ACER
European Union Agency for the Cooperation of Energy Regulators

PUBLIC

Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure:

Overview of existing studies and reflections on the conditions for repurposing

16 July 2021

ACER
European Union Agency for the Cooperation of Energy Regulators

TABLE OF CONTENTS

1. BACKGROUND

In the context of decarbonisation of the energy system, there has been a very rapid increase in interest among industry, government, and other stakeholders over the past two years regarding the potential use of hydrogen (H2) as a green energy vector. In addition to the proliferation of published national hydrogen strategies, starting with Japan in 2017, and followed by South Korea (2019), New Zealand (2019), Australia (2019), Netherlands (2020), Norway (2020), Portugal (2020), Germany (2020) and other EU countries, on 8 July 2020 the European Commission (EC) presented a hydrogen strategy for the Union. The EC strategy notes that today, neither renewable hydrogen nor fossil-based hydrogen with carbon capture are cost-competitive against fossil-based hydrogen. However, the costs of renewable hydrogen are expected to quickly decrease. Electrolyser investment costs, which represent over a half of the hydrogen production costs, have already decreased by 60% in the last ten years[1], and are expected to halve by 2030 compared to today, with economies of scale being the main driver of the decreasing costs. In regions where renewable electricity is cheap and in excess, electrolysers are expected to be able to compete with fossil-based hydrogen by 2030.

The EC strategy on hydrogen notes that the specific infrastructure needs will depend on the patterns of development of production and use of hydrogen. Hydrogen demand will largely be met by localised production in the initial phase (in the form of industrial clusters or hydrogen production destined for refuelling stations). In the long term, there might be a need to transport hydrogen over long distances throughout Europe (to connect hydrogen supply and demand and allow greater competition in the market), and even from third countries. Two main options are considered for transporting hydrogen via pipeline:

- Building new hydrogen-carrying pipelines;
- Repurposing existing natural gas (NG) pipelines for the transportation of pure hydrogen.

In addition, the potential of using NG underground storage and LNG terminals for pure hydrogen or other hydrogen carriers is also reviewed.

2. OBJECTIVES

The main objective of this document is to:

- Collect and analyse information from different sources and types of stakeholders on the state-of-the-art for transporting hydrogen via repurposed gas infrastructure or new hydrogen pipelines;
- Collect insights on key technical aspects and cost estimates.

[1] Based on cost assessments of IEA, IRENA and BNEF. Electrolyser CAPEX to decline from €900/kW to €450/KW or less in the period after 2030, and €180/kW after 2040.

This note follows-up on ACER/CEER Hydrogen White Paper[2] and ACER report on hydrogen and biomethane blending and network adaptations[3].

The note brings together studies carried out by a variety of stakeholders, and dives into the issue of repurposing from an infrastructure angle, with a focus on technical and cost aspects. We provide this review of studies on a "best effort" basis, but cannot guarantee the accuracy, the consistency or the completeness of the information included in the note. Therefore, neither ACER nor any NRA may be held responsible for the use of the information contained in the note; the views quoted or presented in this note do not necessarily represent the views of ACER. This document contains links and multiple references to external websites, for which content ACER is not responsible. In addition, studies, initiatives and developments related to repurposing of NG for pure hydrogen are popping-up on a continuous basis from different quarters, therefore the note should be understood as a "living document" which may become soon obsolete and in need of further updates. We invite stakeholders to provide feedback on the note, in particular to signal important studies on the subject-matter not included in this review, in view of possible further updates of the document.

Section 3 (Main Findings) summarises the studies reviewed, and looks into the technical possibilities of repurposing different types of natural gas infrastructure for pure hydrogen. It continues with a review to the estimations of the investment costs of repurposing, the projected transportation costs of hydrogen, and looks at possible investment needs. While most studies get to similar conclusions about the technical possibilities of repurposing and associated costs, it seems that some studies offer quite divergent visions on the magnitude and extension of any future pure hydrogen network. This chapter closes with a few considerations on safety related to the operation of pure hydrogen, and on the challenges related to the network operation of pure hydrogen networks based on hydrogen produced from RES.

In Section 4 (When and Where to Repurpose), there is a reflection on possible technical and hydrogen market conditions triggering the repurposing of NG pipelines to pure hydrogen, and on the likelihood and uncertainty that those conditions would be met across Europe. These are preliminary views from regulators, and would require of further studies and discussion with all stakeholders involved on this topic.

3. MAIN FINDINGS

3.1 Summary of Literature Review

Of the 24 studies reviewed, 6 (25%) were performed by the gas industry, 7 were commissioned by public institutions, including 4 by the European Commission, (as well as by the IEA and Ministries), 6 (25%) were performed by the hydrogen industry and industry

2 https://www.acer.europa.eu/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf

3 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen%2C%20Biomethane%2C%20and%20Related%20Network%20Adaptations.docx.pdf

partnerships, 2 by academia, one is a report dealing with standards, and two reports are published by a think tank.

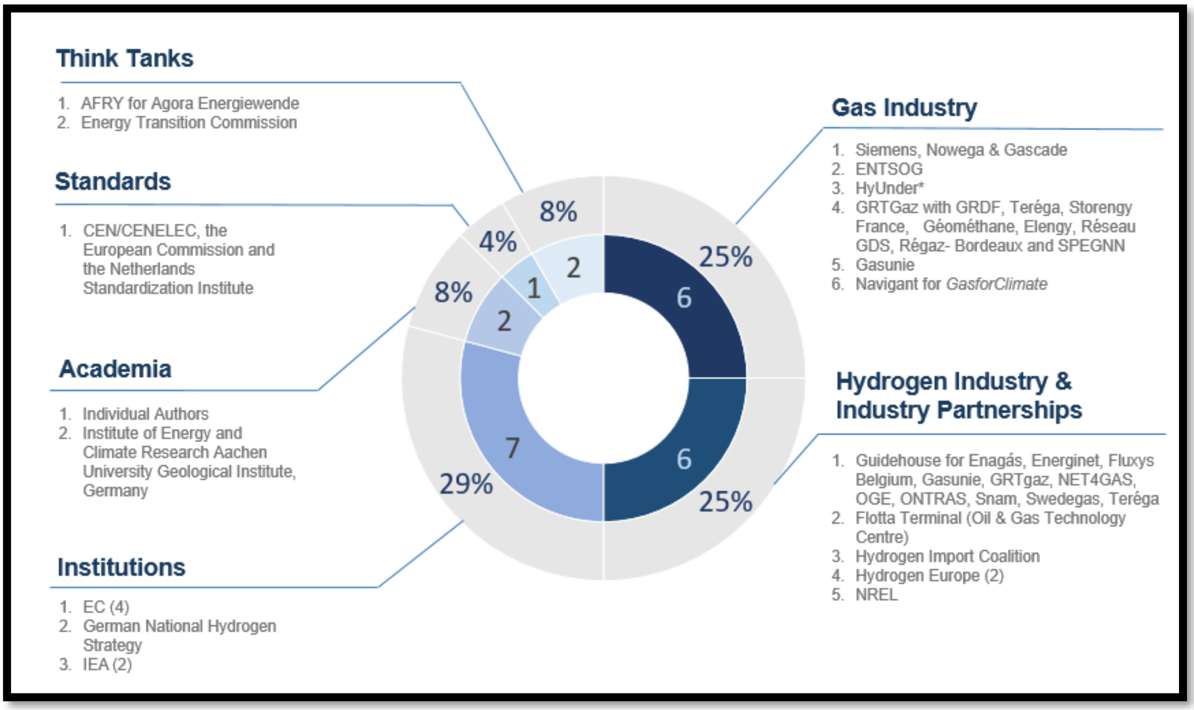


Figure 1- Overview of studies reviewed in the note

The studies that investigate in detail technical and cost aspects of repurposing have been developed or financed mainly by the gas industry. This should not be surprising, given the concentration of technical knowledge within the gas industry, which has a natural interest to investigate and promote the potential repurposing of its assets for hydrogen use. Therefore, the findings of these studies should be interpreted with caution, in view of potential bias.

The most relevant studies in view of the objectives and focus topics covered by this note are the following:

- *European Hydrogen Backbone* (Guidehouse, for several gas TSOs)[4]
- *Hydrogen Generation in Europe: Overview of Costs and Key Benefits* (EC)
- *The Future of Hydrogen* (International Energy Agency – IEA)
- *Hydrogen Infrastructure* (Gasunie)
- *No-regret Hydrogen: Charting Early Steps for Hydrogen Infrastructure in Europe* (AFRY, for Agora Energiewende)

The complete list of documents reviewed are listed in Annex I - References.

3.2 Possibilities for Repurposing

[4] Initial study of July 2020. In April 2021, the EHB report was updated including an extended vision, involving 23 gas infrastructure companies from 21 countries. The updated study estimates a lower investment cost per kilometre of pipeline compared to previous estimate, and a total investment: €43-81bn, being the average transport cost of hydrogen per kg: €0.11-0.21/1 000km.

3.2.1 Pipeline transport capacity: natural gas vs. pure hydrogen

H2 can be transported in a gaseous state in high-pressure containers or in a liquid state at a cryogenic temperature in thermally insulated containers. Hydrogen can also be used to produce methanol or ammonia (which are transported in liquid form) and then used as ammonia or methanol or recovered for use as pure hydrogen. In this review, we focus mainly on transporting hydrogen in gaseous state via pipelines, as well as at the options for storing hydrogen.

In a gaseous state, the **energy density of hydrogen is only slightly lower (from 10% to 20% less) than that of NG,** under the same pressure and temperature conditions. For example, while the calorific value of NG (11 kWh/Nm3) is approximately 3 times higher than that of hydrogen (3.5 kWh/Nm3), hydrogen can be transported by pipelines at three times the flow velocity of NG.[5] Most studies find that the maximum energy flow capacity of a pure hydrogen pipeline could be up to 80% of the maximum energy flow capacity for NG, depending on the operating conditions.[6]

Due to the low molar mass of hydrogen and larger volumetric flow, **greater compression power is needed for hydrogen transport in comparison to NG** in order to achieve similar energy flow. Approximately 3 times more compressor power is needed to transport pure hydrogen in comparison with NG pipelines to reach similar capacity in terms of energy flow.[7]

Operating pure hydrogen pipelines with reduced compressor power, and thus at less than its maximum capacity -the energy transport capacity of the hydrogen pipeline would be much lower than for a NG pipeline of similar diameter- could lead to a lower cost of transportation due to avoided costs of additional compression[8]. This could be an option when the volumes of hydrogen to transport are low, during the early stages of hydrogen market uptake.

3.2.2 Transmission pipelines

Advantages of Repurposing

The main advantages of the repurposing of pipelines are:

- The NG pipeline networks are already available and socially accepted (routes, including rights of way and use);
- NG networks can be converted at a cheaper cost to carry hydrogen compared to the cost of building new, dedicated hydrogen pipes. Besides, such conversion can be done gradually (depending on hydrogen supply demand developments) given a new use to parts of the existing NG network which features extensive geographical coverage throughout the EU;
- Technologies for converting the NG infrastructure to hydrogen operation are already largely available and tested.

Technical Issues of Repurposing

[5] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation*. Siemens, Nowega and Gascade, 2020
[6] *European Hydrogen Backbone*. Guidehouse, July 2020.
[7] Ibid.
[8] Ibid.

Embrittlement of steel

Hydrogen can accelerate pipeline steel degradation, which occurs primarily in the form of embrittlement which causes cracks and may eventually result in pipeline failure. However, technical remedies to prevent embrittlement are readily available: (a) inner coating to chemically protect the steel layer; (b) intelligent pigging (monitoring); (c) operational pressure management (avoiding big pressure changes); (d) admixing degradation inhibitors (e.g. 1000 ppm oxygen).[9]

Some studies[10] suggest that lower-grade, more ductile steel (grades below API X42 and X52) generally used for pipelines built between 1980 and 2000 could be less affected by hydrogen embrittlement than less ductile steels (grades above X52). However, other studies indicate that higher grade steel X70 could be actually better than lower grade (X52)[11]. Therefore, there is no clear unanimous conclusion on the relationship of steel grade and embrittlement.

Additionally, the GRTGaz report notes that French regional networks with smaller diameters of steel pipes and with lower yield strength are less sensitive to hydrogen embrittlement compared to larger transmission pipelines, which are more likely to be made of technologically more advanced types of steel.[12] Fiber- reinforced polymer pipelines are also suitable for hydrogen transport, but they are only available in smaller diameters (mainly for gas distribution) rather than larger diameters of steel pipelines (6" vs. 56" or larger).[13]

For the development of a hydrogen backbone, system pressure regimes also need to be considered. Gasunie analyses two ranges of pressure regimes for hydrogen pipelines, the first one at 10-20 bar; the second one at 30-50 bar.[14] The higher range is seen as the optimal solution for providing sufficient energy transport capacity in the long term, with regional stakeholders preferring the option to start with a temporary lower pressure for regional networks. As such, subsequent connection of regional networks to a hydrogen backbone may require a pressure regime change to the higher pressure levels (30-50 bar).[15]

Hydrogen-enhanced fatigue in pipelines should also be considered. Degradation can set a limit on fatigue loading with regards to pressure variations and/ or the number of pressure cycles, which can be prevented and mitigated in part by the technical remedies above.

Other technical challenges of repurposing

NG networks will have to undergo removal of undesirable parts, pipeline monitoring to identify cracks, replacements of valve fittings, plus preferably a layer of internal coating (for allowing operating with pure hydrogen at high pressures).[16]

---

[9] Ibid, and Sandia National Laboratory presentation, American Gas Association Sustainable Growth Committee, 2019.

[10] *European Hydrogen Backbone, and* Phase 1 Project Report. Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal HOP Project – HS413. The Oil & Gas Technology Centre.

[11] E.g. https://www.amerpipe.com/steel-pipe-products/api-5l-pipe-specifications/; Sandia National Laboratory presentation, American Gas Association Sustainable Growth Committee, 2019: *"A wide variety of pipeline steels display nominally the same fatigue response in high-pressure gaseous hydrogen".*

[12] *Technical and economic conditions for injecting hydrogen into natural gas networks*. GRTGaz et al.,.June, 2019

[13] *Gas for Climate. The optimal role for gas in a net-zero emissions energy system.* Navigant, March 2019.

[14] *Hydrogen Infrastructure* [Webinar] Gasunie, October 2020.

[15] Ibid.

[16] *European Hydrogen Backbone*. Guidehouse, July 2020

The treatment and effects of rests of sulphur used for odorisation of NG and other residues remaining in the NG network which cannot be completely removed when repurposing for pure hydrogen is another technical challenge which may deserve further studies, given that some hydrogen applications require a very high purity of hydrogen[17].

Overall, there is no one-size-fits-all solution for converting NG pipelines to hydrogen, each case would require of detailed and substantiated engineering analysis.

3.2.3 Compressor stations

To enable an energy flow of hydrogen equivalent to 80-90% of the flow of NG, approximately three times the compression power would be required for hydrogen compared to the power required for NG.[18]

There are still challenges related to the conversion of compressor stations to hydrogen[19]. For pure hydrogen, 'tried and tested' reciprocating compressors are available, but reciprocating compressors are generally not an efficient solution for large diameter pipelines. On the other hand, **it is not currently possible to retrofit gas turbo-compressors (TC) to handle gas containing more than 40% hydrogen in volumetric terms.[20]** Studies forecast that by 2030 the industry-standard compressors driven by gas turbine engines could be converted to operating on 100% hydrogen. For that to be possible, new hydrogen- resistant impeller materials are needed that can withstand high centrifugal forces. In the case of electric-driven compressors, no major changes are required for the engines, but only for the compressors.[21]

The EU Hydrogen Backbone study finds **that by 2030, converted (repurposed) pipelines may require modest compression costs in order to serve limited expected hydrogen transportation needs**.[22] **By 2040 and 2050, there would be a need for additional compressor power in order to serve growing transportation needs**. By that time, one solution could be the placement of relatively small pure hydrogen- capable compression stations ("booster" stations) at 100 km intervals or more powerful stations at a range of 600 km each. Preliminary calculations suggest that both approaches lead to the same order-of-magnitude transportation costs per 100 km.[23] Views on how this more powerful compression squares off vs. the suitability of the existing compressor types varies amongst TSOs and compressor manufacturers. It remains unclear if retrofitting the existing gas-engine driven compressor stations to pure hydrogen would be possible in the future (this is currently not possible).

3.2.4 Storage

Underground storage

---

[17] E.g. Fuel cells need at least 99.7% purity of hydrogen. Sulphur may be problematic as low concentrations of only a few ppm could damage fuel cells.
[18] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation*. Siemens, Nowega and Gascade, 2020
[19] *Hydrogen Infrastructure Practical Guideline*.
[20] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation. Siemens, Nowega and Gascade,* 2020
[21] Ibid
[22] *European Hydrogen Backbone*. Guidehouse, April 2021
[23] Ibid.

There are three principal types of NG underground storage reservoirs— depleted oil or gas reservoirs, aquifers, and caverns, among which salt cavern are predominant.

Most of the studies conclude that **salt cavern storage facilities are particularly well suited for storing hydrogen**, owing to their low investment cost, high sealing potential of the rock salt layer, low cushion gas requirement, and the inert nature of salt structures, which prevent the contamination of the stored hydrogen.[24] Besides, salt caverns offer very flexible gas storage (injection) and retrieval.

Underground hydrogen storage has been tested in the US (near Houston) and in the UK, and there is a planned project in Germany. In addition, there is experience with an UGS with helium in Germany (helium has some properties similar to those of hydrogen). [25]

However, opportunities for UGS in salt caverns are geographically limited to a few areas in several EU Member States. **The largest potential is in the southern North Sea and its bordering countries. Germany** has the highest technical storage capacity (9.4 PWh), located in salt domes in the north of the country. Moreover, **Norway** has 7.5 PWh hydrogen of storage potential for offshore caverns, which would all be located in the North Sea Basin (cf. *Fig. 2*).[26]

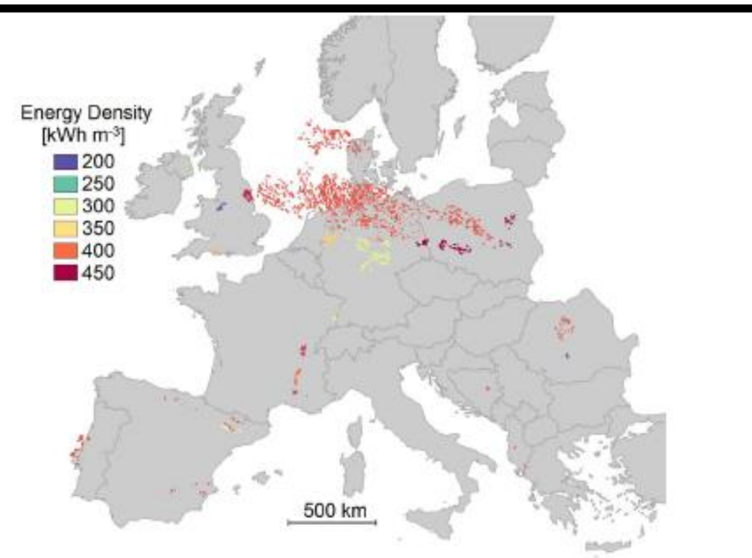


Figure 6. Distribution of potential salt cavern sites across Europe with their corresponding energy densities (cavern storage potential divided by the volume).

Figure 2 - Potential Salt Cavern Sites across Europe (Source: Institute of Energy and Climate Research Aachen, University Geological Institute, Energy and Mineral Resources)

Porous rock storage (storage in depleted gas or oil reservoirs and aquifers) is less suitable for hydrogen. Saline water in combination with hydrogen attacks rock, steel, and cement. In addition, there is a risk of bacterial methanation of hydrogen in existing pore

---

[24] *Technical Potential of Salt Caverns for Hydrogen Storage in Europe.* Institute of Energy and Climate Research Aachen, University Geological Institute, Energy and Mineral Resources, October 2019.
[25] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation*. Siemens, Nowega and Gascade, 2020
[26] *Technical Potential of Salt Caverns for Hydrogen Storage in Europe.* Institute of Energy and Climate Research Aachen, University Geological Institute, Energy and Mineral Resources, October 2019.

storages, as well as possible contamination of hydrogen with hydrocarbons and other gases in the reservoir and at the wellhead.[27]

In any case, all studies show that there is a need of case-by-case examination of the technical and geological integrity of each storage site. In particular, the following parameters should be analysed, some of which are common and others additional to the features to be studied for NG storages: structure of the geological formation, corrosion and diffusion, permeability, long-term tability, microbial activities, qualification of materials for the use of components, compression ability , vicinity to transport needs, vicinity to fluctuating energy sources (sufficient voltage level, distance to hydrogen pipelines, distance to NG consumption centres and industrial consumers, distance to high voltage power grid, NG grid nodes, etc.).[28]

The percentage of insoluble matter in the salt cavern structure is critical, as well as the availability of cheap electricity and good access to hydrogen markets.[29]

<u>Large-scale Storage of Hydrogen</u>

Hydrogen, due to its chemical properties, allows for the storage of large volumes of energy for long periods of time (seasonal storage or longer). The main disadvantage of storing hydrogen vs. storing electricity on other ways is the significant loss of energy in the conversion process (using electricity to produce hydrogen by electrolysis, storing the hydrogen, and then converting it back to electricity by using a gas turbine and a power generator, is a process that has an energy efficiency rate of less than 40%, i.e. >60% of energy losses). [30]

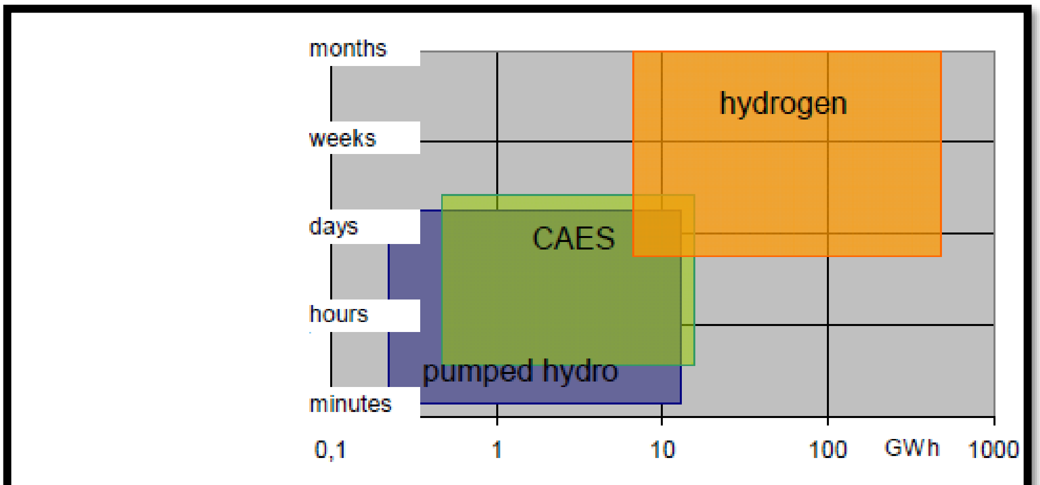


Figure 3-1: Preferential areas of large scale storage options.

Figure 3 - Large scale energy storage options. (Source: Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies).

[27] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation*. Siemens, Nowega and Gascade, 2020
[28] *Assessment of LT Storage of RES Electricity by Hydrogen UGS in Europe.* HyUnder, July 2014
[29] *Ibid*
[30] *Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies.* F. Crotogino, S. Donadei, U. Bünger, H. Landinger, April 2016

Storage of hydrogen in superficial tanks

Hydrogen can be compressed and stored in aerial tanks. However, compressed hydrogen, even at very high pressure of 700 bars, has only 15% of the energy density of gasoline, so storing the equivalent amount of energy as hydrogen at a vehicle refueling station would require nearly seven times the space.[31] Ammonia, as a hydrogen carrier, has greater energy density and would thus reduce the need for large storage tanks, but will also lead to greater energy losses due to the required conversion process.

3.2.5 Liquid hydrogen terminals and hydrogen in shipping (pure hydrogen and ammonia)

Liquefaction of hydrogen requires hydrogen to be cooled to about -253°C (at ambient pressure), vs. -162 °C for NG.[32] In 2019, the IEA noted that if the **hydrogen itself were to be used to provide the energy needed for its liquefaction, then it would consume between around 25% and 35% of the initial quantity of hydrogen (based on today's technologies)**. This is considerably more energy than is required to liquefy NG (around 10% of the initial quantity of NG).[33]

Converting hydrogen to ammonia requires between 7% and 18% of the energy contained in the hydrogen, and similar level of energy is lost if the ammonia needs to be reconverted back to high-purity hydrogen at destination. **Ammonia** liquefies at -33°C, a much higher temperature than hydrogen, and contains 1.7 times more hydrogen per cubic metre than liquefied hydrogen, which means it **is much cheaper to transport than hydrogen**.[34] Recent news points out that Large Liquefied Hydrogen Carriers are under development and technically possible[35], but it remains to be seen if transporting pure hydrogen in cryogenic cargoes will be economical.

3.2.6 Other network equipment

Metering and city gate stations. Given the different chemical composition and properties of H2 compared to methane-containing gas, metering equipment will likely need to be adapted. However, the cost of such equipment typically represents a small portion of the total infrastructure costs.

3.3 Cost of Repurposing (investment and transportation costs)

3.3.1 Transportation (pipelines and compressor stations)

Several studies investigate the cost of repurposing, mainly in terms of investment costs, as well as projecting the cost of transportation of pure hydrogen under assumptions laid out in several scenarios. While the cost of repurposing is, in general, easier to estimate, the unit cost of transportation tends to be much more challenging, since the latter depends on several

[31] *The Future of Hydrogen: Seizing today's opportunities*. IEA, July 2019
[32] Ibid.,
[33] Ohlig and Decker, 2014 qtd., *The Future of Hydrogen: Seizing today's opportunities*. IEA, July 2019
[34] *The Future of Hydrogen: Seizing today's opportunities*. IEA, July 2019
[35] *KHI Develops World's Largest Volume Cargo Storage Facility For Large Liquefied Hydrogen Carriers*. Marine Insight News Network, May 2021. See: https://www.marineinsight.com/shipping-news/khi-develops-worlds-largest-volume-cargo-storage-facility-for-large-liquefied-hydrogen-carriers/

assumptions which are highly uncertain (hydrogen volumes, load factor, tariff setting, length, diameter, pressure, operating costs, etc.).

The practical conversion of long-distance gas networks from NG to hydrogen is possible with limited economic effort, according to the studies reviewed. The **costs of repurposing the lines** (including decommissioning from NG operation, water pressure tests, replacement of fittings and dismantling of connections, etc.) is estimated **at around 10-15% of the cost of construction of new hydrogen lines.**[36] **Hydrogen operation is expected to be more expensive than NG, given that it would require approximately three times the compression power** to maintain similar energy flow to NG.

The *European Hydrogen Backbone* study states that **the capital cost per km of refurbished hydrogen pipelines would amount to ~33% of the cost of newly built hydrogen pipelines.**[37] The operational cost of hydrogen transport is deemed to be low (around 2% of the energy content of the hydrogen transported over a distance of 1 000 km). According to this study, the levelised cost of hydrogen transportation by pipeline could range from €0.09 to €0.17 per H2 kg /1000 km[38], which represents approximately 10% of the hydrogen production costs (when the estimated hydrogen production cost is in the range of €1-2 per kg, assuming a load factor of the electrolisers of 5000 hr/yr – which is an optimistic assessment).[39] Annex A to the European Hydrogen Backbone includes detailed cost assumptions for the construction and the retrofitting of hydrogen pipeline infrastructure. It can be said that Capex for a **new pure hydrogen pipeline are 110-150% of those for a new natural gas pipeline** with similar diameter. Capex for a **repurposed pipeline are 10-35% of those for a new hydrogen pipeline** with similar diameter. In addition, valve replacement costs depend on the distance between valves. If valves must be replaced every 15 km, the cost will increase.

The 2019 *Gas for Climate* study estimates the levelised hydrogen transport costs at €0.23 per H2 kg/1 000km.[40]

The German Association of Gas Transmission Operators estimates the costs for building new hydrogen pipelines to be almost 9 times higher than the repurposing costs.[41]

---

[36] *Hydrogen infrastructure. The practical conversion of long-distance gas networks to hydrogen operation*. Siemens, Nowega and Gascade, 2020
[37] *European Hydrogen Backbone*. Guidehouse, July 2020
[38] Ibid; "*These cost estimates are based on calculations for single stretches of hydrogen pipeline, but now with a weighted average of diameters. They do not incorporate a scenario-based optimisation simulation of a full-scale network as is commonly done for network development planning. Depending on circumstances, the costs for individual stretches can be lower or higher than the range indicated.*"
[39] Ibid,.
[40] *European Hydrogen Backbone*. Guidehouse, July 2020
[41] *Regulatory Framework for Hydrogen.* Trinomics, LBST, November 2020

Study	Asset for Hydrogen	New H2 / Repurposed NG Pipeline	Cost Parameter (Pipeline diameter, inches)	Unit	Low	Average	High
Extended European Hydrogen Backbone (Guidehouse, 2021)	Hydrogen Pipeline	New	<28	M €/km	1.4	1.5	1.8
	Hydrogen Pipeline	New	28-37	M €/km	2	2.2	2.7
	Hydrogen Pipeline	New	>37	M €/km	2.5	2.8	3.4
	Hydrogen Pipeline	Repurposed NG	<28	M €/km	0.2	0.3	0.5
	Hydrogen Pipeline	Repurposed NG	<28-37	M €/km	0.2	0.4	0.5
	Hydrogen Pipeline	Repurposed NG	>37	M €/km	0.3	0.5	0.6
	Compressor Station	N/A	N/A	M €/ MWe	2.2	3.4	6.7
Hydrogen Generation in Europe (Guidehouse, Trectabel, 2020)	Hydrogen Pipeline	New	16	M €/km		0.93	
	Hydrogen Pipeline	New	N/A	M €/km		1.22	
	Hydrogen Pipeline	New	N/A	M €/km		1.4	
	Hydrogen Pipeline	New	N/A	M €/km		1.55	
	Hydrogen Pipeline	New	N/A	M €/km		1.57	
	Hydrogen Pipeline	New	48	M €/km		2.01	
	Hydrogen Pipeline	New	N/A	M €/km		2.48	
	Hydrogen Pipeline	New	48	M €/km		3.28	
	Hydrogen Pipeline	Repurposed NG	N/A	M €/km		0.37	

Figure 4 - Overview of investment costs for repurposing NG vs new hydrogen transmission infrastructure[42]

The Navigant study estimates the cost of new hydrogen pipelines at 124% of the estimated cost of repurposing existing gas infrastructure [€4.6 per MWh/ 600km] compared to the latter at €3.7 per MWh/600km.[43] Additionally, the total costs for making the Dutch distribution networks usable for hydrogen were estimated at €700 million, which, if included in tariffs, would result in network cost increase per individual household of 10%- 50%.[44] Taking into consideration the required replacement of the compressors and metering devices, Navigant evaluates the levelised costs of hydrogen infrastructure, including operational costs, to be around €4.15 per MWh for typical average transport distances of 600 km. The total annual costs of the hydrogen infrastructure will be €9.5 billion by 2050.[45] In addition, the report also compares the cost outlook for "optimistic" and "minimal" gas scenarios through 2050. In the former scenario, gas infrastructure maintenance costs reported by TSOs indicate annual costs of €5.7 billion.[46] This is 2.7 times less than the total decommissioning cost for TSO gas infrastructure, in line with a "minimal" gas scenario (assuming associated costs of approximately 30% of the CAPEX initially required to build the infrastructure).[47] When annualised over a 10-year period, this results in €15.6 billion of costs per year.[48]

---

[42] For full original studies cited list and accompanying comments specific to each entry, see: p.15 Table 2-D: Cost of Hydrogen Transmission, *Hydrogen Generation in Europe*. Guidehouse, Trectabel, 2020
[43] *Gas for Climate. The optimal role for gas in a net-zero emissions energy system.* Navigant, March 2019
[44] Ibid,.
[45] Ibid.,
[46] Ibid.,
[47] Ibid.,
[48] Ibid.,

Study	New H2 / Repurposed NG Pipeline	Hydrogen Pipeline diameter (inches)	Unit cost of transportation (EUR/MWh/1000Km)		
			Low	Average	High
Extended European Hydrogen Backbone Report (Guidehouse, 2021)	New	48		4.8	
	Repurposed NG			2.4	
	New	36		9	
	Repurposed NG			3.3	
	New	20		21	
	Repurposed NG			7.5	
Gas For Climate "Optimised Gas" Scenario	New			7.67	
	Repurposed NG			6.17	
Hydrogen Generation in Europe (Guidehouse, Trectabel, 2020)	New	48		7.67	
	New	34		16.00	
	New			19.00	
	New		26.83		83.00
	New			75.00	
	Repurposed NG			6.17	

Figure 5 -Unit Cost Transportation of pure hydrogen. Based on sources indicated in the table. For consistency purposes, the unit cost of transportation has been normalised to EUR/MWh/1 000km. Figures cited from sources using different units have been converted to EUR/MWh/1 000km.

The study *Hydrogen Generation in Europe: Overview of Costs and Key Benefits Notes a Relatively Low Cost for Repurposing* (see table 2.D, p. 15) commissioned by the European Commission estimates CAPEX for **refurbished pipelines at €0.37 million per km in 2019 prices.**[49]. For **new hydrogen dedicated pipelines, CAPEX ranges from €0.93 (16" in UK) to €3.28 (48" in UK)** million per km in 2019 prices.[50] The levelised cost of transmission (LCOT) for hydrogen transmission ranges from €3.7/ MWh/ 600 km (refurbished) from €4.6 to €45 / MWh/ 600km for new hydrogen dedicated pipelines. For transmission and distribution (T&D), the cost of moving hydrogen ranges from €8 to €66 per MWh/ 600 km of transmission and over 30 km of distribution, only representing a small fraction of the overall costs for delivered hydrogen.[51]

3.3.2 Underground gas storages

While salt cavern storage requires a significant upfront investment, hydrogen storage at such facilities contributes very modestly to the total specific hydrogen costs, by adding less than €0.5/ kg hydrogen[52]. However, simulations indicate that it may take quite some time before situations on the electricity market arise with significantly more than 2 000 hours of available cheap or negatively priced surplus electricity. For this reason, storing surplus electricity as hydrogen does not seem to be an economically viable case in the near-term.

[49] *Hydrogen generation in Europe: Overview of costs and key benefits*. Guidehouse, TRACTEBEL, ENGIE, July 2020
[50] Ibid.,
[51] Ibid., p.8, Figure 1-2: Breakdown of costs for delivered hydrogen in 2020
[52] *Assessment of LT Storage of RES Electricity by Hydrogen UGS in Europe, Authors, Date: HyUnder, July 2014*

In general, as indicated above, hydrogen energy storage as a means to store renewable electricity via electrolysis and underground storage is economically very challenging due to the energy conversion losses from electricity into hydrogen and back to electricity. Furthermore, no single industry sector alone will likely create a viable business case for underground hydrogen storage. Sensitivity analysis indicates that the most important factors for a potential business case are attaining both low electrolyser CAPEX and significant periods of low or negative electricity prices (>2 000 hrs annually of available "surplus" electricity).

3.3.3 Liquefied Hydrogen (pure hydrogen), ammonia, and others for shipping

Costs associated with importing low-carbon hydrogen to the European border are assessed by some studies. The transport technologies considered include ships (transporting liquid hydrogen or ammonia) and pipelines (gaseous hydrogen). In terms of shipping routes, imports from Australia, Chile, Saudi Arabia, North Africa (for renewable hydrogen) and Russia (for fossil-based hydrogen with carbon capture) are considered as the most relevant for cost analysis. **Transport of ammonia by ship appears to be much cheaper than pure hydrogen transport,** with hydrogen of Chilean origin being the cheapest option.[53]

According to the IEA, hydrogen to be shipped overseas generally has to be liquefied or transported as ammonia or in liquid organic hydrogen carriers (LOHCs). For distances below 1 500 km, transporting hydrogen as a gas by pipeline is likely to be the cheapest delivery option; above 1 500 km, shipping hydrogen as ammonia or by LOHC is likely to be more cost-effective.[54] Pipelines are likely to be the most cost-effective, long-term choice for local hydrogen distribution if there is sufficiently large, sustained and localised demand. Distribution on trucks will remain the primary distribution mechanism over the next decade in a number of regions where hydrogen imports could be cheaper than domestic production (e.g. Japan to import from Australia).[55] Using ammonia directly in end-use sectors could further improve the competitiveness of hydrogen- based imports.[56] **Currently no commercial ships can transport pure liquefied hydrogen**. Among hydrogen carriers, the most developed carrier in terms of intercontinental transmission is ammonia. According to the IEA, the cost of conversion and moving hydrogen 1 500 km by ship such as a liquid organic hydrogen carrier (LOHC)[57] is USD 0.6/kg H2, as ammonia is USD 1.2/kg H2 and as liquid hydrogen is USD 2/kg H2.[58]

---

[53] *Hydrogen generation in Europe: Overview of costs and key benefits*. Guidehouse, TRACTEBEL, ENGIE, July 2020

[54] *The Future of Hydrogen: Seizing today's opportunities*. IEA, July 2019.

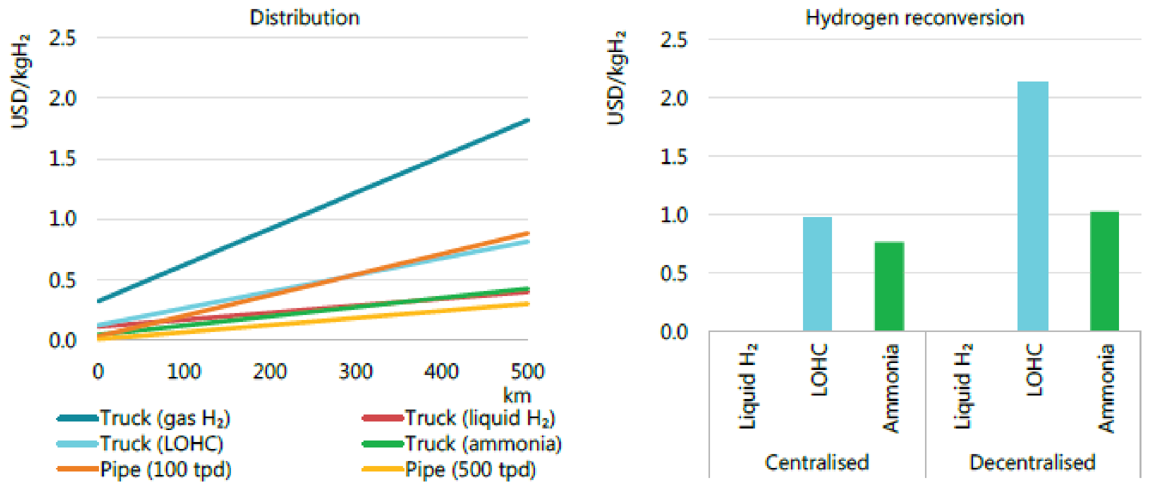
[55] Ibid.

[56] Ibid.

[57] LOHC are organic compounds that can absorb and release hydrogen through chemical reactions. LOHCs can therefore be used as storage media for hydrogen. In principle, every unsaturated compound (organic molecules with C-C double or triple bonds) can take up hydrogen during hydrogenation ("saturation") resulting in molecules which only contain single C-C bonds. Most commonly, such compounds are found in crude oil and refined petroleum products and are available from refineries (e.g. alkenes and alkynes).

[58] *The Future of Hydrogen: Seizing today's opportunities*. IEA, July 2019

Figure 28. Cost of hydrogen distribution to a large centralised facility and cost of reconversion to gaseous hydrogen



Notes: More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019.

Figure 6 – Source: IEA, 2019. Cost of H2 storage and transmission by pipeline and ship

The study *Shipping Sun and Wind to Belgium* provides findings focusing on the technological and economical aspects of the hydrogen import value chain, noting that large-scale green hydrogen imports are both technically feasible and economical. The study indicates that when delivered to Belgium, the cost range of imported hydrogen-based renewable energy from low-cost locations would lie in the range of €65-90 per MWh by 2030-2035, with a further potential cost reduction to € 55-75 per MWh or less by 2050.[59] As several hydrogen-based carriers are feasible as indicated above, many sourcing regions are capable of providing cost-competitive energy, soundly and sufficiently diversified by source geopolitically. Like other studies, this study confirms that the most promising hydrogen-based energy carriers are ammonia, methanol and synthetic methane. The study finds that **the overall economic feasibility of liquefied pure hydrogen is significantly lower.**[60]

3.3.4 Lowest cost form of hydrogen transportation

Hydrogen can be transported in pure form as compressed gas or in liquid cryogenic form, or converted into other hydrogen carriers such as ammonia or LOHC. Similarly to the transport of natural gas and other gases, the most economic form of transporting hydrogen would depend on several factors. A recent report from the Energy Transition Commissions[61] identifies three main “tipping points” to ascertain the most cost-efficient form of transportation of pure hydrogen based on the distance and volumes to be transported.

For smaller volumes and distances (less than 10 tonnes of hydrogen per day and less than ~ 200 km), **transportation of hydrogen by trucks seems to be the most cost-effective**

[59] *Shipping Sun and Wind to Belgium. Hydrogen Import Coalition*, Flanders, Fluxys, Port of Antwerp, 2020
[60] Ibid.,
[61] *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy*. Energy Transition Commission, April 2021

option, in compressed form for short distances, and in liquid form for small volumes over longer distances (hundreds of km). **For volumes exceeding 10 tonnes/per day, pipelines appear to the lowest-cost transportation option** in most cases: distribution pipelines are preferred for local networks, while transmission pipelines with a capacity beyond 100 tonnes per day are more suitable to carry large volumes over longer distances. Shipping hydrogen carriers (ammonia) seems to be more economic for intercontinental distances of thousands of km, requiring high capacities (>100 t/day).

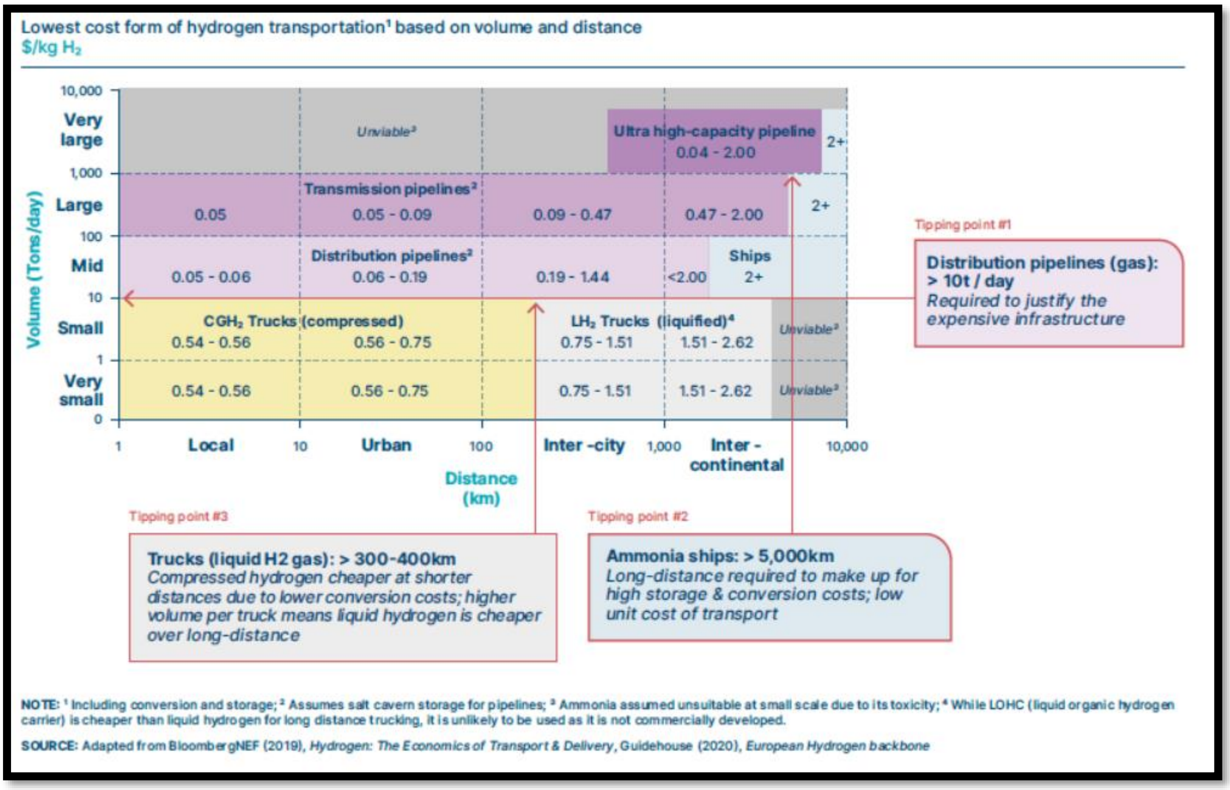


Figure 7 – Source: Energy Transition Commissions. Accelerating Clean Hydrogen in an Electrified Economy. Cost of hydrogen transportation, based on distance and volume.

3.4 Investment Needs

A few studies quantify the investment needs in terms of length (km) and overall investment of repurposing of NG pipelines and new hydrogen pipelines by several time horizons (2030, 2040). The studies offer divergent visions on the extension of future hydrogen pure networks, ranging between a large-scale pan-European backbone transmission infrastructure based primarily on repurposing the existing NG network, to a more regionally clustered, corridor or valley approach where supply and demand of hydrogen are geographically closer.

The ***European Hydrogen Backbone*** **study (July 2020) initially estimated the total investment needs (full CAPEX of repurposed and new lines) at €27-64 billion by 2040 (assuming a mix of 75% of converted natural gas pipelines connected by 25% new hydrogen pipeline segments).**[62]. The study indicates this wide range of costs is mainly due

[62] *European Hydrogen Backbone*. Guidehouse, July 2020

to uncertainties related to compressor stations (need of additional stations, power and costs associated). The network investment needs would be relatively small vis-à-vis the foreseen size of hydrogen markets**. The overall compression costs would be important (from 37% to 56% of all investment costs**, depending on the scenarios). [63] In April 2021, this study was updated and enlarged to 21 European countries, including Central and Eastern Europe, the UK, Ireland, Greece and Nordic countries[64]. With the update, the overall dimension of the envisioned pure hydrogen network almost doubled in size, reaching 39 700 km by 2040, and also the investment needs, estimated between €43 and €81 billion by 2040.[65]

The study ***No-regret hydrogen: Charting early steps for Hydrogen infrastructure in Europe***, carried out by AFRY on behalf of Agora Energiewende, results in much more modest estimates of the investment needs. This study, based on foreseen market developments for pure hydrogen for industrial demand, identifies only a few robust, no-regret corridors for early hydrogen pipelines in the EU.[66] Under the most optimistic scenarios of this study, **any future hydrogen network will be smaller than the current NG network.[67]** A no-regret vision for hydrogen infrastructure needs reduces the risk of oversizing networks by focusing on indispensable hydrogen demand, robust green hydrogen corridors and storage. The study stresses that 40% of today's industrial NG use in the EU goes to low-grade heat applications (below 100°C), for which heat supplied with electric heat pumps would be more advantageous. **AFRY identifies the optimal locations for hydrogen infrastructure across continental Europe.** The resulting infrastructure delivers hydrogen to industrial demand clusters at the lowest possible cost, and provides access to hydrogen storage. Only four so-called **"no-regret" pure hydrogen corridors are identified: Central-West Europe (the primary corridor, distinguishable from the others), East Europe (Poland and Lithuania), the Mediterranean corridor in Spain and South-East Europe.[68] The study concludes that,** based solely on industrial hydrogen demand, technology and cost assumptions considered in th analysis, **there is no justification for creating a larger, pan-European hydrogen backbone.[69]**

Finally, according to the study *Shipping Sun and Wind to Belgium*, the hydrogen pipeline network is currently extensive in Belgium but is not open-access and is only present within the industrial community.[70] Besides, capacity is not necessarily sufficient to support large-scale energy transport of hydrogen carriers.

---

[63] Ibid.,

[64] It envisions a hydrogen pipeline network of 23 000 km covering 10 European countries: Belgium, Czech Republic, Denmark, France, Germany, Italy, the Netherlands, Spain, Sweden and Switzerland

[65] *Extending the European Hydrogen Backbone*. *A European Hydrogen Infrastructure Vision covering 21 countries.* Guidehouse, April 2021; qtd. Euractiv https://www.euractiv.com/section/energy/news/gas-grid-operators-outline-plans-for-expanded-eu-hydrogen-highway/

[66] *No-regret Hydrogen: Charting Early Steps for Hydrogen Infrastructure in Europe.* AFRY Management Consulting, February 2021

[67] Ibid.,

[68] Ibid.,

[69] Ibid.,

[70] *Shipping Sun and Wind to Belgium. Hydrogen Import Coalition*, Flanders, Fluxys, Port of Antwerp, 2020

Figure 8: Comparing visions for an EU hydrogen network: Clear "no-regret H2" corridors based on H2 demand vs. Gas TSOs vision- EU H2 Backbone

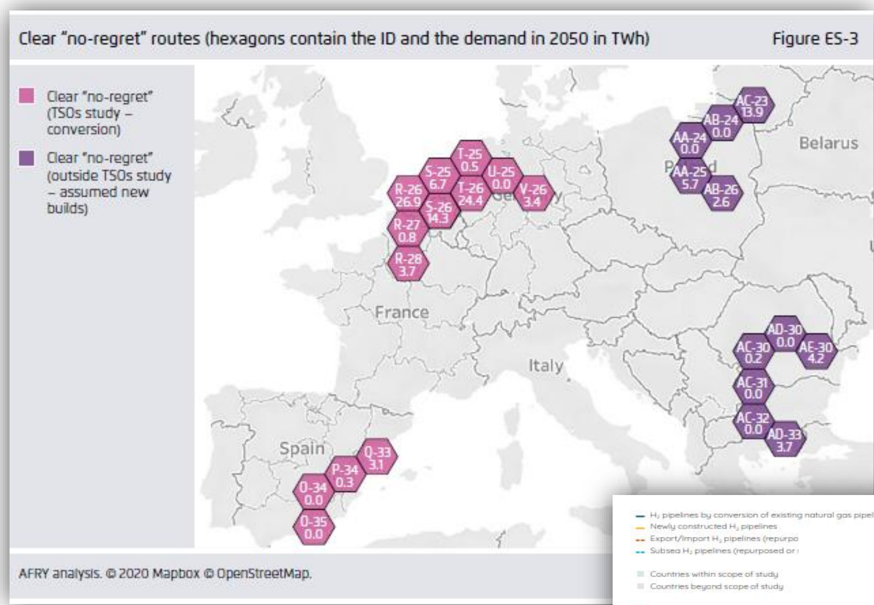


Figure 8.1 (Left):

AFRY identifies only four pure H2 corridors in Europe in selective locations, seeing no justification for creating a larger, pan-European hydrogen network.

Source: AFRY Management Consulting, January 2021

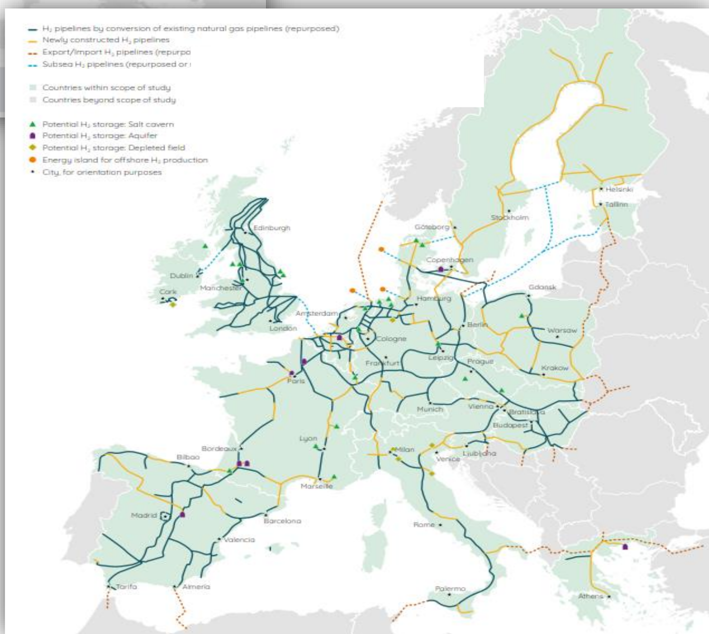


Figure 8.2 (Right):

The European Hydrogen Backbone study estimates full CAPEX of repurposed and new lines at €27-64 billion by 2040 (75% of converted NG pipelines, 25% new H2 pipeline segments).

Source: Guidehouse, April 2021.

3.5 Safety Considerations

Hydrogen is highly flammable. When converting from NG to hydrogen, adaptations are needed to ensure safety[71], some of which include:

- **Pipelines**: the possible need of adapting shut-off valves and pressure regulators to the properties of hydrogen and the behavior of hydrogen gas flow;

- **Integrity management of the systems**: a comprehensive and continuous system integrity management is recommended in order to address any pipe steel embrittlement risks at an early stage;

- **Maintenance:** the current system maintenance concepts as applicable to NG should be adapted, as hydrogen is highly flammable.

The storage of ammonia in tanks is common practice in industry today. However, its toxicity remains an important point of concern. In densely populated areas, such as Western Europe and more specifically Belgium, the transportation of ammonia via pipeline is deemed challenging due to safety reasons. [72]

3.6 Operation of Pure Hydrogen Networks & Green and Low-Carbon Hydrogen

The operation of pure hydrogen networks with hydrogen produced from RES poses challenges. The demand for hydrogen of (mainly) industrial customers is more or less stable, while the availability of renewable energy for hydrogen production is subject to strong fluctuations[73]. Therefore, there are enormous time-related mismatches between the hydrogen demand and the volume of available surplus electricity from removable sources. Therefore, the operation of pure hydrogen networks serving significant hydrogen demand would require the services of highly flexible hydrogen storages (e.g. salt cavern storages).

4. WHEN AND WHERE TO REPURPOSE?

Pure hydrogen networks could initially be built up in parallel and cumulatively to existing natural gas systems. Existing long-term gas supply and transportation contracts do not seem to prevent the development of a hydrogen backbone based on repurposed NG pipelines by 2040 in most of EU MS's.[74] If in the future there would be a need to connect long-distance significant volumes of hydrogen production and demand centres, where hydrogen consumers are far away from large hydrogen supply of RES electricity or CCS, transport via pipeline appears to be far cheaper compared to transport via shipping (relevant for distances exceeding several thousand km).

In the long-term (2050), in a de-carbonized Europe, dedicated pure hydrogen infrastructure will coexist with a NG (methane transport) grid transporting increasing quantities of biomethane and decarbonized NG, and decreasing quantities of "grey" fossil NG.

4.1 Repurposing: under which conditions?

[71] *Hydrogen Infrastructure. The Practical Conversion of Long-Distance Gas Networks to Hydrogen Operation, 2020*.
[72] *Shipping Sun and Wind to Belgium. Hydrogen Import Coalition*, Flanders, Fluxys, Port of Antwerp, etc. 2020
[73] *Hydrogen Infrastructure. The Practical Conversion of Long-Distance Gas Networks to Hydrogen Operation, 2020*
[74] *ENTSOG 2050 Roadmap for Gas Grids.* ENTSOG, 2019

In case of repurposing of NG pipelines in view of a new hydrogen market, there will still be a need to ensure security of supply for existing NG demand during the transitional phase. One may think that all the following conditions should be met in order to consider repurposing for hydrogen as a serious option:

- Presence of loop (parallel) lines of NG pipeline systems, of which at least one string could be repurposed for pure hydrogen.
- Ensuring security of NG supply to consumers, during and after the conversion of a line (or loop) to pure hydrogen. This means that there should be free available capacity for NG transport in that segment of the network, or alternative routes of supply.
- Hydrogen market uptake in the location or regions serving that pure hydrogen corridor. There should be supply developments of clean hydrogen production from RES or CSS, synchronously with demand developments. This hydrogen demand could stem from switching from “grey” to “green” or “blue” hydrogen for existing hydrogen industrial consumers, and switching from fossil fuels (coal, gas) to hydrogen for new hydrogen industrial consumers for high-grade heat applications.

4.2 When and where will these conditions be met?

Currently it is highly unknown when and where these conditions would be met would be met across Europe, and whether they will be met at all. Studies provide some estimates, subject to a high level of uncertainty on the projected uptake of hydrogen markets. Scaling-up technology for hydrogen production, bringing down costs, and increasing hydrogen volumes need to be prioritised prior to considering the deployment of green and low-carbon hydrogen on a commercial scale.

The timing for repurposing NG pipelines to pure hydrogen would be highly dependent on hydrogen market developments (production and demand) in each specific region. There will be a need for clear commitments on hydrogen production uptake and hydrogen demand offtake for industrial use (mostly resulting from switching from other fossil fuels for high-grade heat industrial purposes). It can be expected to have integrated projects in the industrial sector in the beginning, which need direct pipeline connections or local, closed network clusters. In addition, individual transportation lines connecting the local network clusters of pure hydrogen might be needed.

These conditions for repurposing of existing NG lines or for new hydrogen lines are likely to be met in very few, carefully selected locations across Europe. The implementation phase for pure hydrogen corridors should be triggered by compelling hydrogen market commitments or reasonable expectations, backed by serious and detailed market studies of potential industrial consumers of hydrogen. Given the uncertainties at this stage reading hydrogen development, market commitments and interest should trigger repurposing of networks for pure hydrogen, and not the other way around, in order to avoid risks of stranded assets. Repurposing gas infrastructure, should always follow the principles of cost efficiency and cost effectiveness, for the benefit of energy consumers. Against this background, investment decisions on repurposing should follow a prudent and no-regrets approach, based on credible scenarios for market hydrogen developments.

ANNEX I - REFERENCES

Gas Industry Views and Studies

Hydrogen infrastructure- the pillar of energy transition. The practical conversion of long-distance gas network to hydrogen operation (Whitepaper). Siemens Energy, Gascade Gastransport GmbH, Nowega GmbH, 2020. Available at: Link

ENTSOG 2050 Roadmap for Gas Grids, ENTSOG, 2019. Available at: Link

Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe. Joint results from individual case studies. HyUnder, July, 2014. Available at: Link

Technical and economic conditions for injecting hydrogen into natural gas networks. GRTgaz with GRDF, Teréga, Storengy France, Géométhane, Elengy, Réseau GDS, Régaz-Bordeaux and SPEGNN, 2019. Available at: Link

Hydrogen Infrastructure (Webinar). Gasunie, 2020. Presentation available at: Link

Gas for Climate. The optimal role of gas in a net-zero emissions energy system. Navigant (prepared for Gas For Climate, A Path to 2050), March 2019. Available at: Link

Hydrogen Industry; Industry Partnerships, Views and Studies

Extending the European Hydrogen Backbone. A European Hydrogen Infrastructure Vision covering 21 countries. Guidehouse for Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, April 2021. Available at: Link (This report is an updated and extended version of a previous EHB vision report *European Hydrogen Backbone*, Guidehouse. July, 2020. Available here: Link)

Phase 1 Project Report. Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal HOP Project – HS413. The Oil & Gas Technology Centre. Available at: Link

Shipping sun and wind to Belgium is key in climate neutral economy. Hydrogen Import Coalition, 2021 Available at: Link

Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy- A Contribution to the Transition of the Gas Market. Hydrogen Europe, 2019. Available at: Link

Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. M. W. Melaina, O. Antonia, and M. Penev (NREL), March 2013. Available at: Link

Hydrogen Act. Towards the Creation of the European Hydrogen Economy. J. Chatzimarkakis, C. Levoyannis, Prof Dr Ad van Wijk, and F. Wouters (Hydrogen Europe), April 2021. Available at: Link

Institutions Views and Studies

Sector integration - Regulatory framework for hydrogen (Final report), Trinomics and LBST prepared for the European Commission. November, 2020.

Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure. Trinomics, LBST et al., for the European Commission, 2019. Available at: Link

A hydrogen strategy for a climate- neutral Europe. European Commission, July 2020. Available at: Link

Hydrogen generation in Europe: Overview of costs and key benefits. Guidehouse, Tractebel Impact for European Commission, July 2020. Available at: Link

The National Hydrogen Strategy. German Federal Ministry of Economic Affairs and Energy, June 2020.

The Future of Hydrogen. Seizing today's opportunities. Report prepared by the International Energy Agency (IEA) for the G20, Japan. June, 2019. Available at: Link

Hydrogen in North-Western Europe. A vision towards 2030. International Energy Agency (IEA). Available at: Link

Academia Views and Studies

Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies. Document appeared in Detlef Stolten, Thomas Grube (Eds.): 18th World Hydrogen Energy Conference 2010 - WHEC 2010, Parallel Sessions Book 4: Storage Systems / Policy Perspectives, Initiatives and Co-operations. Available at: Link

Technical potential of salt caverns for hydrogen storage in Europe. International Journal of Hydrogen Energy. Dilara Gulcin Caglayan, Nikolaus Weber, Heidi U. Heinrichs, Jochen Linßen, Martin Robinius, Peter A. Kukla, Detlef Stolten. February, 2020. pp. 6793- 6805. Available at: https://doi.org/10.1016/j.ijhydene.2019.12.161

Others (Reports for Standardisation, Think-tanks, etc.)

Sector Forum Energy Management / Working Group Hydrogen Final Report. E. Weidner, M. Honselaar, R. Ortiz Cebolla (JRC), B. Gindroz (CEN/CENELEC), F. de Jong (NEN). CEN – CENELEC, 2016. Available at: Link

No- Regret Hydrogen: Charting Early Steps for Hydrogen Infrastructure in Europe. AFRY Management Consulting Limited on behalf of Agora Energiewende, January, 2021. Available at: Link

Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy. Energy Transition Commission, April 2021. Available at: Link