



# European Hydrogen Backbone

HOW A DEDICATED HYDROGEN  
INFRASTRUCTURE CAN BE CREATED

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Enagás, Energinet, Fluxys Belgium,  
Gasunie, GRTgaz, NET4GAS, OGE,  
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# Executive summary

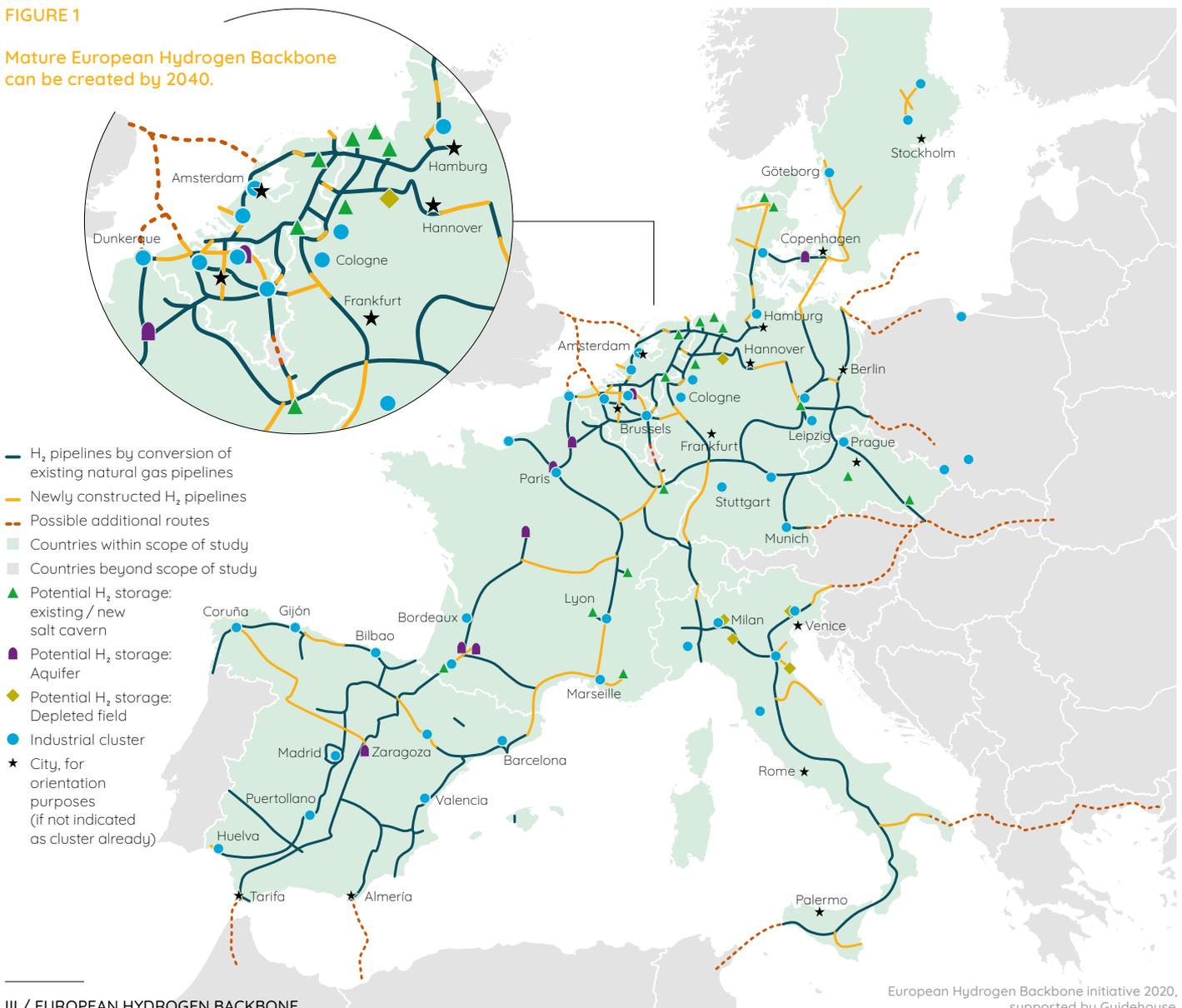
In the transition to a net zero-emission EU energy system, hydrogen and biomethane will play a major role in a smart combination with renewable electricity, using Europe’s well-developed existing energy infrastructure. For hydrogen to develop to its full potential, there must be a tangible perspective towards developing a well-connected European hydrogen market over time.

A rapid scale up of renewable power for direct electricity demand will also provide a basis for renewable green hydrogen supply, especially from the late 2020s onwards. In the medium to long term, most hydrogen will be renewable hydrogen. Yet before cheap renewable electricity has scaled up sufficiently, low carbon blue hydrogen will be useful to accelerate decarbonisation from the mid-2020s onwards. This low carbon hydrogen will partly be based on applying CCS to existing grey hydrogen production at industrial clusters.

Large-scale hydrogen consumption will require a well-developed hydrogen transport infrastructure. This paper presents the European Hydrogen Backbone (“the EHB”): a vision for a truly European undertaking, connecting hydrogen supply and demand from north to south and west to east. Analysing this for ten European countries (Germany, France, Italy, Spain, the Netherlands, Belgium, Czech Republic, Denmark, Sweden and Switzerland), we see a network gradually emerging from the mid-2020s onwards. This leads to an initial 6,800 km pipeline network by 2030, connecting hydrogen valleys. The planning for this first phase should start in the early 2020s. In a second and third phase, the infrastructure further expands by 2035 and stretches into all directions by 2040 with a length almost 23,000 km. Likely additional routes

FIGURE 1

Mature European Hydrogen Backbone can be created by 2040.



through countries not (yet) covered by the EHB initiative are included as dotted lines in the 2040 map. Further network development is expected up to 2050. Ultimately, two parallel gas transport networks will emerge: a dedicated hydrogen and a dedicated (bio)methane network. The hydrogen backbone as presented in this paper will transport hydrogen produced from (offshore) wind and solar-PV within Europe and also allows for hydrogen imports from outside Europe.

European gas infrastructure consists of pipelines with different sizes, from 20 inch in diameter to 48 inch and above. The hydrogen backbone, mainly based on converted existing pipelines, will reflect this diversity. Converted 36- and 48-inch pipelines, commonly in use for long-distance transport of gas within the EU, can transport around 7 resp. 13 GW of hydrogen per pipeline (at lower heating value<sup>1</sup>) across Europe, which provides an indication of the vast potential of the gas infrastructure to take up its role in the future zero-emission EU energy system. And this is not even the highest capacity technically possible; from our analyses, we have concluded that it is more attractive to operate hydrogen pipelines at less than their maximum capacity, leading to substantial savings on investment in compressors and on the cost of operating them, including their energy consumption.

Such a dedicated European Hydrogen Backbone (2040 layout) requires an estimated total investment of €27-64 billion based on using 75% of converted natural gas pipelines connected by 25% new pipeline stretches. These costs are relatively limited in the overall context of the European energy transition and substantially lower than earlier rough estimations. The relatively wide range in the estimate is mainly due to uncertainties in (location dependent) compressor costs.

The operational cost is lower than expected as well; the amount of electricity required is around 2% of the energy content of the hydrogen transported, taken over a transport distance of 1,000 km. So, while the European Hydrogen Backbone provides competition and security of supply, costs for transport of hydrogen account for only a small part of total hydrogen costs for end users. The levelised cost is estimated to be between €0.09-0.17 per kg of hydrogen per 1000 km<sup>2</sup>, allowing hydrogen to be transported cost-effectively over long distances across Europe.

This paper concludes that the cost of such a European Hydrogen Backbone can be very modest compared to the foreseen size of the hydrogen markets. That is why we now propose to launch it as a 'first mover', facilitating developments on the supply and demand side. European gas infrastructure companies are ready to lead and to invest in hydrogen transport to facilitate a scaling up of hydrogen, thereby being part of the solution to create a climate neutral European energy system and a European market for hydrogen. The backbone should allow for access by all interested market parties under equal terms and conditions.

Enabling the creation of a European Hydrogen Backbone has multiple implications for policy making. In its recent Hydrogen Strategy, the European Commission has already announced that it aims to ensure the full integration of hydrogen infrastructure in the infrastructure planning, including through the revision of the Trans-European Networks for Energy and the work on the Ten-Year Network Development Plans (TYNDPs). Policy making on sustainable finance, and the review of the gas legislation for competitive decarbonised gas markets will also need to play their role in enabling the long-term investments in this key European infrastructure.

This European Hydrogen Backbone is an open initiative. We invite other gas infrastructure companies from across Europe and from adjacent geographies and our associations GIE and ENTSOG to join in the thinking, to further developing the plan and expanding it into a truly pan-European undertaking. We are also looking forward to discussing our initiative with stakeholders including policy makers and with initiatives on the supply and demand side, including Hydrogen Europe's 2 \* 40 GW electrolyser plan.

As European gas infrastructure companies, we fully support the European Green Deal and we are willing to play our part in facilitating the scale up of renewable and low carbon gas. We see the European Hydrogen Backbone as a critical piece of the puzzle.

1 We choose to report hydrogen energy and capacity values on the basis of lower heating value (LHV) as it is customarily in energy system analyses and it enables for straightforward comparison between various fuels.

2 Conversion factors for hydrogen:  
1 kg = 0.033 MWh (at lower heating value);  
1 kg = 0.039 MWh (at higher heating value).

# 1. Background and scoping

## 1.1 The promise of hydrogen

The prospects for affordable green and blue hydrogen are rapidly improving, which is good news for a cost-effective decarbonisation of the European economy. It also offers the perspective of creating economic activity and jobs in a future-proof, sustainable, and globally relevant sector. The European Commission has a clear ambition to stimulate the scale-up of hydrogen already before 2030, as highlighted in its Hydrogen Strategy<sup>3</sup> and Energy Integration Strategy<sup>4</sup>, both published on 8 July 2020.

There is a great potential for renewable and low-carbon hydrogen to be produced in large volumes domestically within the European Union. The recently published Gas for Climate study 'Gas Decarbonisation Pathways 2020 to 2050'<sup>5</sup> describes that a large quantity of 1700 TWh of hydrogen could be produced within the EU by 2050. Domestic hydrogen production can be based on solar PV, e.g. in Spain and Italy or based on offshore wind, e.g. on the north and Baltic seas. Domestic hydrogen production can also be blue hydrogen produced at locations (likely industrial clusters) with good transport links to carbon storage locations. In addition to EU domestic production, there is also a promising outlook of large-scale imports of (mainly renewable) hydrogen from countries outside the European Union. In its Hydrogen Strategy, the Commission expects that hydrogen supply will be developed within Europe but also sees an important role for international trade, in particular with the EU's neighbouring countries in Eastern Europe and in the Southern and Eastern Mediterranean countries. The Commission also highlights that hydrogen supply ultimately mainly consist of renewable green hydrogen, yet that low carbon blue hydrogen has a role to play in the short to medium term.<sup>6</sup>

## 1.2 Dedicated infrastructure to connect supply and demand

Hydrogen production could take place on-site close to where it is used. However, this is not always the most efficient supply option. For instance, in cases where hydrogen consumers are located away from large supply of renewable electricity or CCS locations and have access to existing gas grids, it will be cost-effective to receive hydrogen through gas grids. Existing gas infrastructure can be used, with some modifications, to safely transport hydrogen. In addition, the connection to a hydrogen network increases security of supply significantly. Pipeline transport is far cheaper compared to hydrogen transport via shipping,<sup>7</sup> however the latter could become relevant for very long-distance transport of hydrogen (beyond several thousands of kilometres). Pipeline transport of hydrogen can either take the form of blending shares of hydrogen with methane or can be dedicated hydrogen transport. Blending makes sense when hydrogen volumes are small, especially during the 2020s. When hydrogen volumes increase while transported volumes of natural gas decrease, dedicated hydrogen transport will emerge, initially connecting industrial clusters and later connecting regional and national hydrogen infrastructures.

All TSOs are studying and testing the repurposing of (parts of) their gas networks to enable dedicated hydrogen transport.

3 European Commission, A hydrogen strategy for a climate-neutral Europe, COM(2020)310.

4 European Commission, Powering a climate-neutral economy: an EU strategy for Energy System Integration, COM(2020)299.

5 Available at [www.gasforclimate2050.eu](http://www.gasforclimate2050.eu)

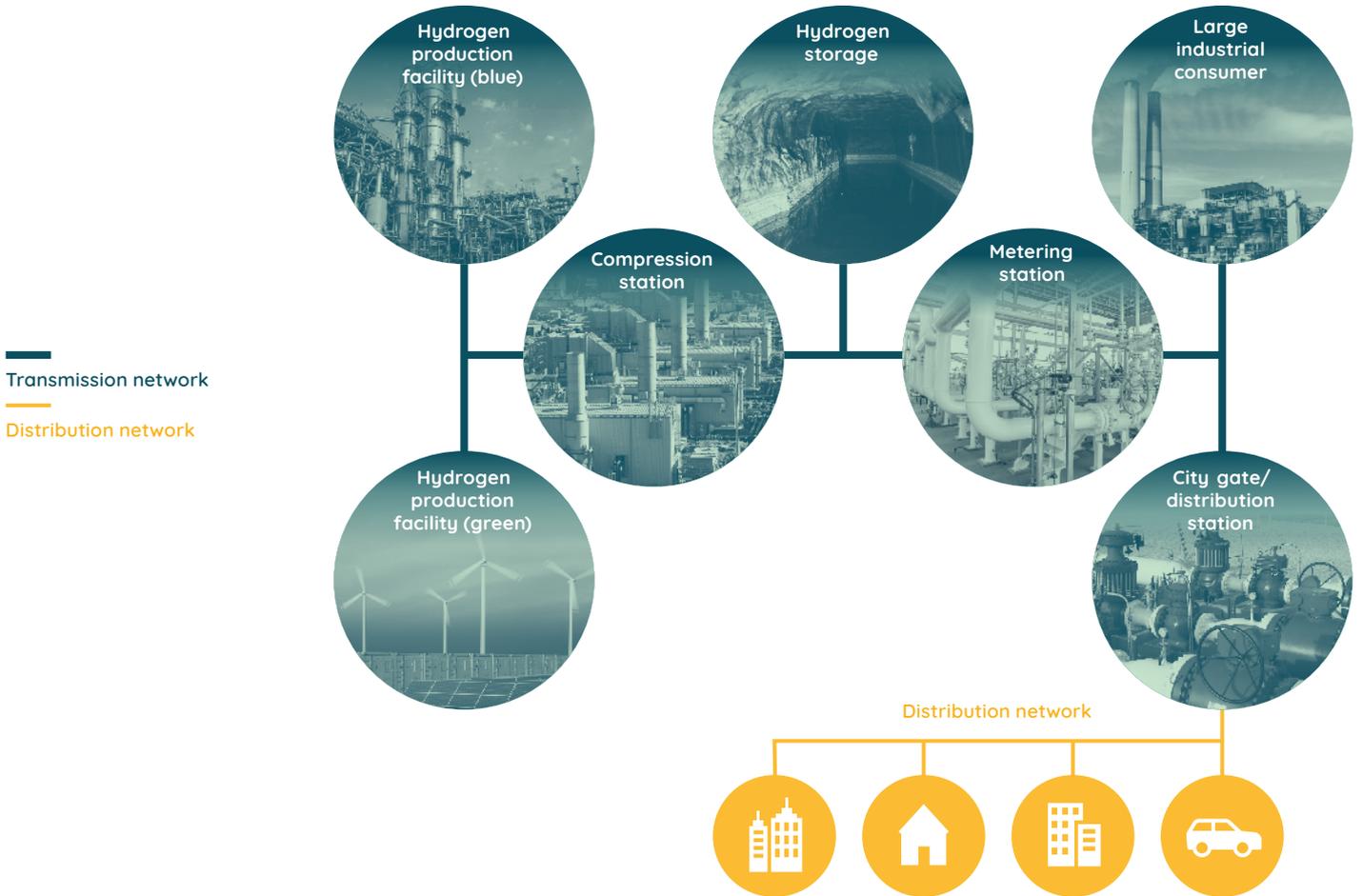
6 COM(2020)310, pages 5 and 7.

7 Navigant, 2019. *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*. Available at: <https://www.gasforclimate2050.eu/publications>

Hydrogen can be used for many applications, from high temperature industrial heat, the production of dispatchable electricity to providing transport fuel and buildings heat. Delivering hydrogen to all these demand sectors also involves distribution grids. While this paper does not explicitly analyse dedicated hydrogen distribution grids it should be highlighted that distribution networks will play an important role in delivering hydrogen to (industrial) end consumers.

FIGURE 2.

The European Hydrogen Backbone transports hydrogen from producers to consumers via pipelines.



### 1.3 Aim of this paper

This paper, authored by eleven gas infrastructure companies and supported by Guidehouse, describes how a dedicated hydrogen infrastructure can be created in a significant part of the EU between 2030 and 2040, requiring work to start during the 2020s. The hydrogen infrastructure as proposed in this paper fits well with the ambitions of the EU Hydrogen Strategy and the Energy System Integration Strategy, plus it aligns well with the goals of the recently announced Clean Hydrogen Alliance to scale up hydrogen, enabled by hydrogen transport. Hydrogen clearly gains momentum and this paper aims to provide a contribution towards accelerating a large scale-up of hydrogen by enabling its transport from supply to demand across Europe. This paper analyses the likely routes across Europe by 2030, 2035 and 2040. The included maps show the suggested topology of hydrogen pipelines in ten European countries: Germany, France, Italy, Spain, the Netherlands, Belgium, Czech Republic, Denmark, Sweden and Switzerland.

This paper describes what transport capacity can be made available while continuing to enable natural gas transport in parallel, although in gradually decreasing quantities. It is crucial that throughout the partial transition of gas infrastructure from natural gas to hydrogen, security of gas supply is ensured. It is expected that alongside dedicated hydrogen infrastructure, a methane transport grid will remain operational to transport increasing quantities of biomethane and decreasing quantities of natural gas including natural gas for blue hydrogen. The lay-out and capacities of the hydrogen backbone as proposed in this paper presents an 'initial offer' by TSOs on what the European gas grid can deliver mainly based on existing gas pipelines. It does take note of existing long-term natural gas transmission agreements as described in Appendix B.

The infrastructure as discussed in this paper is an initial proposal. The ultimate hydrogen grid has to be based on network planning, hydrogen market analysis, and industrial as well as policy commitment. This paper focuses on hydrogen pipelines and compressor stations. A mature European hydrogen backbone assumes well-functioning interoperability across borders and would also include storage, e.g. in salt caverns. Existing salt caverns could be repurposed for this. In this paper we include the locations of possible hydrogen storage locations. The amount of storage that would be required in the future depends on a number of factors and is not further analysed in this paper. Neither does this paper analyse the cost of hydrogen storage.

Also, this paper focuses on hydrogen infrastructure within (parts of the) EU, while highlighting possible hydrogen import pipeline options from outside the European Union.

The European gas infrastructure companies that created this paper support the European Green Deal and are willing to play their part in facilitating the scale up of renewable and low carbon gas. The European hydrogen backbone is a critical piece of the puzzle.

## 2. Gradual creation of a dedicated hydrogen infrastructure

This Chapter presents the topology of a dedicated pan-EU hydrogen backbone. Starting with an emerging infrastructure of approximately 6,800 km of hydrogen transport pipelines in 2030, the backbone gradually grows into a mature backbone by 2040, in line with the evolving nature of hydrogen supply and demand. This should not be taken as a 'final' picture, as growing hydrogen supply and demand will continue to require additional infrastructure development beyond 2040.

The proposed 2040 hydrogen backbone covers just over 22,900 km of pipelines in Germany, France, Italy, Spain, the Netherlands, Belgium, Czech Republic, Denmark, Sweden and Switzerland. These are the ten European countries which are home to the eleven gas infrastructure companies that jointly created this European Hydrogen Backbone vision paper.<sup>8</sup> Additionally, routes in some adjacent countries as well as possible import routes are suggested by means of dotted lines. The almost 23,000 km of pipelines by 2040 consist of approximately 75% repurposed natural gas infrastructure.

A great diversity exists in gas pipeline sizes in Europe today, ranging from modest 20-inch pipelines to large 48-inch pipelines or occasionally even larger transit pipelines. This diversity will also be reflected in the hydrogen infrastructure, which is largely based on existing pipelines. In the proposed 2040 layout, the backbone can provide transport capacities per pipeline of 7 GW for 36 inch and 13 GW for 48-inch pipelines (at LHV<sup>9</sup>), while in certain countries hydrogen pipelines will have smaller diameters of 24 inch.<sup>10</sup> The consolidation of these individual pipeline capacities into an interconnected grid is expected to provide enough capacity across Europe to adequately meet the total hydrogen transport demand by 2040.

The proposed topology represents the shared vision of eleven European gas TSOs based on high-level analysis of future natural gas market developments, availability of existing natural gas infrastructure, and ongoing and expected hydrogen initiatives. Nonetheless, it is important to note that the eventual infrastructure solution is highly dependent on future supply and demand dynamics of the integrated energy system, including natural gas, hydrogen, electricity, and heat. The real development of hydrogen supply and demand may lead to alternative or additional routes compared to the ones included in this paper, and the timeline of some of the 2030, 2035 and 2040 proposed routes may be shifted forward or backward in time.

### 2.1 Connecting industrial clusters to an emerging infrastructure in 2030

By 2030, green hydrogen production capacity may reach 40 GW, as is the ambition stated in the European Hydrogen Strategy.<sup>11</sup> This capacity could produce around 100 TWh of renewable hydrogen within Europe. Such scale-up will require large-scale first-of-a-kind projects, e.g. around the North Sea and in Spain. In addition, 80 TWh blue hydrogen may be created by 2030,<sup>12</sup> including retrofitted grey hydrogen production plants as well as newly built blue hydrogen facilities. Whereas blue hydrogen production will likely be located near hydrogen consumers, green hydrogen will be destined to consumers and offtakers located elsewhere, requiring dedicated transport routes already from the late 2020s onwards, which can be provided by the emerging backbone.

By 2030, a dedicated European Hydrogen Backbone can develop with a total length of approximately 6,800 km, consisting mainly of retrofitted existing natural gas pipelines. This backbone, shown in Figure 3 includes the proposed Dutch<sup>13</sup> and German<sup>14</sup> national hydrogen backbones, with additional branches extending into Belgium and France. Furthermore, unconnected regional networks are likely to emerge in Italy, Spain, Denmark, Sweden, France, and Germany.

8 Or in the case of Switzerland, home FluxSwiss, to a daughter company of Fluxys

9 LHV: Lower heating value or net calorific value (NCV) represents the energetic value of a gas, after subtracting the heat of vaporisation from the higher heating value. All energy values concerning hydrogen are reported in LHV unless noted otherwise.

10 Regions with smaller average pipe diameters (24-36 inch), notably certain areas in France, Spain, and Denmark, will have smaller transport capacities per pipeline.

11 COM(2020)310, page 6.

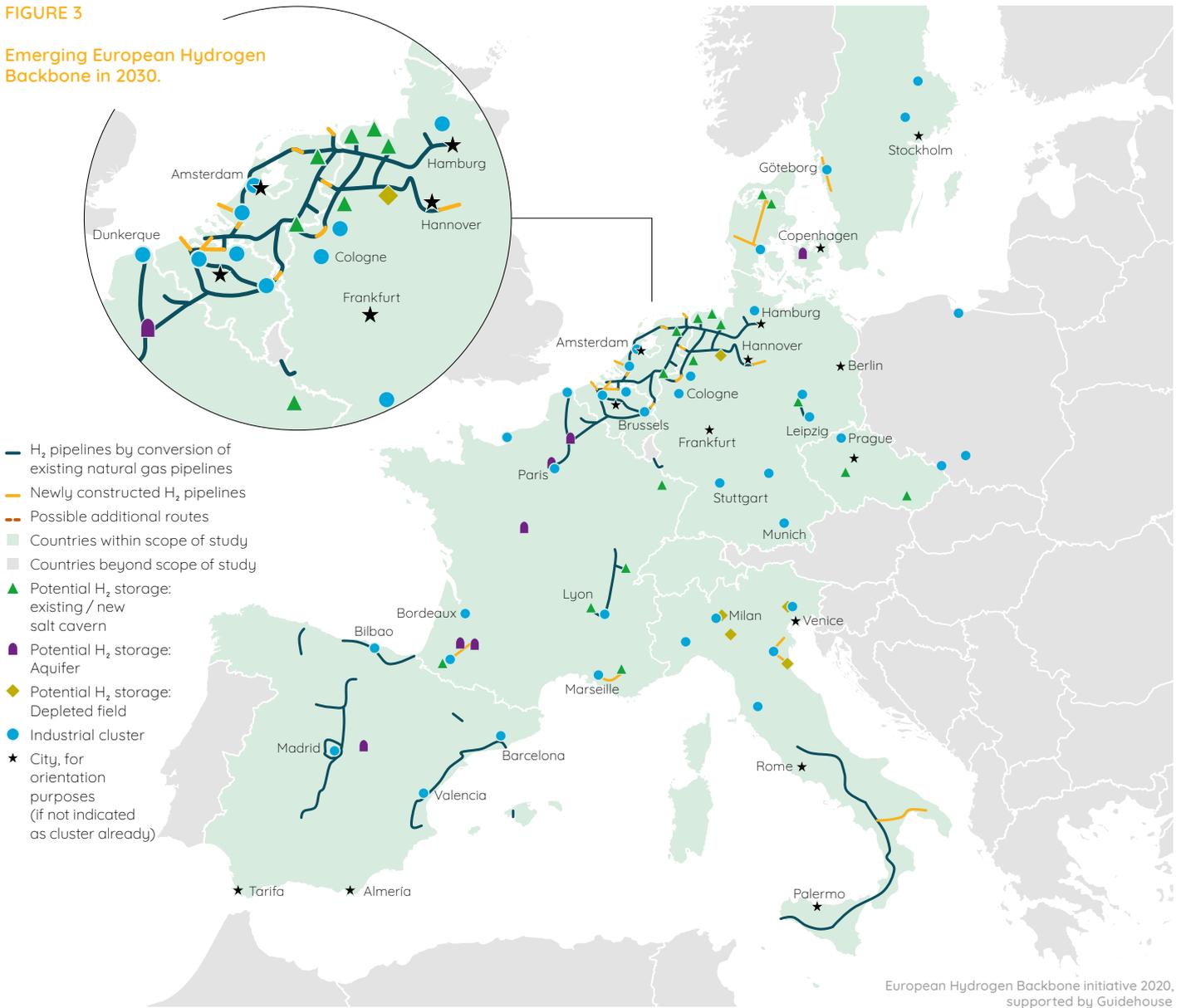
12 Gas for Climate, Gas Decarbonisation Pathways 2020-2050

13 Gasunie, 2019. *Moving towards 2030 and 2050 with hydrogen*. Available at: <https://www.gasunie.nl/en/expertise/hydrogen/hydrogen-projects>

14 FNB Gas, 2020. *Transmission system operators publish H<sub>2</sub> "Startnetz" 2030*. Available at: <https://www.fnb-gas.de/fnb-gas/veroeffentlichungen/pressemitteilungen/fernleitungsnetzbetreiber-veroeffentlichen-h2-startnetz-2030/>

FIGURE 3

Emerging European Hydrogen Backbone in 2030.



Regional backbones are expected to form in and around first-mover hydrogen supply and demand hubs, or “hydrogen valleys”. These include industrial clusters, ports, cities, and other regions that are already embracing pilot projects and commercial hydrogen developments today. Based on ongoing and planned projects, an interconnected cluster will likely emerge in the north of the continent including parts of Belgium, The Netherlands, and North-West Germany. A dedicated backbone in this region can enhance the benefits of various hydrogen initiatives, including co-located electrolysis-plus-wind farms and blue hydrogen plants on the supply-side, and fuelling station deployments and industrial sites on the demand-side. Similarly, regional networks could emerge around clusters in Denmark and Sweden, in and around the regions of Jutland and Göteborg, respectively. Beyond these northern hydrogen valleys, market developments are also encouraging the development of regional networks in France and Spain, where a range of projects are ongoing in the regions surrounding Lacq, Marseille, Fos, Lyon, The Basque Country, Castile and León, Aragon, and Asturias.<sup>15</sup> Lastly, dedicated hydrogen infrastructure developments in Italy are likely to start around existing industrial clusters in the south of the country (Sicily, Puglia), supplied with green hydrogen from regional renewable energy sources

15 For example, the Green Spider IPCEI (Important Project of Common European Interest) aims to develop a large-scale green hydrogen network to export to Europe.

including solar PV as well as brownfield wind farms. Today, small-scale dedicated hydrogen networks of approximately 1,600 km in length<sup>16</sup> exist in Europe to transport fossil-based, “grey” hydrogen between industrial clusters. These pipelines, mostly operated by private hydrogen producers, have limited transport capacity and are not included in this paper’s infrastructure maps. Yet these networks demonstrate that hydrogen transport over longer distances is possible – and safe.

The emerging backbone is mainly based on retrofitted natural gas infrastructure. Retrofitting is often achieved through conversion of existing pipelines where parallel (“looped”) routes are available. This is the case in areas in the Netherlands, Germany, France, Spain, and Italy, where pipeline availability is not constrained by long-term natural gas commitments and capacity contracts. In most accelerated climate scenarios, aggregate natural gas demand in the EU is expected to decline between 2020 and 2030,<sup>17</sup> in part due to electrification of heat in buildings and through substitution by green gases. As such, gas network utilisation at peak demand is expected to decrease over time in certain EU countries. Combined with changes in supply routes due to closure of the Groningen Field and the transition from low-calorific gas supply to high-calorific gas supply in North-West Europe, this will create space in existing pipelines in specific regions and offer possibilities to convert the latter into dedicated hydrogen pipelines.

As the emerging backbone will be a “first-mover” project based predominantly on repurposed infrastructure, theoretical pipeline capacities in 2030 will likely be greater than needed to meet the expected volume flows. However, this approach offers optionality and has negligible cost impact. Firstly, pipeline costs are limited given that most of the network will be retrofitted. Secondly, limited volumes translate to low capacity requirements, which results in modest compression costs. At the same time, the presence of a centrally coordinated European Hydrogen Backbone by 2030 will provide commercial security and project bankability to market actors as well as the political signal that hydrogen will play a critical role in ensuring a decarbonised and integrated European energy system.

## 2.2 Growing network covering more countries in 2035

Between 2030 and 2035, the European Hydrogen Backbone will continue to grow, covering more regions and developing new interconnections across Member States as shown in Figure 4 below. Driven by the ambitious policy environment set by the Green Deal, an increased urgency to meet climate targets, and a rapidly increasing number of projects and initiatives supported by public authorities and industry,<sup>18</sup> the backbone will naturally extend into areas where cost-effective pipeline transport of hydrogen is needed to meet market demands.

From 2030 onwards, renewable electricity generation will have scaled up sufficiently to enable large-scale growth in green hydrogen production, making use of solar resources in the south of France, Italy, and Spain, and wind resources around the North, Baltic, and Mediterranean Seas. As a result, notable additions in the 2035 backbone include (1) the interconnection between Denmark and Germany; (2) extension of the north-south French corridor to Marseille; (3) additional coverage in central and eastern Germany; (4) a dedicated hydrogen microgrid around industrial clusters in the east of Sweden; and (5) the potential completion of an interconnection between eastern Germany and Poland.

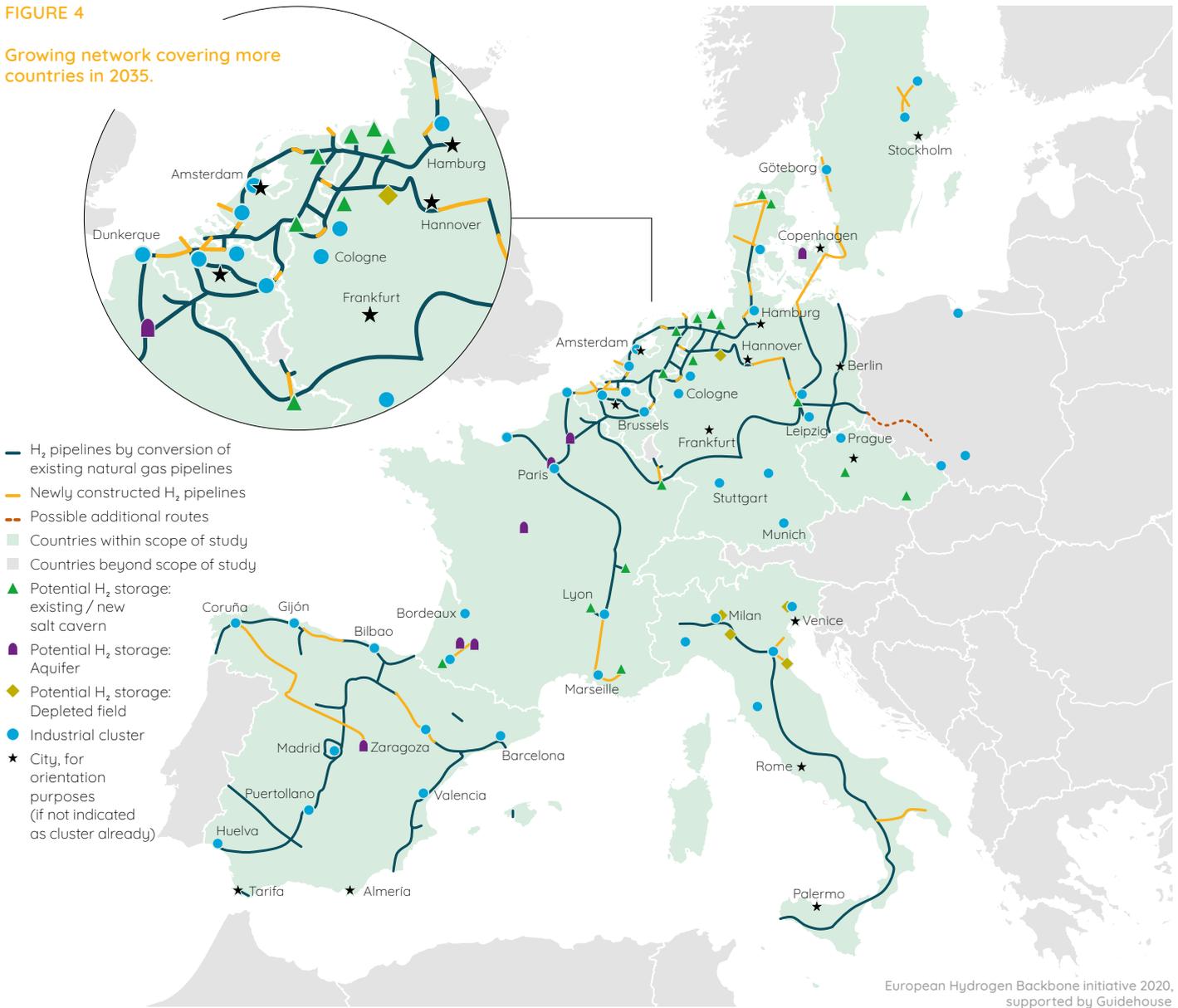
16 H<sub>2</sub> Tools, 2016. *Hydrogen Pipelines September 2016*. Available at: <https://h2tools.org/hyarc/hydrogen-data/hydrogen-pipelines>

17 For example, Navigant, 2020. *Gas for Climate. Gas Decarbonisation Pathways 2020-2050*. Note that some scenarios forecast constant volumes or even growth between 2020-2030.

18 The European Clean Hydrogen Alliance: A collaboration between public authorities, industry, and civil society launched in July 2020 will develop an investment agenda and a pipeline of concrete hydrogen projects, complementing the European Commission’s Strategy for Energy System Integration.

FIGURE 4

Growing network covering more countries in 2035.



These additions around 2035 mean that hydrogen consumers in the centre of the continent will be connected to regions with abundant green hydrogen resource potential, including from Danish offshore wind resources as well as solar and wind resources from the south of France. These north-south corridors will become increasingly important as adoption of hydrogen in the transport, industry, and power sectors accelerates and leads to demand outgrowing supply in regions without access to high levels of renewable electricity. The developments also pave the way for future hydrogen imports from further south including from North Africa through Spain and Italy, which are highly likely by 2040, and possibly even before then.

Finally, the increasing share of green hydrogen produced from volatile renewable energy sources will lead to an inherently more intermittent nature of hydrogen supply. As such, dedicated hydrogen storage facilities become increasingly important to balance daily and seasonal fluctuations in supply and demand. These dedicated storage facilities will complement linepack flexibility in pipelines<sup>19</sup> and can be added to the grid by repurposing existing natural gas storages in salt caverns, by making available new salt caverns, and potentially by using depleted fields and aquifers currently used for natural gas. Research into

19 Linepack refers to the amount of gas “stored” within the pipeline system. The ability to further compress and expand this gas provides an inherent level of flexibility to the system and can act as a storage buffer.

the technical suitability of depleted natural gas fields and aquifers is ongoing, and regulations for using these as storage solutions for hydrogen would still need to be put in place in many countries.

### 2.3 Mature infrastructure stretching towards all directions by 2040

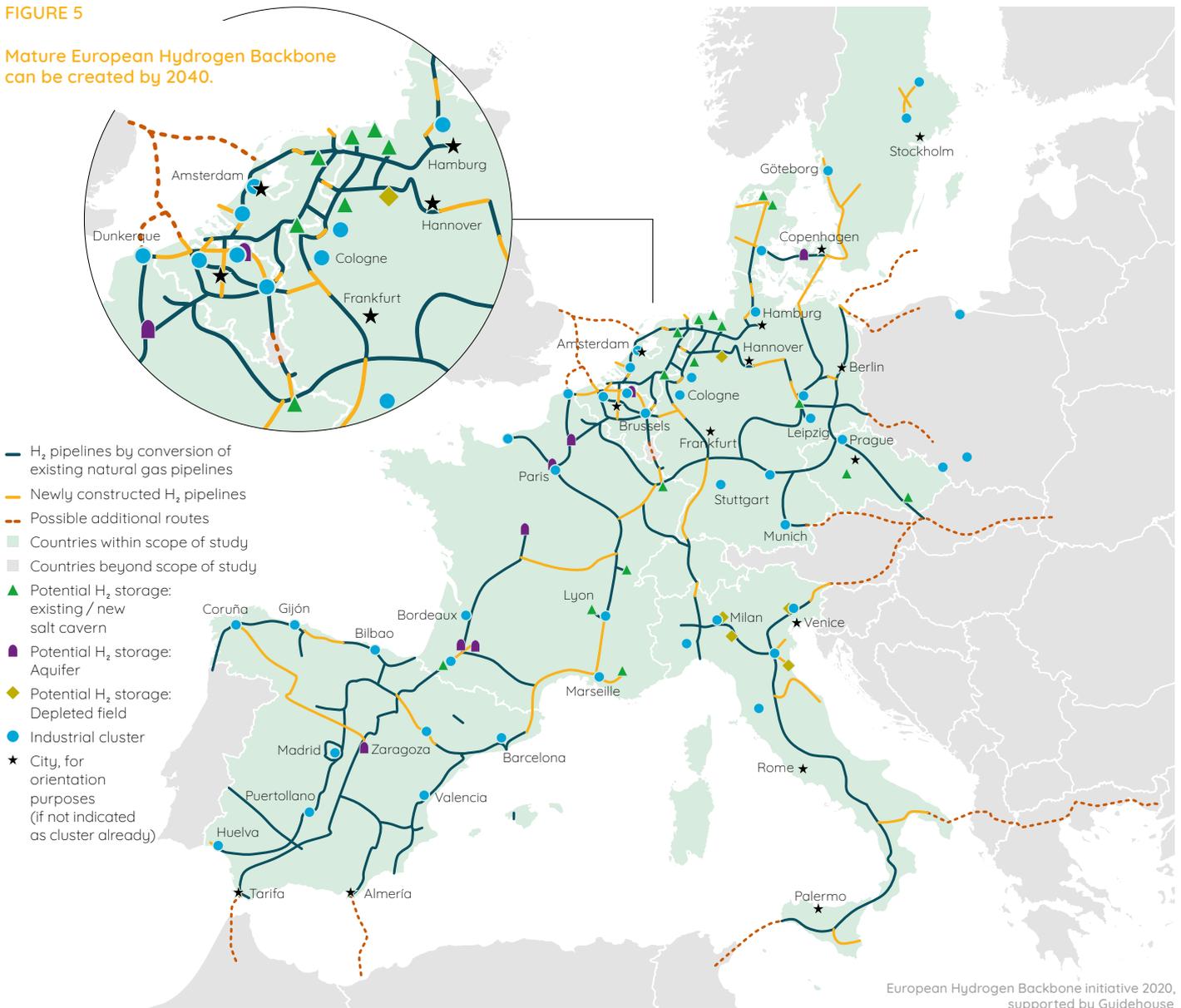
A core European Hydrogen Backbone can be envisaged by 2040. This means that a pan-EU hydrogen infrastructure can be created with large corridors connecting the majority of West-European countries as well as valuable extensions into Central and Eastern Europe, as shown in Figure 5. By 2040, the proposed backbone can have a total length of 22,900 km, consisting of approximately 75% retrofitted existing infrastructure and 25% of new hydrogen pipelines. Assuming that the backbone is equipped with a fit for purpose and technically robust compression system, as detailed in Chapter 3, the proposed network should be able to adequately meet the 1130 TWh<sup>20</sup> of annual hydrogen demand in Europe by 2040.<sup>21</sup>

20 Navigant, 2020. *Gas for Climate. Gas Decarbonisation Pathways 2020-2050*. Available at: <https://gasforclimate2050.eu/publications>

21 Preliminary estimation, the exact capacity of the meshed grid requires more detailed analysis.

FIGURE 5

Mature European Hydrogen Backbone can be created by 2040.



By 2040, the Gas for Climate Decarbonisation Pathway analysis predicts that European natural gas demand will have continued to decrease alongside the expected growth of green gas, with natural gas down to approximately 50% of 2020 demand.<sup>22</sup> The expected expiry of several long-term natural gas pipeline contracts in the 2030s opens additional opportunities for natural gas network conversion.

Whereas the hydrogen backbone predominantly serves industrial demand in the early 2030s with some hydrogen transported to power plants, the latter part of the decade will also see hydrogen become a significant energy vector in multiple adjacent sectors. Especially in regions where new industrial anchor customers trigger larger amounts of hydrogen to be made available, the potential to decarbonise other sectors – e.g. power and transport – along the route increases sharply. By 2040, non-industrial hydrogen consumption is expected to comprise almost 50% of total hydrogen demand.<sup>23</sup> Green hydrogen sources will be a combination of wind energy resources, predominantly from the countries bordering the North Sea, and solar energy from the south. Towards the end of the 2030s, the cost reductions in green hydrogen production from solar PV in southern European countries will drive the significant production increase, which is needed to meet rapid growth in demand, both regionally and beyond. As a result of rapid cost declines and increased system integration, green hydrogen production will overtake blue hydrogen shortly after 2040 and continue to accelerate up to 2050.

The direct link between hydrogen flows and corresponding network capacities is beyond the scope of this paper. However, indicative national hydrogen supply and demand projections based on previous work from the Gas for Climate consortium show that the backbone will play a critical role in transporting hydrogen volumes from production hubs in the north and south towards anchor offtakers and hydrogen sinks in the centre of the continent. Given that hydrogen flows need to cover significant distances by 2040, compression requirements will increase between 2030-2040 and the corresponding investments in pipeline and compression infrastructure will need to scale up in line with capacity requirements needed to meet this demand. Compression system and network design are a multi-faceted optimisation challenge and are discussed in more detail in Chapter 3.

In addition to supporting development of the intra-EU hydrogen market, the EHB enables connection to global hydrogen flows via new import routes. These include green hydrogen imports from North Africa, the North Sea (Norway and the UK), and possibly Ukraine and Greece, as well as blue/turquoise hydrogen from Russia, and connections with retrofitted LNG terminals – insofar the latter are technically feasible. Hydrogen imports from these countries are expected to replace existing natural gas imports and will make up a material portion of hydrogen volumes, approximately 50 TWh by 2040 and continuing to increase to up to a quarter of total EU hydrogen volumes, or 450 TWh by 2050.

Finally, it is important to note that while most accelerated climate scenarios expect hydrogen demand growth between 2030-2040 to be significant, even more growth in volume is expected to occur during the 2040s. As such, the 2040 backbone displayed in Figure 5 should be considered as a critical milestone, but not a final product. The backbone as proposed for 2040 represents a foundational network, “a mature hydrogen highway”, upon which further developments can be built. Depending on the evolution of the hydrogen market, including the pace and location of development, additional reinforcements and extensions to the backbone can be made to accommodate these ambitions.

22 Accelerated Decarbonisation Pathway as analysed in Gas for Climate, Gas Decarbonisation Pathways 2020-2050

23 Navigant 2020, *Gas for Climate. Gas Decarbonisation Pathways 2020-2050*. Available at: <https://gasforclimate2050.eu/publications>

## 3. Cost of the European Hydrogen Backbone

Hydrogen can be transported through pipelines that were built for natural gas. As described in the following, pipelines themselves need little modification, and new stretches of dedicated hydrogen pipeline do not differ a lot from natural gas pipelines either. However, depending on the capacity at which the pipeline is operated, major modifications on the compressor stations may be needed.

Hydrogen has a lower energy density than natural gas: at the same pressure, a cubic meter of hydrogen only contains 1/3 of the energy of a cubic meter of natural gas. However, this does not mean that three times as many pipelines are required to transport the same amount of energy. The volume flow 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. That way, a 48-inch pipeline, one of the widest pipeline types in the intra-EU gas network, can transport around 17 GW in hydrogen (LHV),<sup>24</sup> and a 36-inch pipeline can transport around 9 GW (LHV).

However, this design can be further optimised. Exploratory analysis by gas TSOs shows that operating hydrogen pipelines at less than their maximum capacity, e.g. 13 GW (LHV) for a 48-inch pipeline and 7 GW for a 36-inch pipeline gives much more attractive transport costs per MWh transported as additional expensive high capacity compressor stations and corresponding electricity consumption can be avoided. The fixed pipeline-related costs per MWh obviously increase, yet compressor costs and the corresponding cost of the energy fall sharply.

For new stretches, the picture is similar, meaning that when more than 13 GW of transport capacity is required on a route with one 48-inch hydrogen pipeline, it can be more attractive to partly build a second one with the same or even larger capacity rather than investing in expensive compressors to ramp up the capacity of the first pipeline. The concept of compression versus pipeline dimension, while considering the characteristics and availability of the existing gas network, is one of the main levers for cost optimisation.

Depending on the specifics of the required capacity, also other smaller cost items will be taken into consideration in the attempt to determine the cost optimal way for a given pipeline and network location. For example: inner coating of an existing natural gas pipeline – though not technically required – might allow for higher pressures when switching to hydrogen.<sup>25</sup> The additional cost of coating the pipeline and the higher relative pressures that it enables must be taken into account when doing the overall optimisation for a certain route.

When operating the pipelines at a lower capacity, it can be explored whether electrolysers can bring the hydrogen they produce into the pipeline at a high pressure. At reduced capacity, hydrogen can then already travel over quite large distances without any additional compression needed. This enables a relatively low-cost start of a (national) hydrogen pipeline system, where new compressors or a higher inlet pressure can be considered once demand and supply forecasts start to pick up. In this way, the initial hydrogen infrastructure can be a first mover, enabling the deployment of projects on the supply and demand side, with a modest investment by society.

<sup>24</sup> A 48-inch natural gas pipeline has a capacity of 20.7 GW<sub>LHV</sub> (23 GW<sub>HHV</sub>).

<sup>25</sup> According to R&D results and exploratory analysis by TSOs.

## 3.2 Estimating total cost of the European Hydrogen Backbone

The total cost estimation of the EHB focuses on hydrogen infrastructure development as defined in Chapter 2 for 2040. Herein, the hydrogen backbone is defined as consisting of transmission pipelines, compressor stations, control valves, and gas metering stations. Hydrogen storage, distribution pipelines, and CO<sub>2</sub> infrastructure costs were not quantitatively assessed for this paper.

### 3.2.1 Total investment and operating cost

Total investment costs of the envisaged 2040 European Hydrogen Backbone are expected to range from €27 to €64 billion, covering the full capital cost of building and retrofitting the backbone presented in Chapter 2. This compares to the hundreds of billions in investments in green hydrogen production that the EC Hydrogen Strategy foresees, already for the period up to 2030. The 22,900 km backbone will consist of 75% retrofitted pipelines, with diameters ranging between 24-48 inch, and will provide 3-13 GW (LHV) transport capacity per pipeline. In the medium case, 60% of the total investment costs will be dedicated to pipeline works and the remaining 40% will be spent on compression equipment.

While 75% of the total network or almost 18,000 km will consist of retrofitted infrastructure, this represents only around 50% of the total investment, which shows the value of making use of existing pipelines.

Annual operating costs are expected to be between €1.6 and €3.5 billion<sup>26</sup> when assuming a load factor of 5000 hours per year.<sup>27</sup> This includes operating and maintenance (O&M) costs for the pipeline network and compression stations, as well as electricity costs to power the compressors. In the 'medium' case, O&M and electricity costs each make up approximately 40% and 60% of the total annual amount, respectively. Important to note are the modest electricity costs for compression, which stem from the limited compression requirements as a result of being able to use and retrofit large pipelines across the network. To put things into perspective: when operating at 13 GW (LHV) capacity, electricity requirements for compression are between 190-330 MW<sub>e</sub> per 1000 km. This translates to 1.5-2.3% of the transported hydrogen's energy content being consumed for compression purposes for every 1,000 km of distance covered, assuming electricity-driven compressors. This estimate is lower than some earlier estimates,<sup>28</sup> thanks to the lower, more cost-optimal and energy-efficient flow assumed here.

Finally, whereas the cost estimates reported above represent those for the mature backbone in 2040, the inherent techno-economic characteristics of the gradual creation of the backbone mean that investment needs are ramped up gradually. From the mid-2020s leading up to 2030, required hydrogen capacities will still be modest, resulting in lower compression requirements meaning that investments in compression can be deferred to a later date. At the same time, pipeline costs will also be limited in the early days given that most pipelines are retrofitted at a significant discount compared to new-build costs. All in all, this means that the start-up costs to initiate the hydrogen backbone will only be a fraction of the total costs by 2040, which are shown in Table 1.

26 Not all of these operating costs are additional to current costs of running natural gas infrastructure. For reference, annual operating costs of natural gas infrastructure are around 5% of investment cost.

27 Load factor. This vision paper considers the backbone from an infrastructure investment perspective and does not take a strong stance on the exact level of network utilisation. A load factor of 5000 hours/year is deemed reasonable, cognizant of the fact that this value will change depending on future market developments.

28 Including those in Gas for Climate studies.

TABLE 1

Estimated investment and operating costs of the 22,900 km European Hydrogen Backbone (2040). Input ranges leading to the 'low', 'medium', and 'high' scenarios are presented in Appendix A.

		Low	Medium	High
Pipeline cost	€ billion	17	23	28
Compression cost	€ billion	10	17	36
<b>Total investment cost</b>	<b>€ billion</b>	<b>27</b>	<b>40</b>	<b>64</b>
OPEX (excluding electricity)	€ billion/year	0.7	0.9	1.1
Electricity costs	€ billion/year	0.9	1.2	2.4
<b>Total OPEX</b>	<b>€ billion/year</b>	<b>1.6</b>	<b>2.1</b>	<b>3.5</b>

### 3.2.2 Pipeline transport costs represent a small portion of total hydrogen costs

Given the infrastructure-oriented approach of this vision paper, the focus is on the total investment cost for the proposed 2040 backbone. Nevertheless, indicative levelised transport costs can also be determined to place the backbone's cost in the context of typical production costs from the perspective of end-consumers. A load factor of 5,000 hours per year is used to calculate levelised transport costs, displayed in Table 2 below. As shown, the levelised cost of transporting hydrogen through the European Hydrogen Backbone is estimated to be between €0.09-0.17 per kilo of hydrogen per 1000 km.<sup>29</sup>

These values show that pipeline transmission costs only represent a small portion of total hydrogen costs when considering the full value chain from production through to end consumption. Even assuming future production costs of 1-2 €/kg for green and blue hydrogen, transport through the hydrogen backbone will add less than 10% on top of production costs for 1000 km transported. Taking the example of the Marseille-Essen corridor, a fairly long potential route. Here, pipeline transmission will add 0.2 €/kg in the most pessimistic scenario, assuming the full distance is covered by means of newly constructed pipelines. This illustrates that the European Hydrogen Backbone can be a cost-effective 'first-mover' and facilitator for the European hydrogen market.

<sup>29</sup> Conversion factors for kg to MWh for hydrogen: 1 kg = 0.033 MWh (LHV); 1 kg = 0.039 MWh (HHV).

TABLE 2

Estimated levelised cost of hydrogen transport through pipeline infrastructure. Input ranges leading to the 'low', 'medium', and 'high' scenarios are presented in Appendix A.

		Low	Medium	High
Levelised cost, 100% new infrastructure	€/kg/1000km	0.16	0.20	0.23
Levelised cost, 100% retrofitted infrastructure	€/kg/1000km	0.07	0.11	0.15
<b>Levelised cost, European Hydrogen Backbone (75% retrofitted)</b>	<b>€/kg/1000km</b>	<b>0.09</b>	<b>0.13</b>	<b>0.17</b>

### 3.2.3 Cost estimation method and key network considerations

The starting point for the cost analysis consists of several fundamental network design considerations, as shown in Table 3 below. Herein, key parameters such as the power capacity of hydrogen flow, pipeline diameter, average pipeline length, and operating pressures are predefined based on availability of existing infrastructure as well as initial experimental and computational feasibility studies conducted by participating gas TSOs. However, it must be noted that no two gas transmission networks are the same. Whilst the chosen network parameters reflect a generic, 48-inch diameter system, network designs and consequently costs will undoubtedly vary across regions.

Specifically, there are noticeable variations across regional gas networks when it comes to operating pressures, average pipeline diameters, and existing compression system designs. Other parameters, such as the required hydrogen capacity and load factor, are also expected to shift over time as a result of changing market dynamics. These factors would impact the cost estimate, both positively and negatively. However, by taking an infrastructure-driven view (as opposed to designing for a specific system demand) and by selecting a generic network design for the analysis, the resulting parameters and cost ranges are deemed representative of the EU-average.

It is worth noting that the calculations are based on a straight-line network, do not consider redundant compressor units, and do not incorporate detailed network optimisation considerations of flexibility needed when the network is operated in an entry-exit capacity regime. Since historical data of hydrogen transmission infrastructure do not yet exist, the methodology and results presented below are best estimates based on TSOs' R&D efforts, empirical cost data, and widely-used pipeline engineering techniques applied to hydrogen flows. As indicated by the ranges in Table 1 and Table 2, there remains some uncertainty regarding costs in both directions, especially when it comes to compression.

TABLE 3

Predefined network design parameters for hydraulic simulations.

Parameter	Value
Capacity of hydrogen flow (at full load factor)	13 GW (LHV)
Pipeline diameter	48"
Distance between compressors	100-600 km
Discharge pressure	67-80 bar
Suction pressure	30-40 bar
Compression capacity	190-330 MW <sub>e</sub> per 1000 km
Assumed load factor for compressor electricity consumption	5000 hours/year
Compressor type	Reciprocal or centrifugal

Different approaches to network design are considered: relatively small compression stations placed at 100 km intervals and larger stations providing a range of 600 km each.<sup>30</sup> Preliminary calculations suggest that both approaches lead to the same order of magnitude of costs per 100 km transported, though a detailed analysis of the complex trade-offs between capital and operating expenditure for different pipeline sizes and locations has not yet been carried out.

<sup>30</sup> All compression system configurations shown in Table 3 have been evaluated by TSO technical engineering departments.

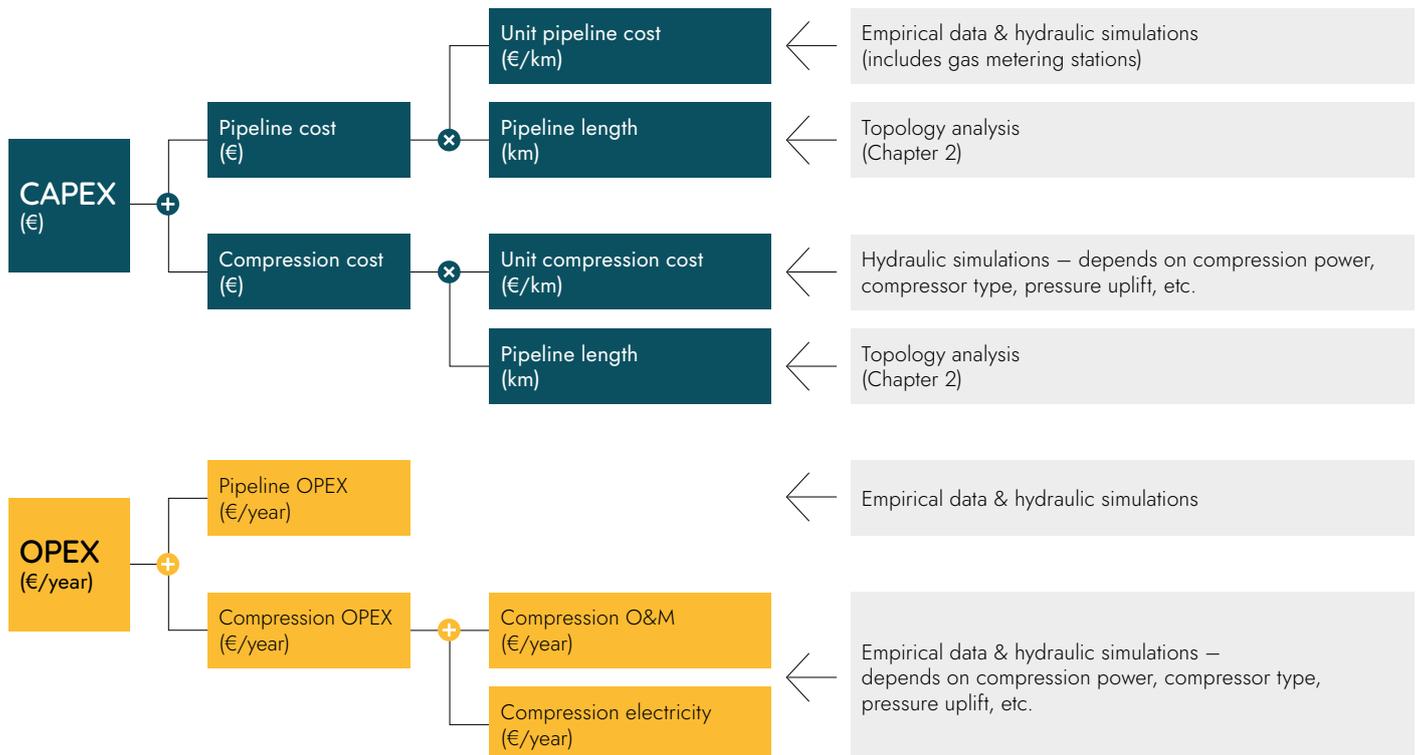
From these starting principles, hydraulic simulations are conducted to determine the operating conditions and requirements of the network. One of the preliminary findings from this exercise is that compression capacity of 190-330 MW<sub>e</sub> per 1000 km is sufficient to operate the network between 40 and 80 bar or between 30 and 67 bar in a 48-inch pipeline. This represents a significant reduction in the compression capacity required compared to previous studies, including the 2019 “Gas for Climate” study<sup>31</sup> which had estimated levelised transport costs of 0.23 €/kg/1000km, in part due to higher volume flow leading to higher compression costs. The latter is almost twice the 0.13 €/kg/1000km calculated in the medium case presented in Table 2.

Combining these operating characteristics with empirical unit cost information from existing natural gas infrastructure projects leads to a range of cost inputs, shown in detail in Appendix A. Based on these inputs, total investment, operating, and maintenance costs are calculated by multiplying the cost inputs by the total network length as determined in the Topology analysis in Chapter 2. The high-level costing equation is shown in Figure 6. Lastly, to reach the levelised figures displayed in Table 2, standard regulatory assumptions and investment criteria are applied as commonly done in European countries, detailed in Appendix A, to depreciate costs over time.

31 Navigant, 2020. *Gas for Climate. Gas Decarbonisation Pathways 2020-2050*. Available at: <https://gasforclimate2050.eu/publications>

FIGURE 6

Overview of cost equations for capital expenditure (CAPEX) and operating expenditure (OPEX).



This Chapter describes how natural gas infrastructure works today and how it can play a role to transport hydrogen. Firstly, covering pipelines, followed by compressor stations, and finally concluding with metering and city gate stations.

## 4. Key infrastructure components

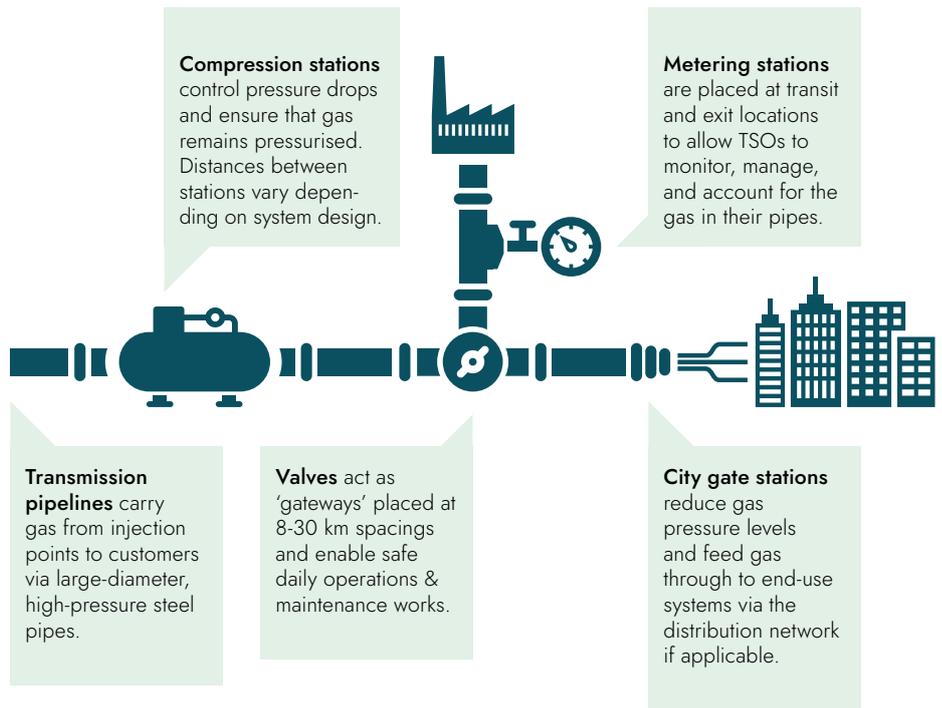


FIGURE 7

Schematic of the physical elements of natural gas infrastructure.

### 4.1 Transmission pipelines for hydrogen do not differ significantly from natural gas pipelines

#### 4.1.1 Physical properties of transmission pipelines

Transmission pipelines make up most of the infrastructure and serve to carry gas from production points to industrial customers and distribution networks via large-diameter, high-pressure steel pipes. These European transmission pipelines are usually between 16 to 56 inches (400 to 1400 mm) in diameter and operate at pressures ranging from 16 to 100 bar (gauge).

Research and lessons learned from first hydrogen projects by European gas TSOs show that dedicated hydrogen pipelines do not differ significantly from natural gas pipelines.<sup>32</sup> Current estimations and empirical evidence from TSOs indicate that the capital cost of a newly built dedicated hydrogen pipeline will be 10-50% more expensive than its natural gas counterpart,<sup>33</sup> though region-specific factors such as typical dimensioning of pipes affect this range. Similarly, existing natural gas pipelines need little modification to be fit for 100% hydrogen transport as the pipeline materials are generally fit for hydrogen transport as well. Initial discussions with manufacturing companies suggest that the capital cost of repurposing existing pipelines represents 10-25% of that of building new dedicated hydrogen pipelines.<sup>32</sup> The main elements of the conversion process include nitrogen purging to remove undesirable parts, pipeline monitoring to identify cracks, and replacements of valves in cases where the latter have been operational for extended periods of time. Furthermore, natural gas pipelines converted to hydrogen have to be operated at a lower pressure, although this may be avoided by adding a layer of internal coating. The relative ease of conversion from a technical standpoint and the modest repurposing costs are two key enablers of the EHB vision.

<sup>32</sup> Results from research and pilot projects conducted by European gas TSOs.

<sup>33</sup> Range varies significantly depending on pipeline diameter. For larger diameters (36 inch or more), range is on the lower side whereas costs for smaller diameter pipelines can reach 150%.

Transmission pipelines include many valves along their length. These valve placements depend on location, but spacings typically range from 8-30 km. Mainline valves work like gateways; they are usually open and allow gas to flow freely, but they can be used to stop gas flow when needed. If a section of pipe requires replacement or maintenance, valves can be closed to allow engineers safe access. Valves are also necessary to separate sections of pipe and minimise gas loss in case of pipe failure. Research relating to valve design and operations for dedicated hydrogen pipelines is ongoing. Initial testing shows that technical requirements under standard operating conditions are comparable to those of existing practices for natural gas. Depending on regional variations in existing network properties, partial replacement of valves and seals will be enough in some regions, whereas other regions will need full equipment replacement to prevent leakages.

#### 4.1.2 Hydrogen quality and structural integrity

Other factors to consider when transitioning from natural gas to hydrogen include chemical composition and gas purity as well as the impact these have on the network's structural integrity. The purity of hydrogen used in the network will be determined by factors on both the supply and demand side. In the case of fuel cells, most commercial types have strict hydrogen purity standards,<sup>34</sup> whereas industrial grade hydrogen – the current standard used for feedstocks – requires a purity of above 99.95%. It is to be expected that the chosen quality will depend on the application group with the largest consumption as well as the technical and economic suitability of retrofitted and new pipelines. For example, repurposed pipelines are unable to deliver 99.999% purity, although these levels are unlikely to be needed at the transmission level as local purification by end-users can be considered for end-use equipment with higher purity requirements. On the production side, hydrogen purities from presently available production technologies range from 97.5-98.5% for methane reforming to >99.999% for alkaline and proton exchange membrane (PEM) electrolysis.<sup>35</sup> Ultimately, a common specification must be defined for hydrogen transport in Europe, otherwise pipelines will not be interoperable.

In terms of impact on structural integrity, due to differences in chemical properties, hydrogen can accelerate pipe degradation through a process known as hydrogen embrittlement, whereby hydrogen induces cracks in the steel. A range of solutions exists to combat this, including: (a) applying inner coating to chemically protect the steel layer; (b) pigging (monitoring) of pipes to regularly check crack widths; (c) operational strategies such as keeping pressures steady to prevent initial crack formation; (d) using lower-grade, more ductile steel. The optimal solution varies per pipeline as it depends on transport capacity requirements, status of existing pipelines, and trade-offs between capital and operating expenditure. For example, whilst initial hydrogen conversion projects in Germany and the Netherlands have shown that existing pipelines in those regions do not require internal coating, studies in France show that re-coating can be a viable part of the optimisation solution by enabling pipes to be operated at pressures closer to the pressure of natural gas.<sup>32</sup> As with all engineering design challenges, there is no one-size-fits-all solution. The key for delivering the hydrogen backbone is that engineering optionality exists and that TSOs have access to many levers for optimisation.

34 H21 North of England, 2019. *A conceptual design for converting the North of England to hydrogen between 2028 and 2035*. Available at: <https://www.h21.green/wp-content/uploads/2019/01/H21-NoE-PRINT-PDF-FINAL-1.pdf>

35 Nel, 2020. *The World's Most Efficient and Reliable Electrolysers*. Available at: <https://nelhydrogen.com/wp-content/uploads/2020/03/Electrolysers-Brochure-Rev-C.pdf>

## 4.2 Compression stations' role in designing the optimal network

Hydrogen is moved through pipelines as a result of pressure differentials. The total pressure required to transport a specified volume from point A to point B is governed by fluid mechanics and depends on friction loss, elevation, pipe delivery (demand-side) pressure, and the properties of the transported medium. A gas TSO's ability to optimise the design and operational management of pressure drops is critical in ensuring it can meet customers' energy requirements in the most cost-effective way.

To control pressure drops and ensure that hydrogen flowing through pipelines remains pressurised, compression of hydrogen gas occurs periodically along the pipeline. This is accomplished by compressor stations. Compression system parameters such as compressor capacity and distance between stations are also dependent on the characteristics of the gas network and the transported medium. Distances between compression stations vary widely depending on system design. The current gas network utilises two types of compressors:

- *Reciprocating compressors* are piston driven. Gas injected into the piston cylinder is compressed as the pistons reduce volume in the cylinder (like combustion engines).
- *Centrifugal compressors* convert kinetic energy from radial blades into pressure energy to pressurise the gas.



FIGURE 8

Schematic comparing reciprocating and centrifugal compressors.

### RECIPROCATING

Compression through reciprocating motion of the piston

### CENTRIFUGAL

Compression through centrifugal force of rotation

The energy density (calorific value) of hydrogen is a factor of three times lower than that of natural gas. To provide the same energetic content, the volume of hydrogen transported must be three times greater than in the case of natural gas. Moreover, due to its physical and chemical properties – low molar mass, large volume flow – greater efforts for compression are to be expected with hydrogen. Views on how these greater compression efforts impact the suitability of existing compressor types varies amongst TSOs and compressor OEMs. Whereas some see a potential to retrofit existing stations, other studies<sup>36</sup> suggest that existing stations may not be fit for hydrogen's higher gas volumes.

36 DNV-GL, 2017. *Verkenning waterstof-infrastructuur*. Available at: [https://www.topsectorenergie.nl/sites/default/files/uploads/TKI%20Gas/publicaties/DNVGL%20rapport%20verkenning%20waterstofinfrastructuur\\_rev2.pdf](https://www.topsectorenergie.nl/sites/default/files/uploads/TKI%20Gas/publicaties/DNVGL%20rapport%20verkenning%20waterstofinfrastructuur_rev2.pdf)

The cost of a compressor depends on the amount of pressure lift that said compressor must provide. Furthermore, the relation between compressor cost and pressure lift is nonlinear; a big pressure gap leads to much higher fixed and variable (electricity) costs. This makes compressor sizing a key element of overall network optimisation, particularly in the case of hydrogen, where compression costs – both investment and operational – are higher than in the case of natural gas. Hence, even though the physical network and underlying principles between a natural gas and hydrogen backbone are similar, the cost-optimal solution will differ across regions as a result of varying levels of pipeline availability, compression needs, geographical distribution of injection points, internal coating and pressure regulation strategies, parallel piping approach, and regulatory cost recovery frameworks amongst other factors.

### **4.3 Metering and city gate stations as the link to end consumers**

Metering stations are placed at entry, exit, and cross-border locations to allow TSOs to monitor, manage, and account for the gas in their pipes. Even a small error in flow measurement on large-capacity pipelines can result in huge financial losses to the owner or customer of the gas. Hence, it is easy to appreciate the importance of joint standards and procedures as well as accurate metering equipment. Given the different chemical composition of hydrogen compared to methane gas, metering equipment will likely need to be adapted. However, such equipment typically represents a small portion of total infrastructure costs.

Excluding large industrial consumers, gas for end-use systems is fed through ‘city gate’, or distribution stations. The basic function of these stations is to meter the gas and reduce its pressure from that of the transmission system to that of the distribution system, which operates at a lower pressure. As part of the pressure reduction process, these stations must accommodate for the so-called ‘Joule-Thompson’ effect in gases, whereby a change in pressure leads to a change in temperature.

Whereas the temperature of natural gas decreases by approximately 0.5 °C/bar when pressure is reduced, hydrogen has an “inverse Joule-Thompson” coefficient of 0.035 °C/bar. This means that a pressure reduction from 80 to 20 bar leads to a 2.1 °C increase in temperature for hydrogen, compared to a 30 °C temperature reduction in the case of natural gas. Like metering stations, city gate stations represent a small portion of total infrastructure costs, and hydrogen-specific conversion requirements are minimal. Nonetheless, given that these stations are the link with the distribution network, coordination with distribution system operators (DSOs) will be of great importance. This is particularly important as hydrogen injection points – namely electrolysis-based ones – are expected to become increasingly geographically distributed compared to existing natural gas injection points.

# Appendix A.

## Cost assumptions

The cost estimates presented below are based on gas TSOs' preliminary R&D efforts with regards to hydrogen infrastructure. Ranges are estimated based on comparison with experience investing in and operating existing natural gas networks. Although some dedicated hydrogen components have been tested in pilot projects, no large-scale hydrogen infrastructure exists to date to provide real historical benchmark figures.

TABLE 4

Basic cost assumptions for construction and retrofitting of hydrogen pipeline infrastructure.

Cost parameter	Unit	Estimate / range
Pipeline capex, new	% of natural gas pipeline with similar diameter	110-150% <sup>37</sup>
Pipeline capex, retrofit	% of new hydrogen pipeline with similar diameter	10-35%
Compression capex, new	% of similar natural gas compressor	140-180%
Compression capex, retrofit	% of new built H <sub>2</sub> compression capex (line above) compressor	100%
Gas metering station, new	% of similar natural gas metering station	110-120%
Gas metering station, retrofit	% of similar natural gas pipeline	20-40%
Valve and seal replacements <sup>38</sup>	k€/km	~40
Internal coating	k€/km	~40

<sup>37</sup> Range varies significantly depending on pipeline diameter. For larger diameters (36 inch or more), range is on the lower side whereas costs for smaller diameter pipelines can reach 150%.

<sup>38</sup> Valve replacement cost depends on frequency of replacement. If valves must be replaced every 15 km, cost will be higher.

TABLE 5

Cost input ranges used for estimating total investment, operating, and maintenance costs for hydrogen infrastructure. Values are for 48-inch pipelines.

Cost parameter	Unit	Low	Medium	High
Pipeline (including gas metering) capex, new	M€/km	2.5	2.75	3.36
Pipeline (including gas metering) capex, retrofit	M€/km	0.25	0.5	0.64
Compressor station capex, new	M€/MW	2.2	3.4	6.7
Compressor station capex, retrofit	M€/MW <sub>e</sub>	2.2	3.4	6.7
Electricity price	€/MWh	40	50	90
Depreciation period pipelines	Years		30-55	
Depreciation period compressors	Years		15-33	
Weighted average cost of capital	%		5-7%	
Operating & maintenance costs (excluding electricity)	€/year as a % of CAPEX		0.8-1.7%	

# Appendix B.

## Considerations on topology

This Appendix provides some background to the proposed backbone topology in three tables. Table 6 describes large relevant planned hydrogen projects that include or require hydrogen pipeline transport. Table 7 provides a rationale for the proposed backbone topology in the ten represented countries. Finally, Table 8 describes to what extent long-term natural gas contracts influences the timing of creating hydrogen infrastructure based on existing gas infrastructure.

TABLE 6

Ongoing pilot projects and hydrogen initiatives in various European countries.

Cost parameter	FR	BE	NL	IT	SE	DK	DE	CZ	CH	ES
<b>Green Octopus Project</b> (IPCEI): Decarbonising power production, infrastructure, North Sea ports, heavy industry by boosting offshore wind, retrofitting gas infrastructure, supporting green offtake and CO <sub>2</sub> reduction mechanisms. Project aims to drive cross-border solutions, create a backbone of hydrogen, scale the green hydrogen value chain, encourage collaboration between companies and Member States.	✓	✓	✓			✓	✓			
<b>H2V Program</b> : Goal to produce 500,000 tonnes of carbon-free hydrogen per year, representing an investment of EUR 3.5B in the next 5 years. Ongoing projects include an electrolysis facility producing hydrogen using grid electricity combined with guarantees of origin near Lacq, as well as projects in Dunkerque and Le Havre.	✓									
<b>Green Spider Project</b> (Important Project of Common European Interest, IPCEI): Development of a large-scale green hydrogen network to export hydrogen produced from industrial hubs in Spain to northern European countries through a range of hydrogen transport solutions.	✓		✓				✓			✓
<b>Golden Eagle</b> : 3 GW wind-based hydrogen production, transportation by pipelines, supply to steel plants, HRS, 500 public transport buses.				✓		✓	✓			
<b>HYBRIT</b> : pilot plant producing fossil-free steel using hydrogen; collaboration between Vattenfall, Swedish steel group SSAB, and mining group LKAB					✓					

TABLE 7

Summary of supply and demand considerations that informed network topology.

Country	2030	2040
<b>Belgium</b>	The Belgian national backbone is expected to emerge through developments in and around the industrial clusters in Antwerp, Ghent, and along the industrial valley in Wallonia. Given the proximity between Antwerp and Rotterdam, port-to-port interconnections with the Netherlands are likely. In addition, the interconnection with France through Taisnières gives Belgium access to hydrogen from France.	Hydrogen demand in Belgium in 2040 is expected to exceed production capacity from offshore wind parks and blue hydrogen from industry. Imports, from France, including through the Zeebrugge terminal, will play an important role beyond up to 2040 and beyond, for Belgium and North-Western Europe with new connections to Germany and Luxembourg
<b>Czech Republic</b>	The Czech gas transmission system has three major branches consisting of double or even triple pipelines. The system offers the possibility to dedicate one of these pipelines to hydrogen. By 2030, it is not expected that any major part of the transmission system could become available for pure hydrogen transport. The first assets (the western “Gazelle” pipeline) could become available in 2035 and onwards and can offer an efficient connection between north and south Germany.	Even with the shift from natural gas to hydrogen, the Czech Republic is expected to remain predominantly a transit country. Relevant markets include mainly Germany and eastern and southern European markets. By 2040, one of the pipelines on the northern branch could become available for pure hydrogen transport and it can connect Germany to Slovakia and serve as (one of) the entry point(s) to central Europe. Due to the system reversibility, the Czech Republic could also become an entry point for hydrogen sourced at distance eastern markets.
<b>Denmark</b>	Denmark has set out a 70% greenhouse gas emissions reduction target by 2030. Power-to-X is an integral part of the government’s plan to install two energy islands of each 2 GW in 2030. One of the islands will be located in the North Sea and should be scalable to 10 GW. Analyses show that effective utilization of more than 10 GW of additional offshore wind require up to 5-8 GW of electrolysis by 2035. Several electrolysis projects are underway in Denmark, which indicates an installed capacity of around 3 GW in 2030. This include a 1.3 GW plant outside Copenhagen and two projects in Northern and Southern Jutland linking the west coast (wind production) to industrial clusters and hydrogen storage facilities in the east and north of Jutland. Additionally, an announced bilateral cooperation agreement with the Netherlands includes a €135 mln Dutch investment in large-scale Power-to-X plants in Denmark, ensuring that both countries fulfil their 2020 renewable energy targets. Initial development of the Danish backbone consists of constructing new pipelines parallel to the existing natural gas network	Beyond 2035, Denmark seeks to draw upon its significant offshore wind resource in combination with electrolysis to attract new industries (e.g. green fuels e.g.: bio-kerosene, biomethane, e-ammonia). As such, the national backbone expands throughout the 2040s into all directions. The eastern route is extended all the way to Copenhagen region by retrofitting the existing pipeline and connecting to Sweden. In addition, the existing north-south corridor in Jutland (interconnection with Germany) can be retrofitted and a new transmission pipeline could be constructed from Copenhagen area southwards toward Germany.
<b>France</b>	Hydrogen will primarily be used in industry and for mobility. Regional dedicated hydrogen networks with a total length of ~700 km will emerge around industrial clusters in Dunkerque, le Havre, Paris, Lyon, and Marseille. The hydrogen cluster in the north of France will be supplied with green hydrogen from offshore wind, as well as blue hydrogen from industry. This cluster will also co-benefit from the hydrogen valleys in Belgium and the Netherlands. In the East, a regional cluster will also develop at the border between France, Germany and Luxembourg. The southern clusters in Marseille-Fos and Lacq are also expected to have access to green hydrogen, from solar PV and Mediterranean offshore wind. Lastly, dynamic development of green hydrogen and fuel cell projects is expected to continue to lead to a need for a dedicated hydrogen pipeline in the region surrounding Lyon.	The Afhyac study estimates French hydrogen demand to be increase to approximately 110 TWh/a by 2040. In addition, the French network is expected to play a role as a transit network for hydrogen flows between Spain, South of France (Mediterranean coast), and the north of Europe (in particular via interconnection with Belgium in Taisnières and with Germany in Obergailbach). To serve these transport needs, regional networks will extend throughout the 2030s and a 3,300 km network is expected to emerge by 2040. This national backbone will be connected to Spain through the west (Larrau) and the East (Catalonia), enabling large-scale imports from renewable hydrogen produced in Spain (and possibly North Africa).  →

Country	2030	2040
<b>Germany</b>	<p>As part of the network development plan process (2020-2030), the German transmission system operators queried specific projects for the generation or use of hydrogen by means of a market partner query. For 2030, the market participants asked for 1 GW of green hydrogen feed-in capacity. The exit capacity requested for the same point in time was significantly higher with 3GW. This should be based on an annual hydrogen requirement of around 20TWh for industrial purposes only. To close the gap in the entry-exit balance for H<sub>2</sub> in 2030, the network operators envisage hydrogen imports from the Netherlands, the connection of cavern storage facilities and additional feeds from wind farms that are equipped with electrolysers. The plans for the German H<sub>2</sub> start grid 2030 foresee pipeline connections to the Dutch H<sub>2</sub> grid.</p> <p>Since the market partner query is the first broad-based query for future hydrogen transport needs, it can be assumed that further requirements will become apparent in the coming years. This also corresponds to the view of the German government expressed in the national hydrogen strategy, which forecasts hydrogen requirement of 90-110TWh for 2030.</p>	<p>German transmission system operators plan to determine the need for entry and exit capacity as part of the network development plan process in order to be able to provide the necessary transport capacities. Studies estimate the 2040 hydrogen demand for Germany at over 300 TWh (GfC's Decarbonization Pathways Study; DENA - Pilot study on integrated energy system transformation). Regarding sources of hydrogen an increase in domestic production as well as additional imports of hydrogen from the Netherlands, Denmark and Russia are expected. In addition, the European Hydrogen Backbone creates additional import opportunities from across the continent, e.g. solar-based green hydrogen from Spain or North Africa.</p>
<b>Italy</b>	<p>The Italian regional backbone will develop around existing industrial clusters in the south of the country (Sicily, Puglia), gradually expanding towards the north. Most of these developments will consist of retrofitted existing natural gas pipelines as a result of the availability of parallel routes.</p>	<p>Under a scenario where hydrogen demand is met through a combination of North African imports and national production, a relatively contained infrastructure development would be needed to transport hydrogen from injection points in southern Italy to industrial clusters in the north. Interconnections with Austria and Switzerland will likely develop to support supply in northern European countries. Whether these interconnections end up being retrofitted natural gas pipelines or newly built hydrogen ones, depends on the volumes of natural gas that will need to be transported.</p>
<b>Netherlands</b>	<p>By 2030, annual hydrogen demand in the Netherlands is forecast to be between 55-120 TWh/a (Gasunie, 2019) driven primarily by demand from industry. Industrial clusters are located in the south, west, and north of the country (Zeeland, IJmond, Rijnmond, Limburg, Eemshaven) with regional hydrogen markets of up to 15 TWh/a, served by a mix of local blue and centralised green and blue hydrogen production. By 2030, the Dutch ~1100 km national backbone will cover most of the country. Based on a current assessment of natural gas transport pipelines becoming available due to decreasing production from the Groningen field, between 70-90% of the Dutch hydrogen backbone will be retrofitted infrastructure. Hydrogen storage will be developed to balance supply and demand. Lastly, interconnections with Belgium (Rotterdam – Antwerp) and Germany (to North-Germany and the Ruhr area) will be established.</p>	<p>In a medium to high scenario, hydrogen demand in the Netherlands can reach up to 120-190 TWh/a (Waterstof in het klimaatakkoord, werkgroep H<sub>2</sub>), driven by increasing demand from the power, buildings, and mobility sectors in addition to industrial demand. Between 2030-2040, additional infrastructure developments consist of incremental adaptations and modifications to meet increasing supply, demand, and capacity needs. This can come in the form of conversion of more parallel pipeline sections, additional compression capacity, or a combination of the two.</p>
<b>Spain</b>	<p>Industrial clusters within reach of the proposed parallel network and therefore relevant for initial development of the backbone are along the Mediterranean coast and in the center and north of the peninsula.</p>	<p>Spain's long-term ambition is to be one of the main hydrogen suppliers in Europe, building on large-scale solar PV and wind combined with electrolysis. By 2040, the national backbone will enable this by connecting to France through reinforce the existing connection by Larrau and Catalonia linked to North Africa imports. Connections to North Africa can be made towards the latter end of the 2030s to complement national supply with imports from the south.</p>
<b>Sweden</b>	<p>The Swedish backbone emerges through the creation of regional routes between the industrial clusters in Lysekil, Stenungsund, and Göteborg, all in the same coastal region in the south-west of the country. Given the absence of parallel piping infrastructure, dedicated hydrogen pipelines will have to be newly built.</p>	<p>Given the nature of Sweden's geography, terrain, and location of industrial clusters, hydrogen island grids are an attractive option for hydrogen producers and consumers alike. By 2035, distributed micro-grids are expected to emerge near the steel industries in mid-Sweden. Despite being unconnected to the western part of the Swedish grid, the value of larger pipeline networks that offer non-discriminatory third-party access will make this an attractive proposition.</p>

TABLE 8

Summary of existing long-term natural gas transmission contracts and pipeline availability in different EU countries.

TSO, country	Long-term natural gas contracts & pipeline availability
<b>Enagás, Spain</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand. In this sense, this report shows the Enagas network adaptation if Magreb-Europ Gazoduc (MEG) and Medgaz pipeline could bring hydrogen from North Africa from the 2040s, bearing in mind that the current natural gas long-term contracts will have already expired.
<b>Energinet, Denmark</b>	Long term contracts generally do not prevent part of the Danish gas grid to connect to a Hydrogen Backbone. The double lined system that connects Denmark to Germany could be used to transport hydrogen by retrofitting one of the pipes. Most of the Danish gas system however, consists of single pipelines. With the anticipated reduction in gas consumption, pipeline availability is mostly a question of biogas (methane) demand. A nationwide hydrogen network that connects Jutland to Zealand will not be possible in the short term, since Baltic pipe, which will bring Norwegian gas through Denmark to Poland, is locked into 15-year capacity agreements with market participants. When the contracts expire in 2038 (assuming COD in 2022 as planned) a larger share of the Danish transmission system opens up for conversion.
<b>Fluxys, Belgium</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand.
<b>Gasunie, Netherlands</b>	No long-term contracts. Pipeline availability is primarily a question of natural gas demand. Due to rapidly decreasing production from the Groningen field the export of low calorific gas will be built off and significant transport capacities will become available for hydrogen transport.
<b>GRTgaz, France</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand.
<b>NET4GAS, Czech Republic</b>	There are several long-term contracts. The major contracts expire in 2034 and in 2039 respectively. Combined with existing natural gas demand this means that by 2030 there will be no available capacity to convert existing infrastructure into a (pure) hydrogen route.
<b>OGE &amp; ONTRAS, Germany</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand. Opportunities will arise from the transition from low-calorific gas supply to high-calorific gas supply in North Western region of Germany.
<b>Snam, Italy</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand.
<b>Swedegas, Sweden</b>	No long-term contracts. Given the absence of parallel piping infrastructure, a dedicated Swedish hydrogen backbone will have to be newly built.
<b>Teréga, France</b>	Long-term contracts do not prevent the development of a hydrogen backbone. Pipeline availability is principally a question of natural gas demand.