator	NDC	Nationally Determined Contribution
EBRD	European Bank for Reconstruction and Development	NH₃	Ammonia
EHB	European Hydrogen Backbone	NPS	Nominal pipeline size
ELTIFs	European Long-Term Investment Funds	NRA	National regulatory authority
ENNOH	European Network of Network Operators for Hydrogen	nTPA	Negotiated third-party access
ENTSO-G	European Network of Transmission System Operators for Gas	OPEX	Operating expenses
EU ETS	EU Emission Trading System	PCI/PMI	Projects of Common/Mutual Interest
EWI	Institute of Energy Economics at the University of Cologne	PPA	Power Purchase Agreement
FEED	Front End Engineering Design	PV	Photovoltaic
FTD	Fischer-Tropsch diesel	RAB	Regulated Asset Base
GH₂	Gaseous hydrogen	RCF	Recycled carbon fuels
GHG	Greenhouse gas	RED	Renewable Energy Directive
GLGF	Global Gateway Fund	RFNBO	Renewable Fuels of Non-Biological Origin
GW	Gigawatt	rTPA	Regulated third-party access
H₂	Hydrogen	SEEHyC	Southeast European Hydrogen Corridor
ICA	Intertemporal cost allocation	SMR	Steam methane reforming
IEA	International Energy Agency	TEN-E	Trans-European energy networks
IPCEI	Important Projects of Common European Interest	TPA	Third-party access
		TSO	Transmission system operator
		TWh	Terawatt-hour
		TWh/a	Terawatt-hour per year
		TYNDP	Ten-year network development plan

