Facilitating hydrogen imports from non-EU countries

October 2022

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GAS FOR CLIMATE
A path to 2050

Guidehouse

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Imprint

Authors:
Tareq Zahw, Jaap Peterse, Matthias Schimmel, Jan Cihlar

Date:
October 2022

Contact:
Guidehouse
Stadsplateau 15, 3521 AZ Utrecht
The Netherlands
+31 30 662 3300
www.guidehouse.com

Photo credit (title):
Adobe Stock

Design:
res d Design und Architektur GmbH,

Layout:
IDEENGESTALT, Kerstin Liermann

Executive summary

The European Commission recently published its REPowerEU plan which aims to rapidly reduce dependence on Russian fossil fuels and accelerate the green transition. Hydrogen plays a key role in this plan. A total of 20 Mt of hydrogen is targeted by 2030 – 10 Mt via domestic production and up to 10 Mt via imports. To meet the hydrogen import target, infrastructure, regulation, and support mechanisms must be fit for purpose. However, this is currently not the case. This paper provides insights on the existing challenges of imports and how they can be overcome.

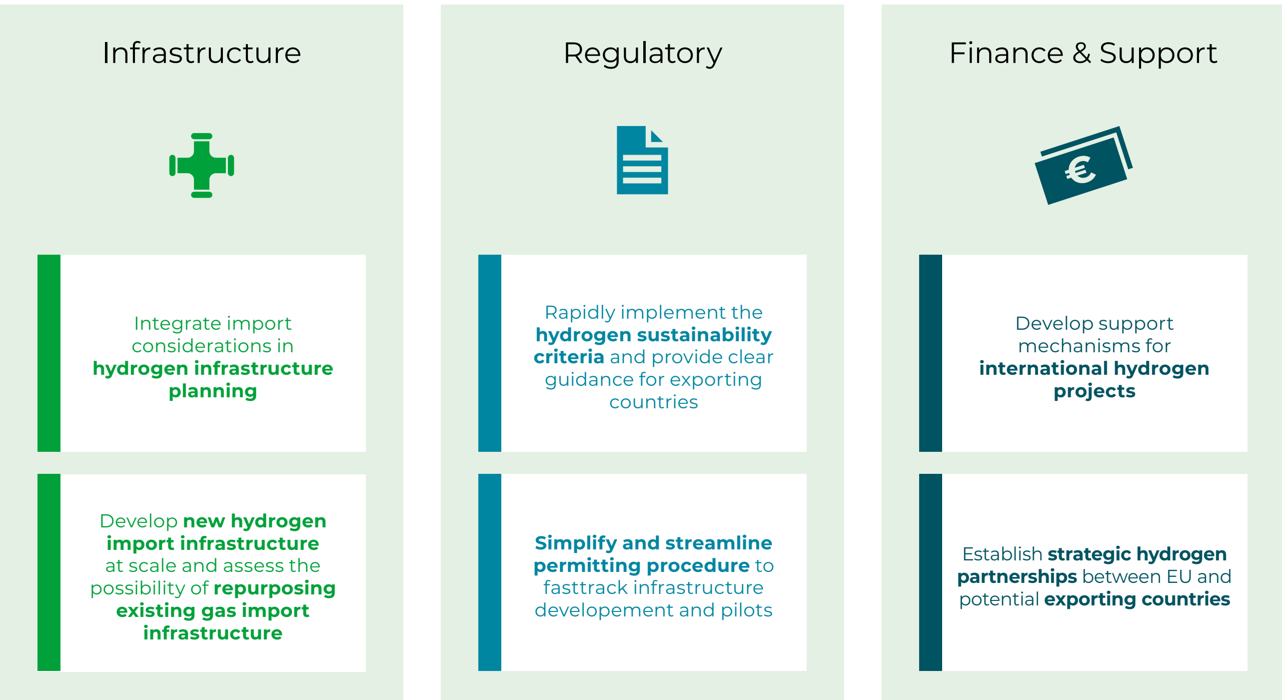
Transport options and import infrastructure. Hydrogen can be imported via pipeline or ship (e.g., liquid hydrogen, liquid organic hydrogen carriers (LOHC), methanol, ammonia and synthetic methane). Existing natural gas pipelines from third countries can be repurposed to allow high-volume imports at low costs. Shipping enables imports of hydrogen carries from countries further away from Europe, thus contributing to the diversification of supply. When assessing import options, it is important to consider how these imports can be integrated in the emerging European Hydrogen Backbone so that the imported hydrogen is readily transported to the demand centres.

Regulation, certification, and standardisation. There are multiple proposals on the table concerning hydrogen at EU level, however, they often miss an international perspective relevant to facilitate imports. Pragmatic sustainability requirements for hydrogen, transparent certification mechanisms and harmonised standards are needed to implement international hydrogen projects and the required import infrastructure.

Supporting international hydrogen projects. Several mechanisms are put forward in the REPowerEU plan to support hydrogen projects across the value chain. H2Global is a best-practice example which could serve as a blueprint for incentivising imports to Europe. Next to financial support, bilateral or multilateral hydrogen partnerships with third countries can facilitate knowledge exchange, e.g., on certification or production technologies, thus, positively impacting timely hydrogen imports.

Actions to facilitate hydrogen imports from non-EU countries. In summary, there is an exhaustive list of actions to be taken before the EU can receive large volumes of hydrogen from third countries. An overview of key actions for policy makers, regulators and infrastructure providers derived from this paper is shown in Figure 1.

Figure 1: Actions to facilitate hydrogen imports to the EU by 2030



1. Background

Europe is heavily dependent on energy imports from Russia. To become independent from Russian natural gas, the European Commission published REPowerEU – a plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition.[1] Building on REPowerEU, Gas for Climate published 10 concrete, short-term measures to accelerate renewable gas uptake in Europe and replace a significant amount of natural gas imports.[2] This acceleration can increase European energy security by reducing dependency on Russian natural gas, speed up the implementation of climate targets and alleviate part of the energy cost pressure on households and the economy.

Hydrogen is a cornerstone of the REPowerEU plan. The "Hydrogen accelerator", as part of REPowerEU, aims to develop hydrogen infrastructure, storage and terminal facilities and replace demand for Russian gas and other fossil fuels with 20 Mt/year of hydrogen by 2030, of which 10 Mt will be produced domestically. The other 10 Mt will be imported via pipelines and ships.[3] Part of the imports will feed into the emerging European Hydrogen Backbone (EHB) to be transported to demand centres across Europe.

The targeted European hydrogen infrastructure will be organised in three priority supply corridors according to the REPowerEU plan, namely the Mediterranean, the North-Sea region and as soon as conditions allow Ukraine. These corridors are well in line with the supply corridors published by the EHB initiative and would be a first, tangible step towards a pan-European hydrogen infrastructure connected to neighbouring regions.[4]

Apart from this, the Global European Hydrogen Facility and the Green Hydrogen Partnerships will be established and promoted. The Global European Hydrogen Facility should create investment certainty and business opportunities for renewable and low-carbon hydrogen production and reliable supply and transparency for European hydrogen usage. This facility should be coherent with intra-EU measures and market functioning. The Green Hydrogen Partnerships promote the import of renewable hydrogen and should incentivise decarbonisation and the development of renewable energy production for domestic use in partner countries, while encompassing policy dialogue, including on sustainability standards. On top of this, the EU aims at developing at least 100 hydrogen valleys worldwide by 2030 and the joint purchasing of hydrogen.[5]

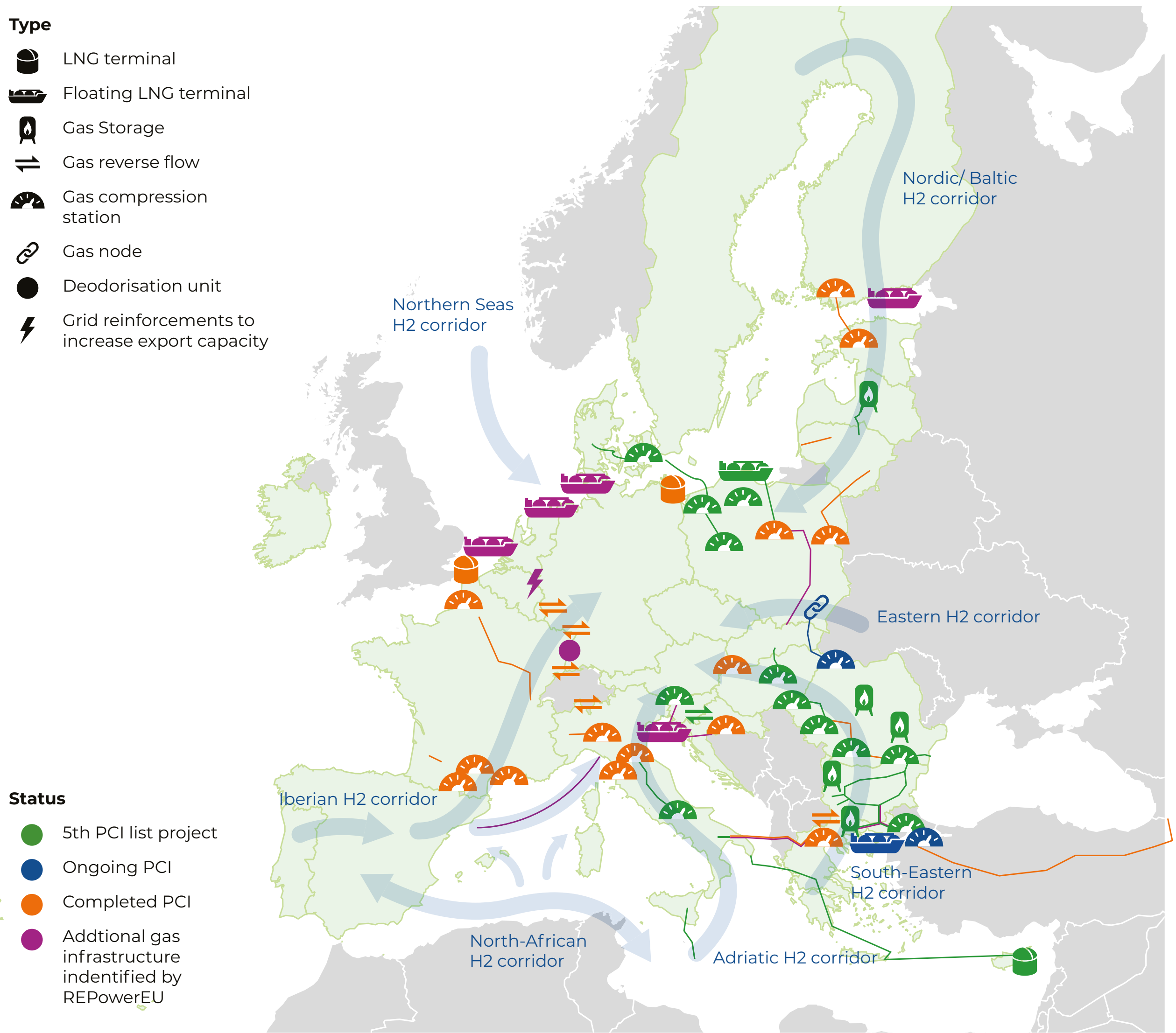
These intentions make clear that the EU is looking to take a leading role in the development of international hydrogen supply chains. However, the current hydrogen market is still at an early stage and policy measures are insufficient to kick-start the hydrogen accelerator.

1 European Commission (2022). *REPowerEU Plan.* Link
2 Gas for Climate (2022). *Action Plan for Implementing REPowerEU.* Link
3 European Commission (2022). *Staff Working Document – Implementing the REPower EU Action Plan: Investment needs, Hydrogen Accelerator and achieving the Bio-methane targets.* Link
4 European Hydrogen Backbone (2022). *Five hydrogen supply corridors for Europe in 2030.* Link
5 European Commission (2022). *Staff Working Document – Implementing the REPower EU Action Plan: Investment needs, Hydrogen Accelerator and achieving the Bio-methane targets* . Link

The three hydrogen imports corridors prioritised by the REPowerEU plan will pave the way for hydrogen imports via pipelines, as well via ship to planned, new, or repurposed import terminals. Figure 1 shows the REPowerEU vision of the corridors, as well as their corresponding Projects of Common Interest (PCIs) and additional projects identified through REPowerEU by the European Commission. The corridors will initially connect local supply and demand in different parts of Europe, before expanding and connecting Europe with neighbouring regions with export potential.

This paper discusses the different hydrogen transport options and related infrastructural needs, such as hydrogen import terminals and pipelines. Next to this, the different policy and regulatory needs are addressed, including certification and financing options to support international hydrogen projects.

Figure 2: European map of infrastructure for gas – PCIs and additional projects identified through REPowerEU, including hydrogen corridors.[6]



6 European Commission (2022). *REPower EU Plan.* Link

2. Transport options and import infrastructure

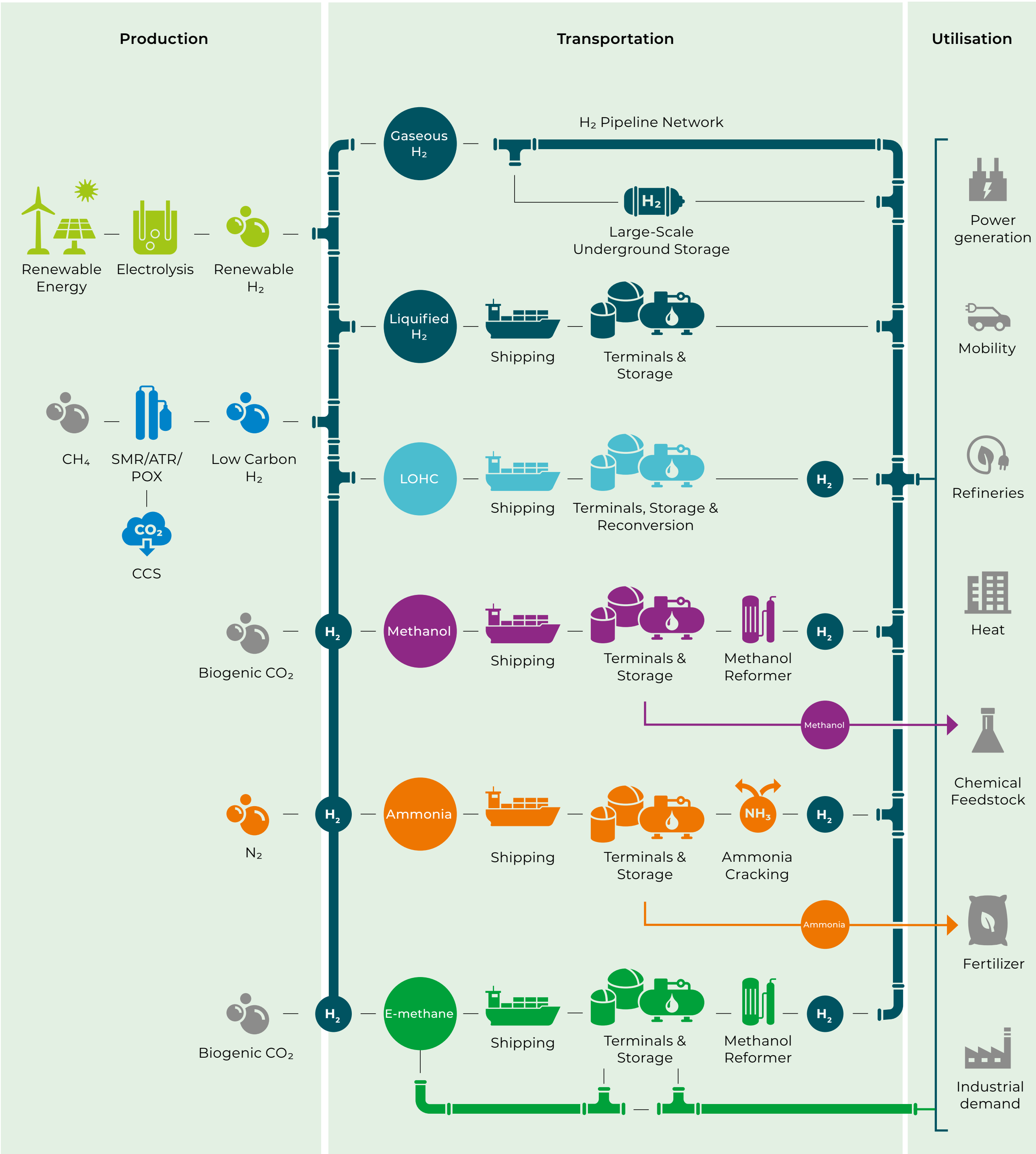
Key messages

- Hydrogen can be imported via pipelines or shipping. Beside scaling up dedicated hydrogen imports infrastructure, hydrogen imports can be facilitated through repurposing natural gas pipelines and LNG terminals existing along all EHB corridors.
- For shipping, hydrogen can be either compressed, liquified or embedded in one of its potential carriers e.g., LOHC, ammonia, synthetic methane, or methanol. Import terminals for synthetic methane (to be used as hydrogen), ammonia and methanol are currently either in planning or under construction.
- In total, up to 4.4 Mt of hydrogen imports could be realised by 2030 via already planned terminals and repurposed infrastructure dedicated to hydrogen carriers (ammonia, methanol, and synthetic methane).[7] Importantly, hydrogen production projects in exporting countries needed to be realised accordingly.
- Besides the already planned terminals and repurposed infrastructure, the potential capacity for hydrogen imports via repurposed natural gas pipelines or LNG terminals could be substantial. However, it is uncertain to what extent this infrastructure could be made available for hydrogen in the short term, given the need to compensate for the phase out of Russian natural gas imports.
- Current salt cavern storage capacities are insufficient to meet hydrogen storage demand in 2030. New and repurposed storage infrastructure are needed to facilitate hydrogen imports.

Importing hydrogen from global production sites can be done through pipelines or shipping. Hydrogen can be either compressed, liquified or embedded in one of its potential carriers at the expense of energy losses. The selected transport option depends on the quantities, distances, form of hydrogen carrier, and overall cost of supply. This chapter discusses the potential transport options for hydrogen and its corresponding carriers, as well as the potential capacities of existing infrastructure (pipelines and terminals). Further, the infrastructural needs and the potential for infrastructure repurposing are assessed, including preliminary cost estimations.

7 The 4.4 Mt of hydrogen is specified in hydrogen (gravimetric) terms, whereas the imports would be realised utilising hydrogen carriers. To ensure comparability to the REPowerEU target of 10 Mt of hydrogen imports, it assumed that hydrogen would be extracted from its carrier upon delivery to the EU import infrastructure.

Figure 3: Overview of hydrogen transport options



To facilitate imports of the targeted 10 Mt of hydrogen by 2030, substantial efforts are needed to ensure the feasibility of existing infrastructure as well as potential hydrogen carriers. An overview of transport options for hydrogen is shown in Figure 3. As the chapter focuses on import options, a special attention is given to the various transport options shown in middle section of the figure. Gaseous hydrogen is typically compressed and transported through pipelines. Hydrogen can also be liquified or transformed into a carrier such as LOHCs, ammonia, methanol, or synthetic methane and shipped to import destinations. The scope mainly considers serving hydrogen imports needs. Hydrogen can be extracted from its carriers, resulting in efficiency losses and cost increase, and injected into the EHB to be transported towards its demand locations. Hydrogen carriers can be directly utilized e.g., ammonia as a fertilizer, methanol as a chemical feedstock, or methane covering a wide range of applications in industrial, residential and transportation sectors.

The following sections discuss the various transport options shown in Figure 3 and potential capacities of their corresponding infrastructure. They incorporate the three major corridors of the REPowerEU plan as main routes of importing the targeted amount of hydrogen.

2.1 Pipelines

As a first viable option, hydrogen can be transported via pipelines. Hydrogen pipelines currently extend globally more than 5,000 km, with >90% located in Europe and the United States.8 Pipeline transport is generally considered the most cost-efficient option for distances of up to 5,000 km.9 Hydrogen pipelines are capital-intensive projects, similar to natural gas pipelines.10 However, the cost of pipeline transport per tonne (or per kWh) decreases strongly with the transported volume. That is the reason pipelines are mainly constructed for relatively large imports capacities.

2.1.1 Repurposed gas pipelines as a potential option

A hydrogen pipeline network would be comprised of essentially the same components as natural gas pipeline network. Accordingly, repurposing natural gas infrastructure for the use of hydrogen is technically feasible.[11] This can range from simple adjustments (e.g., replacing valves, meters, and other components) to more complex refurbishments, including new compressor stations and replacing/ recoating pipeline segments, depending on operation conditions. It is foreseen by 2030 that more than 9,000 km of hydrogen pipelines in several member states will be repurposed natural gas pipelines.[12] The EHB initiative expects that the share of repurposed pipelines will be 60-70% of all European hydrogen pipelines by 2040.[13]

Hydrogen has different properties than natural gas that must be considered when designing or repurposing a pipeline network. It can over time cause localized embrittlement when in contact with bare steel. Hence, repurposing existing natural gas pipelines into dedicated hydrogen pipelines requires integrity assessments to be conducted concerning the potential presence of crack-like defects and tightness-related modifications of valves and fittings.[14] This will also require an adjustment of the compression strategy, often including compressor replacements and a thorough inspection of the pipeline and the integrity of its components.

Repurposing existing natural gas pipelines can be substantially less costly and the lead times can be much shorter.[15] This can lead to more cost-competitive transport tariffs and support the ramp-up of renewable and low-carbon hydrogen. As shown in Figure 4, the major cost components of a gas pipeline are the pipeline capital expenditures (CAPEX), pipeline operational expenditures (OPEX), compressor CAPEX, and compressors operational expenditure (OPEX). European gas transmission system operators (TSOs) conducted hydraulic simulations to determine the throughput and

8 IEA (2021). *Global Hydrogen Review 2021.* Link
9 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
10 Guidehouse (2022). *Covering Germany's green hydrogen demand: Transport options for enabling imports.* Link
11 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
12 IEA (2021). *Global Hydrogen Review 2021.* Link
13 European Hydrogen Backbone (2021). *Extending the European Hydrogen Backbone.* Link
14 Melaina et al. (2013). *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.* Link
15 Guidehouse (2022). *Covering Germany's green hydrogen demand: Transport options for enabling imports.* Link

compression power for various natural gas pipeline configurations to estimate the levelized cost of transport for new and repurposed pipelines.[16] The simulations concluded that pipe CAPEX represents the major cost component in a new pipeline, while compressor OPEX represents the major cost component in a repurposed pipeline. Smaller diameter pipelines have lower unit capital costs than larger diameter pipelines. However, they have higher costs per kg of hydrogen transported due to their lower throughput.[17]

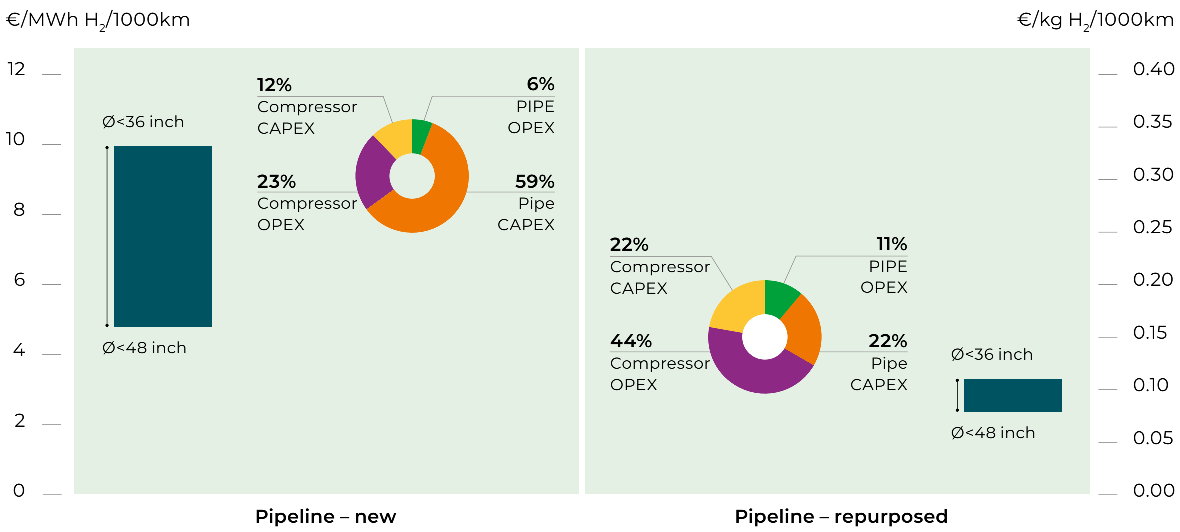
The following section discusses the estimated capacities of importing hydrogen, putting into account the difference in the energy densities of natural gas and hydrogen transported through the same pipeline.

2.1.2 Existing natural gas imports pipelines

The EHB initiative developed a visionary hydrogen pipeline network, which will be realized by repurposing natural gas pipelines and building new, dedicated hydrogen pipelines when repurposing is not viable.[18] The EHB will connect local supply and demand in different parts of Europe and connect with neighbouring regions with export potential. In this section, potential hydrogen imports via repurposed natural gas pipelines are investigated.

Hydrogen pipeline imports from the North Sea, North Africa and Ukraine represent a potential option to achieve the REPowerEU 2030 targets. The current natural gas pipelines and their corresponding capacities are listed in Annex 1. The capacities of the pipelines are assessed to provide a preliminary estimate of the potential hydrogen import capacity. Hydrogen pipelines usually run at operating pressures between 35 and 80 bar.[19] Given this range of operating pressures, the volumetric energy density of hydrogen in a repurposed pipeline would be 20-30%[20] of the natural gas in the same pipeline. However, this does not necessarily mean that three times the pipeline capacity is required to transport the same amount of energy. The volume flow rate of hydrogen can be higher than for natural gas, bringing the maximum energy capacity of a hydrogen pipeline to a value of up to 80% of the energy capacity it has when transporting natural gas.[21]

Figure 4: Levelised cost comparison of new and repurposed hydrogen pipelines



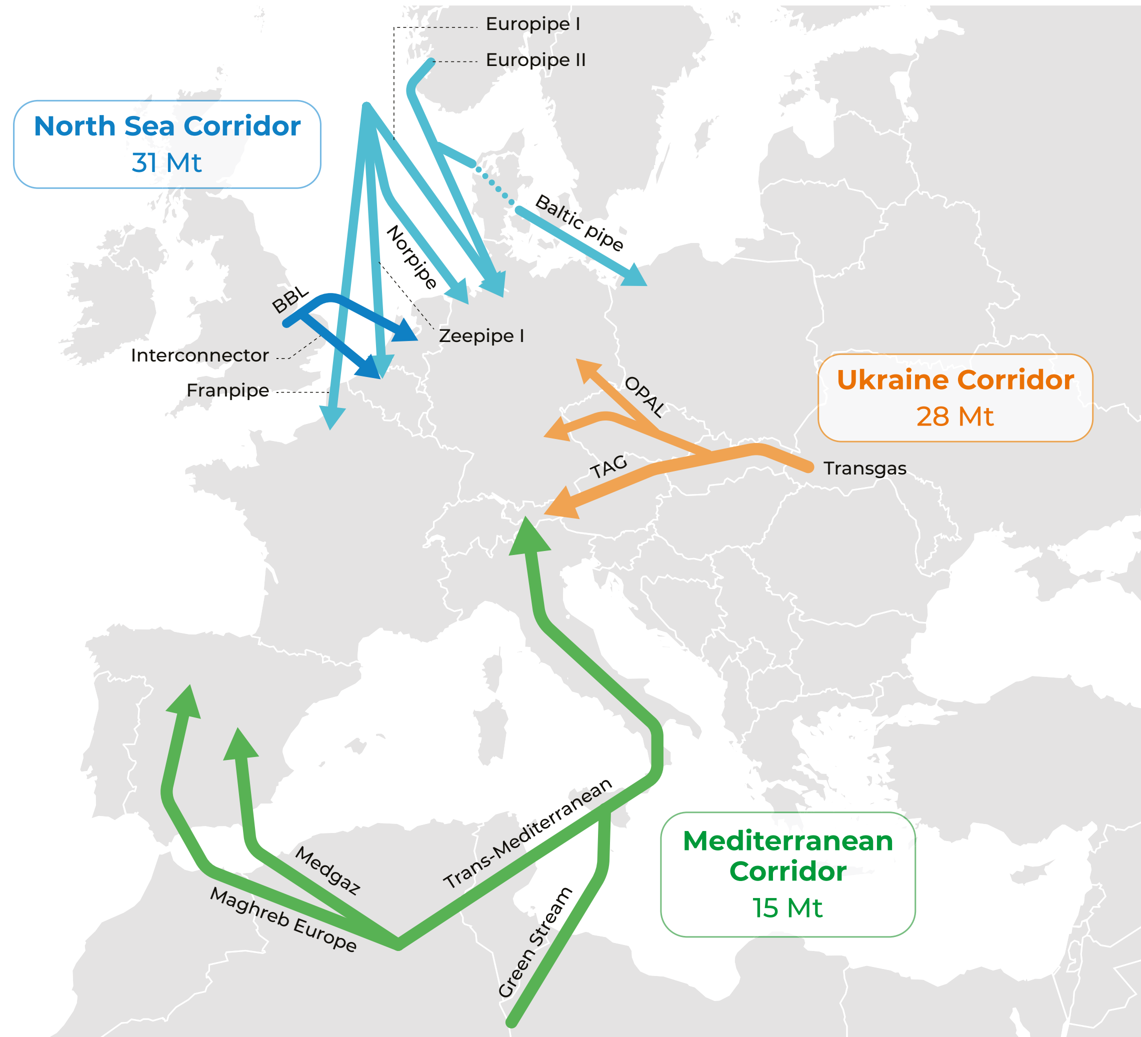
16 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
17 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
18 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
19 Penev et al (2019). *Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling station, 500 – 1200 psi.* Link
20 Volumetric energy density of natural gas = 47.97 kg/m³ x 13.1 kWh/kg, volumetric energy density of compressed hydrogen in pipelines = 3.95 kg/m³ x 33.3 kWh/kg. The ratio = 21%. As hydrogen pressure ranges between 35 – 80 bar, the ratio approximately varies between 20-30%
21 European Hydrogen Backbone (2020). *How a dedicated hydrogen infrastructure can be created.* Link

Considering the natural gas pipeline capacities listed in Annex 1, the amount of hydrogen flow in the pipeline can be calculated accordingly.[22] Figure 5 shows an overview of the estimated capacities of the pipelines in the three corridors, as can be also seen in Annex 1.

In the North Sea region, there are six pipelines from Norway (Europipe I & II, Norpipe, Zeepipe, Franpipe, and Baltic Pipe) and two from UK (Interconnector and Balgzand Bacton Line) that could be repurposed. With its large renewable energy potential, North Sea pipelines could provide competitive renewable and low-carbon hydrogen, given its near distance and being potentially produced from wind resources. The overall potential import capacity utilising North Sea pipelines can reach 31 Mt of hydrogen.

Next to the North Sea region, North Africa is also in an advantageous position for hydrogen pipeline transport to Europe. North Africa has a large renewable energy potential, specifically in the form of solar and wind resources. Tapping into this renewable energy potential using repurposed existing natural gas pipeline infrastructure could offer an additional source of large-scale renewable hydrogen. Two pipelines are connected to Southwestern Europe (Spain) through Algeria and

Figure 5: Natural gas import pipelines with their potential hydrogen import capacities



22 Calculated by the relative energy density to natural gas (80%), given the pipeline volume capacity (Annex 1). e.g., 1 bcm natural gas ~9.8 TWh →1 bcm hydrogen = 7.8 TWh ~ 0.23 Mt of hydrogen

Morocco (Medgaz and Maghreb-Europe). While an additional two are connected to Southern Europe (Italy) through Algeria, Tunisia, and Libya (Trans-Mediterranean and Green Stream). The overall potential import capacity through these pipelines can reach 15 Mt of hydrogen.

In the Ukrainian corridor, there are key opportunities including leveraging the abundant renewables potential in Eastern Europe. In the mid-term, the pipeline corridor offers access to low-cost, hydrogen supply from Eastern and South-Eastern Europe – including hydrogen imports from Ukraine (once conditions allow for it), and partially from Poland (Yamal II). The main supply pipeline from Ukraine is the Transgas pipeline, which then feeds Slovakia, Czech Republic, Austria, Germany and Italy. The overall potential import capacity through the Transgas pipeline can reach 28 Mt of hydrogen.

Individual pipelines capacities are estimated as shown in Annex 1. The total import capacity via pipelines can reach up to 74 Mt of hydrogen This can potentially contribute to the REPowerEU 2030 target of 10 Mt of imports, if a share of these pipelines can be freed from natural gas supply and hydrogen supply projects in third countries are realised in time. However, this scenario remains uncertain due to the need for compensating Russian natural gas, which used to constitute 39% of EU natural gas pipeline imports prior to the Russian war on Ukrainian.[23] Another uncertainty is the development of hydrogen projects in the potential export regions. While there are multiple announcements of large-scale hydrogen projects, especially in the North Sea region and North Africa, none are operational at the moment.

To conclude, repurposing natural gas pipelines offers a suitable and a cost-effective solution for hydrogen transport. This makes them especially suitable for intra-European transport and imports through the North Sea and Mediterranean corridors. Another advantage of repurposing natural gas pipelines for hydrogen transport is the higher social acceptance of already existing infrastructure compared to new pipelines. However, the expected performances, capacities and routes of future flows should be taken into consideration. Conflicts with needed or planned natural gas pipelines need to be avoided. Unless they are utilised for natural gas imports, fostering the development of repurposed pipelines, and facilitating their efficient use for hydrogen are key to accelerate hydrogen imports to reach the REPowerEU targets.

2.2 Shipping

Shipping of hydrogen and hydrogen carriers is another viable import option. This alternative is more attractive for longer distances, where pipelines would not be an option. Potential hydrogen shipping options involve either liquefying hydrogen or transforming it into a carrier and shipped in liquid forms to import destinations. Hydrogen can either be extracted from its carriers and injected in gaseous form into the EHB or the carriers can be directly utilised. From a demand perspective, gaseous hydrogen is needed across sectors in different regions to decarbonise (e.g., steel industry), while imported renewable or low-carbon ammonia/methanol could be used to replace existing grey ammonia/methanol production close to the import terminal.

Shipping hydrogen or its carriers involves multiple steps including:

1. Pipeline from the hydrogen production site to the export terminal
2. Conversion of gaseous hydrogen into the shipping medium
3. Storage at the export terminal
4. Shipping
5. Storage at the import terminal
6. Reconversion to gaseous hydrogen
7. Pipeline to the demand location

The final utilisation of hydrogen impacts the selection of hydrogen shipping options and the decision of hydrogen reconversion afterwards. The following sections provide an overview on hydrogen shipping options, assessment of terminal capacities, their repurposing potential as well as preliminary cost estimates of repurposing.

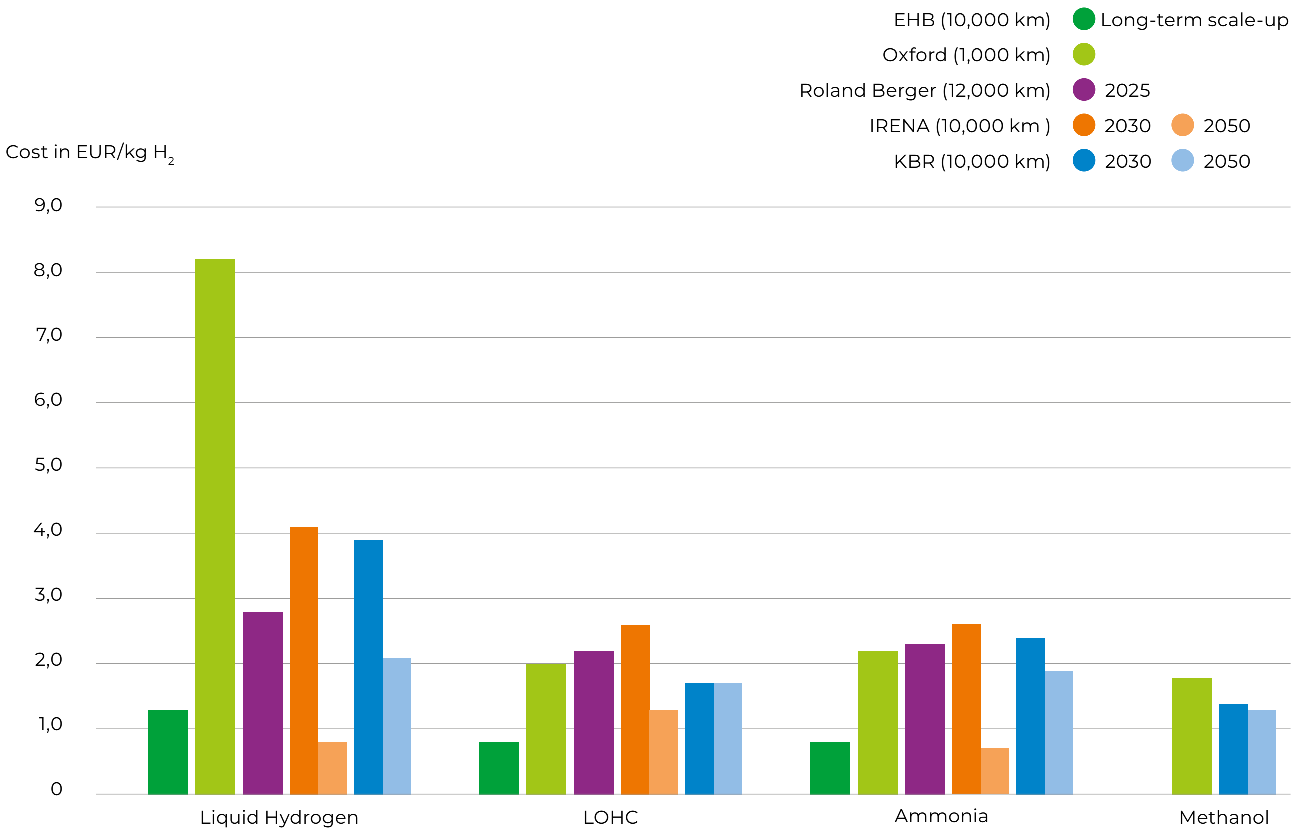
23 European Commission (2016). *Liquefied Natural Gas and gas storage will boost EU's energy security (accessed in September 2022).* Link

2.2.1 Potential hydrogen carriers

Several options for hydrogen shipping in various forms exist. Fossil-derived ammonia (liquified), methanol and natural gas (for synthetic methane) are currently transported in large quantities with tankers. Necessary infrastructures and technologies are also in place and can also be used if these energy carriers become established as a storage and transport medium. However, the infrastructure would need to be expanded to account for additional imports. The current expectation is that hydrogen imports to Europe arrive in the form of liquid hydrogen, LOHCs, ammonia, methanol, or synthetic methane.[24] A high-level comparison of the five hydrogen carriers is elaborated in Table 1.

The five carriers have similar value chains including hydrogen production, conversion, storage, shipping, and, if needed, reconversion. Depending on transport conditions and final utilisation of the carriers, different conversion and/or reconversion losses apply. Liquid hydrogen transport requires highly insulated metal tanks to keep temperatures below boiling point (-253°C). Liquid ammonia can be transported at -33°C under atmospheric pressure, or at 25°C under pressure of 10 bar. Methanol is liquid under normal ambient conditions and can be easily transported via vessels. LOHCs are liquids under normal ambient conditions and can be transported via oil vessels.

Figure 6: Hydrogen carriers transport costs on the short term (in addition to long term costs estimated by EHB, IRENA and KBR)



24 Based on discussions with Gas for Climate consortium members.

Transport costs of four carriers are assessed in five recent studies; liquid hydrogen, LOHC, ammonia and methanol.[25] The assumptions and calculation models vary across each study. Our assessment mainly considers reconversion of hydrogen from its carriers and injecting it into the EHB, to be further transported towards its demand locations. It is noted that comparing hydrogen carriers to be directly utilized, would give notably different conclusion. To provide a fair comparison, the production costs calculated in the studies have been excluded. The comparison considers the costs of hydrogen conversion, shipping, storage, and reconversion.

The five studies included liquid hydrogen, LOHC and ammonia in their comparison. The KBR and oxford have additionally considered methanol. None of the studies have considered synthetic methane in the comparison, partly due to the fact that it is more likely to be directly utilized, than reconverted into hydrogen. We can fairly assume that the synthetic methane pathway should be in the same order of magnitude as methanol. Figure 6 shows the comparison of transport costs of the four carriers calculated by each study.

Three studies (EHB, IRENA and KBR) have assumed a transport route of 10,000 km. While 1,000 km are assumed in the Oxford study and 12,000 km in the Roland Berger study. This does not substantially affect the overall conclusion as the marginal cost increase per shipped km is relatively minor.[26] Only in case of liquid hydrogen, distances may impact the cost, due to boil-off losses. The longer the transport distance is, the more boil-off losses are. Hence, more vessels will be needed and the marginal cost increases.[27]

Cost estimates are projected in different years across each study. The costs in IRENA and KBR are estimated for 2030, 2040 and 2050, while Roland Berger estimated them for 2025. Oxford did not provide a specific year. EHB assumptions are beyond 2030.

The EHB report has an optimistic view on hydrogen carriers transport costs. It provides a future vision of cost reduction potential, considering a significant scale-up in deployment and technology development. This explains the low transport costs of EHB in comparison to other studies. Except liquid hydrogen, transport costs of hydrogen carriers across the studies are convergent. Excluding EHB's estimates, the LOHC transport costs in the short-term range between 1.6–2.5 €/kg H_2, ammonia costs range between 2.2–2.5 €/kg H_2 and methanol costs range between 1.4–1.8 €/kg H_2.

As shown in the figure, liquid ammonia and methanol (and synthetic methane) would offer competitive options on the short term as potential hydrogen shipping carriers. The cost across their value chains would be different if each carrier is directly utilized. Considering carrier conversion and later reconversion into hydrogen, they would offer almost similar cost magnitudes. Additionally, ammonia and methanol can be used as shipping fuels.[28] However, ammonia-powered vessels must also carry heavy fuel oil or diesel to ensure quick start-up of engines in case of emergency. It should be noted that methanol and ammonia are highly toxic, flammable (especially methanol) and explosive under certain conditions. Stringent safety measures must be ensured for transport and storage tanks.

The wide variation of liquid hydrogen costs in the short term can be understood in the context of its early-stage development, which creates a level of uncertainty. From the figure, the cost estimate of Oxford seems widely divergent. By excluding it, the transport costs of liquid hydrogen range accordingly between 2.9 – 4.1 €/kg H_2. Hydrogen liquefaction, which takes place in the exporting country, is the most energy intensive step while little energy is required to gasify it in the import country.

25 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
The Oxford Institute for Energy Studies (2022). *Global trade of hydrogen: what is the best way to transfer hydrogen over long distances?* Link
KRB (2021). *Hydrogen imports and downstream applications.* Link
Roland Berger (2021). *Hydrogen transportation | The key to unlocking the clean hydrogen economy.* Link
IRENA (2022). *Global Hydrogen Trade to Meet the 1.5°C Climate Goal, Part II.* Link
26 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
27 Hydrogen Council (2020). *Path to hydrogen competitiveness A cost perspective.* Link
28 The Oxford Institute for Energy Studies (2022). *Global trade of hydrogen: what is the best way to transfer hydrogen over long distances?* Link

Table 1: High-level comparison of the five hydrogen carriers[29, 30]

	Liquid hydrogen	LOHC	Ammonia	Methanol	Synthetic Methane
Infrastructure	• Lacking global infrastructure • Safety measures are not in place	• Existing oil infrastructure can be used	• Widely traded • Mature supply chain, with existing infrastructure • Additional infrastructure required	• Mature supply chain, with existing infrastructure • Widely traded • Supply of green CO_2 necessary for synthetic methanol • CO_2 infrastructure needs to be built (e.g., pipelines, storage)	• Existing mature infrastructure • Supply of green CO_2 necessary for synthetic methane • CO_2 infrastructure needs to be built (e.g., pipelines, storage)
Conversion / reconversion	• High energy input for liquefaction (roughly one third of hydrogen's energy content)	• Very high energy demand for extraction of H_2	• Cracking is an energy intensive process and not commercially mature • Low purity of reconverted H_2	• Synthetic methanol can be produced from low-carbon hydrogen • Cracking is energy intensive	• Methanation and cracking are energy intensive
Transport	• Boil-off losses (Storage and transport containers for the liquid hydrogen must be very well insulated to minimize boil-off losses)	• The ship contains a full load each way and cannot transport a different cargo on the return trip • LOHC cargo cannot be used as fuel, higher life cycle emission	• Proven at scale (only on port-to-port level) • Use of "pure" NH_3 in existing and new markets possible	• Transport to hinterlands incurs few more safety challenges	• High compatibility with existing transport infrastructure
Costs	• Currently very expensive due to high conversion cost • 2.9 – 4.1 €/kg H_2/1,000 km	• High investment cost for carrier material • 1.6 – 2.5 €/kg H_2/1,000 km	• Competitive costs, if reconversion is not needed • 2.2 – 2.5 €/kg H_2/1,000 km	• Costs are lower compared to other carriers if reconversion is not needed • Carbon capture and utilisation is not commercially mature	• Costs are lower compared to other carriers, if reconversion is not needed • Carbon capture and utilisation is not commercially mature

Two of the five studies (IRENA and KBR) have further forecasted the costs of hydrogen carriers on the long term. Including the EHB estimates, liquid hydrogen transport costs range between 0.8–2.1 €/kg H_2, while LOHC costs range between 0.8–1.7 €/kg H_2, and 0.7–1.9 €/kg H_2 for ammonia. Transport costs of liquid hydrogen may become comparable to other carriers and may compete in the medium/long term. Cost advantages of carriers will uniquely depend on their project sizes, quantities, and transport distances as well as their long-term cost forecast. Furthermore, cost estimates for future value chains are, by definition, uncertain, becoming more precise when technologies develop further, which already means that no absolute winner can be pointed out in this stage.

29 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link
30 Gas for Climate (2019). *Gas Decarbonisation Pathways 2020–2050.* Link

2.2.2 Potential capacity of import terminals

Terminals are a key component in the value chain of hydrogen imports. To fulfil shipping transport activities, they include, amongst others: jetties, storage tanks, truck loading, evaporation units, dehydrogenation plants, cracking installations (e.g., for ammonia), and other equipment.[31] The following sections discuss the potential import capacities of hydrogen carriers and liquified hydrogen, in comparison to the REPowerEU plan.

Ammonia

The current European imports of ammonia reach 4 Mt.[32] Many European terminals can potentially contribute to the imports of ammonia, as a hydrogen carrier, to meet REPowerEU 2030 targets. REPowerEU estimates that up to 4 Mt of hydrogen are imported in the form of ammonia or potentially other hydrogen carriers and derivatives. As hydrogen constitutes approximately 18% the weight of ammonia, the amount of ammonia required is around 31 Mt. To meet the REPowerEU target, 27 Mt of ammonia would need be imported additionally. Additional ammonia import capacities are currently planned in the Netherlands, Germany, and Belgium as shown in Table 2.

In total, existing (4 Mt), and planned infrastructure could accommodate up to 12.4 Mt of ammonia imports. An illustration of ammonia terminal components is shown in Figure 7. It is important to note that cracking of ammonia back to hydrogen is not yet available at scale. First large-scale ammonia crackers are expected to become operational towards the end of this decade.[39]

Methanol

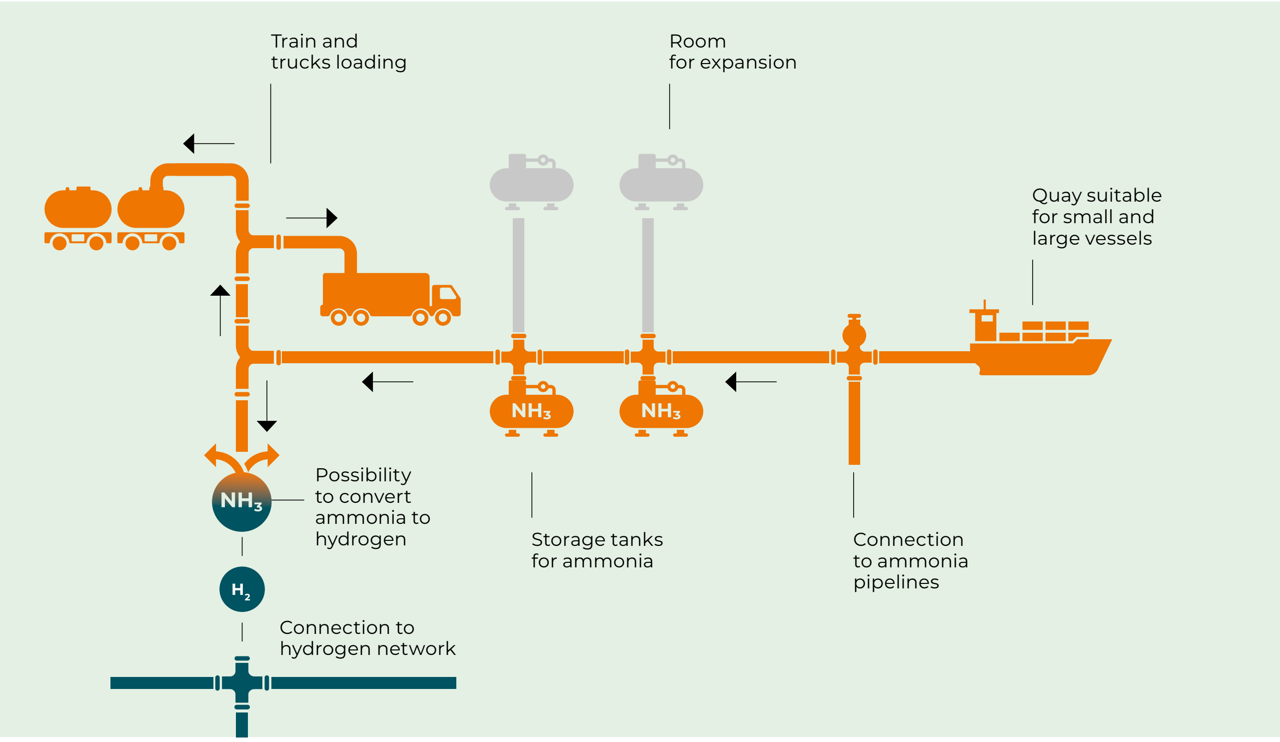
Repurposing of infrastructure for other hydrogen carriers may also be an option e.g., methanol. Similar to ammonia, infrastructure for shipping methanol already exists today. Liquefaction is not necessary as methanol is already liquid at normal temperature. Safety concerns are still high due to its flammability and corrosiveness.

Table 2: List of planned ammonia import terminals in Germany, Belgium and the Netherlands

Terminal	Start year	Ammonia imports capacity (Mt)	Imported hydrogen mass (Mt)[33]
RWE Ammonia Terminal Brunsbüttel, Germany[34]	2026	2	0.27
Uniper Wilhemlshaven, Germany[35]	2026	3	0.41
Fluxys Advario Antwerp Green Ammonia Termina, Belgium[36]	2027	1.2	0.16
Horisont Koole Ammonia Terminal, Rotterdam, Netherlands[37]	2026	1	0.14
Gasunie ACE Terminal, Rotterdam, Netherlands[38]	2026	1.2	0.16
Total		**8.4**	**1.14**

31 ENTEC (2022). *The role of renewable H_2 import & storage to scale up the EU deployment of renewable H_2.* Link
32 IEA. *Production, consumption and trade of ammonia in selected countries and regions, 2020 (accessed in September 2022).* Link
33 Hydrogen mass constitutes 18% of ammonia mass, after considering the cracking losses (25%)
34 RWE (2022). *Import of green energy: RWE builds ammonia terminal in Brunsbüttel (accessed in September 2022).* Link
35 Uniper. Green Wilhelmshaven (accessed in September 2022). Link
36 Fluxys (2022). *Driving Europe's hydrogen strategy: Fluxys and Advario join forces to develop a green ammonia import terminal at the Port of Antwerp-Bruges (accessed in September 2022).* Link
37 Koole (2022). *Horisont Energi signs MoU with Koole Terminals on development of ammonia terminal and storage facility at port (accessed in September 2022).* Link
38 Gasunie. *ACE Terminal (accessed in September 2022).* Link
39 Interview with Uniper – Held on 21 July 2022

Figure 7: Ammonia terminal components[40]



Most of EU methanol demand is met through methanol imports. European countries are primarily importing methanol from Asia-Pacific, predominantly China, owing to its low energy prices.[41] Several EU terminals have been selected as potential import terminals for green methanol, due to their existing methanol storage facilities as well as future methanol production projects. The terminals are mapped in Figure 8. Their facilities and capacities are listed in Annex 2. The overall potential capacities of importing methanol in these selected terminals are 1.1 Mt of methanol. As hydrogen forms approximately 12.6% of the mass of methanol, the potential amount of hydrogen mass import via methanol as a carrier is 136,600 tonnes (0.137 Mt).

Synthetic Methane

Hydrogen import capacities (in the form of synthetic methane) are currently planned at TES Wilhelmshaven terminal in Germany. The terminal model is to create a carbon cycle, which eliminates emissions through closed loops. Hydrogen is imported in the form of synthetic methane, to be fed into existing gas pipelines or reconverted into hydrogen and injected in hydrogen network. The terminal commissioning will be in 2025. The terminal capacity is expected to be between 16-20 bcm[42] of natural gas. Hydrogen constitutes 25% of methane mass. Hydrogen mass can be estimated – after considering cracking losses (25%) – up to 2.6 Mt

LOHCs

LOHCs offer a potential alternative as a carrier. As mentioned previously, existing oil infrastructure can be used for importing LOHCs. Several planned import projects have been announced in various member states such as Netherlands[43] and Germany [44]. However, their commercial size is still uncertain.

40 Energy News. *Fluxys to build ammonia terminal in Antwerp (accessed in September 2022).* Link
41 Triton Market Research (2018). *Europe Methanol Market.* Link
42 TES H2. TES announces LNG Open Season at Wilhelmshaven Green Energy Hub to bring climate neutrality and energy securityto-gether for European customers (accessed in September 2022). Link
43 Port of Rotterdam. *Study Into Hydrogen Import Terminals (accessed in October 2022)* Link
44 Recharge. ENERGY TRANSITION. *Germany plans to import hydrogen from UAE using 'liquid organic carrier' technology (accessed in October 2022)* Link

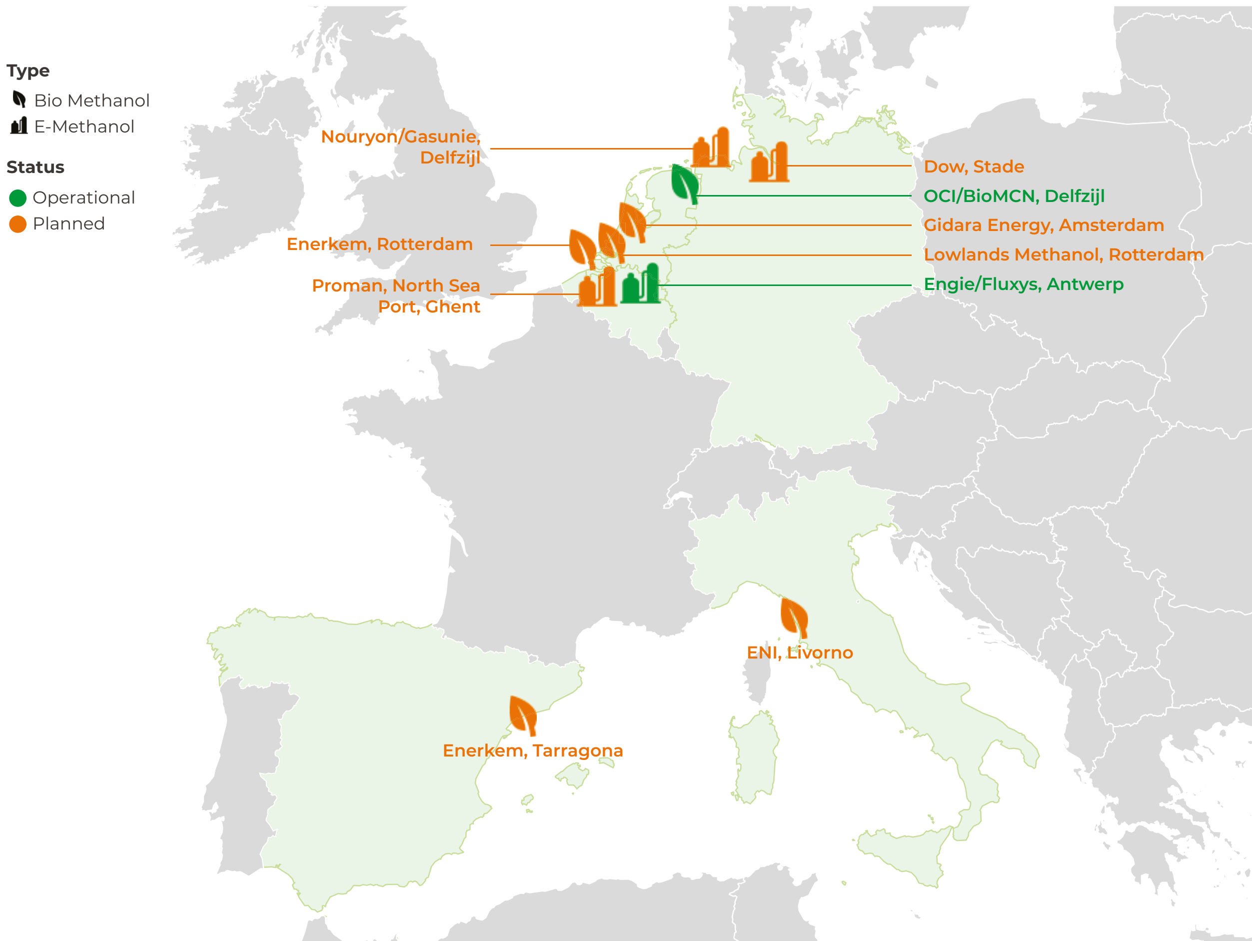
Liquified Hydrogen

Unlike ammonia and methanol, hydrogen, due to its chemical properties, requires a different condensing/refrigeration capacity and associated insulation requirements. Currently, no operating terminal for liquified hydrogen exists in Europe. Pure hydrogen has not yet been transported via ships on large scale, except by Suiso Frontier, which transports liquid hydrogen between Japan and Australia.[45] Commercial availability of vessels for global large-scale transport of liquid hydrogen is expected in the 2030s.

Total Capacities

The overall capacities of hydrogen imports through existing or planned import infrastructure of hydrogen and hydrogen carriers are summarized in Table 3. The total hydrogen import capacity reaches 4.4 Mt. There is still a gap between planned potential capacities hydrogen carriers and the REPowerEU 10 Mt targets. Hence, scaling up further hydrogen carriers import facilities will be needed. In parallel, further options are investigated in the following section.

Figure 8: Existing and planned synthetic and bio methanol import terminals in Europe[46]



45 Reuters. Kawasaki Heavy says liquefied hydrogen carrier departs Japan for Australia (accessed in September 2022). Link
46 Methanol Institute. Renewable and Biomethanol Projects 2021 *(accessed in September 2022).* Link

Table 3: Overall current and planned hydrogen import capacities

Terminal	Import Quantities (Mt)	Hydrogen mass (Mt)
Synthetic Methane	Planned 13.6	2.6
Ammonia	Current* 4.0 Planned 8.4	0.5 1.14
Methanol	Planned 1.0	0.14
LOHC	Unknown	Unknown
Liquid hydrogen	-	-
Total hydrogen imports capacities		**4.4**

* Current ammonia imports are assumed to be potentially from renewable or low-carbon hydrogen by 2030

2.2.3 Repurposing LNG terminals

Additional hydrogen import capacities could be attained through repurposing LNG terminals; however, this is uncertain before 2030, given the need for additional LNG imports in the short to medium term to replace Russian gas. There is a total of 53 LNG terminals in EU member states.49 Figure 9 shows LNG terminals in Mediterranean and North Sea corridors. They could be utilized for hydrogen carrier imports. In this section, the capacities of these LNG terminals in EU member states are assessed. Annex 3 and Annex 4 list the North Sea terminals and Mediterranean terminals respectively, including their annual nominal capacity of LNG imports in billion cubic meters (bcm).[47]

Repurposing LNG terminals for importing hydrogen carriers depends uniquely on each carrier and its characteristics, which differ from LNG. First, all existing and planned LNG terminals can already import synthetic methane without the need to be repurposed. LNG terminals with access to major gas pipelines would also be good candidates for methanol imports. However, the aim of repurposing LNG terminals in the context of this paper is to further facilitate the reconversion to hydrogen and injection in the hydrogen network. Using LNG terminals for synthetic methane and repurposing LNG terminals for methanol will mostly lead to their direct utilization.

When repurposing LNG terminals for ammonia imports, the working capacity of the storage tank will be lower, due to different densities of LNG and ammonia. Equipment of different steel grades as well as different welding characteristics need to be used to avoid embrittlement. The Boil-off Gas (BOG) system[48] needs to be evaluated in detail to identify the proper compressor configuration to avoid inefficient BOG compressor operation. The piping system needs to be enforced for ammonia service. The instrumentation and measuring devices need to be evaluated in detail to ensure their functionality with ammonia and identify the components which need to be replaced. Figure 10 illustrates which elements can be reused. The green-coloured components would have to be replaced or newly built if ammonia is handled. In addition, ammonia is a highly toxic substance. This incurs further safety and material handling challenges.[49]

47 Gas Infrastructure Europe (GIE). *LNG Database (accessed in September 2022)* Link
48 When boil off gas enters into the suction line of the compressor, it is compressed and sent either to a condenser for re-liquefaction, fed into a gas turbine as fuel in a power generation plant, or is directed into a pipeline for city gas usage.

Figure 9: The European LNG infrastructure

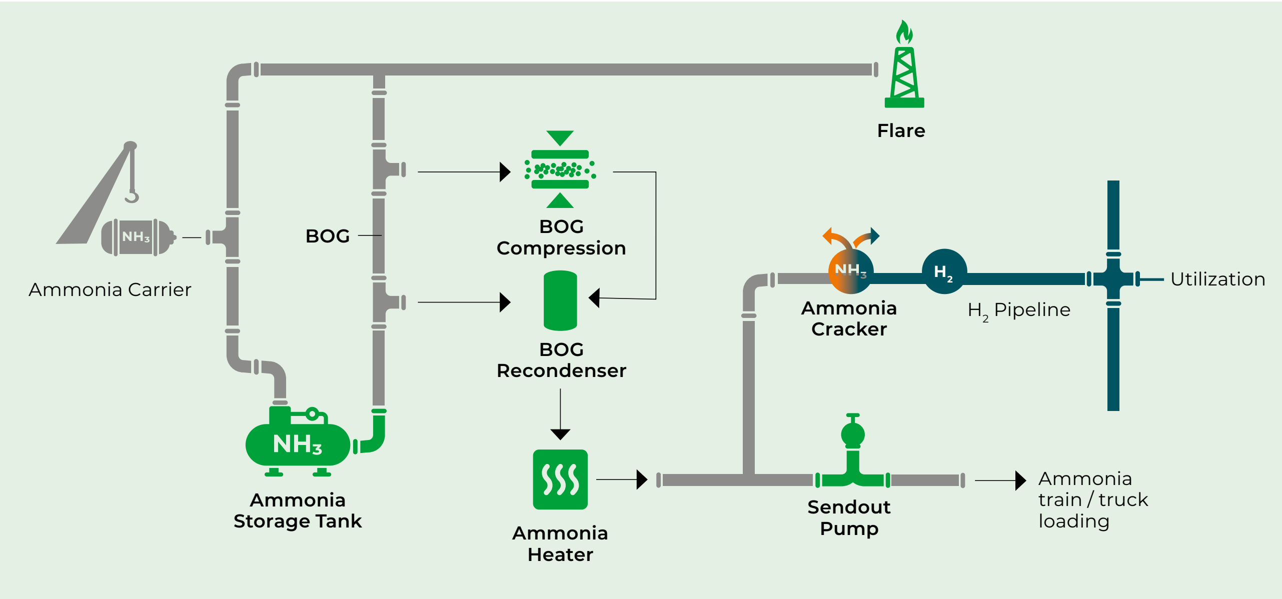
Floating storage and regasification units (FSRU) are increasingly being used to provide a flexible, effective way to receive and process shipments. As elaborated in Annex 3 and 4, their individual capacity can reach 8 bcm per year. Similar to onshore terminals, they can import synthetic methane without the need for repurposing. In general, FSRUs can provide a competitive alternative to onshore terminals when it comes to repurposing them for hydrogen carriers in the short term till 2030. On the other hand, they can still move between global markets. If LNG demand decreases in Europe, they can keep operating for LNG imports in another region, unlike fixed onshore LNG terminals. Accordingly, FSRUs will unlikely be repurposed for importing hydrogen carriers by 2030.

The overall capacities of LNG terminals are 133 bcm in North Sea and Baltic Sea Terminals and 163 bcm in Mediterranean terminals. The volumetric energy density of liquid ammonia is 55%[50] of that of LNG.

49 Black and Veatch (2020). *Converting LNG Import Terminals to Ammonia Import Terminals.* Link

50 Volumetric energy density = LHV x density (kg/m³) at operating conditions. For LNG = 470 kg/m³ x 13.5 kWh/kg, for ammonia = 681 kg/m³ x 5.167 kWh/kg = 55% of LNG / 1 bcm LNG = 9.8 TWh → 1 bcm ammonia = 5.4 TWh → 66% of (1 bcm ammonia) = 3.5 TWh → Mass of ammonia = 0.68 Mt → Mass of cracked ammonia = 0.51 Mt
Mass of hydrogen injected in the grid = 18% x 0.51 = 0.092 Mt
Therefore, 1 bcm LNG will have a potential capacity of importing 0.092 Mt of hydrogen from ammonia

Figure 10: Repurposing LNG terminal to ammonia[51]



The energy content of ammonia is calculated considering that 65%[52] of LNG terminal import capacities are utilised (the foundation design of an LNG tank cannot accommodate higher than 65% of its volume when used for ammonia).[53] After considering 25% losses in cracking and with a hydrogen content of 18% per kg of ammonia, the import capacity for hydrogen is calculated. This would result in a total import of 91 Mt of ammonia in North Sea and Baltic Sea terminals and 111 Mt in Mediterranean terminals. Considering energy losses in cracking[54,55], the potential hydrogen amount injected in the grid will be 12 Mt in North Sea and Baltic Sea terminals and 15 Mt in Mediterranean terminals. Total terminal imports capacities of hydrogen can reach 27 Mt.

Terminal Repurposing Cost Estimates

The cost of converting an LNG import terminal to meet ammonia requirements includes engineering, equipment, materials, and civil works to dismantle and remove items and install new materials and equipment. Investments in repurposing an LNG terminal to become "ammonia ready" are roughly estimated as 20% of its CAPEX, as stated by an interviewed terminal operator.[56] This estimate is comparable to a recent analysis of Black and Veatch.[57]

Table 4 shows the impact of installed equipment and material costs, including engineering work required and item removal. Absolute CAPEX estimates are currently not available as repurposing projects are still in planning phases. The estimates in the table are shown relative to CAPEX of an existing LNG import terminals, which typically costs $500 million or more, and $250-400 million for an FSRU, depending on their regasification capacity, the amount of storage included, and the associated infrastructure.[58] Converting an existing LNG import terminal to an ammonia-ready terminal results in a CAPEX increase of 11–20 %.

51 Black and Veatch (2020). *Converting LNG Import Terminals to Ammonia Import Terminals.* Link
52 Black and Veatch (2020). Converting LNG Import Terminals to Ammonia Import Terminals. Link
53 Because ammonia is heavier in its liquid form than LNG. Approximate ratio between natural gas density and ammonia density = 450 kg/m³ ÷ 682/kg/m³ = ~65%
54 Mass of cracked ammonia = 67 Mt in North Sea and 128 Mt in Mediterranean terminals
55 US Department of Energy (2006). *Potential Roles of Ammonia in a Hydrogen Economy.* Link
56 Interview with Uniper – Held on 21 July 2022
57 Black and Veatch (2020). *Converting LNG Import Terminals to Ammonia Import Terminals.* Link
58 US Department of Energy (2018). Global LNG Fundamentals. Link

Table 4: CAPEX breakdown for converting LNG import terminals to ammonia import terminals and for designing (newly) ammonia-ready LNG import terminals

Modified or Replaced Components	Converting Existing LNG Import Terminals to Ammonia-Ready LNG Import Terminals			Newly built Ammonia-Ready LNG Import Terminals	
Impacted Systems LNG Import	Component CAPEX of Terminal CAPEX (%)	Modification Cost Impact on each component (%)	Total CAPEX Increase (%)	Component CAPEX of Terminal CAPEX (%)	Total CAPEX Increase (%)
Storage tank	45 – 50	3.0	1.0 – 1.5	45 – 50	2.0 – 2.5
BOG system	10 – 15	5.0 – 8.0	5.0 – 8.0	10 – 15	3.0 – 6.0
Pumps	3.0 – 5.0	1.0 - 3.0	1.0 – 3.0	3.0 – 5.0	0
Piping	5.0 – 10	40	2.0 – 4.0	5.0 – 10.0	0.5 – 1.0
Instrument and control system	3.0 – 5.0	70	2.0 – 3.5	2.0 – 4.0	1.0 – 2.0
Others: civil, electrical work, etc.					
Total			**11.0 – 20.0**		**6.5 – 11.5**

Newly built LNG import facilities can be designed to be ammonia-ready with less required modifications. The CAPEX increase of newly built ammonia-ready terminals ranges accordingly from 6.5–11.5%. In the latter case, the CAPEX increase from initial LNG terminal investments is explained by pre-investment plannings required for ammonia-ready terminals. Being a new investment, the absolute value of CAPEX increase in the latter case is higher than that of repurposing already existing terminals.

2.3 Total import capacities

Based on the estimates in the previous sections, the potential hydrogen import capacity across all corridors could reach 105 Mt in the long term (see Table 5). This is a theoretical estimate of all available capacities of existing import infrastructure under the assumption of repurposing all of them for hydrogen. In reality, only a small fraction can realistically be made available by 2030 to meet the target of 10 Mt of hydrogen imports.

Given the announcements by developers, it is likely that the dedicated hydrogen carrier terminals (4.4 Mt from synthetic methane, ammonia, methanol) can be realised before 2030. Therefore, additional infrastructure dedicated to hydrogen imports is needed to reach the 10 Mt target set out by REPowerEU. Some of the gap is expected to be closed by LOHC. Repurposing natural gas pipelines and LNG terminals could further close the gap. For example, repurposing one natural gas pipeline in the Mediterranean corridor and one in the North Sea corridor would already suffice to reach a hydrogen import capacity exceeding 10 Mt. While sufficient hydrogen import capacities could be developed by 2030 it is critical that renewable and low-carbon hydrogen production projects in exporting countries are realised in time to guarantee supply.

Table 5: Summary of overall potential import capacities

Transport option	Imports capacity potential (Mt of hydrogen)
Dedicated hydrogen carrier terminals	4.4
North Sea pipelines	31
Mediterranean pipelines	15
Ukraine pipelines	28
North Sea and Baltic Sea terminals	12
Mediterranean terminals (including Atlantic terminals)	15
Total	**105**

2.4 Storage

Large-scale storage facilities will be an essential component of hydrogen import infrastructure. Imports that cannot feed directly into the EHB can either be stored for later injection and use or can be stored within the EHB. Future hydrogen storage enables constant delivery of energy to customers, balances seasonal differences in demand and production, allows for more efficient pipeline infrastructure investment and provides backup in periods of low renewable hydrogen production.

Today, natural gas is stored in large geologic structures underground such as depleted oil and gas fields, aquifers, salt caverns, and rock cavern at enormous volumes. Table 6 shows the natural gas storage potential in various underground structures in Europe. It has been demonstrated that hydrogen can be stored in salt caverns.[59] In addition to the large-scale storage potential in terms of quantity, salt caverns offer a safe and loss-free hydrogen storage.

The ramp-up of the hydrogen market in Europe is expected to be concentrated around several industrial clusters. The North Sea corridor is one of these clusters, where storage will play a crucial role to facilitate, beside domestic production, the imports and supply of hydrogen. Salt caverns are mostly concentrated near the North Sea corridor.[60] An economic advantage of deploying hydrogen storage in this area is the use of existing assets, which could be repurposed, and capabilities developed for natural gas storage.

Repurposing could take anywhere from 1 to 7 years.[61] Further, not all salt caverns, depleted gas fields, and aquifers are expected to be converted for hydrogen because a portion of storage capacity will likely remain dedicated to storing natural gas and biomethane, and some may be converted to CO_2 storage for carbon capture and storage (CCS) applications. An average salt cavern with a diameter of 60 m, a height of 300 m and a filling pressure of 175 bar has a capacity of 100 million m^3. Applying the same calculations of equivalent hydrogen energy density, this corresponds to an energy quantity of 300 GWh for hydrogen storage.[62]

59 In Teesside salt field (25 GWh), UK and in Clemens Dome, Moss Bluff and Spindletop (~90 to 120 GWh) in Texas salt domes, United States. Based on Elegancy (2020). *Theoretical capacity for underground hydrogen storage in UK salt caverns.* Link
60 Caglayan et al. (2020). *Technical potential of salt caverns for hydrogen storage in Europe, International Journal of Hydrogen Energy, Volume 45, Issue 11* Link
61 GIE (2021). *Picturing the value of gas storage to the European hydrogen system.* Link
62 Neuman Esser. *Storing Hydrogen (accessed in September 2022).* Link

Table 6: Technical working gas volume and number of underground gas storage facilities per type[63]

	Operational		Under construction		Planned		Total	
	TWh	No.	TWh	No.	TWh	No.	TWh	No.
Aquifer	64.5	22.0	0.0	0.0	0.0	0.0	64.5	22.0
Depleted gas fields	717.6	70.0	9.4	1.0	66.2	11.0	793.2	82.0
Rock cavern	0.1	2.0	0.0	0.0	0.0	0.0	0.1	2.0
Salt cavern	175.5	52.0	0.7	0.0	19.0	2.0	195.2	54.0
Total	**957.7**	**146.0**	**10.0**	**1.0**	**85.0**	**13.0**	**1,053.0**	**160.0**

The EHB will require large-scale storage to function effectively and efficiently. Hydrogen storage capacity requirements have been preliminarily estimated for around 70 TWh by 2030, with a growing storage potential to around 450 TWh in 2050.[64] Given the current gas storage capacities in Table 6, hydrogen storage requirements by 2030 will be equivalent to approx. 40% of existing storage capacity in salt caverns. This is a significant part of operating gas capacity across existing salt caverns in Europe. It is highly unlikely that such significant capacity will be converted within the coming years, given the time required for conversion and the remaining need for natural gas storage to meet its 2030 storage requirements. Furthermore, salt cavern capacity is mostly limited to only countries in the North Sea corridor. It is accordingly insufficient to meet hydrogen storage demand in 2030, by repurposing salt caverns for storing 70 TWh of hydrogen.[65] Therefore, next to repurposing existing sites, new sites should be developed for hydrogen storage in both short and long terms. In terms of costs, according to various studies,[66] hydrogen storage in salt caverns would add 5-20 €/MWh to the levelised cost of hydrogen.[67]

In the medium term (after 2030), the EHB could start to interconnect the North Sea corridor with other industrial clusters, both intra-country and cross-border. These developments could also support the large-scale integration of renewables in the regions, particularly offshore wind, with hydrogen storage as a critical component. Most of the existing hydrogen storage assets would start serving broader areas beyond the initial valleys. On the long term (by 2040), industrial clusters will be interconnected, facilitating the transmission of hydrogen across regions and member states. More natural gas storage would need to be repurposed for hydrogen, and the interconnectivity of the network will enable the use of storage for imports from other corridors. The overall hydrogen infrastructure, including storage, will enable a better hydrogen price convergence between the interconnected regions and the already established industrial clusters.

63 Gas Infrastructure Europe (GIE). *GIE Storage Map (accessed in September 2022).* Link
64 GIE (2021). *Picturing the value of gas storage to the European hydrogen system.* Link
65 GIE (2021). *Picturing the value of gas storage to the European hydrogen system.* Link
66 Agora: No regret Hydrogen (2021); Energy Transitions Commission: Making the Hydrogen Economy Possible (2021); R.K. Ahluwalia (2019); DNVGL: Hydrogen in the Electricity Value Chain (2019); Lazard LCOS Analysis (2020); Schmidt et al. (2019)
67 European Hydrogen Backbone (2021). *Analysing future demand, supply, and transport of hydrogen.* Link

3. Certification, permitting and standardisation

Key messages

- To meet the European target of up to 10 Mt of hydrogen imports by 2030, there should be a larger focus on fast-tracking, accelerating, and standardising permitting for hydrogen import infrastructure.
- A consistent implementation of sustainability criteria for hydrogen (carriers) across the market should be achieved from the start, including voluntary schemes and guidelines on how this will be audited for all involved stakeholders in the supply chain.
- When facilitating imports and transport of hydrogen in the EU, standardisation of gas quality and purity is required across borders.

To enable and accelerate international trade of hydrogen three preconditions are important:

- Transparent criteria and certification procedures for renewable and low-carbon hydrogen
- Streamlined and accelerated permitting procedures for key hydrogen import infrastructure
- Harmonised (gas) quality standards to produce, transport and use hydrogen and hydrogen carriers

This chapter explores how these preconditions can be met.

3.1 Regulation & certification

As more projects will be developed to produce renewable and low-carbon hydrogen, the need for rapid implementation of sustainability criteria and accompanying auditing and certification schemes emerges. There will be two delegate acts supplementing the Renewable Energy Directive (RED II) further defining the sustainability criteria for hydrogen:

- Delegated Act on Art. 27 of RED II[68] sets out requirements for renewable electricity used to produce renewable fuels of non-biological origin (RFNBO) (e.g., renewable hydrogen).
- Delegated Act on Art. 28 of RED II[69] aims to establish a methodology to assess greenhouse gas (GHG) emission savings from RFNBO, recycled carbon fuels[70] and low-carbon hydrogen.

Importantly, the European Parliament has voted through Amendment 13 to RED II's Art. 27(3) that puts the RFNBO production requirements (which are much diluted compared to the proposed delegated act) directly into the RED II text and removes the reference to a delegated act (on September 14, 2022). If the EU Parliament's position would become law, the additionality, temporal, and geographical correlation requirements would all become much less stringent. Thus, it is important to note that both delegated acts are still under preparation and have not been adopted yet. RED II includes a 70% GHG emission savings threshold for low-carbon fuels (including renewable and low-carbon hydrogen) compared to a fossil fuel comparator, which corresponds to GHG intensity of less than 3.4 kg CO2eq/kg of hydrogen[71]. It is important to note that the emission threshold is based on lifecycle emissions, including emissions from production, transport and use. Emissions from transport are particularly relevant for shipping of hydrogen and hydrogen carriers.

Figure 11: Different cases for hydrogen production

Case 1

Average gird electricity
Renewable share of grid mix = renewable share of H_2

Case 2

Direct connection
100 % renewable H_2, but:

- Renewable generation must be new

Case 3

Renewable grid electricity
100% renewable H_2, either:

- RFNBO production located in bidding zones with >90% RES share in grid mix, or
- RNFBO production must conclude PPA(s) fulfilling additionality, temporal and geographical correlation, or
- Surplus electricity

68 European Commission (2022). *Production of renewable transport fuels – share of renewable electricity (requirements).* Link
69 European Commission (2022). *Renewable energy – method for assessing greenhouse gas emission savings for certain fuels.* Link
70 Recycled carbon fuels are liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin.
71 Hydrogen Europe (2020). *Clean Hydrogen Monitor 2020.* Link

The Delegated Act on Art. 27 differentiates between three cases of hydrogen production, which are shown in Figure 11.

Case 1 is the default accounting method unless Case 2 or Case 3 requirements are fulfilled. Under this default case, the renewable electricity share in the grid mix (calculated as average from 2 years prior) determines the RFNBO share of the total hydrogen produced in the electrolyser.

Case 2 relates to a direct connection between renewable electricity installations and hydrogen production. This can be achieved either through an isolated direct connection, where electricity is consumed by the hydrogen production facility or curtailed, or by a direct connection plus a grid connection.

Case 3 relates to grid connected production aiming to produce 100% RFNBO, without being directly connected to RES. Two options exist here. First, RFNBO production located in bidding zones with over 90% share of RES in their electricity generation can automatically count all the hydrogen produced as RFNBO (the maximum amount of operation hours cannot exceed 8760*% RES share in the previous calendar year). Second, if the average RES share is below 90%, a power purchase agreement(s) (PPA) must be in place between renewable electricity producer(s) and the fuel producer. In addition, the following criteria apply:

- **Additionality** of the renewable electricity production. The fuel producer needs to add to the renewable electricity deployment or to the financing of renewable energy.

- **Temporal correlation** between the electricity and the hydrogen production. The producer will have to prove if there has been renewable generation or an injection to a storage facility to match the hydrogen production, but the timestep to which this must be proven is still to be finalized.[72]

- **Geographical correlation** between the electricity and the hydrogen production. The rational is to avoid grid congestion between the place where the renewable electricity is produced and the location where the renewable hydrogen is produced.

- **Surplus electricity** can be consumed by RFNBO producers without the need for a PPA (and compliance with the above requirements). Such surplus electricity is defined as consumption that reduced the need for redispatch of RE plant and evidence (of that) from a national TSO is required.

These criteria are set to apply regardless of whether the production takes place in- or outside the EU. Complying with the sustainability criteria for hydrogen may be challenging for third countries as their electricity market is set up different. To solve this challenge, transparent and pragmatic guidance is needed for investments to take place. Next to this, sharing lessons learned should be key across different regions.

3.1.1 Voluntary schemes

Voluntary schemes need to be developed to verify compliance with the sustainability criteria (as is already the case for bioenergy today) and the rules on traceability and auditing. The European Commission recognises voluntary schemes that cover the criteria and the "standards" that production companies need to demonstrate compliance with.

Currently, the European Commission recognises voluntary schemes for bioenergy, but none are recognised yet for renewable and low-carbon hydrogen. Biofuels can only count towards EU renewable energy targets when they are produced according to the sustainability criteria. Voluntary schemes are the main mechanism used by the biofuels market to demonstrate compliance with the sustainability criteria.

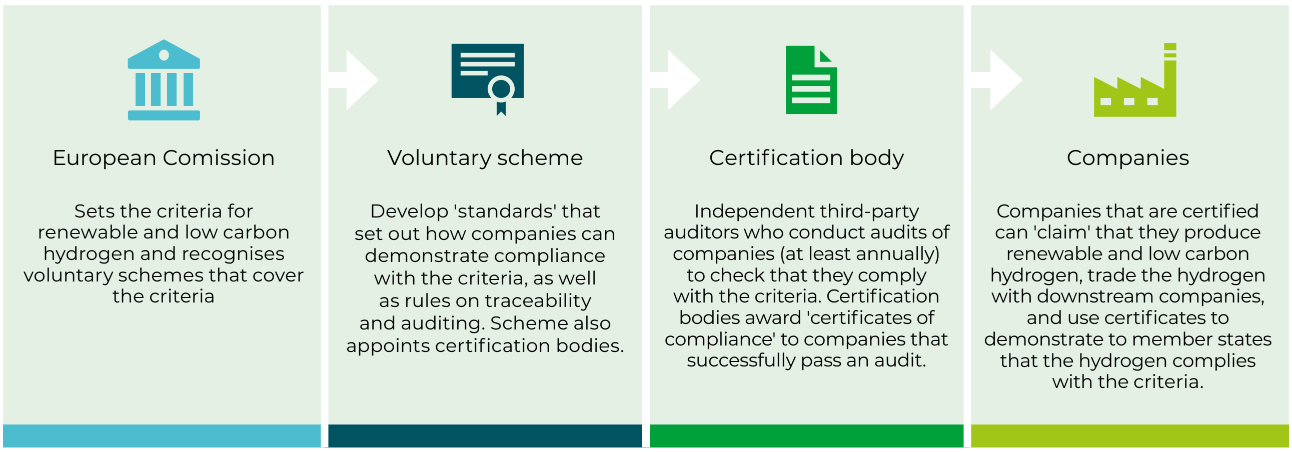
72 Except for low electricity prices (< 20€/MW) during the production hour.

Examples of these schemes for biofuels are the International Sustainability and Carbon Certification (ISCC EU) and the Roundtable for Sustainable Biomaterials (RSB EU).[73] It is anticipated that such schemes could extend their scope to also cover hydrogen production. However, there are also renewable and low-carbon hydrogen standards in place or in development that could be set up as voluntary scheme, such as CertifHy (Fuel Cells and Hydrogen Joint Undertaking) and CMS 70 (TÜV SÜD)[74]. There could be a variety of players in place to certify hydrogen, as there are also multiple schemes for biofuels. However, in different regions of the world, different regulations might call for potential exporting companies to certify their products more than once. This could mean that producers already need to decide in the concept phase of the project with whom they aim to trade hydrogen. This could result in limited flexibility and increased efforts and thus higher prices for the products. It might also create dependencies between regions making it key to harmonize standards and certification on a global scale.[75]

Voluntary schemes appoint certification bodies, which employ independent third-party auditors (see Figure 12). The auditors are responsible for auditing the entire value chain. Audits should be done at least annually to check compliance with the criteria. Certificates of compliance are awarded to companies that pass the audit. Certified companies can than claim that they produce renewable or low-carbon hydrogen.

Tracing of renewable and low carbon hydrogen is critical to ensure that the sustainability criteria are met and double counting is avoided. A so-called single Union database is currently being developed to enable tracing liquid and gaseous renewable and recycled carbon fuels. Extending the Union database to also cover hydrogen would be one way to ensure robust accounting of renewable and low-carbon hydrogen. To assess whether the produced hydrogen stays below the emissions threshold of 3.4 kg CO_2/kg of hydrogen[76] the certificate with the cumulative GHG intensity value travels with the hydrogen-molecule down the full supply chain, from production to use. This process needs to be digitised in the Union database or an alternative, similar database, to ensure transparency and traceability.

Figure 12: Roles in hydrogen (carriers) certification [2022 Guidehouse]



73 European Commission. *Voluntary schemes (accessed in September 2022).* Link
74 Dena & World Energy Council (2020). *Global Harmonisation of Hydrogen Certification.* Link
75 Dena & World Energy Council (2020). *Global Harmonisation of Hydrogen Certification.* Link
76 Hydrogen Europe (2020). *Clean Hydrogen Monitor 2020.* Link

3.1.2 Recommendations on certification

Transparent and reliable certification of hydrogen is necessary. To accelerate the certification of renewable and low-carbon hydrogen production, several measures should be taken. Firstly, more than a decade of experience in biofuels certification should be leveraged and built upon. A large part of the certification processes and structure can be utilised for hydrogen, although the additional production criteria for renewable hydrogen will require a thorough understanding of the electricity markets and technical skills across the different parties that will be involved in hydrogen certification. This means that capacity building and knowledge sharing should start early, for instance by hosting training sessions for auditors and other stakeholders.

Voluntary schemes should facilitate an efficient certification process. This could be done by making checklists, monitoring manuals and templates available for companies that want to be certified. There may be a need for flexibility in the first years after adopting the sustainability criteria to allow for lessons learned. With biofuels, it is common practice that if a company does not fully comply, they are allowed to conform over time (e.g., improve next year) before the auditor suspends or even withdraws certification. This can, on a shorter timeframe, already be facilitated by mass balance requirements over a period of three months, where you can correct or compensate for your shortcomings at an earlier stage. This would allow for some flexibility in the certification procedure.
The key policy aim should be to ensure consistent implementation of criteria for renewable and low-carbon hydrogen across the market from the start. To achieve this, there will be a strong need for open cooperation and communication between all involved stakeholders as the market develops, and a willingness to learn from all sides to ensure that systems can evolve to meet the needs of a market that is expected to develop rapidly.

3.2 Permitting

Accelerating the development of cross-border infrastructure requires substantial simplification and shortening of planning and permitting procedures. As stated in the REPowerEU plan, production and integration of renewable energy projects should be considered an overriding public interest and qualify for the most favourable procedure available for planning and permitting. For projects with third countries the Projects of Mutual Interest (PMI) process should be used to rapidly develop key infrastructure projects for hydrogen imports. Moreover, other projects that do not qualify as PMI but enable the scaling-up hydrogen imports to meet the REPowerEU targets should also be subject to favourable permitting procedures.

Further actions to accelerate permitting include:

- Simplifying existing rules for planning and permitting in member states, for instance by rapid mapping, assessment and allocation of suitable land for renewable energy projects.
- Implementation of one-stop-shop principles with a single point of access for developers with the respective authorities.
- Effective implementation of existing rules on the national, regional, and local levels (e.g., by capacity building in local municipalities, which often issue permits, and defining the maximum time limit for permit processing).

77 Taylor Wessing (2022). *LNG Projects in Germany: The LNG Acceleration Act (accessed in September 2022)* Link

On top of this, political willingness and close consultation with relevant stakeholder (e.g., civil society NGOs) is needed to make large-scale infrastructure projects a success. A good example for political willingness is the German LNG Acceleration Act[77], an emergency act prioritising LNG import infrastructure to improve energy security (see text box below).

German LNG Acceleration Act:
To reduce Germany's dependency on Russian natural gas, the German government has passed this Act on the 19th of May 2022. The intention of this Act is to simplify licensing procedures for LNG terminals and associated facilities and the procurement law for LNG projects. Permitting procedures which normally would take up to a year were shortened to a few days. As a result, first FSRUs will become operational already in Germany already in the Winter of 2022/23 and land-based LNG terminals in 2026.

3.3 Standardisation

To facilitate hydrogen imports standardisation is required across borders. As different applications require different purity standards for hydrogen, a hydrogen gas quality standard set across the EU is desirable for facilitating cross-border flows as part of a possible set of interoperability rules.[78]

These purity standards can differ based on:

- Supply and demand composition (i.e., different production technologies produce hydrogen of different levels of quality, different end-use technologies have various impurity tolerances).
- Specific domestic hydrogen infrastructure (e.g., different types of storage might result in different impurities).

Currently, there is no general, European-wide hydrogen purity specification in place, but different suggestions have been made, for instance by Gasunie[77] and the UK gas grid for heat applications.[80] Typically, the minimum mole fraction is set to be 98%. Locally, for specific costumers' clusters, this could be up to 99.5%.[81] Next to this, maximum impurity concentrations are defined for both pipeline degradation as well as safety requirements.

In general, all impurities could be removed from hydrogen by different production and purification routes, at varying costs. The necessity and placement of these purification steps depends on the hydrogen production methods, transport means and end-use applications. In order to facilitate imports, a lean cross-border coordination on gas quality and purity is needed to efficiently ramp-up decarbonisation. As mature solutions are available to cope with specific purity needs in certain industries, market segmentation based on purity constraint is not needed.
If hydrogen is used to produce fuels, it is important to note that the situation might change. As it is not yet clear which energy-carriers will be utilised in which situations, additional standardisation specifications might be required, for instance if dedicated ammonia pipelines would be used at scale.

From a technical perspective, there multiple possibilities and suitable solutions to meet any hydrogen gas quality standard. However, before cross-border transport and imports can be facilitated, clear regulatory guidance is needed rather sooner than later.

78 European Commission (2021). *Assistance to the impact assessment for designing a regulatory framework for hydrogen.* Link
79 Gasunie (2020). *"Webinar Hydrogen Infrastructure."*
80 DNVGL (2019). *Hydrogen Purity – Final Report. Department for Business, Energy & Industrial Strategy.* Link
81 European Commission (2021). *Assistance to the impact assessment for designing a regulatory framework for hydrogen.* Link

4. Supporting international hydrogen projects

Key messages

- Currently, no dedicated funding instrument for hydrogen imports exist on EU level. However, existing support mechanism can accelerate the ramp up of the hydrogen economy across Europe, thereby also incentivising imports.
- Without long-term offtake contracts, it will be difficult to make investment in hydrogen production bankable in potential export regions. H2Global is a positive example on how to de-risk investment on the supply and demand side.
- International hydrogen partnerships are important to accelerate hydrogen imports to Europe. Existing partnerships should be strengthened and new partnerships with potential exporters established – both on a bilateral and multilateral level.

Renewable and low-carbon hydrogen is a niche market today. To scale it up, massive investments are needed in the coming years. While private investments will play a dominate role, dedicated funding is also needed to make projects bankable. The REPowerEU plan put forward various instruments dedicated to support hydrogen research, transport, and infrastructure projects. In addition, member states are announcing an increasing number of support schemes for hydrogen. While most support schemes are focused on EU and national hydrogen projects, schemes like H2Global are designed specifically for imports. Nonetheless, also EU and national hydrogen support mechanisms can facilitate imports, e.g., through funding of import terminals or pipelines.

4.1 EU funding schemes

There are multiple funding mechanisms on EU level are being announced, e.g., the "European Hydrogen Bank" will invest over €3 billion in building up the domestic hydrogen market.[82] For hydrogen imports, the REPowerEU highlighted the role of the Connecting Europe Facility – Energy (CEF-E) and the Recovery and Resilience Facility (RRF) in facilitating and securing available funds for hydrogen imports projects. In addition, a third instrument (InvestEU) is proposed as a potential funding option for hydrogen imports.

Table 7 provides an initial outlook of the three support schemes. They are extracted from the Hydrogen Public Funding Compass[83], based on their potential to support hydrogen imports projects. Each scheme has its own coverage range of projects, selection criteria and call details. This shall be further investigated in more details for specific imports projects, according to their unique characteristics; location, infrastructure sizes, quantities of imports...etc.

82 Recharge (2022). *'From niche to scale' | EU launches €3bn European Hydrogen Bank with a bang but keeps quiet about the details (accessed in September 2022).* Link

83 It is the official EU funding compass for hydrogen projects. It compromises 10 major EU programs, out of which three were selected, where hydrogen imports projects are relevant to fund projects on a country-level Link

Table 7: Initial outlook on mechanisms that could support hydrogen imports

	Connecting Europe Facility – Energy (CEF-E)[84]	Recovery and Resilience Facility (RRF)[85]	InvestEU[86]
Objectives	Accelerate investments in Europe's transport, energy and digital infrastructure networks. It is a key EU funding instrument for targeted infrastructure investment at European level.	Mitigate the economic and social impact of the COVID-19 crisis and make European economies and societies more sustainable, resilient and better prepared for the challenges and opportunities of the green and digital transitions. The European Commission proposed to make targeted amendments to the RRF Regulation to integrate dedicated REPowerEU chapters in member states' existing recovery and resilience plans.	Provide crucial support to physical and human capital investment, especially to recover from the pandemic and to promote the EU's policy priorities, such as making the EU climate neutral by 2050 and achieving its digital transition.
Relevance for hydrogen imports	No explicit funding for international hydrogen projects. However, funds could be used to for infrastructure projects the also benefit imports, e.g., terminals or cross-border pipelines.	No explicit funding for international hydrogen projects. However, many aims of the RRF relate to the ramp-up of the hydrogen economy also benefiting imports, including: • Demonstration and first deployment of new technologies (e.g., hydrogen-based technologies) • Flagship projects in the context of the National Hydrogen Strategy • Preparation and adoption of a national roadmap for developing the potential of hydrogen technologies	Similar to the CEF-E and RRF, no direct investments are foreseen for international hydrogen projects. InvestEU can support development of the hydrogen economy by promoting clean and sustainable transport modes, energy storage, and improving energy infrastructure interconnection levels
Financing details	CEF will dedicate at least 60% of its budget to EU climate objectives. Projects must qualify as PCIs.[87]	Funding is disbursed in the form of non-repayable financial supports and loans. Once the national recovery and resilience plans are approved, the Commission can pay 13% of total support upfront to kick start the recovery. Further disbursements are made, as EU countries demonstrate that they have reached milestones and targets specified in the Council implementing decision approving their plan.	The funds are allocated under the indirect management scheme through the European Investment Bank Group (75% of the guarantee) and other implementing partners. The InvestEU fund may provide funding in the form of grants and loans. €372 billion
Budget	€5.84 billion, out of which 15% should be allocated to cross-border renewable energy projects (which may be increased to 20% should that threshold be reached)	€337.97 billion in grants and €385.85 billion in loans	Demonstration and first deployment of new technologies (e.g., hydrogen-based technologies)
Type of support	A mix of grants, procurement, and financial instruments	A mix of grants, procurement, and financial instruments	A mix of Loan/Guarantee, and other financial instruments
Payment modalities	Lump-sum payments	Performance-based	Lump-sum payments

84 European Commission. Connecting Europe Facility – Energy (accessed in September 2022). Link
85 European Commission. *Recovery and Resilience Facility (accessed in September 2022).* Link
86 European Commission. *European Regional Development Fund, Cohesion Fund and REACT-EU (accessed in September 2022).* Link
87 European Commission. Transparency Platform (accessed in September 2022). Link

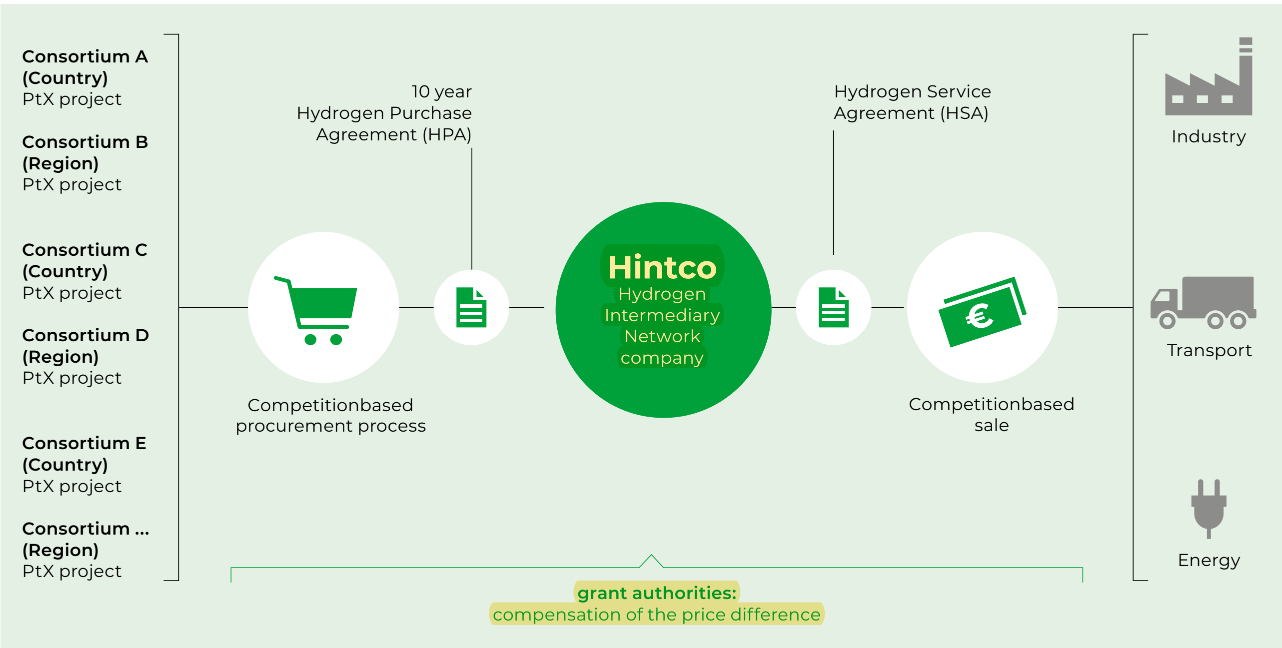
4.2 H2Global as best-practice

H2Global is a centralized renewable hydrogen auction scheme designed to ramp-up the production of renewable hydrogen, renewable ammonia and sustainable aviation fuels at national and international level.[88] It works as a contract for difference covering the difference (CfD) between the lowest possible production cost and the highest willingness to pay. The program uses a double-auction mode, meaning there are separate auctions on the supply and the demand side (see Figure 13).[89] On the supply side, a competitive procurements process results in 10-year hydrogen purchase agreements (HPA) with non-EU producers. On the demand side, short-term hydrogen service agreements (HSA) are established via an annual auction with EU customers. The Hydrogen Intermediary Network Company (HINT.CO) acts as central auctioneer to conclude long-term HPA and short-term HAS. The rationale behind the difference in duration of the contracts reflects the needs of the market actors:

- On the demand side, it is expected that future adjustments to the regulatory framework will increase the off-takers willingness to pay while an increasing number of suppliers may reduce the price. To captures these dynamics, HSA are short-term.
- On the supply side, certainty on long-term revenues is required to make investment decisions, thus 10-year contracts are sensible.

The German Federal Ministry for Economic Affairs and Climate Action provides the funding for first H2Global window. Initially, €900 million is made available to compensate the difference between the HPA and HSA. Additional funds of €3.6 billion are expected in the coming years.[90]

Figure 13: H2Global mechanism[91]



88 H2Global Stiftung *(accessed in September 2022).* Link
89 GIZ (2022). *International green hydrogen funding opportunities – A scoping study*
90 Energate messenger (2022). *Bundesregierung plant knapp 4 mrd. Euro für Wasserstoff (accessed in September 2022).* Link
91 H2Global. *The H2Global Mechanism (accessed in September 2022).* Link

4.3 International cooperation

Europe is a global frontrunner in green technologies, including hydrogen. Several leading hydrogen technology providers are based in Europe, such as ThyssenKrupp, Nel Hydrogen or SunFire. On top of the domestic production potential for hydrogen assessed the EHB initiative[92], there are multiple regions in the world that have abundant renewable energy potential that can be used to produce hydrogen. The combination of leading hydrogen technology providers and plentiful renewables potential is the perfect foundation for mutually beneficial partnerships. In relation to the REPowerEU Plan, such partnerships could help to meet climate targets in an affordable way, while increasing the resiliency of the European energy system by diversifying the supply.

Examples of partnerships focusing on hydrogen include:

- MENA Europe Future Energy Dialogue (MEFED)[93]
- EU and Gulf Cooperation Council: Strategic Partnership with the Gulf
- Bilateral energy/hydrogen partnerships, e.g., between Belgium/Chile[94] and Germany/Canada[95]

These partnerships are important to foster knowledge exchange and develop joint projects. A prime example for a successful partnership is the Hydrogen Task Force[96] between Germany and the United Arabic Emirates which aims to rapidly develop hydrogen value chains between the two countries. As a first tangible result, a shipment of low-carbon ammonia produced by the Abu Dhabi National Oil company arrived in Hamburg in September 2022.[97] The low-carbon ammonia will be used locally to replace natural gas in industrial applications.

92 European Hydrogen Backbone (2022). *Five hydrogen supply corridors for Europe in 2030.* Link
93 MENA Europe Future Energy Dialogue (MEFED) (accessed in September 2022). Link
94 Renewables Now (2021). *Belgium-Chile deal to boost cheap EU green hydrogen supply (accessed in September 2022).* Link
95 Government of Canada (2022). *Canada and Germany Sign Agreement to Enhance German Energy Security with Clean Canadian Hydrogen (accessed in September 2022).* Link
96 Emirati-German Energy Partnership *(accessed in September 2022).* Link
97 Gulf Business (2022). *Abu Dhabi's Adnoc sends firs low-carbon ammonia shipment to Germany (accessed in September 2022).* Link

5. Actions to facilitate hydrogen imports

The current import infrastructure, regulatory framework and the support mechanisms are insufficient to meet the European 10 Mt hydrogen import target by 2030. The following overview provides no-regret actions that should be taken in the short-term to accelerate hydrogen imports.

Infrastructure actions

Integrate import considerations in hydrogen infrastructure planning
More in-depth understanding is required on how import infrastructure impacts the implementation of the EHB and the broader infrastructure planning. This covers not only the actual import via pipelines or ports, but also the transmission and distribution networks on the mainland (e.g., to industrial sites that need to be decarbonised).

Develop new hydrogen import infrastructure at scale and assess the possibility of repurposing existing gas import infrastructure
As hydrogen imports will become more relevant in the coming years, there is a need to have a better view on the technical characteristics and limitations of hydrogen and hydrogen carrier imports. Research focus should be on feasibility and timing of repurposing (parts of) the current infrastructure, as well as on the scale-up of ammonia crackers, as these assets will play a key role in the energy security of Europe in the coming decades.

Regulatory actions

Rapidly implement the hydrogen sustainability criteria and provide clear guidance for exporting countries
To reach the target of 10 Mt of hydrogen imports, adequate regulatory frameworks should be in place as soon as possible. Key are the RFNBO sustainability criteria and the methodology to assess GHG emission savings from RFNBO and recycled carbon fuels, which will provide a clear regulatory framework for hydrogen producers aiming to export to the EU. Related to this, an extension of the Union database to hydrogen or a system similar in nature to the Union database should be set up and voluntary schemes for certification should be developed and recognised urgently. In addition, to allow for free trade with third countries, gas standards concerning the production, use and transport should be aligned.

Simplify and streamline permitting procedures to fast-track infrastructure development and pilots
Hydrogen import infrastructure is not yet available at scale to reach the 10 Mt target. To rapidly develop the required infrastructure, permitting procedures should be simplified and accelerated. Hydrogen import infrastructure can be describe as novel, thus, capacity building along is needed to prevent delays.

Finance and support actions

Develop support mechanism for international hydrogen projects
To facilitate imports, support mechanisms for hydrogen projects, also internationally, should be put in place. This could be done by expanding H2Global across Europe. On top of this, a mechanism should be put in place for offtake contracts to make sure that continuous hydrogen is purchased, and investment decisions are made.

Establish strategic hydrogen partnerships between EU and potential exporting countries
Existing strategic energy partnerships with third countries should be extended to also cover cooperation on hydrogen. In addition, new partnerships need to be established to diversify potential hydrogen exporters. To strengthen international partnerships, knowledge exchange and joint investments in hydrogen projects should be executed.

Annexes

Annex 1: List of pipelines along the three corridors[98]

Pipeline	Pipe Size (inch)	Commissioning Year	Capacity (bcm)	Estimated hydrogen imports capacity (Mt)
Maghreb Europe (Morocco – Spain)	48”	1996	12.0	2.8
MEDGAZ (Algeria – Spain)	24"	2011	8.0	1.8
Galsi Project (Algeria – Italy)	24"	Cancelled	-	-
Transmediterranian (Algeria – Italy)	2 x 48"	1983	33.5	7.7
Green Stream (Libya – Italy)	32"	2004	11.0	2.5
Mediterranean Pipelines Capacities			**64.5**	**15**
Baltic pipe (Norway – Poland)	32"	2023	10.0	2.3
Europipe I (Norway – Germany)	40"	1995	18.0	4.1
Europipe II (Norway – Germany)	42"	1999	24.0	5.5
Franpipe (Norway – France)	42"	1998	19.6	4.5
Norpipe (Norway – Germany)	36"	1975	16.0	3.7
Zeepipe I (Norway – Belgium)	40"	1993	15.0	3.5
Interconnector (UK – Belgium)	40"	1998	25.5	5.9
Balgzand Bacton Line (UK – NL)	36"	2006	19.0	4.4
North Sea Pipelines Capacities			**137.1**	**31**
Transgas		1973	120.0	28
Ukraine Corridor			**120**	**28**
Total			**321.6**	**74**

98 Entsog. Transmission Capacity and System Development Maps (accessed in September 2022). Link

Annex 2: Potential methanol import terminals

Country	Terminal	Type	Status	Storage capacity (kg methanol)	Equivalent hydrogen mass (tonnes)
North Sea Corridor					
Belgium	Engie/Fluxys, Antwerp	E-Methanol	Starting in 2022	8,000	1,008
	Proman, North Sea Port, Ghent	E-Methanol	Planned	44,000	5,544
Germany	Dow, Stade	E-Methanol	Planned	200,000	25,200
Netherlands	OCI/BioMCN, Delfzijl	Bio Methanol	Operational	60,000	7,560
	Nouryon/Gasunie, Delfzil	E-Methanol	Planned	15,000	1,890
	Gidara Energy, Amsterdam	Bio Methanol	Starting in 2023	87,500	11,025
	Enerkem, Rotterdam	Bio Methanol	Planned	215,000	27,090
	Lowlands Methanol, Rotterdam	Bio Methanol	Planned	120,000	15,120
			Total North Sea Capacities	**749,500**	**94,437**
Mediterranean Corridor					
Italy	ENI, Livorno	Bio Methanol	Starting in 2024	115,000	14,490
Spain	Enerkem, Tarragona	Bio Methanol	Planned	220,000	27,720
			Total Mediterranean Capacities	**335,000**	**42,210**
			Total	**~ 1.1 Mt**	**~0.14 Mt**

Annex 3: North Sea and Baltic Sea (LNG) terminals imports capacities[99]

Country	Terminal	Status	Type	Start-up year	Operator	Nominal annual capacity billion m³/ year	LNG storage capacity m³
Belgium	Zeebrugge LNG Terminal	operational	large onshore	1987	Fluxys LNG	11.4	566,000
		Expansion under construction	large onshore	2024	Fluxys LNG	3.9	
		Expansion under construction	large onshore	2026	Fluxys LNG	1.8	
Estonia	Paldiski LNG Terminal	Planned new facility	large onshore	2025	Alexela	2.5	160,000
	TallinnLNG (Muuga)	Planned new facility	large onshore		Liwathon E.O.S.	4.0	160,000
Finnland	Gasgrid	Planned new facility	FSRU	2023	Gasgrid	5.0	
France	Dunkerque LNG Terminal	Operational	large onshore	2016	Dunkerque LNG	13.0	600,000
Germany	Brunsbüttel	Planned new facility	large onshore	2026	Gasunie	8.0	330,000
		Planned new facility	FSRU	2023	RWE	7.5	
	Lubmin FSRU	Planned new facility	FSRU	2023	Deutsch ReGas	5.0	
	Stade	Planned new facility	FSRU	2024	Hanseatic Energy Hub	5.0	
		Planned new facility	large onshore	2026	Hanseatic Energy Hub	12.0	up to 480 000
	Wilhelms-haven	Planned new facility	FSRU	2023	UNIPER	5.0	263,000
		Planned new facility	FSRU	2023	TES, EON, Engie	5.0	
Latvia	Skulte LNG terminal	Planned new facility	FRU + direct link to UGS	2023	Skulte LNG Terminal	1.5	
Lithuania	FSRU Inependence	operational	FSRU	2014	Klaipedos Nafta	4.0	170,000

99 Gas Infrastructure Europe (GIE). LNG Database (accessed in September 2022) Link

Annex 3: North Sea and Baltic Sea (LNG) terminals imports capacities[99]

Country	Terminal	Status	Type	Start-up year	Operator	Nominal annual capacity billion m³/ year	LNG storage capacity m³
Netherlands	Gate terminal, Rotterdam	operational	large onshore	2011	Gate terminal	12.0	540,000
		Expansion under construction	large onshore	2024	Gate terminal	1.5	
		expansion planned	large onshore	2026	Gate terminal	2.5	180,000
	Eemsenergy-terminal	planned new facility	large onshore	2022	Gasunie	8.0	
Poland	GDANSK LNG	Planned new facility	FSRU	2025	GAZ SYSTEM	6.1	170,000
	Swinoujscie LNG Terminal	operational	large onshore	2016	GAZ SYSTEM	6.2	320,000
		Expansion under construction	large onshore	2023	GAZ SYSTEM	2.1	180,000
					Total	**133.0**	**4,119,000**

Annex 4: Mediterranean (LNG) terminals imports capacities[100, 101]

Country	Terminal	Status	Type	Start-up year	Operator	Nominal annual capacity billion m³/ year	LNG storage capacity m³
Croatia	Krk Terminal	operational	FSRU	2021	LNG Croatia	2.6	140,000
		planned expansion	FSRU	2029	LNG Croatia	2.60	300,000
France	Fos Cavaou	operational	Large onshore	2010	Fosmax LNG	8.5	330,000
		planned expansion	large onshore	2022	Fosmax LNG	1.5	
		planned expansion	large onshore	2030	Fosmax LNG	2.0	
	Fos-Tonkin	operational	large onshore	1972	Elengy	1.5	80,000
	Montoir-de-Bretagne*	operational	large onshore	1980	Elengy	10.0	360,000
	Le Havre*	planned new facility	FSRU		TOTAL		
Greece	Dioriga Gas	planned new facility	FSRU	2023	Dioryga Gas	2.5	
	Alexandrou-polis	under construction	FSRU	2023	Gastrade	5.5	153,500
	Thrace	planned new facility	FSRU		Gastrade	5.5	170,000
	Revithoussa	operational	large onshore	1999	DESFA	7.0	225,000
	Argo	planned new facility	FSRU	2024	Medgas	5.2	170,000

100 Gas Infrastructure Europe (GIE). LNG Database (accessed in September 2022) Link
101 Terminals in Cyprus and Malta are excluded

Annex 4: Mediterranean (LNG) terminals imports capacities

Country	Terminal	Status	Type	Start-up year	Operator	Nominal annual capacity billion m³/ year	LNG storage capacity m³
Italy	OLT Offshore LNG Toscana	operational	FSRU	2013	OLT Offshore LNG Toscana	3.6	137,500
	Panigaglia	operational	large onshore	1971	GNL Italia	3.4	100,000
	FSRU 1 - SNAM	planned new facility	FSRU	2023	SNAM	5.0	170,000[102]
	FSRU 2 - SNAM	planned new facility	FSRU	2024	SNAM	5.0	170,000[103]
	Porto Empedocle (Sicilia)	planned new facility	large onshore		Nuove Energie	8.0	320,000
	Adriatic LNG	operational planned expansion	Fixed offshore re-gasification & storage	2009 2024	Adriatic LNG Adriatic LNG	8.6 0.5	250,000
Portugal	Sines*	operational	large onshore	2004	REN Atlantico	7.6	390,000
Spain	Barcelona	operational	large onshore	1969	ENAGAS	17.1	760,000
	Bilbao*	operational	large onshore	2003	BBG	7.0	450,000
	Cartagena	operational	large onshore	1989	ENAGAS	11.8	587,000
	Gijón (Musel)*	built not operational	large onshore	2012	ENAGAS	7.0	300,000
	Huelva*	operational	large onshore	1988	ENAGAS	11.8	619,500
	Mugardos*	operational	large onshore	2007	Reganosa	3.6	300,000
	Sagunto	operational	large onshore	2006	Saggas	8.8	600,000
					Total	**163.1**	**6,742,500**

* Terminals in France, Portugal, and Spain at the Atlantic Ocean

102 Finanza, Floating regasifiers, Snam takes over a second ship of 5 billion cubic meters. It will be off the coast of Ravenna (accessed in October 2022), Link

103 Snam, Floating Storage and Regasification Units (FSRU): *Everything You Need To Know (accessed in October 2022)*, Link