CLEAN HYDROGEN MONITOR

2022

Hydrogen Europe

Reviewers: Matus Muron, Grzegorz Pawelec, Stephen Jackson, Ivan-Petar Yovchev

Editors: Amy Allsop and Michela Bortolotti

Design: Think Things Studio Barcelona

Foreword

Just two years after the launch of the European Hydrogen Strategy, hydrogen is now at the forefront of the European energy transition conversation.

2022 has seen many significant policy developments as we strive to create a bona fide hydrogen market. The priority now must be to tie up all remaining loose ends and provide clear regulatory certainty to producers, end-users, and all parts of the value chain.

The 14 September plenary vote on the Renewable Energy Directive established ambitious clean hydrogen targets for 2030. Commission President von der Leyen's State of the Union address saw the announcement of the European Hydrogen Bank and its initial funding of €3 billion.

The bank should provide a level of surety that boosts investor confidence. Together with the financing support mechanisms currently under discussion, we see the formation of a proper incentive structure to complement the favourable regulatory environment.

While we must acknowledge the positive steps being taken, we must also be aware of the fast-closing gap between Europe and its regional competitors for a slice of the hydrogen pie. The US Inflation Reduction Act has made the journey across the Atlantic a potentially lucrative one for those in the hydrogen value chain. For its part, China's hydrogen strategy, released in March, shows that the East Asian giant has no intention of being left out in the cold.

The time has come to deploy European hydrogen infrastructure and projects. We must turn our hydrogen plans from pipe dreams to pipelines and do it fast. Not just to stave off international competitors but to use the potential of renewable hydrogen to reach our climate goals and create a sustainable and energy-secure Europe.

This third edition of Hydrogen Europe's Clean Hydrogen Monitor offers stakeholders a window into the ins and outs of the sector's development in Europe. We hope you find it useful as we continue to work towards our common goals.

Stephen Jackson
Chief Technology and Market Officer
Hydrogen Europe

Executive summary

It is now widely acknowledged that clean hydrogen will play a critical role in mitigating global warming and its effects on human societies and ecosystems. While hydrogen has been used in industry in large volumes for decades, the clean hydrogen market is only emerging. This report aims to provide facts and figures on the current hydrogen market in Europe, the development of the clean hydrogen market, the industry's ambitions, the policy and funding landscape, and the supply capacity of some critical raw materials.

In recent years, the EU published the European Green Deal, the European Hydrogen Strategy, and the "Fit for 55" packages, amongst others. Within those policies, hydrogen is identified as one of the key technologies to achieve decarbonisation and European energy security as part of the REPowerEU plan published in 2022. The latter plan significantly increases Europe's ambition to 10Mt of locally produced renewable hydrogen and 10Mt of imports. In parallel, policymakers have been actively working on creating sectorial demand for industry and transport through legislative acts such as the Renewable Energy Directive revision, the new ReFuelEU Aviation, Fuel EU Maritime, or the Alternative Fuel Infrastructure Regulation. Finally, policymakers are revising the gas package and rules on renewable and low-carbon hydrogen production to achieve a workable and clear regulatory environment for Europe to develop a thriving hydrogen ecosystem.

By August 2022, 27 countries have adopted national hydrogen policy/strategy documents, with another 31 at different stages of preparation. Europe continues to lead, with 16 countries adopting national hydrogen strategies, 14 of which are EU MS. However, important global and regional players are catching up fast, including China and the United States. A fragmented and unclear regulatory framework creates a risk to the emerging clean hydrogen market in the face of growing competition.

In the current European[1] hydrogen market, over 95% of hydrogen production capacity was from fossil fuels in 2020.[2] The conventional hydrogen market in Europe remained stable in 2020 with 11.5 Mt of production capacity and 8.7 Mt of demand. Since the last report, no facilities have been established in Europe that reform natural gas and capture the associated emissions. 35 MW_{el} of power-to-hydrogen capacity came online in 2022 by August, reaching 162 MW_{el}.

General industry ambitions for renewable hydrogen have continued to increase in 2022. Partially due to the skyrocketing natural gas prices, the average fossil hydrogen production costs for 2021 were estimated at 2.65 EUR/kg and grew as high as 10 EUR/kg in August 2022. As a result, renewable hydrogen started becoming cost competitive with fossil hydrogen. The estimated renewable hydrogen production costs in the EU, UK, and Norway in 2021 vary from 3.3 EUR/kg to 6.5 EUR/kg, while, in limited geographical locations with the best solar irradiation and wind conditions, it is possible to reduce those costs to as low as 2.2-2.9 EUR/kg.

As a result, the project pipeline for hydrogen production projects kept steadily growing in 2022, with a Power-to-Hydrogen (PtH) pipeline increasing from 118 GW_{el} last year to 138 GW_{el} by 2030. There are also almost 17 GW_{LHV} of reforming with carbon capture capacity by 2030. Should all the projects be implemented, they would amount to 14 Mt of annual clean hydrogen production. However, even though the pipeline of projects is growing, projects are being delayed. PtH projects are being pushed back due to regulatory uncertainty, expectations of future financial incentives, and supply chain/permitting issues. The 2020 report expected 523 MW to come online in 2022, while the 2021 report only expected 253 MW for the same year. Only 35 MW came online by August 2022.

Increased hydrogen ambitions will require overcoming equipment bottlenecks, one of the most crucial being electrolyser manufacturing capacity. Europe's current (as of August 2022) water electrolyser manufacturing capacity

1 / EU, EFTA, and UK
2 / The reporting year is 2020, as some 2021 data was unavailable at the time of the update.

amounted to over 3.3 GW/y. Planned capacity should increase 16-fold, reaching 53 GW/y by 2030. However, 79% of the capacity planned between 2023-2030 is still conditional on final investment decisions and can change significantly.

On the industrial end-use side, the project pipeline consists of 6.1 Mt of annual clean hydrogen consumption by 2030, with more than half (53%) planned in the steel sector. 17% of the consumption is planned to be applied to the production of ammonia, and 13% to refining processes. As identified by REPowerEU, hydrogen imports are meant to provide 10 Mt of hydrogen to Europe annually by 2030. A selection of the largest projects that could potentially ship hydrogen to Europe amounts to 5 Mt/y of renewable hydrogen by 2030. It also identifies 2.8 Mt/y of potential imports under MoU by 2030. These projects and agreements are likely to change before the FID, and it is highly uncertain how much of the volume would be available exclusively for Europe.

Development of transmission, distribution and storage infrastructure will be fundamental to realise the ambitious goals set by the REPowerEU and mirrored by industry ambitions in both production and end-uses. The main industry initiative is the European Hydrogen Backbone representing the vision of natural gas infrastructure operators for a future hydrogen grid in Europe, comprising 28,000 km of new and repurposed pipelines and three pipeline import corridors by 2030. The Netherlands is the most advanced EU member state committed to a phased development of its national hydrogen infrastructure.

A new addition to this report is a perspective on critical raw materials. It focuses on the annual production capacity of platinum and palladium, as two of the essential materials for the hydrogen economy used in fuel cells and electrolysers. The annual mining capacity of platinum is 227 tonnes, with South Africa providing 75%, and the mining capacity of palladium is 305 tonnes, with Russia providing 42%. New mining capacities are expected to come online, but capacity from recycling will play a significant role in Pt and Pd production in the near and long run.

Public funding and private financing will be essential to fulfil the policy goals and industry ambitions. The European Commission has at its disposal funds to support the ramp-up of the hydrogen value chain, including schemes for research and development, commercialisation, and infrastructure. In addition, the EU announced the launch of the Hydrogen bank with a budget of €3B to kick start the hydrogen market by covering the green premium. Since hundreds of billions will be needed by 2030 to finance the hydrogen economy, private investment will play a decisive role in enabling the deployment of the hydrogen sector. The invested capital and number of deals are growing quickly, but a broader involvement of various financial institutions is required to share risks efficiently and unlock the amounts necessary to scale up the value chain. The capital is needed now as countries worldwide begin to compete for leadership in the hydrogen ecosystem.

This Monitor covers many of the hydrogen developments from 2021 and 2022. A lot remains to be done, and 2023 will be crucial as regulatory frameworks will be adopted, providing the necessary certainty for the EU hydrogen industry to thrive.

© Justin Jin for Hydrogen Europe

01

Existing hydrogen production capacity and demand

Despite the increasing deployment of clean hydrogen across Europe, conventional hydrogen production capacity accounted for 99.3% of total in 2020

Introduction

The following chapter contains information on current hydrogen production capacity and demand in the European Union, the European Free Trade Association (EFTA), and the United Kingdom. Although most of the production capacity is relatively stable, the lack of official and accurate hydrogen statistics makes the hydrogen market non-transparent and difficult to track. Until such statistics exist, Hydrogen Europe will continue to report on hydrogen market data.

The hydrogen production section of this report provides information about current production capacities, expressed in million tonnes (Mt) per year, of all identified hydrogen production plants in Europe. The hydrogen demand section provides information about the quantities of hydrogen, expressed in million tonnes, that were consumed by different end-use sectors. The information presented refers to data collected until December 2020 unless otherwise specified.[1] The power-to-hydrogen (PtH) sub-chapter refers to data collected until August 2022.

Much of the data collection for this chapter has been conducted as part of Hydrogen Europe's work for the Fuel Cells and Hydrogen Observatory. Its reports and downloadable excels can be accessed at https://fchobservatory.eu/.

1 / The reporting year is 2020 as some 2021 data was unavailable at the time of the update.

1.1.

Hydrogen production capacity

In total, **504 hydrogen production sites** have been identified as being in operation in Europe by the end of 2020[2], with a total production capacity of **11.5 Mt per year**.[3] Based on the estimated size of the hydrogen consumption in 2020 (see the following sub-chapter), the **average production capacity utilisation in 2020 was 76%.**

Germany, Netherlands, Poland, Italy, and France have the largest hydrogen production capacity. These five countries account for **55% of the total hydrogen production capacity of the EU, EFTA, and the UK. Figure 1** gives an overview of the hydrogen production capacity per country.

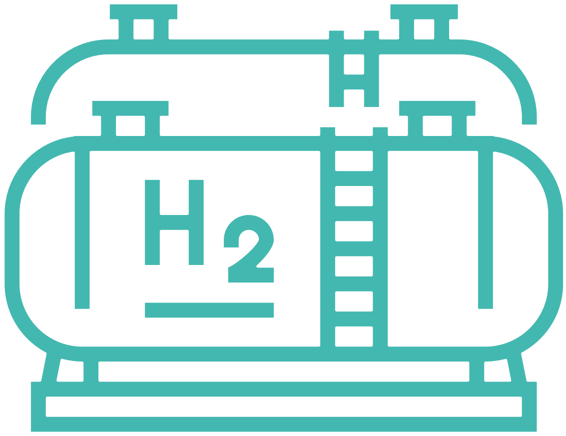
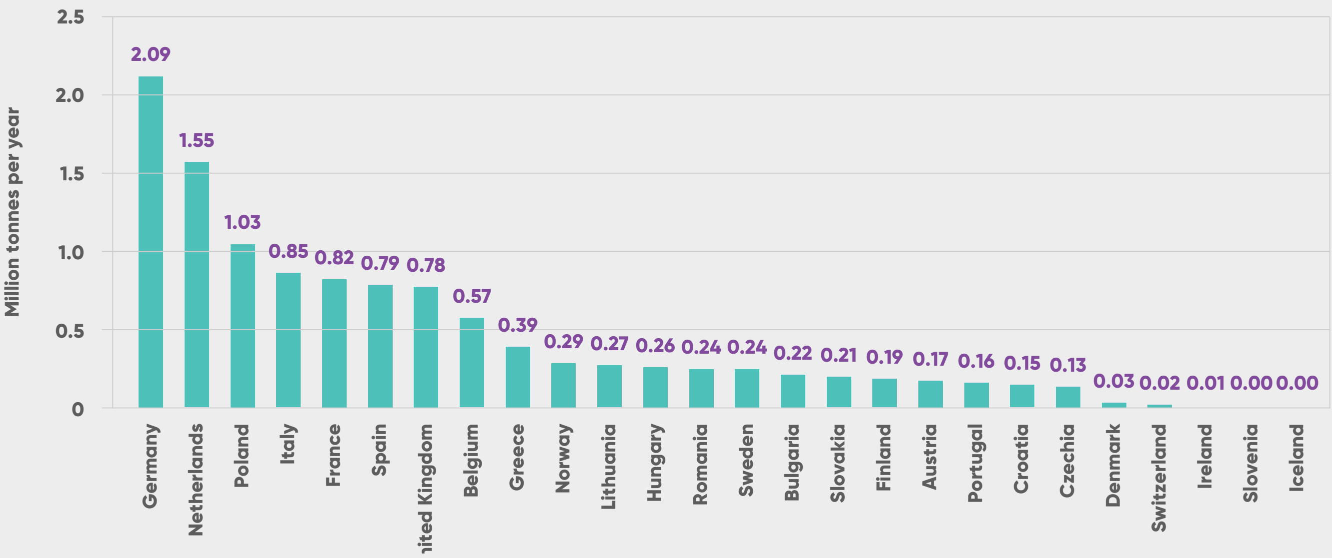


FIGURE 1

Total hydrogen production capacity by country.[4]



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

2 / The reporting year is 2020 as some 2021 data was unavailable at the time of the update.
3 / Previous versions of the Clean Hydrogen Monitor have included hydrogen in coke oven gas in the total numbers. If we were to include coke plants, there would be 12.2 Mt of hydrogen production capacity spread across 535 hydrogen production sites. While hydrogen generally comprises 56% of coke oven gas, only in rare cases is it extracted and separated from the mix. Nor will these hydrogen volumes need to be replaced by clean hydrogen. As such, while the technical production capacity exists, this report does not include it in the total production capacity numbers.
4 / Production capacities for Slovenia and Iceland are less than 50,000 t/y so they show as 0.00 Mt.

This chapter refers to various production processes intended for captive use, merchant use, or produced as a by-product, the explanation of which is given in **Table 1.**

TABLE 1

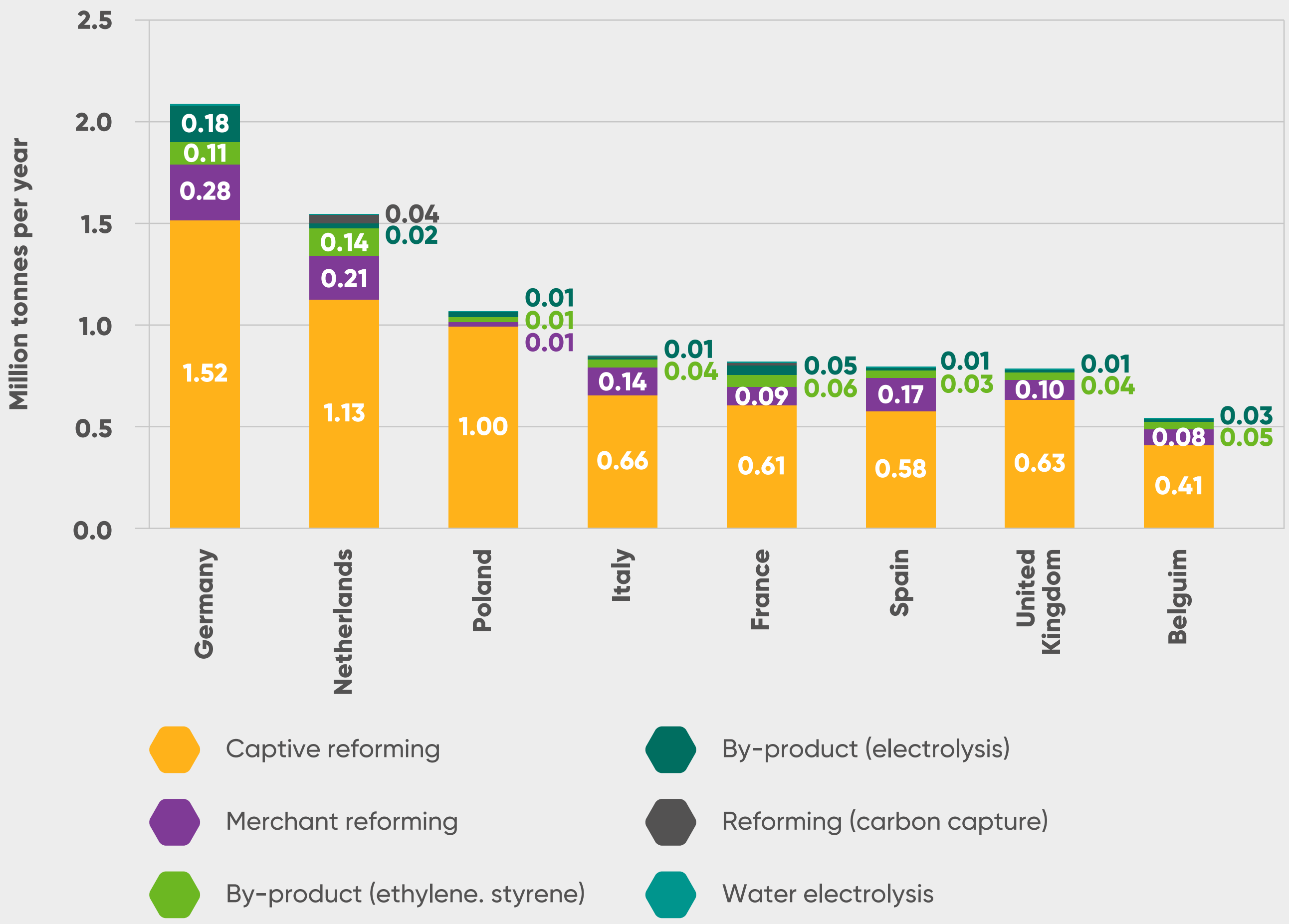
Overview of terminology used in this chapter for different hydrogen production processes

Captive reforming	Refers to hydrogen production from steam reforming, partial oxidation, gasification, and autothermal reforming of fossil fuels that is subsequently used onsite. These processes account for the largest hydrogen production capacity. This category also includes hydrogen produced in refineries as a by-product, e.g., during catalytic reforming. These capacities are included in the captive section because, although those hydrogen volumes are produced as a by-product, they are only consumed onsite as other purely captive production.
Merchant reforming	Refers to production from steam reforming, partial oxidation, gasification, and autothermal reforming of fossil fuels that is subsequently sold as merchant hydrogen.
By-product (ethylene, styrene)	Refers to the hydrogen production capacity as a by-product of ethylene and styrene production.
By-product (electrolysis)	Refers to by-product hydrogen production capacity from chlorine and sodium chlorate production.
Reforming (carbon capture)	Refers to reforming, gasification, or partial oxidation of fossil fuels coupled with carbon capture of the emissions.
Water electrolysis	Power-to-hydrogen (PtH) refers to the hydrogen production capacity of installed electrolysers splitting water with electricity.

There are large differences in hydrogen production capacity between countries depending on their industrial base. The eight countries with the largest production capacity account for **74% of the total** hydrogen production capacity in EU, EFTA, and the UK.

FIGURE 2

Total hydrogen production capacity of top 8 hydrogen producers by the production process

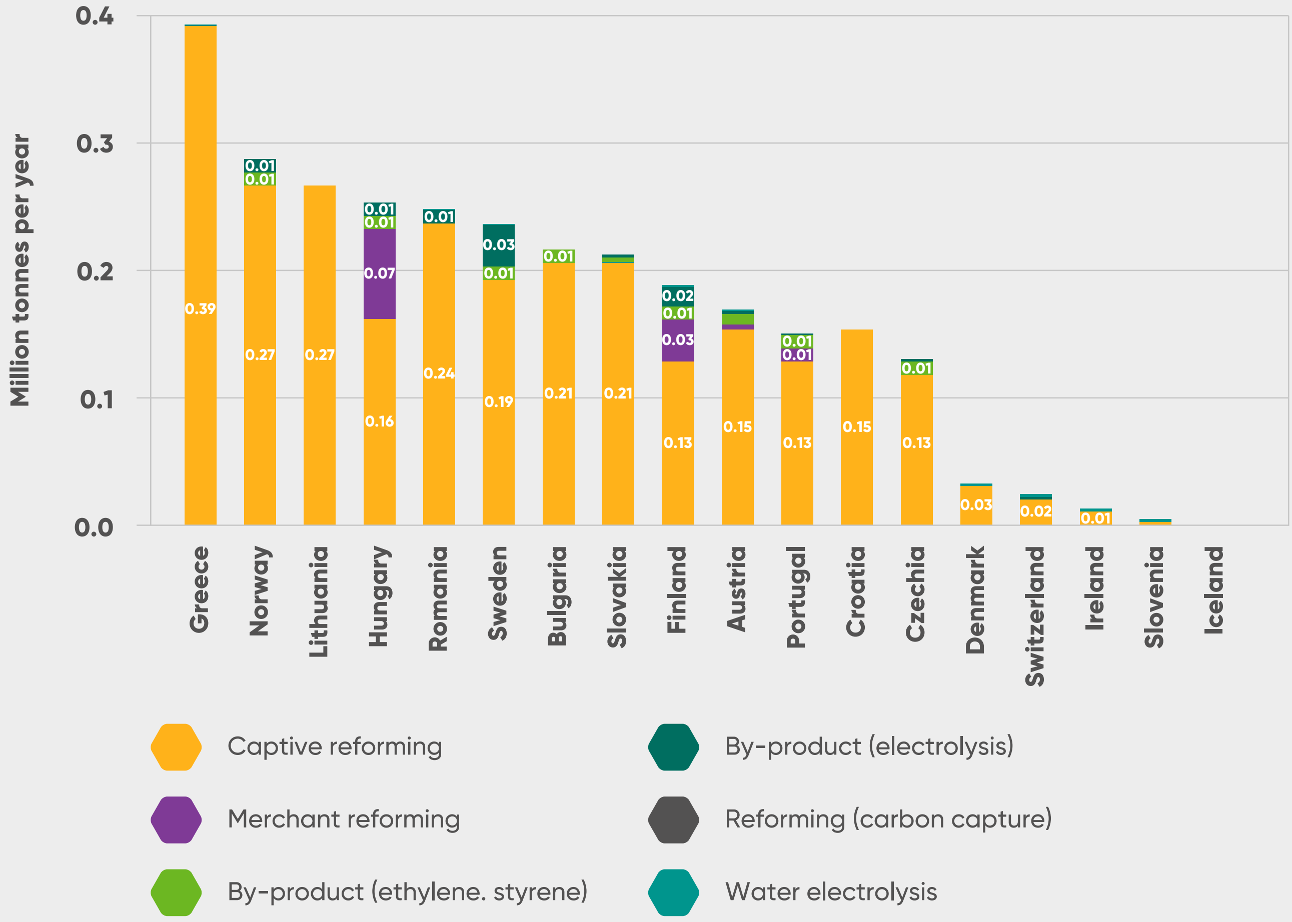


Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

The other 18 countries with hydrogen production capacities have only **26% of the total** installed capacity in the EU, EFTA, and the UK. The composition of this capacity depends on the industries in each country but remains dominated by captive reforming capacity in the refining and ammonia sectors.

FIGURE 3

Total hydrogen production capacity of the other 18 hydrogen producers by the production process (Mt)[5]



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

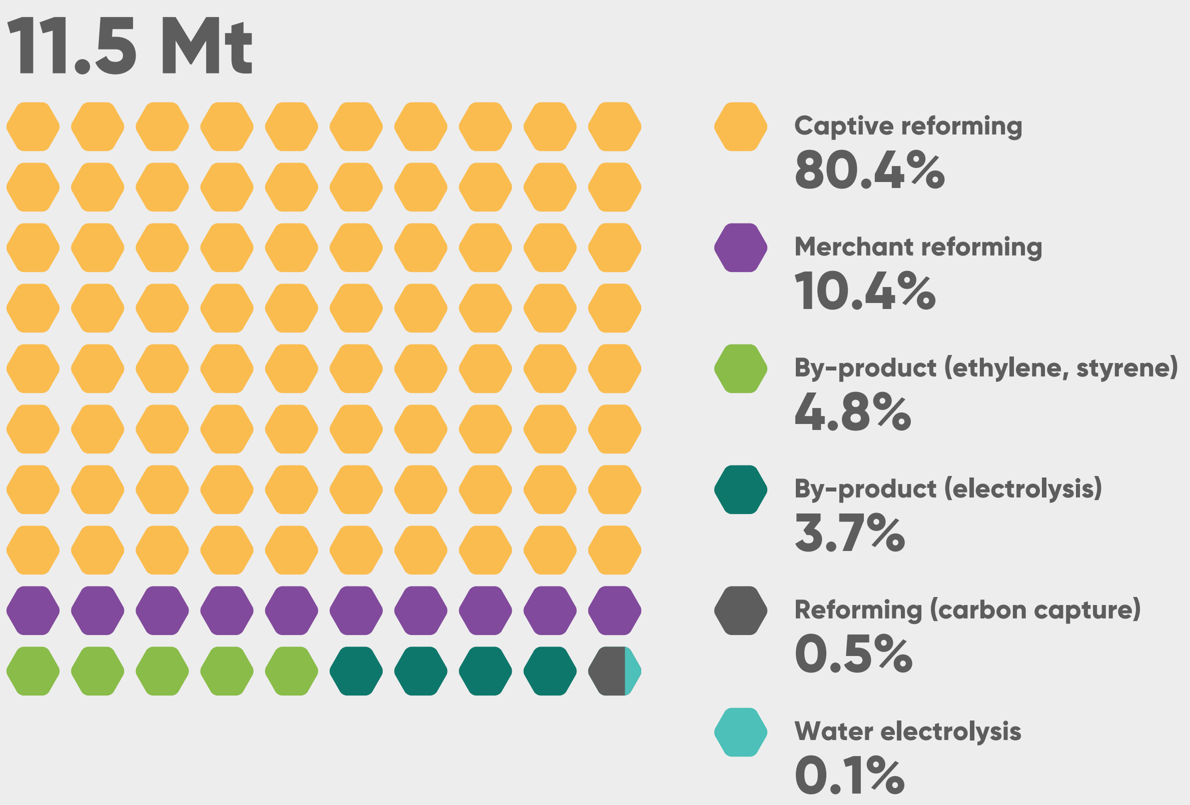
5 / Production capacities for Slovenia and Iceland are less than 50,000 t/y so they show as 0.00 Mt.

Figure 4 gives an overview of the hydrogen production capacity in 2020 spread across different production technologies. The conventional production methods of reforming, partial oxidation, gasification, by-product production from refining operations, and by-product production from ethylene and styrene represent 95.7% of total capacity.[6] By-product electrolysis (i.e., capacity from chlorine and sodium chlorate production) accounts for 3.7%. Reforming with carbon capture contributes 0.5% of total hydrogen production capacity. Power-to-hydrogen accounted for only 0.1% of total hydrogen production capacity in 2020.

This report further divides these volumes and **provides information on conventional hydrogen production capacity, reforming with carbon capture, and power-to-hydrogen facilities more specifically.**

FIGURE 4

Hydrogen generation capacity by the production process in 2020[7]



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

6 / Unlike in CHM 2021, hydrogen production capacities from coke oven gas are not included.
7 / Numbers may not sum up to 100% due to rounding

1.1.1. Conventional production capacity

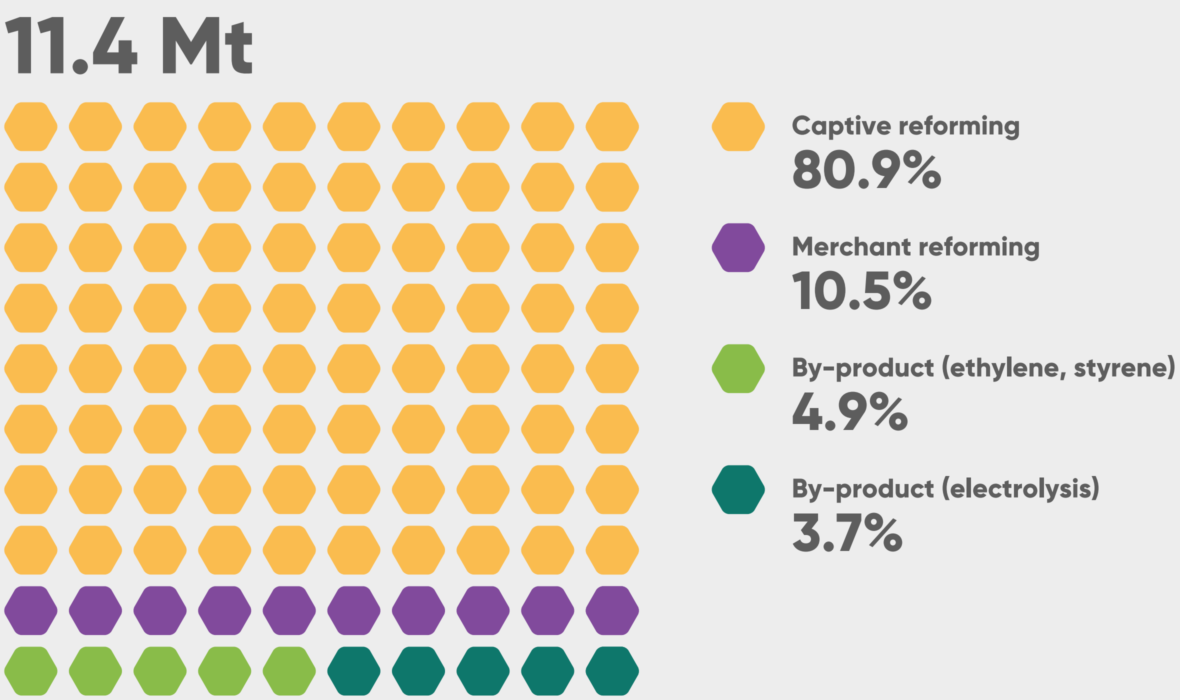
The conventional category, as used in this report, consists of captive and merchant reforming (which also includes partial oxidation and gasification), and by-product hydrogen capacities from ethylene, styrene, and electrolysis of brine.

The most common technology for producing hydrogen is steam reforming of natural gas (SMR). Less common are partial oxidation (POX), gasification, and autothermal reforming (ATR). All are widely used for applications ranging from refining, ammonia production, or any other large-scale hydrogen production. Even though natural gas is the most common feed, there is production from other mostly liquid hydrocarbons such as liquefied petroleum gas (LPG) or naphtha.

The **conventional hydrogen production capacity** adds up to a total of **11.4 Mt of hydrogen per year** spread across **387 production points.**[8]

FIGURE 5

Structure of conventional hydrogen production capacity by the production process in 2020



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

8 / Excluding by-product hydrogen generated as part of coke oven gas (COG). The number increased from 10.5 Mt in last year's report due to methodological changes and continuous improvements in data accuracy.

The geographical visualisation of the production sites and their relative capacities can be seen in **Figure 6** below. Most of the large-scale production is concentrated in industrial areas around refineries, ammonia producers, and chemical plants. By-product hydrogen production from ethylene and styrene production is generally located around refineries and chemical plants. Chlorine and sodium chlorate production is slightly more independent, and brine electrolysis can be observed outside the main industrial clusters. As mentioned above, current hydrogen production is largely concentrated and benefits from economies of scale. As a result, the average size of captive reforming plants is 57,000 t of hydrogen a year.[9] Merchant reforming plants have an average production capacity of 13,000 t a year, ethylene and styrene have an average production capacity of 10,689 t a year, and an average by-product electrolytic plant has a capacity of 5 128 t of hydrogen a year.

FIGURE 6

Identified conventional hydrogen production sites (2020)[10]

Captive reforming | Merchant reforming | By-product (ethylene, styrene) | By-product (ectrolysis)

Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

9 / This number is slightly skewed upwards due to a methodological decision to include by-product hydrogen from refining processes in the category of "captive reforming".
10 / The column height is only indicative of production capacities. It has been manually adjusted so as not to reveal any potentially confidential information.

Captive reforming

On-site captive hydrogen production is the most common method of hydrogen supply. In 2020, 80% of conventional hydrogen production capacity (9.2 Mt per year in 161 production plants) was dedicated to on-site captive consumption and produced by steam reforming, partial oxidation, autothermal reforming, and gasification of fossil fuels.

Refining accounts for 55% or 5 Mt, ammonia 37% or 3.4 Mt, and methanol and other chemicals 8% or 0.7 Mt of production capacity. It is important to note that our definition of captive reforming includes hydrogen produced in refineries as a by-product during refining processes such as during catalytic reforming. These capacities are considered captive because although these hydrogen volumes are produced as a by-product, they are only consumed onsite as other purely captive production.

Merchant reforming

Another large group of conventional hydrogen production are merchant plants that produce hydrogen mostly for external sale. This report identified 91 operational merchant hydrogen plants using reforming of fossil fuels to produce hydrogen in 2020. They represent 10.5% of total conventional hydrogen production capacity (1.2 Mt per year).

Merchant hydrogen plants that produce hydrogen from fossil fuels can be divided into two main sub-categories. The first category consists of plants operated by merchant industrial gas producers but dedicated to supplying a single large-scale consumer with only excess capacity available to supply the retail hydrogen market. The second category consists of mostly small and medium-scale hydrogen production sites designed to supply retail customers. While merchant plants dedicated to a single large consumer are comparable in size to captive hydrogen production facilities, purely merchant plants supplying retail customers tend to be significantly smaller.

The merchant hydrogen market from fossil fuels in Europe is led by four companies: Air Liquide, Air Products, Linde, and Messer. Their assets constitute 97% of capacity and 90% of merchant reforming hydrogen production plants.

With PtH capacity representing only 0.14% of total hydrogen production capacity in 2020 and 0.25% in 2022, the only other hydrogen production plants competing in the merchant market are chlorine and sodium chlorate producers, some of which valorise their by-product hydrogen and sell it on the retail hydrogen market. For this report, these are included in the “by-products” category below.

Hydrogen as a by-product

Hydrogen as a by-product[11] of other processes is produced at 135 plants. The total by-product hydrogen production capacity has been estimated at 0.98 Mt per year (around 9% of total conventional production capacity), including:

0.43 Mt per year of by-product hydrogen capacity from ethylene production

0.36 Mt per year of by-product hydrogen capacity from the chlor-alkali process

0.13 Mt per year of by-product hydrogen capacity from styrene production

0.06 Mt per year of by-product hydrogen capacity from sodium chlorate production.

11 / Excluding by-product hydrogen generated as part of coke oven gas (COG).

Comparatively, the largest amount of by-product hydrogen production capacity is found in refineries from catalytic reforming and other processes. As previously mentioned, the methodology includes such production capacity under the captive reforming category.

Another potentially significant source of by-product hydrogen is coke oven gas (COG), which is produced as a by-product of coke from coking/metallurgical coal. Coke oven gas is used to enrich the calorific value of other process gases for use in blast furnace stoves, in the reheating furnaces of the hot strip mills, for the under-firing of coke ovens, and other high-temperature processes. Surplus COG may be utilised in the blast furnace as an alternative reducing agent and power plants (Remus, Monsonet, Roudier, & Sancho, 2013). While hydrogen generally comprises 56% of coke oven gas, it is only rarely extracted and separated from the mix. Therefore, while it is important to mention, it is not included in the hydrogen production capacity numbers above.

1.1.2. Reforming with carbon capture

In 2020, no new hydrogen production plants with carbon capture came into operation. Of the 504 hydrogen production plants, only the following three use carbon capture technologies:

Air Liquide CRYOCAP installation in Port Jerome, France, capturing CO_2 from a steam methane reformer, which supplies hydrogen to an Exxon refinery. The CRYOCAP technology uses cryogenic purification to separate CO_2 from the PSA off-gas. The captured and liquefied CO_2 is delivered to the local beverage industry. The utilised capture is up to 100 000 tonnes of CO2 per year (Pichot, et al., 2017).

Shell's Pernis refinery in Rotterdam, where various low-value refinery residues are gasified to produce hydrogen. CO2 is captured as part of the gasification process, transported via pipeline, and sold mostly to the agriculture sector.[12]

Grupo Sappio hydrogen production unit in Mantova, Italy with a hydrogen production capacity of around 1 500 Nm3/h.

The total share of reforming with carbon capture (known also as "blue" hydrogen) in all hydrogen production capacity is 56 148 tonnes a year or 0.5% of the total.

12 / More information available at: https://www.ocap.nl/

1.1.3. Power-to-hydrogen production capacity

While power-to-hydrogen technology has been available and utilised for decades, it is only now emerging as a future technology for large-scale hydrogen production. In the past, power-to-hydrogen has been employed in some industries where hydrogen demand exceeded the economic feasibility of hydrogen deliveries in cylinders or tube trailers, but the demand was insufficient to invest in a steam methane reformer and associated on-site infrastructure. The most common examples include electrolysers installed for captive hydrogen production at food processing facilities (fat hardening), glass manufacturers, small-scale merchant production, or power plants where hydrogen is used for cooling purposes.

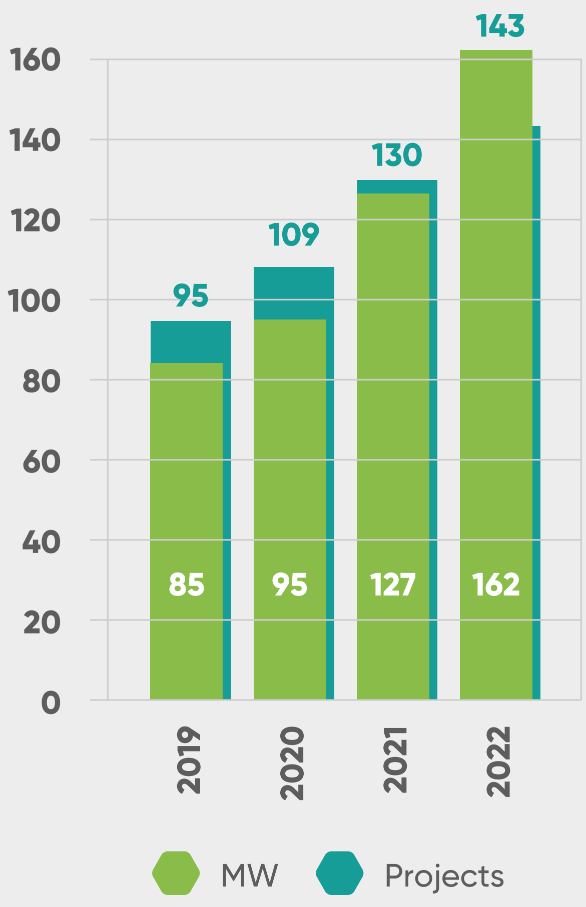
By August 2022, Hydrogen Europe identified 143 PtH sites in operation in the EU, EFTA, and the UK amounting to 162 MW_{el} or 29 kt/year of capacity. So far, they are a marginal part of the market constituting only 0.25% of the total 2020 installed European hydrogen production capacity of 11.5 Mt.[13] **For comparison, the total operational PtH capacity identified in Europe is only slightly higher than the world's largest operational PtH facility, the 150 MW alkaline plant in China put into operation by Ningxia Baofeng Energy Group.**

Figure 7 shows the cumulative installed power-to-hydrogen capacity from 2019 to 2022. **The total installed PtH capacity has almost doubled between 2019 and 2022, adding 77 MW of capacity.** While Hydrogen Europe aims to be exhaustive, it recognises that there might be other operational power-to-hydrogen facilities in the tens or hundreds of kW range that might have not been included in the figures below.

A significant percentage of this capacity has been built as demonstration projects, some of which continue their operations after the research project finishes while others

FIGURE 7

Cumulative installed power-to-hydrogen capacity and number of projects in EU, EFTA, UK (MW)[14]



Source: Hydrogen Europe.

13 / This differs from water electrolysis percentage of 0.1% in Figure 4 because Figure 4 uses 2020 PtH capacity while this sub-chapter refers to 2022 PtH capacity against 2020 total production capacity

14 / Cumulative capacities for years 2019, 2020, 2021 slightly differ from those reported in Clean Hydrogen Monitor 2021. The retroactive changes are due to continuously improving data accuracy.

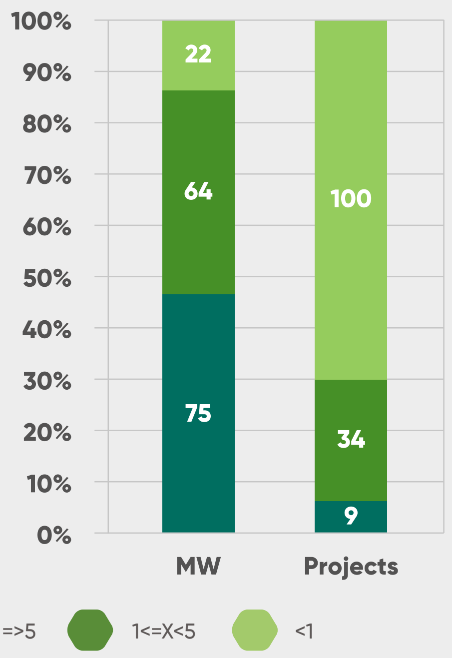
are decommissioned. The average project size is 1.13 MW. **Figure 8** demonstrates the capacity and number of projects by electrolyser size. 47% or 75 MW of the total installed PtH capacity in the EU, EFTA, and the UK is in nine projects larger or equal to 5 MW. These represent some of the larger deployed industrial PtH capacity. On the other hand, there are 100 operational projects of less than 1 MW of capacity, representing only 22 MW. These include many hydrogen refuelling stations with on-site electrolysis and various research and demonstration water electrolysis units.

In recent years, some of the larger multi-MW capacities have been added for fertiliser production, refining, small-scale merchant production, grid services, and e-fuel production. At least 50 MW are used for feedstock in refining, ammonia, steel, or other industries. 59 MW is related to hydrogen or synthetic fuels mobility in some way while at least 18 MW of PtH capacity is currently on-site co-located at hydrogen refuelling stations. Many installations serve multiple end-users. Some of the other end-users include industrial heat, grid injection, combined heat and power, and storage solutions.

Germany accounts for 36% of the identified capacity and 28% of operational projects in the EU, EFTA, and the UK. Other countries with significant installed capacity are Spain with 25 MW, Switzerland with 14 MW, and Austria with 10 MW. Given the small capacity deployed per country, any significant addition can catapult a country into the top five countries, as was the case with Spain in 2022. Current deployment figures should not be perceived as an indication of the country's future PtH leadership.

FIGURE 8

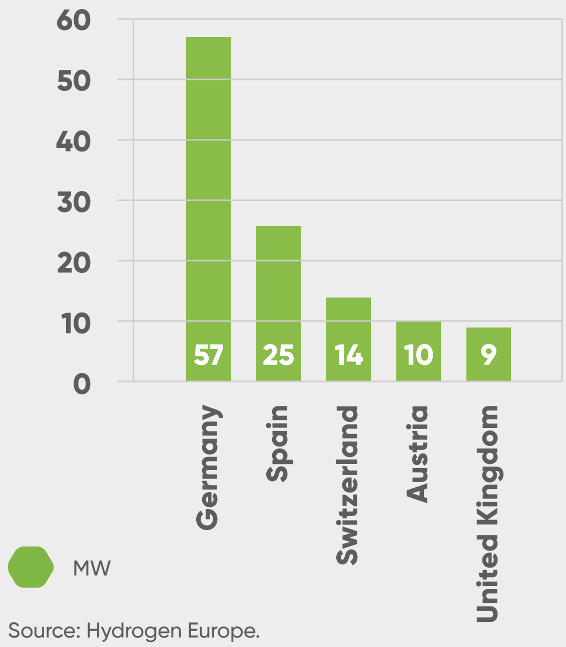
PtH projects based on size (MW & # of projects)



Source: Hydrogen Europe.

FIGURE 9

Countries with the highest cumulative installed power-to-hydrogen capacity (MW)



Source: Hydrogen Europe.

Figure 10 provides details on the electrolyser technology data that is available for 106 projects representing 142 MW of the operational PtH capacity. PEM electrolysers account for 59% or 84 MW while ALK electrolysers constitute 40% or 57 MW of known operational capacity in Europe. PEM also leads in terms of projects with 55 projects or 52% using PEM technology and 42 projects or 40% using ALK technology. This report further identified less than 1 MW and less than 10 operational deployments for each solid oxide and anion exchange membrane electrolysers in Europe.

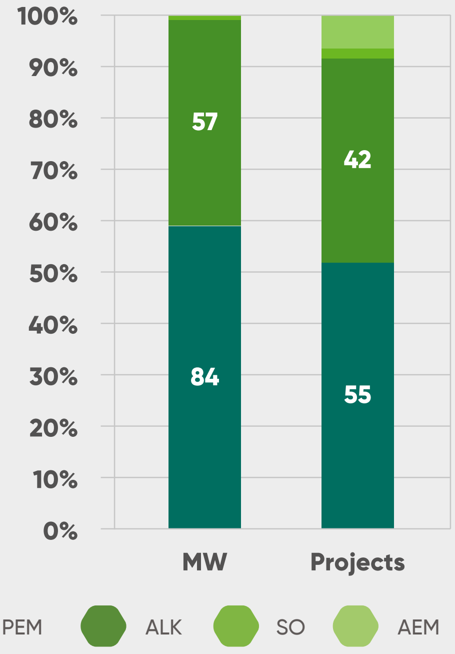
Due to the small total size of the operational PtH capacity, the deployed technology capacity numbers can change significantly just by adding a single project. This was the case in 2022 by adding 20 MW of PEM in Spain and 2021 by adding 10 MW of PEM in Germany. For now, the technologies are being deployed interchangeably across different end-uses.

Figure 11 provides details on the electrical connection of the 143 operational PtH projects. Grid connections predominate, providing 59% or 95 MW of PtH capacity and 59% or 85 projects. Direct connection to an electricity source accounts for 24% or 39 MW of capacity and 35% or 50 projects. Projects with direct and grid connections are less common now, with 28 MW spread among 8 projects.

15 / The authors identified only a small single digit number of operational SO and AEM electrolysers, with each technology having less than 1 MW of operational capacity in Europe and have chosen not to report these numbers in this year's edition.

FIGURE 10

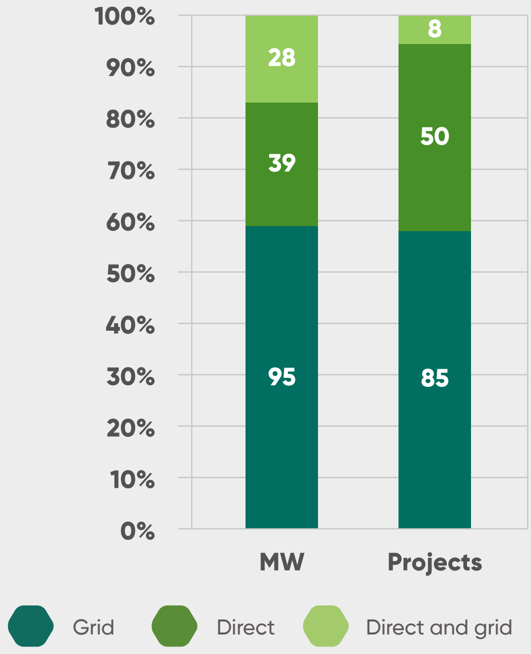
Operational electrolyser technology (MW & # of projects)[15]



Source: Hydrogen Europe.

FIGURE 11

Electricity connection of operational PtH projects (MW & # of projects)

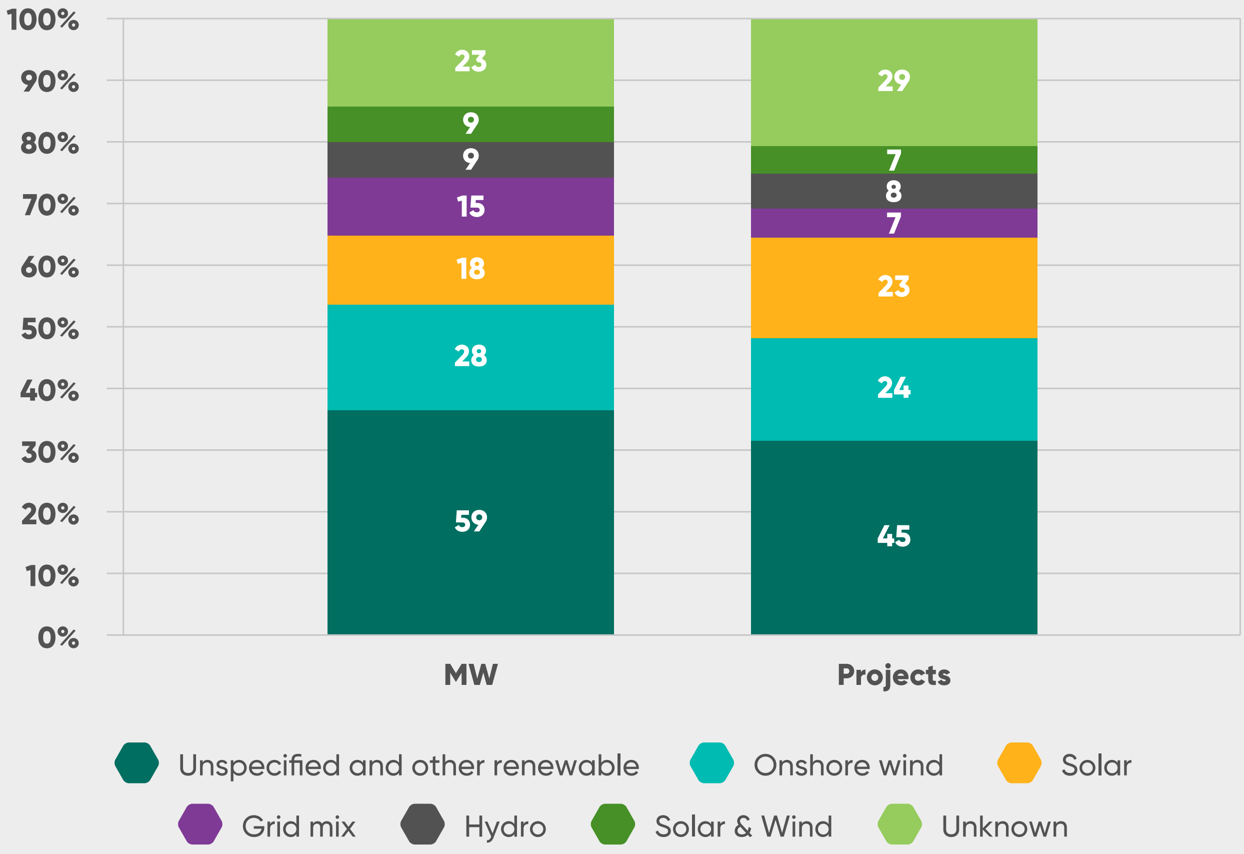


Source: Hydrogen Europe.

Figure 12 provides details on the electricity source of operational PtH projects regardless of whether they use a direct or grid connection. 37% or 59 MW come from unspecified and other renewable sources.[16] Onshore wind energy constitutes 17% or 28 MW. Overall, 77% of PtH capacity and 75% of projects are powered by renewable electricity either directly or via a power purchase agreement.

FIGURE 12

Electricity source of operational electrolysers (MW & # of projects)



Source: Hydrogen Europe.

16 / This includes all non-specific renewable electricity as well as electricity from geothermal, biomass, and ocean energy.

© Justin Jin for Hydrogen Europe

1.2.

Hydrogen demand

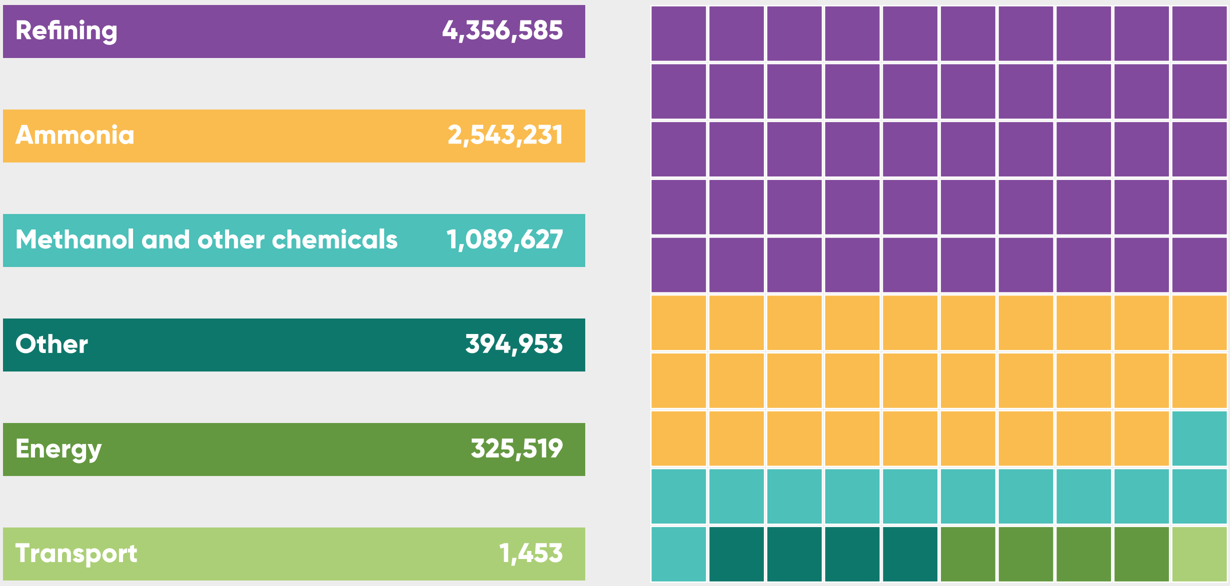
1.2.1. Demand by sector

Total demand for hydrogen in 2020 has been estimated at 8.7 Mt compared to 8.4 Mt reported in last year's Clean Hydrogen Monitor.[17] [18] **The biggest share of hydrogen demand comes from refineries, which were responsible for 50% of total hydrogen use (~4.4 Mt), followed by the ammonia industry with 29% (~2.5 Mt).** Together, these two sectors consumed 79% of the total hydrogen consumption in the EU, EFTA, and the UK. About 13% is consumed for methanol production and other uses in the chemical industry. The category "other" of 4.5% includes hydrogen production that was not allocated to an end-user and net imports into a country. The energy category represents hydrogen burned for its energy content, mostly produced as a by-product from ethylene, styrene, chlorine, or sodium chlorate production. Emerging hydrogen applications for clean hydrogen, like the transportation sector, continued to comprise only a small portion of the market (<0.1%).

Total hydrogen consumption in the EU, EFTA, and the UK represents only 8.7% of global hydrogen demand in 2020 (IRENA, 2022).

FIGURE 13

Total hydrogen demand in 2020 by application (t)



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

17 / Same as for production capacity, the reporting year is 2020 instead of 2021 as some 2021 data was unavailable at the time of the update.
18 / The market as a whole is stable and despite upgrades and changing utilizations in 2020, most of the difference compared to last year's numbers, that refer to reporting year 2019, is due to improving data accuracy and methodological changes as described in the methodology section.

Refining

The refining sector is the largest hydrogen consumer in the EU. Hydrogen in refineries is used for hydrotreating and hydrocracking processes. Hydrotreatment is one of the key stages of the diesel refining process and is related to several processes such as hydrogenation, hydrodesulfurization, hydrodenitrification, and hydrodemetallization. Hydrocracking involves the transformation of long and unsaturated products into products with a lower molecular weight than the feed. Based on information gathered on refinery hydrogen production capacities, together with information on capacity utilisation, this report estimates that the total hydrogen demand of the petroleum refining and petrochemicals industry was 4.4 Mt in 2020.

Ammonia

The ammonia industry is the second largest hydrogen-consuming sector in the EU. The ammonia production process involves a synthesis of hydrogen with nitrogen with a consumption of 175-180 kg of hydrogen per t of ammonia. The total demand for hydrogen by the ammonia industry in 2020 has been estimated at 2.5 Mt, most of it for subsequent fertiliser production.

Chemical industry

In addition to ammonia, hydrogen is a feedstock or intermediate product necessary for other chemical products, such as methanol, hydrogen peroxide, cyclohexane, aniline, caprolactam, oxo alcohols, toluene diisocyanate (TDI), hexamethylenediamine, adipic acid, hydrochloric acid, tetrahydrofuran, and others.

Total demand for hydrogen from the chemical industry (excluding ammonia production) has been estimated at 1.1 Mt in 2020.

Refining, ammonia production, and other chemical industries as described above together account for around 92% of the total demand for hydrogen. Hydrogen burned for its energy content accounts for 3.7% with the remainder of the demand coming from the following applications.

Steel manufacturing and metals processing

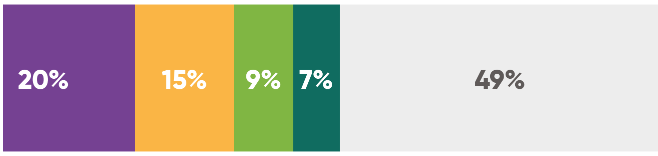
A mixture of hydrogen and nitrogen (5% to 7% hydrogen) is commonly used as an inert protective atmosphere in conventional batch annealing in annealing furnaces. Batch annealing with 100 % hydrogen is also possible and results in better productivity, improved mechanical properties, and surface and product quality. Using hydrogen for Direct Reduction of Iron (DRI) is another important future driver of hydrogen consumption in steel production with the HYBRIT project in Sweden having produced its first hydrogen-reduced sponge iron in 2021. For more details on future industrial demand for clean hydrogen in steel production, please consult **Chapter 5**.

Other industries

In glass manufacturing, hydrogen is used as an inert or protective gas. In food processing, hydrogen is used for margarine production by hydrogenation of fatty acids from vegetable oils. The category “other” also encompasses hydrogen production that was not allocated to an end-user and net imports into the country.

1.2.2. Demand per country

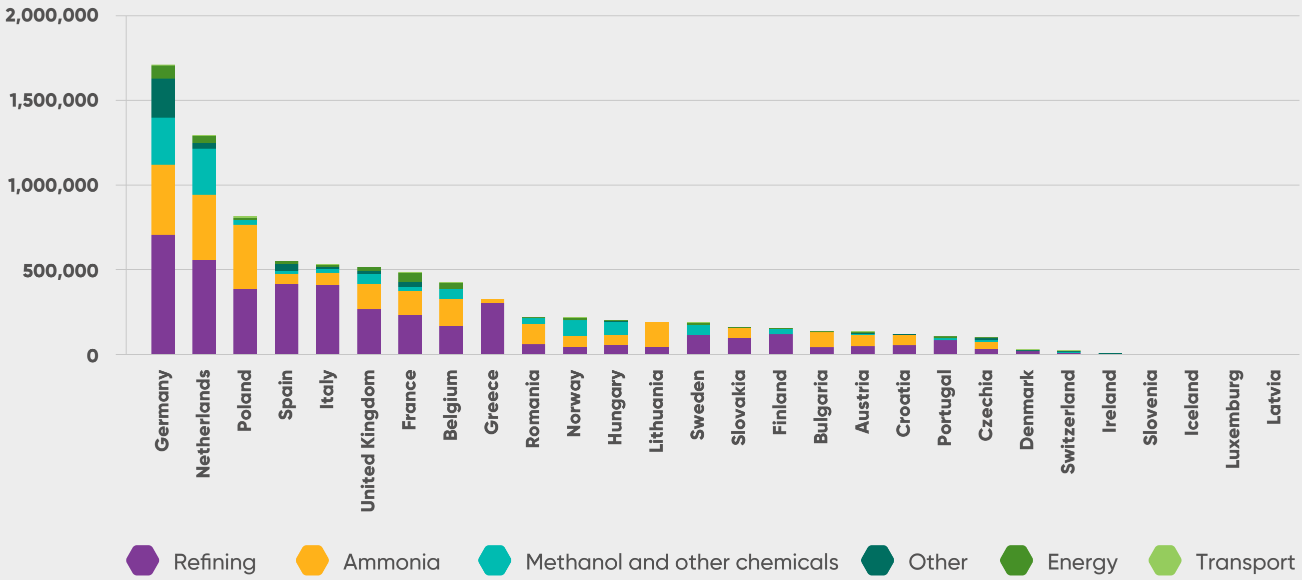
More than half of the total EU, EFTA, and UK hydrogen consumption takes place in just four countries: Germany (20%), the Netherlands (15%), Poland (9%), and Spain (7%).



Similar to the overall results for the entire geographic scope of this report, in most countries, the dominant hydrogen demand comes from the refining industry. In some countries such as Finland, Italy, Greece, Portugal or Spain, refining is responsible for most of the domestic hydrogen consumption. In the case of Poland and Lithuania, a significant share of hydrogen demand comes from the ammonia industry.

FIGURE 14

Total demand for hydrogen in 2020 by country (t)[19]



Source: Fuel Cells and Hydrogen Observatory.

19 / All countries on the graph have at least some hydrogen consumption.

Conclusion

The conventional hydrogen market remained stable in 2020 and most of the changes were due to upgrades, capacity retirements, and improved data accuracy. Capacity factors in key industries such as refining and ammonia have been affected by COVID-19 only in some markets in 2020. A larger impact on utilisation is expected in 2021 and 2022 due to higher natural gas prices.

There have been no new deployments of hydrogen production reforming with carbon capture and the three operational plans for this production pathway still represent only ~0.5% of total hydrogen production capacity. Chapter 3 describes the planned reforming with carbon capture projects in more detail.

Despite the gradual decommissioning of several research units, power-to-hydrogen installations have almost doubled from 85 MW in 2019 to 162 MW in August 2022, with their share reaching 0.25% of the total 2020 hydrogen production capacity. While 35 MW came online in 2022, at the time of writing this report, there are dozens of MW projects postponed to 2023 and 2024. In addition to the usual commercial issues, the delays are due to regulatory uncertainty, lack of expected financial incentives, and, in some cases, supply chain and permitting issues. Chapter 3 describes the planned power-to-hydrogen projects in more detail.

Methodological Note

The geographical scope of the report covers the European Union, Iceland, Norway, Switzerland, and the United Kingdom.

The reporting year is 2020, as some of the sources did not have 2021 data available during the data collection process. The power-to-hydrogen sub-chapter refers to data collected until August 2022.

Hydrogen production capacity was collected on a plant-by-plant basis. Hydrogen demand is a calculation based on production capacity numbers, utilizations, industry resources, and Eurostat.

The verification process involves contacting asset owners, industry associations, and statistical offices.

Much of the data collection for this chapter has been conducted as part of Hydrogen Europe's work for the Fuel Cells and Hydrogen Observatory. Its reports and downloadable excels can be accessed at https://fchobservatory.eu/

Hydrogen Europe continues to improve the data quality every year as it collects more information. The most significant improvement occurred in the production capacities in refineries which lead to a significant increase in captive reforming production capacity. The main methodological changes compared to CHM 2021 report include classifying by-product hydrogen production capacity in refineries as captive reforming and reducing the potential of hydrogen production capacity from coke production.

Due to the improving data set and methodological changes, the results from CHM 2021 are not directly comparable to this year's results.

© Justin Jin for Hydrogen Europe

02

Levelised costs of hydrogen production

© Justin Jin for Hydrogen Europe

Introduction

The following chapter contains an analysis of hydrogen production costs in the EU for the year 2021. It should be underlined that the production costs presented in the chapter are not reported statistical costs gathered from real projects but estimates based on updated cost assumptions.

The production costs were estimated for two scenarios:

- Electrolyser using grid electricity.
- A direct, physical connection between a renewable electricity source (RES) and the electrolyser.

The goal of this analysis is to track the development of those costs to compare them with several benchmarks, most crucially – the costs of hydrogen production using the incumbent fossil fuel technology, which is steam methane reforming without CCS (so-called "grey" or "fossil" hydrogen).

Therefore, the ultimate purpose of this analysis is to demonstrate the current cost gap that needs to be bridged to make unsubsidised electrolytic hydrogen production competitive in the EU compared to the current fossil fuel-based SMR benchmark.

The **Table 1** summarises the parameters used in the two analysed scenarios for hydrogen production.

For both scenarios, key techno-economic parameters of the electrolysis were adopted based on current state-of-the-art 10,000 kW alkaline electrolysis. For detailed techno-economic assumptions, see also the **Methodological Note.**

The analysis in this chapter is based on data for which a complete annual dataset is available, i.e., 2021. However, the second half of 2021 saw a significant increase in both natural gas and electricity prices across Europe. This price increase was even further strengthened in 2022, partially due to the war in Ukraine. As a consequence of these dynamic developments in the energy markets, it needs to be recognised that since the analysis is based on average data for 2021, the results do not accurately depict the current market situation where renewable hydrogen costs are already, in many EU MS, lower than SMR benchmark.

TABLE 1

Key distinctions between the two hydrogen production scenarios

Criteria	Grid-connected electrolysis	Direct connection to RES
Carbon intensity	Carbon intensity of the grid (based on the most recent EEA assessment)	Zero-carbon (100% renewable)
Electricity costs	Wholesale electricity price (based on data obtained from the ENTSO-e Transparency Portal)	RES Levelised cost of electricity (own estimation of LCOE based on most recent IRENA RES deployment costs data)
Network costs, taxes and fees	Applicable (based on data obtained from Eurostat)	Not applicable
Scale	10.0 MW electrolysis	10.0 MW electrolysis
Capacity factor	4,000 off-peak hours	Equal to the capacity factor of the RES it is connected to[1]

1 / Only in case when the electrolyser's power is equal to that of the RES. When the size of an electrolyser is smaller than RES, its capacity factor can be significantly increased.

2.1.

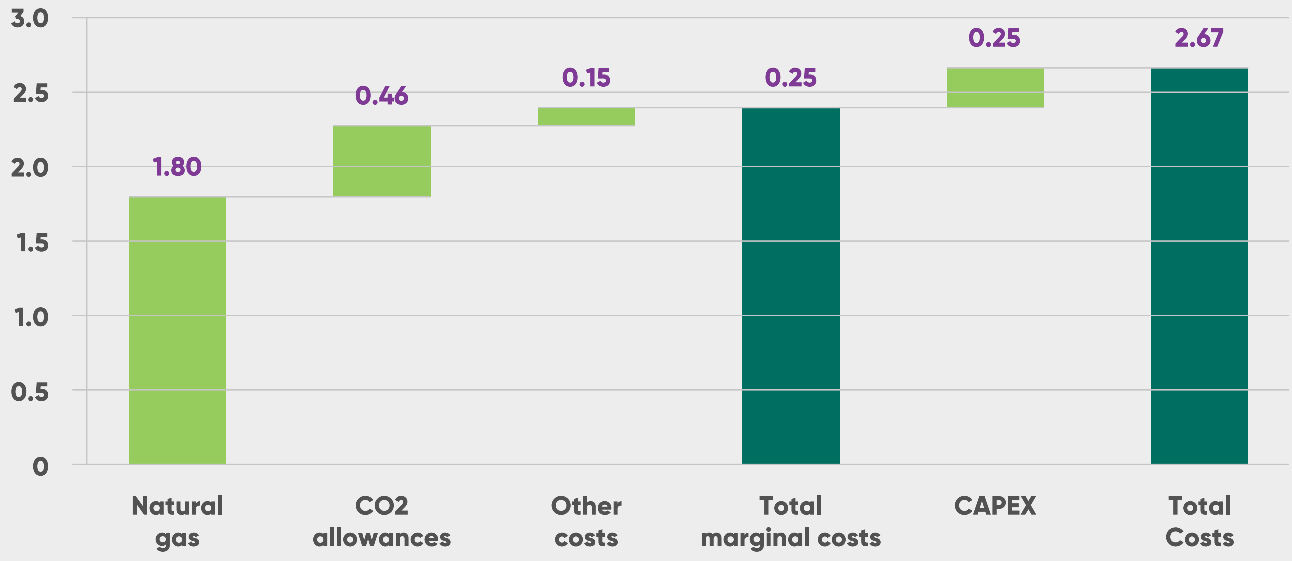
SMR benchmark

Currently, 'grey' hydrogen, i.e., hydrogen produced from fossil fuels, most commonly from natural gas via steam methane reforming - accounts for an overwhelming portion of hydrogen production in the EU (and worldwide). Replacing 'grey' hydrogen presents the most immediate market opportunity for clean hydrogen. Hydrogen production costs through the SMR process provide a useful price benchmark for all other production technologies.

For 2021, we estimate that, on average, the levelised production costs of hydrogen by SMR in the EU-27 were approximately **EUR 2.67 per kg of H2.** Furthermore, as SMR plants are already operational (and in many cases long amortised), marginal - not levelised - costs may, in many cases, be a better benchmark. Excluding the impact of CAPEX (amortisation) and other fixed costs, estimated grey hydrogen marginal production costs in the EU-27 in 2021 were around **EUR 2.42 /kg.**

FIGURE 1

Average hydrogen production costs via SMR in the EU-27 in 2021 (in EUR/kg)



Source: Hydrogen Europe.

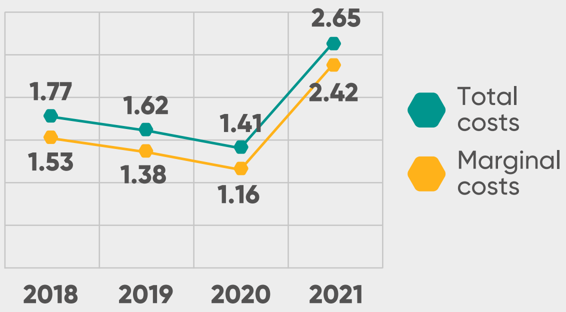
Such cost level represents a significant increase compared to estimates from previous years when 'grey' hydrogen costs were oscillating around **EUR 1.4-1.8 /kg.**

Furthermore, as costs estimates are based on average annual cost levels, because the second half of 2021 saw a dramatic increase in natural gas prices, at the end of 2021, costs of producing hydrogen from natural gas were significantly higher than the annual average.

For reference, the 2021 SMR benchmark cost was estimated using an average natural gas price of EUR 37.1 /MWh. However, at the end of 2021, the price of natural gas was more than double that level at around EUR 80 /MWh, increasing grey hydrogen production costs to EUR 4.8 /kg. Furthermore, on 12 September 2022, Dutch TTF gas futures amounted to EUR 190.59 /MWh. Increased CO2 allowances costs at EUR 71.8 /t would increase natural gas-based hydrogen production to more than EUR 10 /kg.

FIGURE 2

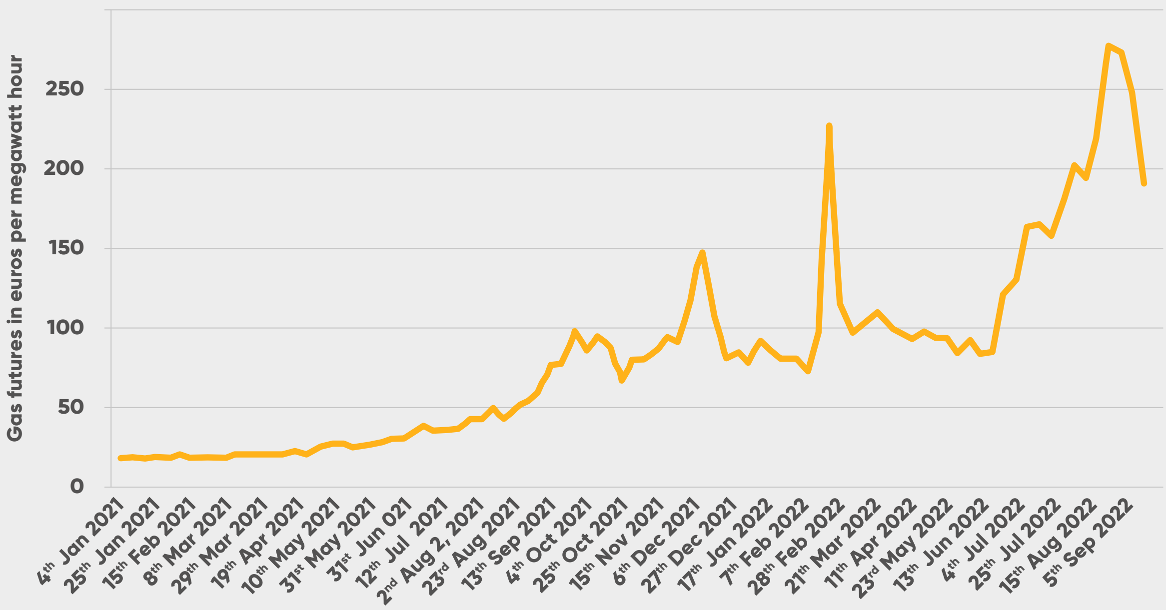
Average hydrogen production costs via SMR in the EU-27 in 2018-2021 (in EUR/kg)



Source: Hydrogen Europe.

FIGURE 3

Dutch TTF gas futures at the beginning of each week from 4 January 2021 to 12 September 2022 (in EUR/MWh)



Source: Statista.

2.2.

Grid-connected electrolysis

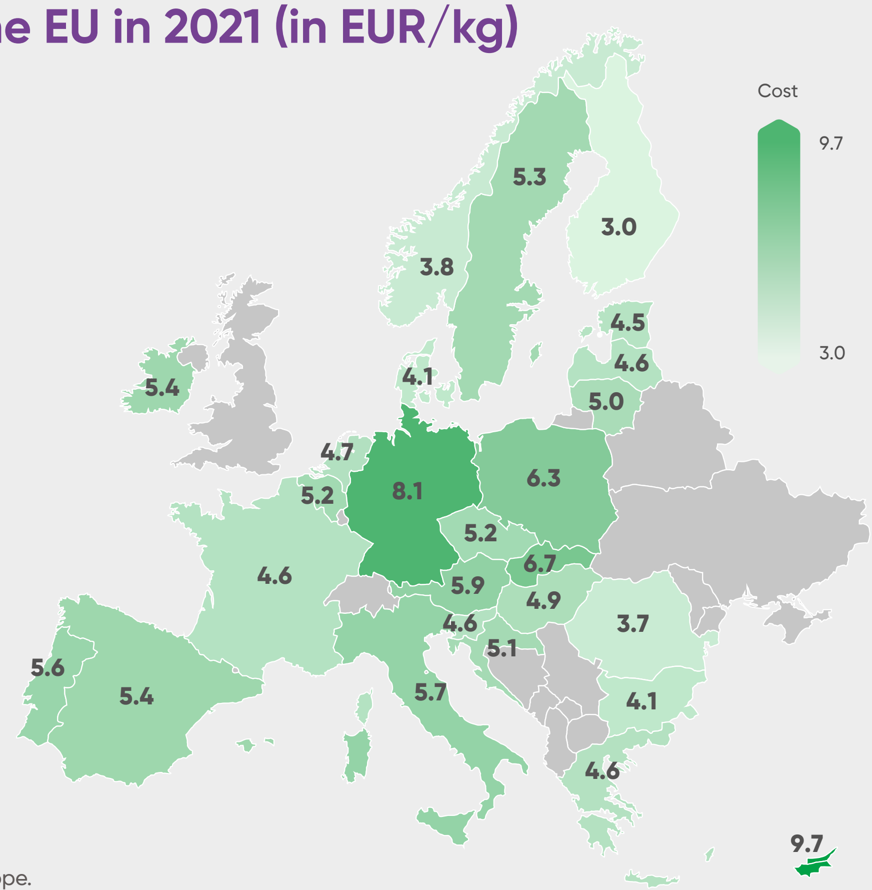
2.2.1. Costs of production

The hydrogen production costs using grid electricity in the EU (together with Norway) in 2021 **have been estimated in the range of EUR 3.0-9.7/kg** (compared to 1.8-7.7 in 2020), with the average for all countries being **EUR 5.3 /kg** and a median of EUR 5.1 /kg (3.75 and 3.5 respectively in 2020). Similarly to 'grey' hydrogen, this rather significant cost increase is linked to the spike in natural gas and oil prices, which indirectly translated into an increase in wholesale electricity prices in Europe.

As was the case in 2020, the highest grid electricity hydrogen production costs are in Germany, Cyprus, and Malta, estimated at around EUR 8 - 10 /kg. On the other end of the spectrum are the Scandinavian countries: Finland (EUR 3.0 /kg), Norway (EUR 3.8 /kg) and Denmark (EUR 4.1 /kg). The only other country outside of Scandinavia where the costs of producing hydrogen using grid electricity were comparably low were Luxemburg and Romania (around EUR 3.6 and 3.7 /kg, respectively).

FIGURE 4

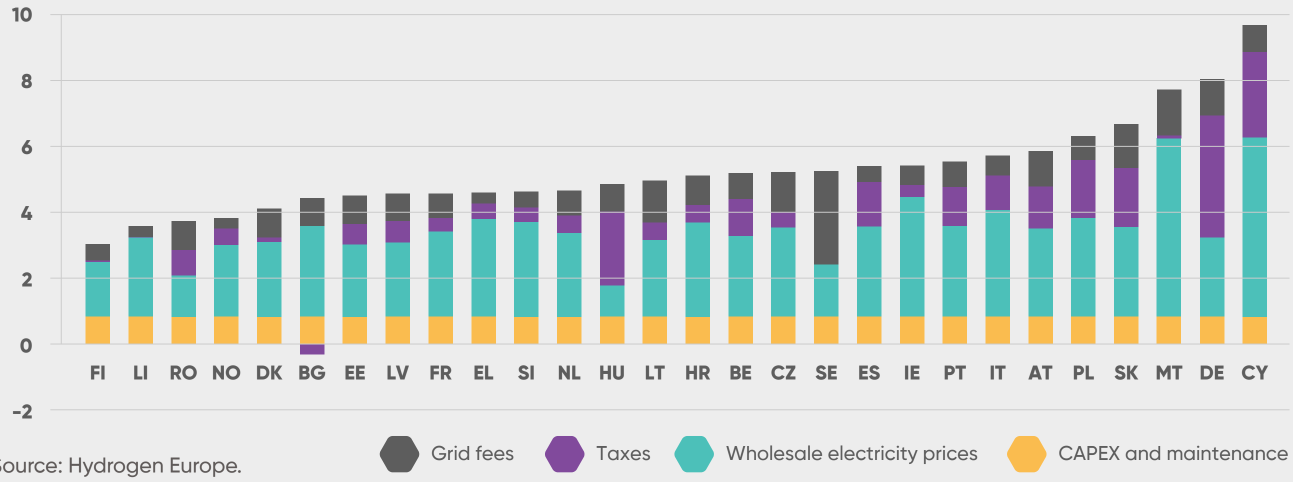
Map of grid-connected electrolysis hydrogen production costs in the EU in 2021 (in EUR/kg)



Source: Hydrogen Europe.

FIGURE 5

Grid-connected electrolysis hydrogen production costs in the EU in 2021 (in EUR/kg)[2]



Source: Hydrogen Europe.

There are at least a couple of reasons for such significant differences between countries. The most obvious one is the difference between wholesale electricity prices, which contributes the most to most countries' final cost of hydrogen. High wholesale electricity prices explain to a large extent the high hydrogen cost in Cyprus and Malta, where the electricity prices are among the highest in Europe. Yet, in the case of Germany, the hydrogen production costs are high even though it has one of the lowest wholesale electricity prices in Europe.

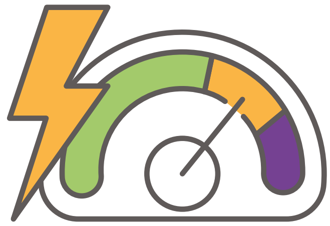
The reason why hydrogen production costs in Germany are so high is that taxes charged on top of wholesale electricity price are the highest in the EU and, in this case, constitute around 51% of the total cost, while in Bulgaria, Sweden, Luxembourg or Malta the contribution of taxes to the final hydrogen production costs are only about 0-3%.

It is especially interesting to compare costs in Germany to those in Luxembourg. As Luxembourg is participating in a single energy grid with Germany, it enjoys the same low wholesale electricity prices as Germany, thanks to the high penetration of cheap renewables. Still, most of the balancing costs are borne by the German end-users, with very low taxes and grid fees applied in Luxembourg. As a result, it is one of the cheapest countries to produce hydrogen with grid-connected electrolysis in the EU, with total costs less than half of those in Germany, with the same electricity prices.

It should also be noted that one of the key contributors to grid fees in Germany is the renewable energy surcharge (EEG surcharge). If the electricity supplied via the grid were of renewable origin, this surcharge would not apply, which would significantly reduce the impact of grid fees on renewable hydrogen production costs in Germany via the grid.

The **Figure 5** shows calculated hydrogen generation costs in the EU, based on wholesale electricity prices and network costs and fees for 2021.[3]

2 / According to Eurostat data, grid fees in Bulgaria in the relevant consumption band, were negative in 2021.
3 / Source: ENTSO-e Transparency Portal, 2022 for wholesale electricity prices and Eurostat, 2022 for electricity network costs, fees, and taxes for the 20,000 – 69,999 MWh energy consumption band.



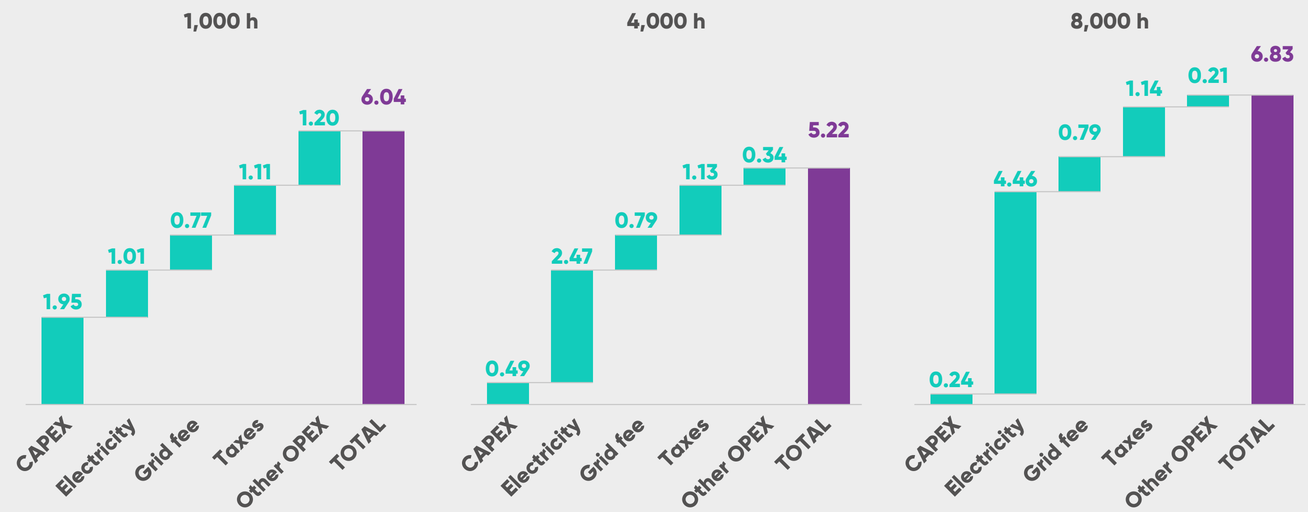
The described calculations assumed that the electrolyser would run, on average, around 4,000 hours per year in off-peak hours, when the wholesale electricity prices are lowest (see methodology note for more details). This is close to optimum for most EU countries. If one increased the number of operating hours, the impact of CAPEX on final hydrogen production costs would decrease.

Yet, as more and more of the electricity would have to be bought in peak hours at higher prices, the additional electricity consumption costs would more than offset any gains resulting from a higher electrolyser capacity factor.

Reversely, limiting the operational time to a few hours daily could reduce the average electricity price.[4] In this case, however, as lower amounts of hydrogen would be produced, the impact of CAPEX on the final cost would increase – again offsetting any gains from lower electricity prices. This relationship is depicted in the **Figure 6** (on the example of Belgium).

FIGURE 6

Comparison of hydrogen production costs (in EUR/kg) with grid-connected electrolysis in Belgium, depending on the number of operating hours



Source: Hydrogen Europe.

4 / In the case of Belgium, it would result in an average price of 20.0 EUR/MWh compared to 47.8 EUR/MWh in the 4,000 hour per year base case.

2.2.2. Carbon intensity

As previously mentioned, if a grid-connected electrolyser would be dispatched by the TSO/DSO and would use electricity that would otherwise be curtailed, it would make sense for the carbon intensity of the produced hydrogen to be counted as zero. Another way of ensuring a renewable character of hydrogen produced with grid-connected electrolysis would be to use electricity based on a PPA with a renewable energy source and GOs.

If none of those conditions is met, **the carbon intensity of hydrogen would depend on the carbon intensity of the grid it is connected to.** Although electricity supplied by the grids is far from being fully decarbonised in many EU countries, this scenario has merit even in high carbon-intensive electricity grids. An increasing amount of intermittent renewable energy sources, like wind and solar, can pose several challenges for the grid operators, including load and generation imbalances and grid congestion issues. Both of which can result in renewable energy curtailment.

Assuming the average grid electricity carbon intensities of European countries, as estimated by the European Environment Agency (EEA) for 2020, the carbon footprint of hydrogen ranges from 0 kgCO2/kgH2 in Iceland to 35.5 kgCO2/kgH2 in Poland. **Production of hydrogen using the EU-27 average electricity mix in 2020 would have resulted in emissions of 11.5 kgCO2/kgH2.** While with average EU grid-mix electricity, the GHG intensity of hydrogen would still be higher than even grey hydrogen (around 9 kgCO2/kgH2); one can notice a clear downward trend as the average GHG intensity was 12.8 kgCO2/kgH2 last year and 14.8 kgCO2/kgH2 before that (European Environment Agency, 2022).

For Iceland, because the electricity grid is almost 100% decarbonised, hydrogen produced from grid electricity has a carbon footprint that is effectively equal to that of renewable hydrogen (i.e., zero).

In several other countries, including **(besides Iceland) Norway, Sweden and France, the carbon intensity of grid electricity is low enough that even without Power Purchase Agreements (PPAs) and Certificates of Origin (GO), the produced hydrogen's carbon footprint would be low enough to meet all hydrogen emission benchmarks set on the EU level,** including the one set in EU taxonomy on sustainable finance[5] and the RED II for renewable transport fuels of non-biological origin (RFNBO) – which has been set at least 70% GHG savings compared to fossil fuel benchmark (equivalent to 3.384kgCO2 /kgH2).

In all those countries, with the addition of Finland and Austria, the carbon intensity of hydrogen from grid electricity would be lower than the CERTIFHy threshold for low-carbon hydrogen, set at 36.4 gCO2/MJ (4.4 kgCO2 /kgH2). In other words, the carbon footprint of that hydrogen would be lower than the standard value achievable with exiting SMR installations with CCS retrofit (CertifHy, 2022).[6]

In a total of 14 countries, including all the countries above with the addition of Slovakia, Latvia, Denmark, Croatia, Lithuania, Belgium and Spain, the carbon intensity of hydrogen from grid electricity would be lower than the average "grey" hydrogen emission intensity (around 9.0 kgCO2 /kgH2).

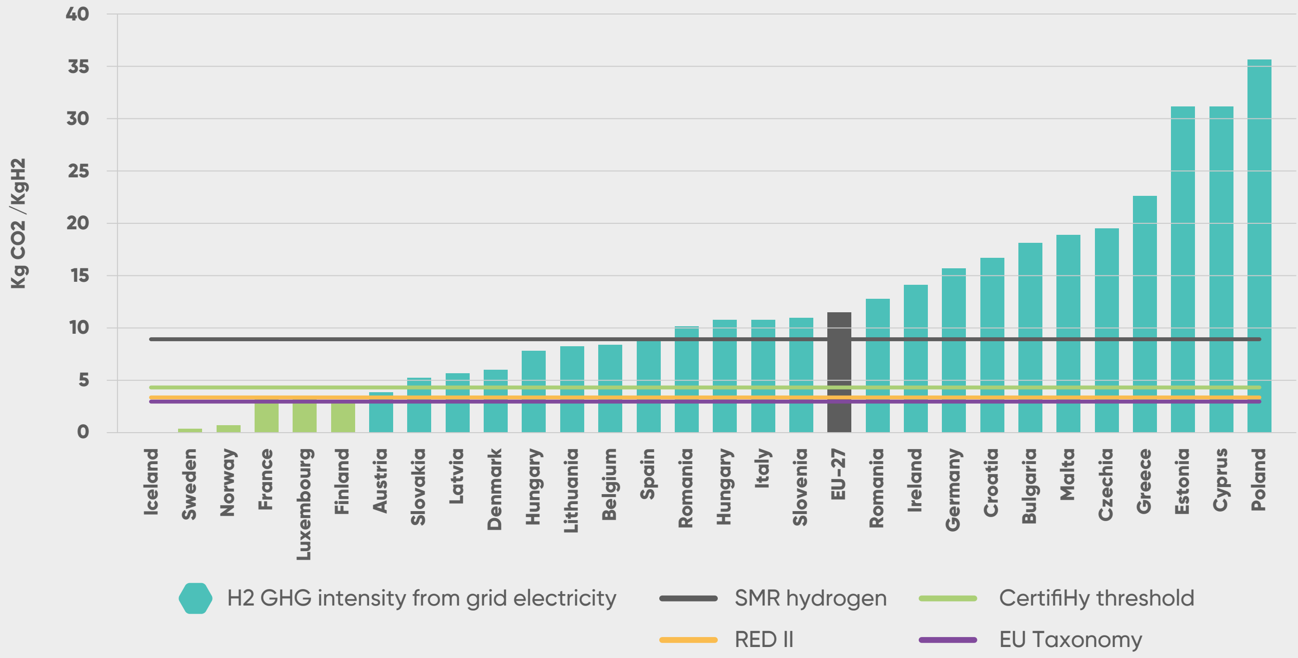
In all the remaining countries, hydrogen production from grid electricity, including the average EU-27 energy mix, would be more carbon-intensive than hydrogen from Steam Methane Reforming (SMR) without CCS.

However, it should be noted that grid-connected electrolysis can also have an indirect positive GHG emission impact. Located strategically, electrolysers can produce hydrogen when the renewable production exceeds grid export capacity avoiding curtailment of wind and solar energy, especially if hydrogen infrastructures (transport and/or storage) are made available. When addressing long-term (structural) congestions, strategically placed, large-scale electrolysis installations would not only benefit from the economies of scale but could help balance the entire grid and not only a single RES. In cases where the TSO/DSO would dispatch Power-to-Hydrogen (PtH) installations specifically to address

5 / 3.0 tonnes of CO2 per tonne of hydrogen
6 / With a retrofit CCS capture rate of around 60%.

FIGURE 7

Carbon intensity of hydrogen produced from grid electricity, compared to selected benchmarks



Source: Hydrogen Europe, based on EEA data

Note: SMR Hydrogen: 9.0 kg CO_2 / kg H_2 (75.0 gCO_2/ MJLHV), EU Taxonomy threshold for sustainable hydrogen manufacturing: 3 kg CO_2 / kg H_2 (25 gCO_2/ MJLHV), CertifHy threshold for low carbon hydrogen: 4.4 kg CO_2 / kg H_2 (36.4 gCO_2/ MJLHV), RED II threshold for RFNBO: 3.384 kg CO_2 / kg H_2 (28.2 gCO_2/MJLHV).

the RES curtailment issue, it would make sense for the produced hydrogen to be viewed as entirely renewable, even when connected to a high carbon-intensive electricity grid.

Electrolysers can also serve as a variable load, following signals from electricity transmission system operators to provide frequency reserves such as Frequency Restoration Reserve (FRR) or as a Frequency Containment Reserve (FCR), voltage control and even synthetic inertia, as today other technologies already offer (e.g., power generators, demand response, battery storage). Some of these capabilities have been tested and demonstrated in various European projects.

In the coming years, grid-connected PtH plants should be able to produce 100% renewable hydrogen using grid electricity together with a combination of PPAs signed with a renewable energy producer and GO to prove the renewable character of the electricity consumed. Nevertheless, since the legal framework and market conditions for such a scenario are not yet in place, such a scenario was not included in the quantitative analysis.

2.3. Direct connection to a renewable energy source

Hydrogen production via electrolysis with a direct connection to a renewable energy source avoids electricity costs like network costs and taxes. On the other hand, the electrolyser capacity factor is limited by the capacity factor of the renewable source it is connected to. Especially in the case of solar photovoltaic (PV) in Central and Northern Europe, this may potentially translate into a very low-capacity factor of just around 1,000 full-load equivalent hours per year. Yet, even with potentially lower capacity factors, compared to grid-powered electrolysis, **the ever-decreasing costs of renewable electricity are making it possible to produce renewable hydrogen at prices that are not far off from being competitive in most EU countries.**[7]

Considering the average solar irradiation and wind conditions in the EU Member States, Norway, and the UK, estimated renewable hydrogen production costs vary from EUR 3.3 /kg (from offshore wind in Ireland) to EUR 6.5 /kg (from solar PV in Luxembourg). In southern European countries, the cheapest pathway of renewable hydrogen production is solar PV, while for northern European countries, the most affordable option is offshore wind.

One can observe at least two important developments compared to last year's data. First of all, for renewable hydrogen production costs with utility-scale solar PV or onshore wind, the costs have not changed by much. The decrease in CAPEX for those technologies was relatively small, and, as a result, the estimated production costs fell by only around EUR 0.5 /kg. On the other hand, however, the situation in the offshore wind market was noticeably different.

However, it should also be stressed that the costs above have been calculated based on each country's average wind and solar conditions.[8] Especially for large countries like Germany, Spain, or France, this can be misleading as there are areas with significantly better than average wind or solar conditions, where production of renewable hydrogen with direct connection to the RES source would also be considerably less expensive than on average.

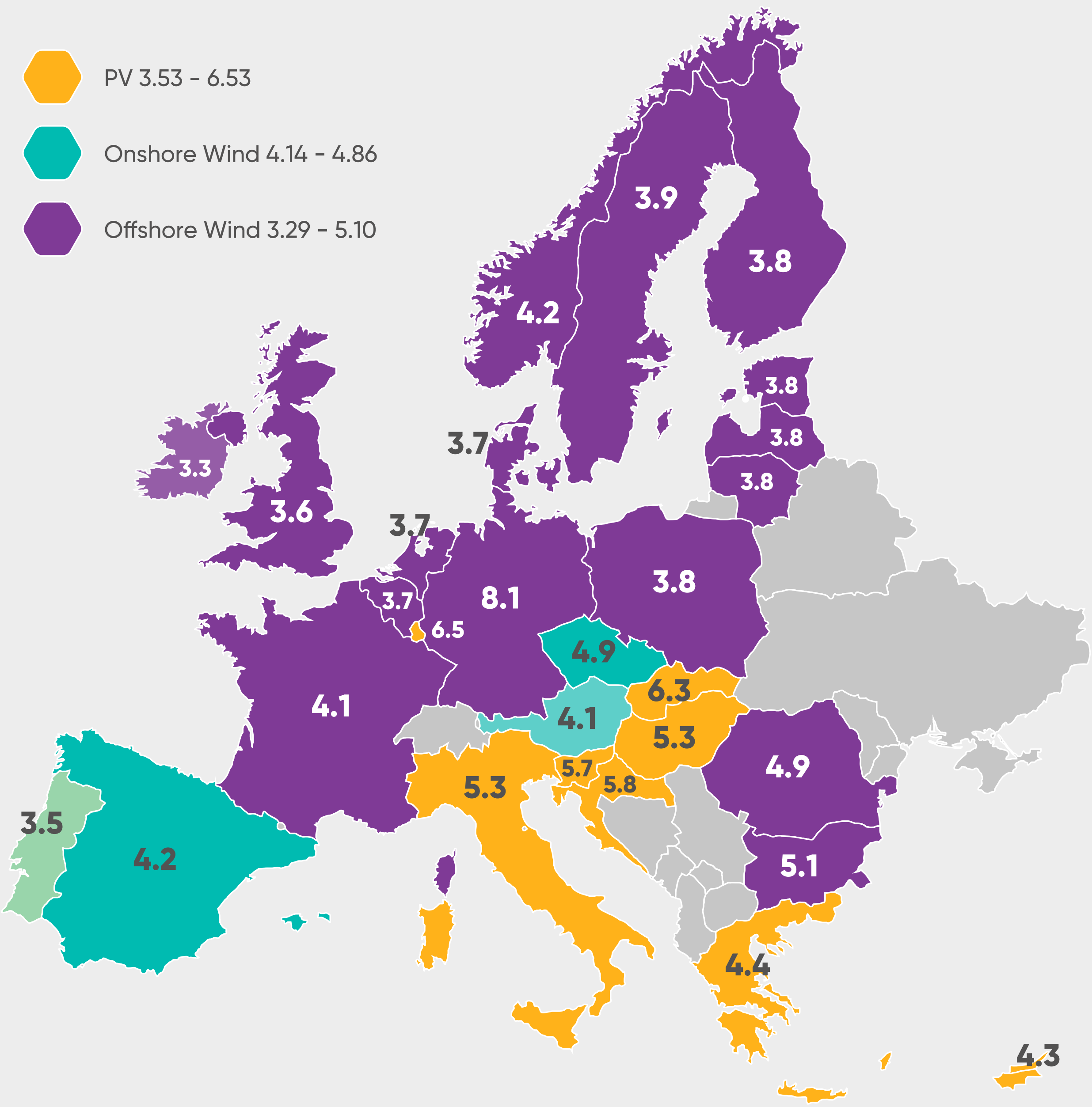
This can be illustrated in the example of Poland, where according to JRC ENSPRESSO and EMHIRES databases, the average onshore wind capacity factor is around 23% (Ruiz-Castello, et al., 2021; Gonzalez-Aparicio, et al., 2016; Careri, Gonzalez-Aparicio, Huld, Monforti, & Zucker, 2017). In contrast, according to the most recent IRENA renewable power generation costs report, the average capacity factor for onshore wind projects in Poland in 2021 was 36%, i.e., 56% (or 13 percentage points) higher than the assumed average (IRENA, 2022). This would reduce the estimated renewable hydrogen production costs from EUR 4.9 to EUR 3.2 per kilogram.

Therefore, it is essential, especially for large countries, to look at the average and best available conditions for new renewable development. The results of such an analysis are presented in the following two graphs. The lower end of the cost range has been estimated, assuming the best irradiation or wind conditions available in each country.[9]

7 / For detailed techno-economic assumptions used for production costs estimations see the Methodological Note.
8 / It also does not include other potentially cheap renewable energy sources like hydropower in Austria, Slovenia, or Scandinavia.
9 / For solar PV, the best available conditions were estimated as a maximum capacity factor for a NUTS-2 region in a country based on the ir_global_tracking with a 0.85 performance dataset. In contrast, the best conditions for wind were assumed based on the maximum wind capacity factor available for any NUTS-2 region. Both values were adopted based on the JRC ENSPRESSO database.

FIGURE 8

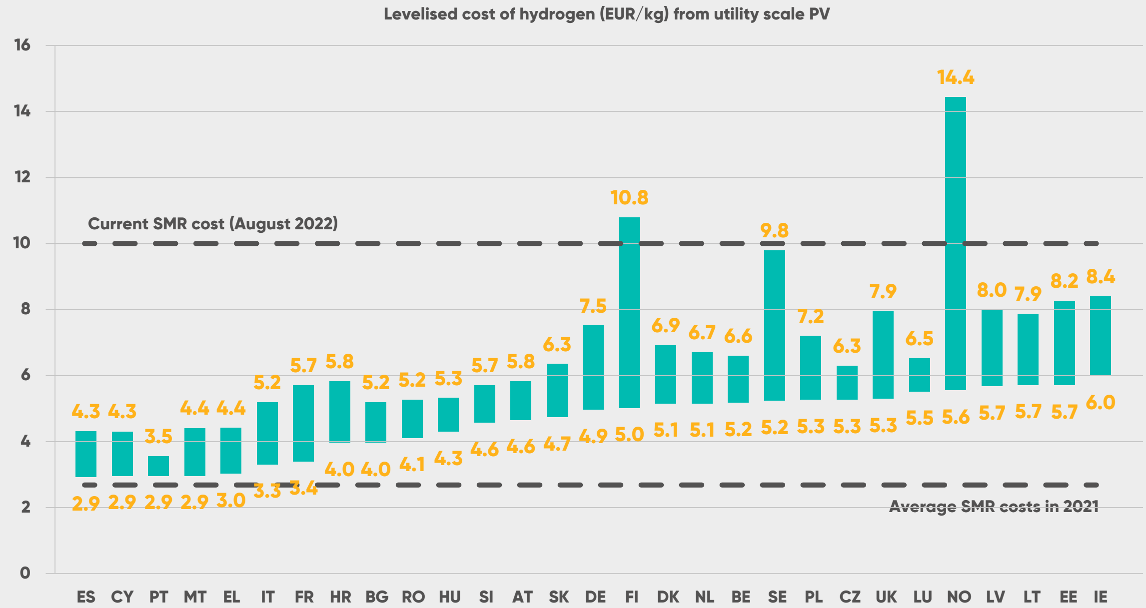
Average renewable hydrogen production costs in the EU (with UK and Norway) in 2021 (in EUR/kg), using the lowest-cost RES technology for a given country

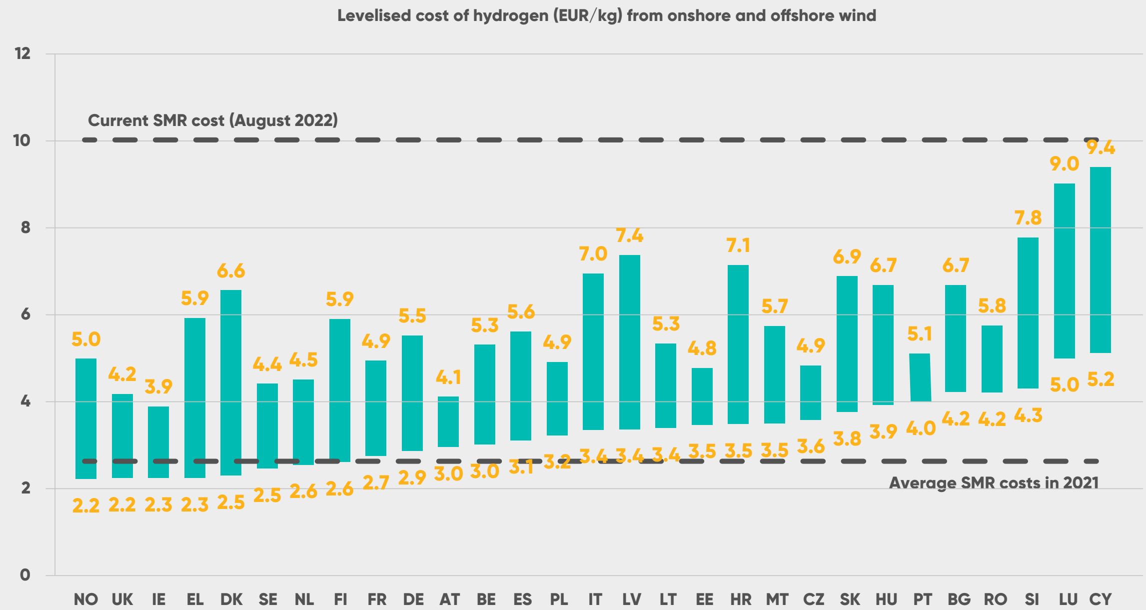


Source: Hydrogen Europe

FIGURE 9

Levelised costs of renewable hydrogen production in EU countries (with UK and Norway) in 2021, using solar PV or wind power





Source: Hydrogen Europe.

Note: The cost range for each technology is defined according to the best wind/irradiation conditions (lower end of the cost range) in a given country and the average conditions available in that country (upper end of the range).

Based on this analysis, it can be noted that the **renewable hydrogen production costs in the EU can be as low as EUR 2.9 /kg (PV in South of Europe, a decrease from 3.0 last year) and as low as EUR 2.2 /kg in countries with good wind conditions (mainly Northern Europe, a reduction from 2.5 last year).**

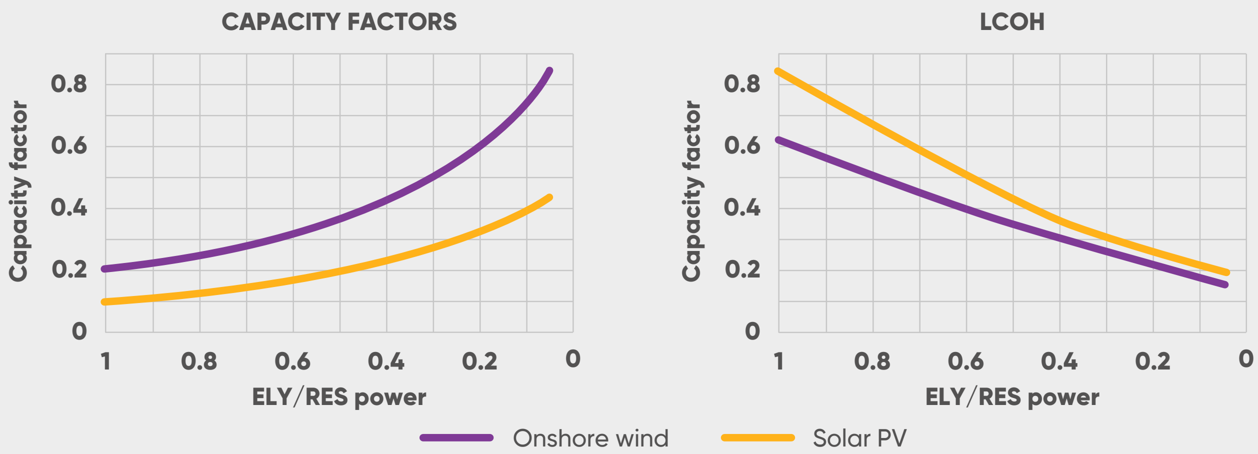
Further cost optimisation can be done by combining renewable energy sources like PV and wind, which increases the electrolyser's capacity factor and thus reduces the impact of CAPEX on the total levelised cost of hydrogen. **Similar positive effects can be achieved by downscaling the electrolyser compared to the RES it is connected to.** Employing this strategy would require that the excess renewable electricity that could not be used for hydrogen production would have to be supplied to the grid (or consumed in another way), but the electrolyser capacity factor could be increased significantly.

Figure 10 illustrates, **using the example of Germany,** the relationship between the electrolyser capacity factor and the power of the electrolyser relative to the renewable energy source it is connected to (assuming the electrolyser is prioritised oversupplying energy to the grid). As can be seen on the graph, when the electrolyser power is equal to RES (ratio of 1), the electrolyser's capacity factor is similar to that of the RES, which in the case of Germany is (on average) around 900 h full load equivalent for solar PV and 1,800 h for onshore wind. Reducing the electrolyser power to half that of the RES (ratio of 0.5), the capacity factor increases to around 1,700 h for solar PV and 3,300 h for onshore wind.

Taking advantage of this optimisation strategy could lower the costs of renewable hydrogen. Keeping with the example of Germany, as can be seen in the **Figure 10,** with an electrolyser-to-RES power ratio of 0.5, renewable hydrogen production costs would fall to EUR 3.8 /kg for solar PV and EUR 3.1 /kg for onshore wind (vs 7.5 and 5.5 respectively for average conditions). For best-suited RES development locations in the country, the costs could be reduced as low as below EUR 2.0 /kg for solar PV and below EUR 1.6 /kg for onshore wind.

FIGURE 10

Electrolyser capacity factor and levelised cost of hydrogen as a function of the ratio between ELY and RES installed power. Example: Germany



Source: Hydrogen Europe.

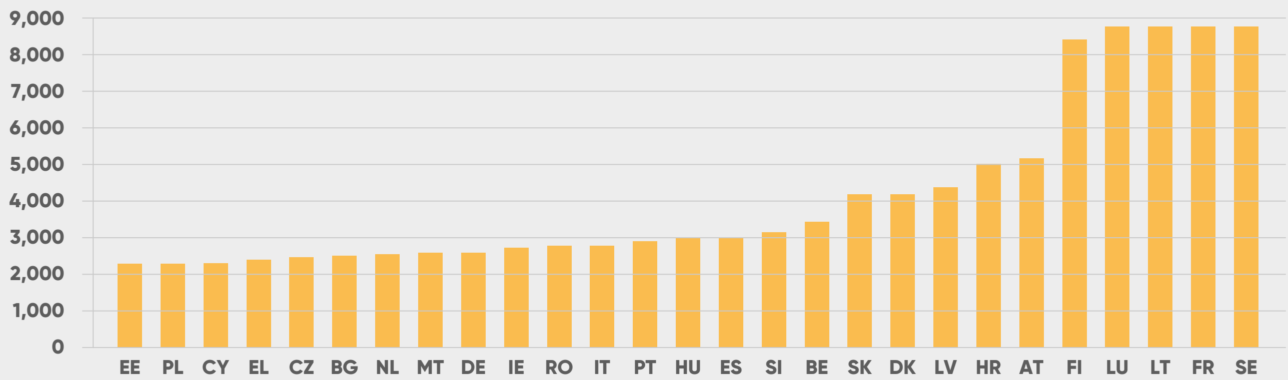
Note: The electrolyser has proprietary access to RES output

This optimisation strategy would also be beneficial from the perspective of the RES investor and the electric grid operator. Reducing the amount of energy supplied to the grid decreases the stress on the electricity grid and makes it possible to build larger RES than the local grid connection capacity would normally allow for. Additionally, being connected to the grid and having an onsite electrolyser would enable the RES operator to provide valuable grid balancing services to the grid operator in the form of demand-side response or uptake of excess renewable electricity from other sources. It would also allow the RES plant to optimise revenues by prioritising the dispatching of electricity to the grid when prices are high and the production of hydrogen when electricity prices are low.

A similar cost reduction effect could be achieved by connecting the electrolyser to the power grid and drawing additional electricity at times when the primary RES source is producing below full capacity or when there is an excess renewable generation on the market – thus avoiding RES curtailment. However, there are several limitations to this approach. One is the potential RES additionality requirement which might be imposed on renewable hydrogen, limiting the access to renewable energy generation assets. The other is the Renewable Energy Directive minimum 70% GHG emission reduction compared to fossil fuel comparator of 94 gCO_2/MJ, required for renewable hydrogen to be recognised as such in the framework of the Directive. Depending on the GHG intensity of the electricity grid of various EU Member States, this would limit the potential to draw additional electricity from the grid. Countries like Poland or Estonia with highly GHG-intensive power grids would limit it to as little as 15% over the amount provided by fully additional renewable sources. At the same time, in some countries like France or Sweden, one could potentially increase the capacity factor of the electrolyser to 8,760 hours regardless of the amount of contracted renewable power.

FIGURE 11

Total possible electrolyser full load hours equivalent capacity factor using a combination of RES PPA and grid electricity, assuming a RES PPA guaranteeing 2,000 h p.a.



Source: Hydrogen Europe.

2.4.

Renewable hydrogen production costs developments

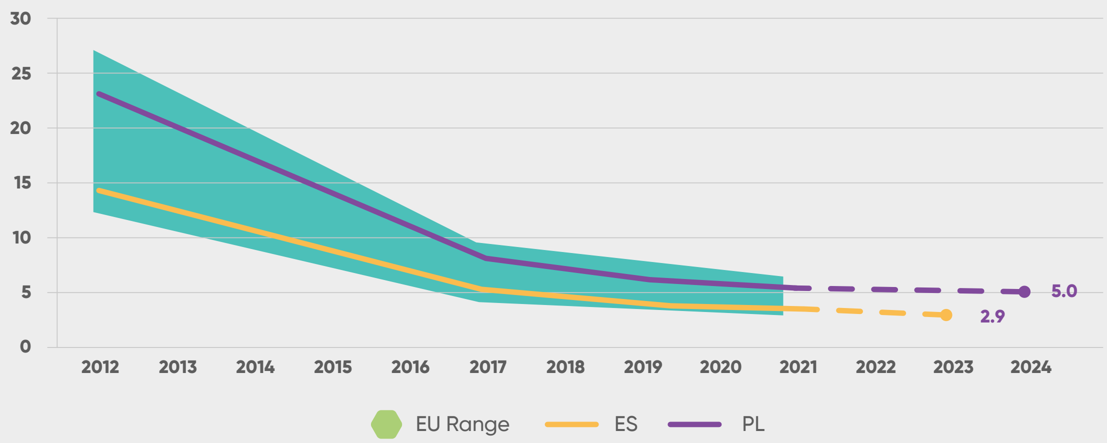
The year 2021 saw a continuation of the downwards trend of renewable hydrogen production costs. The fall in production costs applies to all key RES technologies – i.e., solar PV as well as the onshore and offshore wind but was the most profound in the case of offshore wind following the 12% fall in levelised cost of electricity of offshore wind in 2021 compared to last year (IRENA, 2022). In 2012, renewable hydrogen production from solar PV in the EU was, on average, close to EUR 27 /kg. In 2021 the median for EU countries was around EUR 6.3 /kg, which means over 77% cost reduction. The production costs in the most favourable locations in the EU (Portugal and Spain) fell by a similar fraction from around EUR 12 /kg in 2012 to EUR 2.9 /kg in 2021.

Hydrogen from onshore wind has seen a similar fall in production costs since 2012. The median of "green" hydrogen production costs from onshore wind in EU countries fell by more than 65% in this period – from around EUR 15 /kg in 2012 to about EUR 5.3 /kg in 2021. At the same time, the production costs in areas with the most favourable wind conditions in Europe fell from around EUR 7 /kg in 2012 to EUR 2.3 /kg in 2021.

Based on recent RES auction results in some EU countries, one should reasonably expect the downwards trend to continue in the coming years – albeit at a slower pace. In Spain's example, the RES auction organised in 2021 allowed the Spanish Government to successfully contract over 3.1 GW of additional solar PV and onshore wind capacity, with a weighted average price of EUR 24.5 /MWh and EUR 25.3 /MWh, respectively. Using those values, one could estimate that it would allow renewable hydrogen production at around **EUR 2.5-2.9 per kg** (at current electrolyser CAPEX levels).

FIGURE 12

Renewable hydrogen production costs (in EUR/kg) via water electrolysis with solar PV over the 2012-2021 period and expected developments in selected countries based on 2021 RES auction results



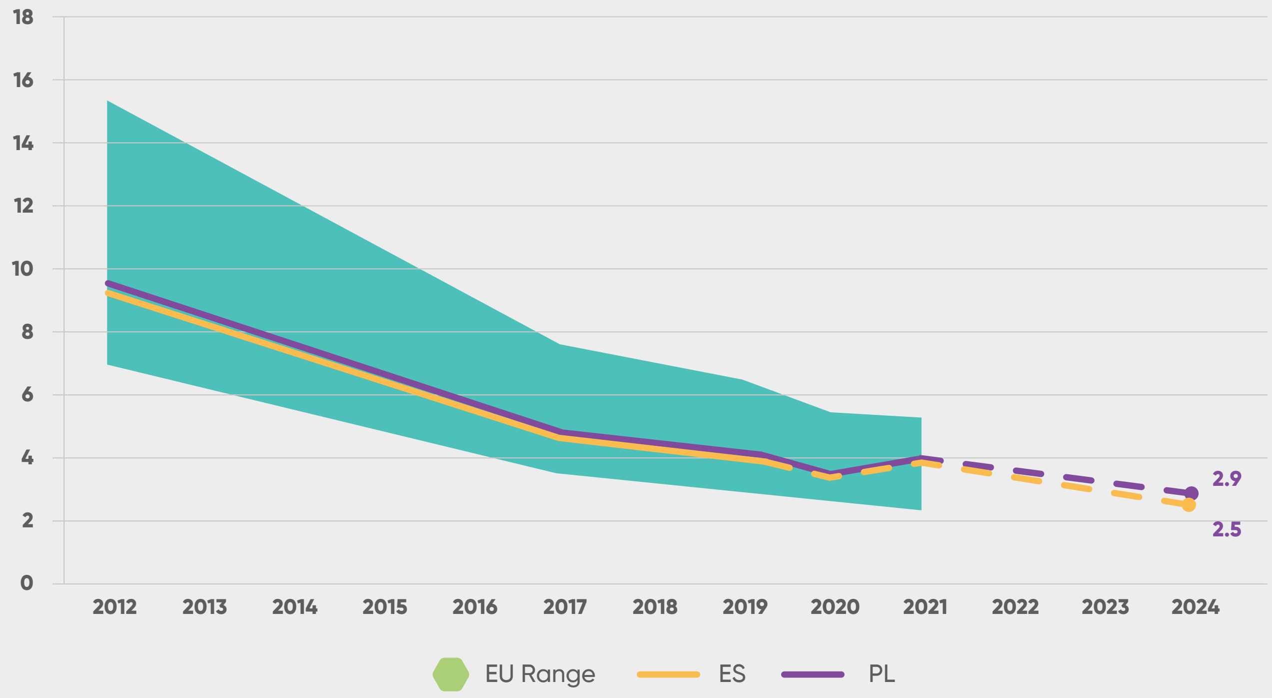
Source: Hydrogen Europe.

Note: the upper boundary of the EU range is defined as the median for all EU countries (+ UK and NO), and the lower boundary is the production costs in assuming the most favourable solar irradiation conditions available in the EU.

In Northern and Central European countries, renewable hydrogen produced from solar PV will remain relatively high in the immediate future. Still, auctions for onshore wind show a similar cost level is possible, with the recent RES auction in Poland indicating a possible production cost level in the next couple of years of around **EUR 5 per kg for solar PV** and **EUR 2.9 per kg for onshore wind.**

FIGURE 13

Renewable hydrogen production costs (in EUR/kg) via water electrolysis with the onshore wind over the 2012-2021 period and expected developments in selected countries based on 2021 RES auction results



Source: Hydrogen Europe.

Note: the upper boundary of the EU range is defined as the median for all EU countries (+ UK and NO), and the lower boundary, as the production costs in assuming the most favourable solar irradiation conditions available in the EU.

Conclusion

The estimated renewable hydrogen production costs in the EU (+UK and Norway) in 2021 vary from EUR 3.3 /kg to EUR 6.5 /kg, while, in limited geographical locations with the best solar irradiation and wind conditions, it is possible to reduce those costs as low as EUR 2.2-2.9 /kg. As a result, for the first time, renewable hydrogen is becoming cost competitive with 'grey' hydrogen, for which the average production costs for 2021 were estimated at EUR 2.65 per kg, growing as high as EUR 10 /kg in today's (August 2022) high natural gas prices environment.

However, as a positive development as this is, one should refrain from drawing too far going conclusions from it as it is, for the time being at least, more related to the significant increase in natural gas prices than with sharp reduction of renewable hydrogen production costs (even though such a reduction can be noticed as well). A cost gap still exists compared to historical SMR costs of around EUR 1.2 per kg.

Furthermore, there is at least one additional caveat one should not lose sight of when assessing the results of the LCOH analysis presented in this chapter, which is related to the scope of the analysis. Firstly, the electrolyser capital cost estimations are based on a 100 MW system for installation on a pre-prepared site (fundament/ building and necessary connections are available). While this is certainly possible for some projects, it might not be possible for all and not even for most projects, where additional expenses related to electrical installation, site preparation, EPC contract and even various contingencies can be expected to occur and inflate total capital expenses.

Secondly, the estimated costs only cover hydrogen production costs. While in the case of 'grey' (or 'blue') hydrogen, it is usually the case that hydrogen generation takes place at the same location as its consumption, for renewable hydrogen, such a setup might rarely be possible, especially for industrial off-takers, where the electrolysis requirement is measured in GW scale. In such a scenario, additional costs of hydrogen compression (or liquefaction) and transportation should also be considered for a full-cost comparison with fossil fuel-based hydrogen.

In addition, especially for industrial use, where the demand profile is often stable and not flexible, renewable hydrogen generation's variable and intermittent characteristics would also create a need for at least buffer storage. In some cases, where renewable generation is not only variable but also highly seasonal (e.g., solar PV), large-scale seasonal storage might be necessary. There are several ways to deal with the RES variability problem.

One would be to sign PPAs with multiple RES providers of a lot higher power in total than the maximum power of the electrolyser. However, this is only possible if one can trade-off (or use otherwise) the excess renewable generation that would invariably occur and might be viable at a limited scale.

Another strategy would be to use battery electric storage before the electrolyser to smoothen the electricity input.

Unfortunately, this would be prohibitively expensive. Battery storage sufficient just for 4 hours of electricity consumption of an electrolyser for a plant of a size required to decarbonise 50% of medium-sized ammonia manufacturing plant would need to have a storage capacity of 1.8 GWh (i.e. 50% larger than the world's biggest battery storage facility in Moss Landing / US) – and would be still highly insufficient, as it will allow increasing the capacity factor to just over 60% (onshore wind as primary power supply source). To achieve a capacity factor of 80%+, the battery would have a capacity of around 75 GWh, which would incur an additional capital investment of EUR 6.5 billion (with an optimistic CAPEX of EUR 100 /kWh).

Hence, large-scale underground hydrogen storage may be the only viable route for large industrial off-takers. While underground hydrogen storage is a cost-effective storage method, it could still add up to EUR 0.9 per kg of hydrogen for highly seasonal RES like solar PV (Fonseca & Pawelec, 2022) and might not be equally possible all-around Europe as favourable salt formations are not uniformly spread around the continent.

As a result, a flexible approach to temporal correlation requirements between RES generation and electricity consumption could go a long way in facilitating the use of green hydrogen in industry.

Yet, regardless of the above point, further lowering renewable hydrogen production costs is still essential if hydrogen is to deliver on its role as an enabler in the ongoing EU-wide decarbonisation effort – both via increased R&D effort envisaged under the Clean Hydrogen JU Partnership as well as through scaling up electrolyser manufacturing as well as hydrogen production projects.

One final caveat one should also not forget about is the fact that there are also multiple other alternative ways of renewable and low carbon hydrogen production methods, which this report does not cover but which also offer significant opportunities for cheap, clean hydrogen production, including not only alternative renewable energy sources like hydro-energy, but also emerging technologies like direct solar-to-hydrogen photoelectrochemical cells, as well as the thermal conversion of biomass or waste into hydrogen, pyrolysis and nuclear energy.

Methodological note

In all cases, the general approach to estimating the levelised cost of hydrogen (LCOH) is based on a standard discounted cash flow model and the following formula.

$$\frac{I_0 + \sum_{t=1}^{n} \frac{I_t + E_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}}$$

Where, I_0 - Investment expenditure in year 0; I_t - Investment expenditure in year t (stack replacement costs); E_t - Electricity consumed in year t including generation costs (wholesale price or RES LCOE + capacity factor), grid costs and taxes when applicable; M_t - Other operational expenditures in year t; H_t - Hydrogen production in year t; r - Discount rate; n - Lifetime of the system in years.

The electrolysis system cost assumptions were based mainly on the latest information for current state-of-the-art alkaline electrolysis, provided by the Strategic Research and Innovation Agenda of the Clean Hydrogen Joint Undertaking.

For hydrogen produced exclusively from renewable energy, the levelised cost of that electricity was calculated individually for each member state for three technologies: PV, onshore wind, and offshore wind (excluding the landlocked EU Member States). No network costs, taxes and fees were considered for this scenario, and the capacity factor of the electrolyser was assumed to be equal to that of the renewable energy source to which it is connected to. Capacity factors for various renewable energy technologies and the EU Member States were taken from the JRC EMHIRES and ENTSPRESSO databases. Data on current renewable energy costs were taken from the most recent IRENA Renewable Power Generation Costs report (from July 2022).

For grid-connected electrolysis, the capacity factor of the electrolyser was assumed to be 4,000 hours, with the running hour set to fall in time with the lowest wholesale electricity prices (based on data from the ENTSO-e's transparency portal). Network costs, taxes and fees were included in this scenario (based on Eurostat data on electricity prices for non-household consumers in the consumption range from 20 000 MWh to 69 999 MWh per year).

TABLE 2

Assumptions for estimation of hydrogen production costs

Item	Unit	Value	Source
CAPEX (Alkaline)	EUR/kW	600	[CHE SRIA 2021]
Economic lifetime	years	30	Own assumption
Energy consumption	kWh/kgH2	50.00	[CHE SRIA 2021]
Stack degradation[10]	per 1000 hrs	0.12%	[CHE SRIA 2021]
Other OPEX[11]	% CAPEX	4.00%	[CHE SRIA 2021]
Costs of capital	%	5.0% in real terms	[IRENA 2022]

Source: Hydrogen Europe based on updated Strategic Research and Innovation Agenda of the Clean Hydrogen for Europe partnership and IRENA, "Renewable Power Generation Costs in 2021", 2022.

TABLE 3

Renewable energy generation cost assumptions

Item	Unit	PV	Wind Onshore	Wind Offshore	Source
Economic lifetime	years	25	25	25	[IRENA 2022]
CAPEX	EUR/kW	697	1,425	2,346	[IRENA 2022]
O&M	EUR/kW/year	15	31	64	[IRENA 2022]

Source: Hydrogen Europe.

10 / Stack degradation is defined as percentage efficiency loss when run at nominal capacity. For example, 0.125%/1,000h results in a 10% increase in energy consumption over 10 years with 8,000 operating hours per year.
11 / Operation and maintenance costs averaged over the first ten years of the system. Potential stack replacements are included in O&M cost. Electricity costs are not included in O&M cost.

References

Careri, F., Gonzalez-Aparicio, I., Huld, T., Monforti, F., & Zucker, A. (2017, May 30). EMHIRES dataset. Part II, Solar power generation. European Commission Joint Research Centre. Retrieved September 28, 2022, from https://op.europa.eu/en/publication-detail/-/publication/a6c0cf55-45aa-11e7-aea8-01aa75ed71a1/language-en

CertifHy. (2022). CertifHy. Retrieved September 28, 2022, from CertifHy: https://www.certifhy.eu/

ENTSO-e. (2022). ENTSO-e Transparency Portal. Retrieved September 28, 2022, from ENTSO-e: https://transparency.entsoe.eu/

European Environment Agency. (2022, July 04). Greenhouse gas emission intensity of electricity generation. Copenhagen, Denmark. Retrieved September 28, 2022, from https://www.eea.europa.eu/data-and-maps/daviz/co2-emission-intensity-10/#tab-chart_2

Eurostat. (2022, September 13). Electricity prices components for non-household consumers - annual data (from 2007 onwards). Retrieved September 28, 2022, from https://ec.europa.eu/eurostat/databrowser/view/NRG_PC_205_C__custom_3464110/default/table?lang=en

Fonseca, J., & Pawelec, G. (2022). Steel From Solar Energy. Hydrogen Europe.

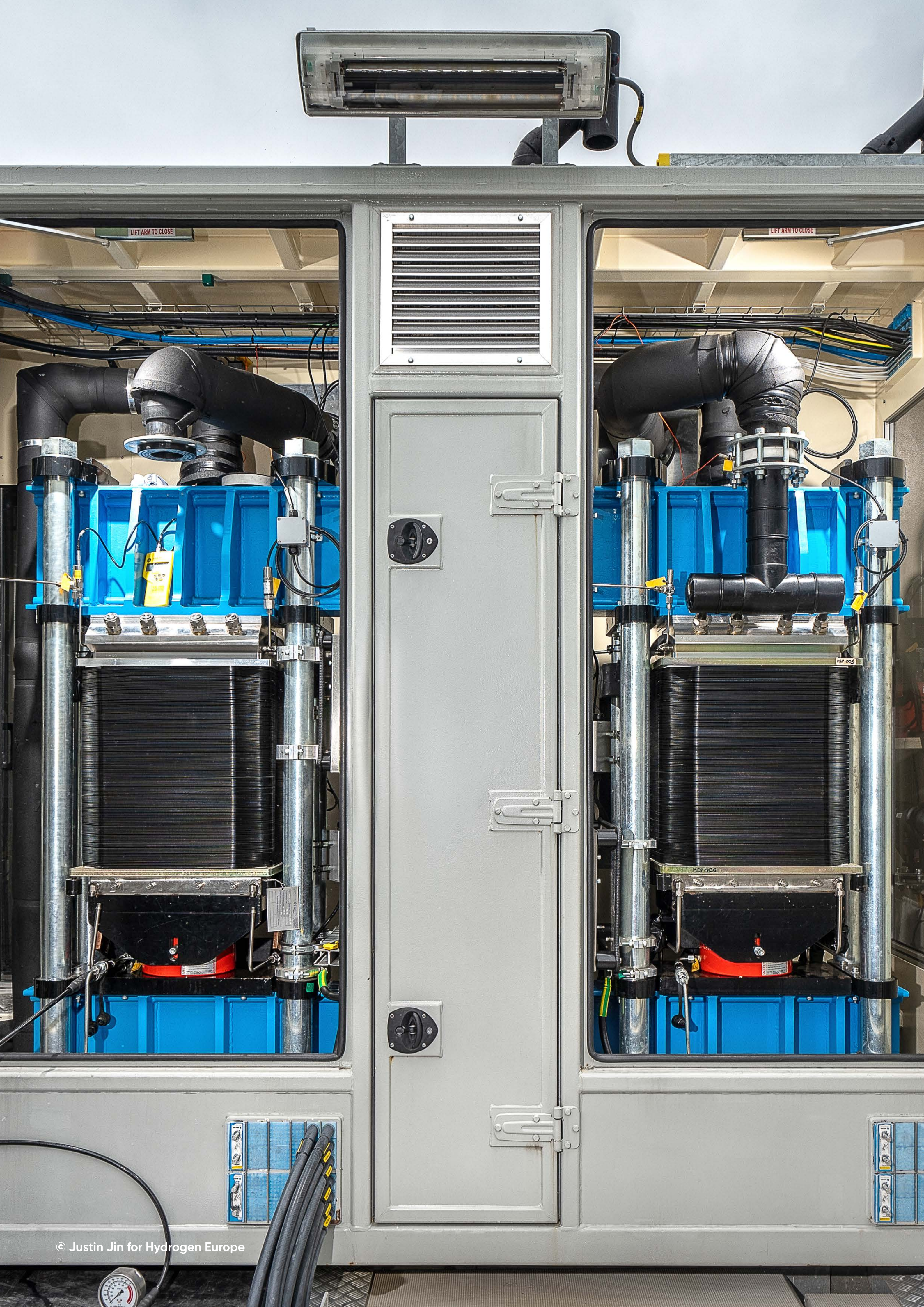
Gonzalez-Aparicio, I., Zucker, A., Careri, F., Monforti-Ferrario, F., Huld, T., & Badger, J. (2016, November 08). EMHIRES dataset Part I: Wind power generation. European Meteorological derived HIgh resolution RES generation time series for present and future scenarios. Retrieved September 28, 2022, from https://publications.jrc.ec.europa.eu/repository/handle/JRC103442

IRENA. (2022). Global hydrogen trade to meet the 1.5°C climate goal: Part I – Trade outlook for 2050 and way forward. Abu Dhabi: International Renewable Energy Agency.

IRENA. (2022). Renewable Power Generation Costs in 2021. Abu Dhabi: International Renewable Energy Agency. Retrieved September 28, 2022, from https://irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021

Ruiz-Castello, P., Nijs, W., Tarvydas, D., Sgobbi, A., Zucker, A., Pilli, R.,... Jonsson, K. (2021, September 27). ENSPRESO - an open data, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials. European Commission Joint Research Centre. Retrieved September 27, 2022, from https://data.jrc.ec.europa.eu/collection/id-00138

© Justin Jin for Hydrogen Europe



© Justin Jin for Hydrogen Europe

03

Hydrogen production plans, shipping imports, and electrolyser manufacturing capacity

3.1.

Planned hydrogen production capacities in Europe

As discussed in **Chapter 1,** hydrogen produced via water electrolysis (also known as Power-to-Hydrogen or PtH) has the potential to be generated with very low or zero-emissions, depending on the carbon intensity of the electricity used. At the same time, as discussed in **Chapter 1,** PtH hydrogen production capacity by August 2022 amounted to only 0.25% of 2020 total European hydrogen production capacity.

Therefore, it is essential to track the development of hydrogen production and infrastructure projects to assess the progress of the hydrogen sector as an enabler of a zero-emission energy system.

The following chapter presents an aggregation of planned PtH and reforming projects with carbon capture projects across Europe. This chapter aims to provide information on planned hydrogen production assets to monitor hydrogen developments against national and European targets, strategies, and roadmaps.

Hydrogen Europe has collected the data and information in this chapter from public and restricted sources. While the intention is to provide an accurate snapshot of planned developments, this overview likely does not reflect all projects currently planned (e.g., some may not have been made public at all). The projects used to generate the overview are still evolving; therefore, the presented numbers will continue to change. For more details on the methodology, please consult the **Methodological note.**

If all planned production projects covered in this sub-chapter were realised, there could be 138 GW_{el} of electrolyser capacity and 17 GW_{LHV} of projects reforming natural gas and capturing associated emissions by 2030, potentially producing 10 Mt of electrolytic hydrogen and 4 Mt of hydrogen from natural gas, most of whose emissions have been captured.

© Justin Jin for Hydrogen Europe

3.1.1. Power-to-hydrogen projects

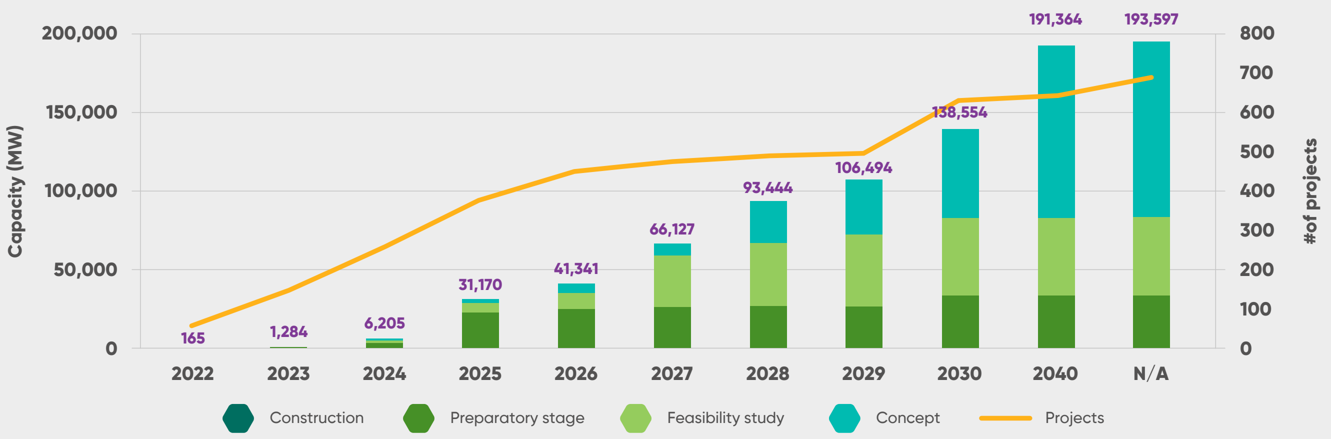
The total planned capacity of PtH projects[1] in Europe[2] is 191,364 MW of electrolyser installed power by 2040 (644 projects) with an extra 2,233 MW (41 projects) with an unspecified start date. There are 628 planned PtH projects with announced start dates amounting to 138,554 MW by 2030. In the medium term, there are 379 planned projects totalling 31,170 MW by 2025. **Figure 1** presents the cumulative planned PtH projects per year until 2040. Based on available information, 165 MW of additional PtH capacity is planned to come online by the end of 2022 and 1,284 MW by 2023.

The period up to 2030 is a critical medium-term objective for the European Hydrogen Strategy (EHS), RePower EU, and the 2030 climate targets. For 2022 – 2030, the average tracked capacity growth rate is 111% annually. This is an impressive annual increase, which, if achieved, would result in 138 GW of installed water electrolysis capacity by 2030, which could be sufficient to reach the RePowerEU target of 10 Mt.

Compared with 9,101 MW by 2030 of planned projects published in the Clean Hydrogen Monitor 2020, the capacity data collected for this report have increased by more than 15 times. Compared with the 2021 report, the project pipeline increased by 20 GW by 2030. The impressive increase reflects the continued commitment of the EU, national governments, and industry to decarbonise the European economy using power-to-hydrogen technology. **Figure 2** illustrates this development. In addition to the encouraging increase in the project pipeline by 2030, this figure also shows some of the delays that the industry is experiencing. These can be seen in the difference between 2022 and 2021 reports for planned projects to be deployed by 2023 and 2024.

FIGURE 1

Cumulative planned PtH projects by the year 2022 - 2040 in MW and # of projects

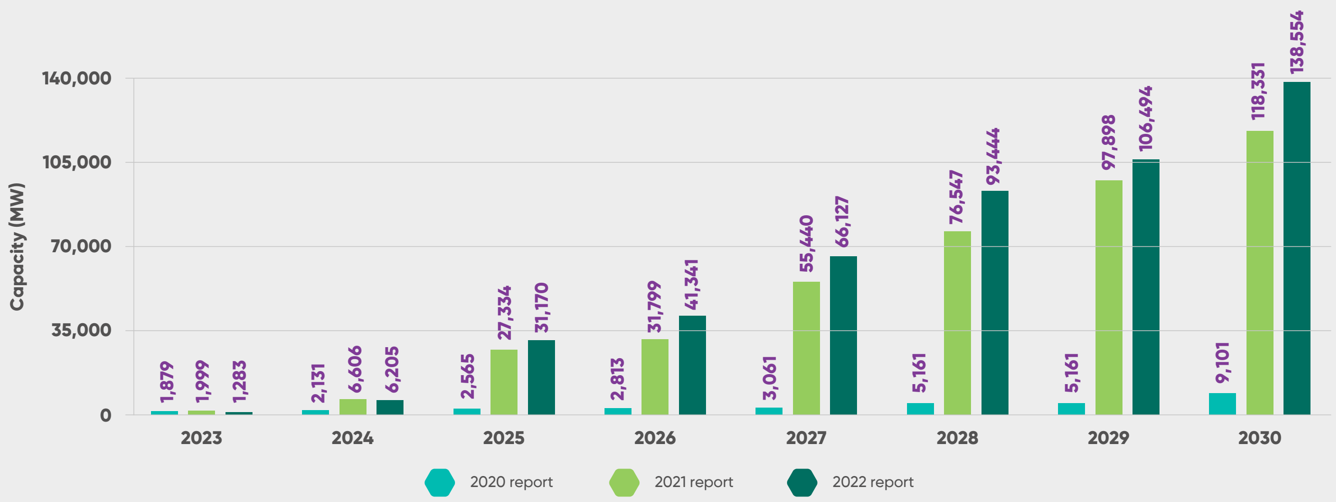


Source: Hydrogen Europe.

1 / The term "project" refers to an individual project or a project phase. One project can have multiple phases that gradually enlarge its capacity. In this report, each project phase with three phases of 10 MW, 100 MW, and 300 MW in the same location and with the same project partners is counted as a separate project.
2 / Europe refers to the EU, EFTA, and UK.

FIGURE 2

Comparison of cumulative planned PtH project capacity by the year of entry into operation



Source: Hydrogen Europe.

For these years, the 2021 report expected more projects to come online by 2023 and 2024, while this year's report reflects revised start dates of many projects that have been delayed.

Figure 3 focuses on short-term trends and deployment. The 2020 publication reported 45 MW to be deployed in 2021, while 33 MW was deployed in 2021. Delays and revisions of announced commercial operation dates are evident when comparing 2022 numbers. 2020 report expected 523 MW to come online in 2022, but the 2021 report only expected 253 MW for the same year. 35 MW came online by August 2022. These delays and revisions continue to be seen in later years. By 2023, the increase from 1,241 MW to 1,681 MW between the 2020 and 2021 reports can be explained mainly by additional project announcements. Still, the decrease from 1,681 MW to 1,119 MW is due to the postponement of the projects' commercial operation date (COD). The most cited reasons include regulatory uncertainty, lack of financial incentives, and supply chain/pandemic delays.

In the short term, by 2024, the project pipeline has decreased, with the total planned capacity by 2024 decreasing from 6,606 MW to 6,205 MW. While project announcements continue, the focus will be on realising and executing the announcements in the following years. **Figure 4** demonstrates the short-term development of projects. Out of the 165 MW planned to come online by the end of 2022, excluding the 162 MW already in operation and not visualised, 97 MW are under construction, 64 MW are in the preparatory stage, and 4 MW are undergoing feasibility studies. As expected, the current status of projects planning to be online by 2024 differs from the 2022 composition as the pipeline is less concrete in the future. Out of the 6,205 MW planned to be deployed by then, 180 MW are under construction, 3,393 MW are in a preparatory stage, 1,859 MW are undergoing a feasibility study, and 773 MW are still only a concept. If all these projects were realised by 2024, there would be 6,367 MW of operational PtH capacity.

The project pipeline continues to be robust. Continuing clarification on the regulatory treatment of hydrogen on

FIGURE 3

Comparison of planned PtH project capacity by the year of entry into operation

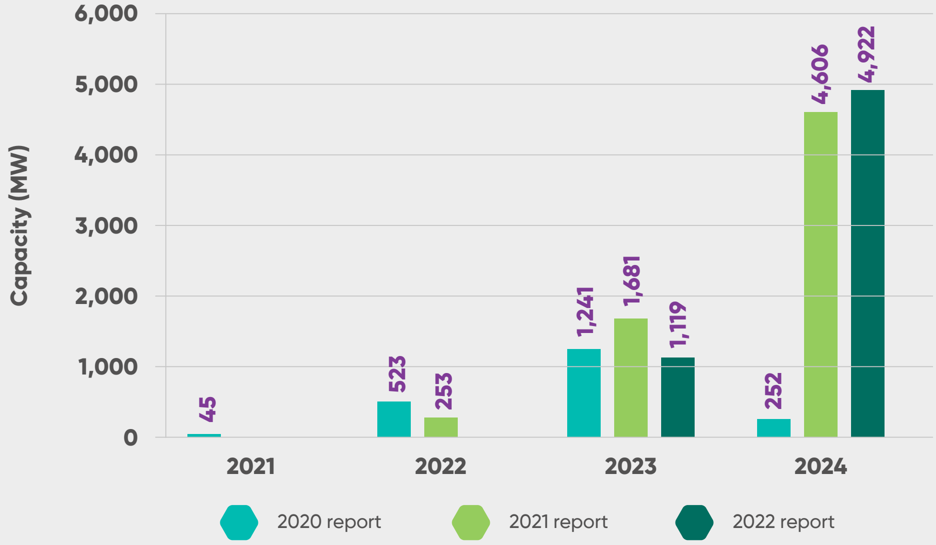
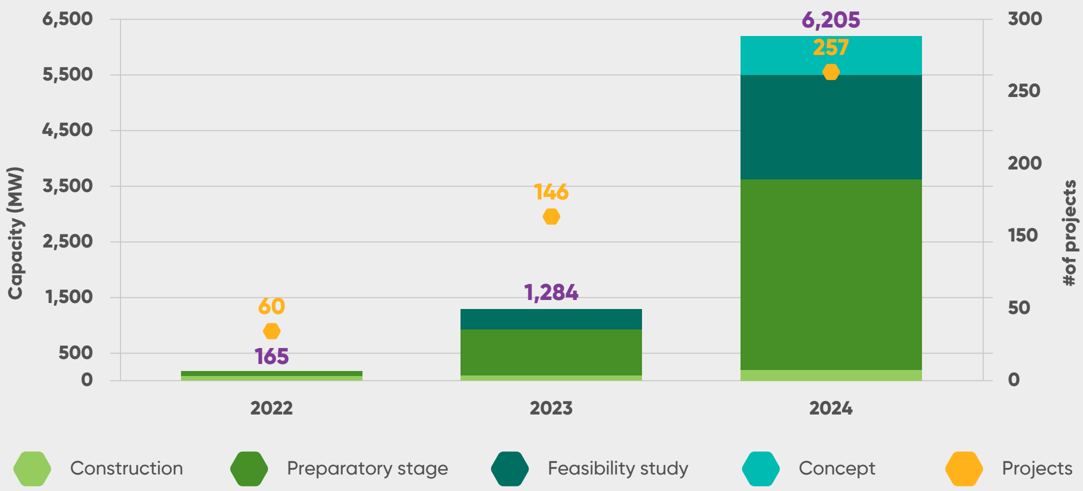


FIGURE 4

Cumulative planned PtH projects by year and project stage 2022 - 2024 in MW and # of projects



Source: Hydrogen Europe.

both European and national levels, the interest and support in the IPCEI process, the popularity of the European Clean Hydrogen Alliance, and the emergence of new funding instruments have and will continue to contribute to additional project announcements and deployments. The emphasis will have to be on realising those announcements on schedule.

Annual capacity additions

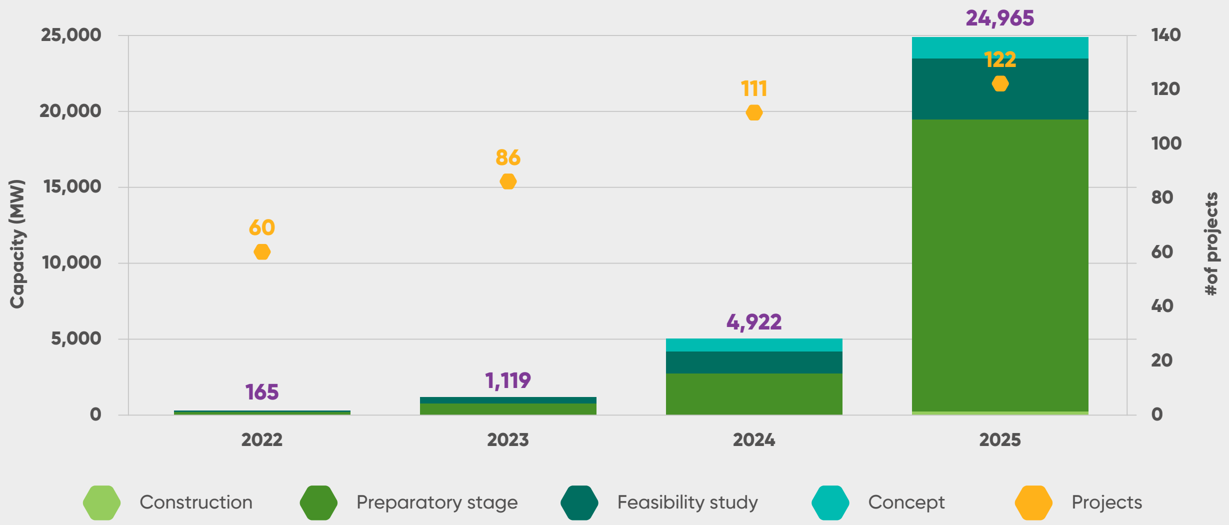
The average annual planned addition between 2023 and 2030 is 15,395 MW of PtH capacity, with additions of over 20,000 MW in 2025, 2027, 2028, 2029, and 2030. The 138,554 MW of planned deployments with announced dates between 2022 and 2030 are split between 628 projects at an average project size of 221 MW. The average project size is 82 MW 2022-2025 and 431 MW 2026-2030.

Figure 5 provides an annual addition perspective for 2022 – 2025. While the expected average project size in 2023 is 13 MW, the expected average project size two years later in 2024 is 44 MW and 205 MW in 2025. Should these projects be realised, this would result in the average project size increasing almost 16 times within two years.

Figure 6 provides an annual addition perspective for 2026 – 2030. The average yearly addition is 21,477 MW of PtH capacity, with the largest expected additions planned for 2028 and 2030. The 107,184 MW are split between 248 projects with an impressive 432 MW per project. The average project sizes differ significantly between the different years. In 2026, the 10,171 MW is split between 71 projects averaging 143 MW per project. In 2028, the 27,317 MW of new additions are the result of only seventeen new projects resulting in an average project size in 2027 of 1,607 MW. This trend is even more evident in 2029 when seven new projects are expected to add an additional 13,050 MW of PtH capacity. The results suggest that project developers will increase their ambitions to build multi-GW projects in

FIGURE 5

Planned PtH projects added by the year 2022 – 2025 in MW and number of projects



Source: Hydrogen Europe.

the second half of the decade. Many of the projects being built at that time will be expansions of existing installations. According to the data, 130 projects are expected to come online in 2030. This is due to many indicative dates when some projects in earlier stages of development have only indicated 2030 instead of a more specific operation date.

FIGURE 6

Planned PtH projects added by the year 2026 - 2030 in MW and number of projects

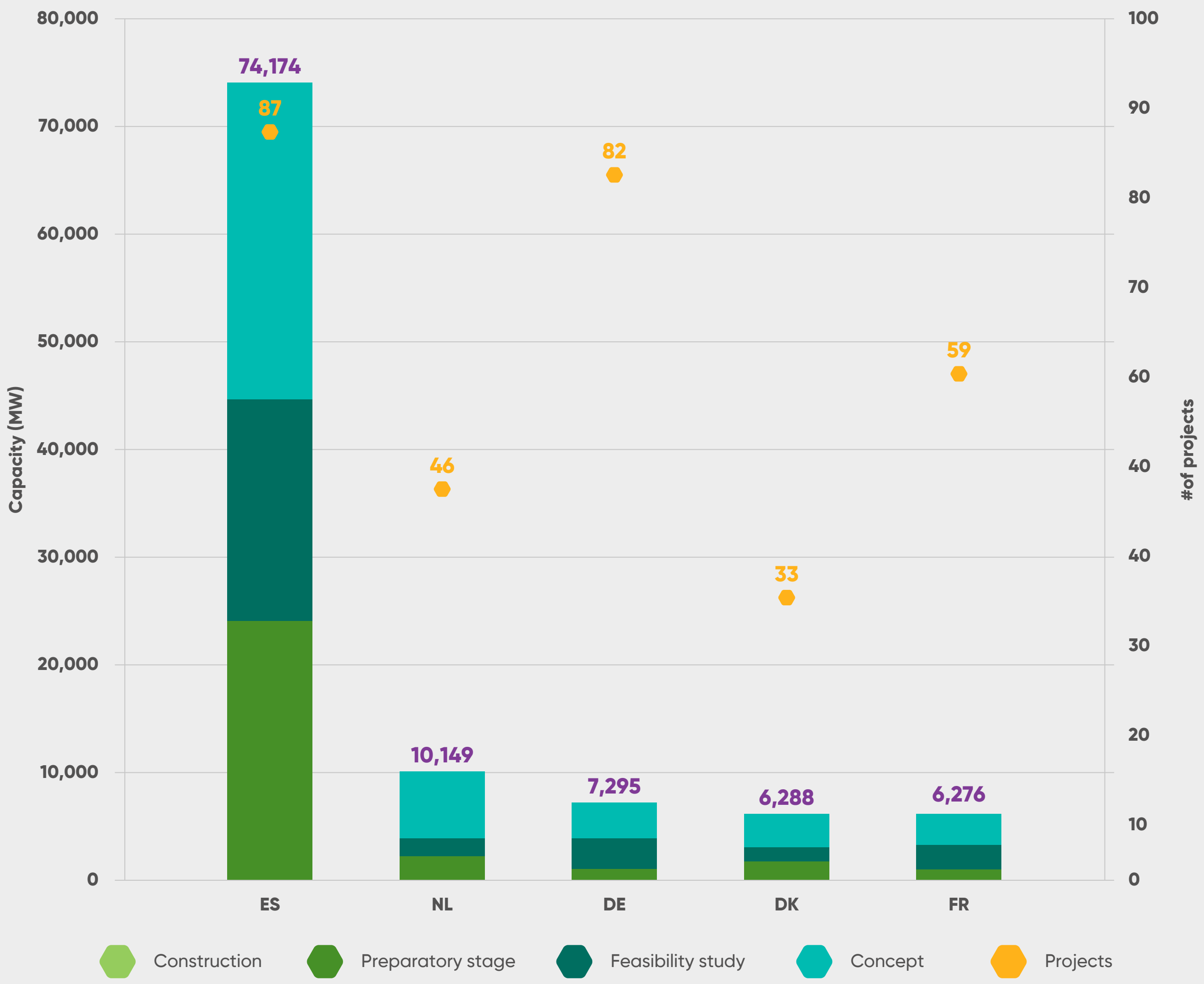
Source: Hydrogen Europe.

Country perspective

The country with the highest planned PtH capacity by 2030 is Spain with 74,174[3] MW, followed by the Netherlands with 10,149 MW, Germany with 7,295 MW, Denmark with 6,288 MW, and France with 6,276 MW. These five countries together represent 75% of planned PtH capacity in Europe and 49% of planned projects.

FIGURE 7

Planned PtH capacity additions by project stage of five countries by 2030



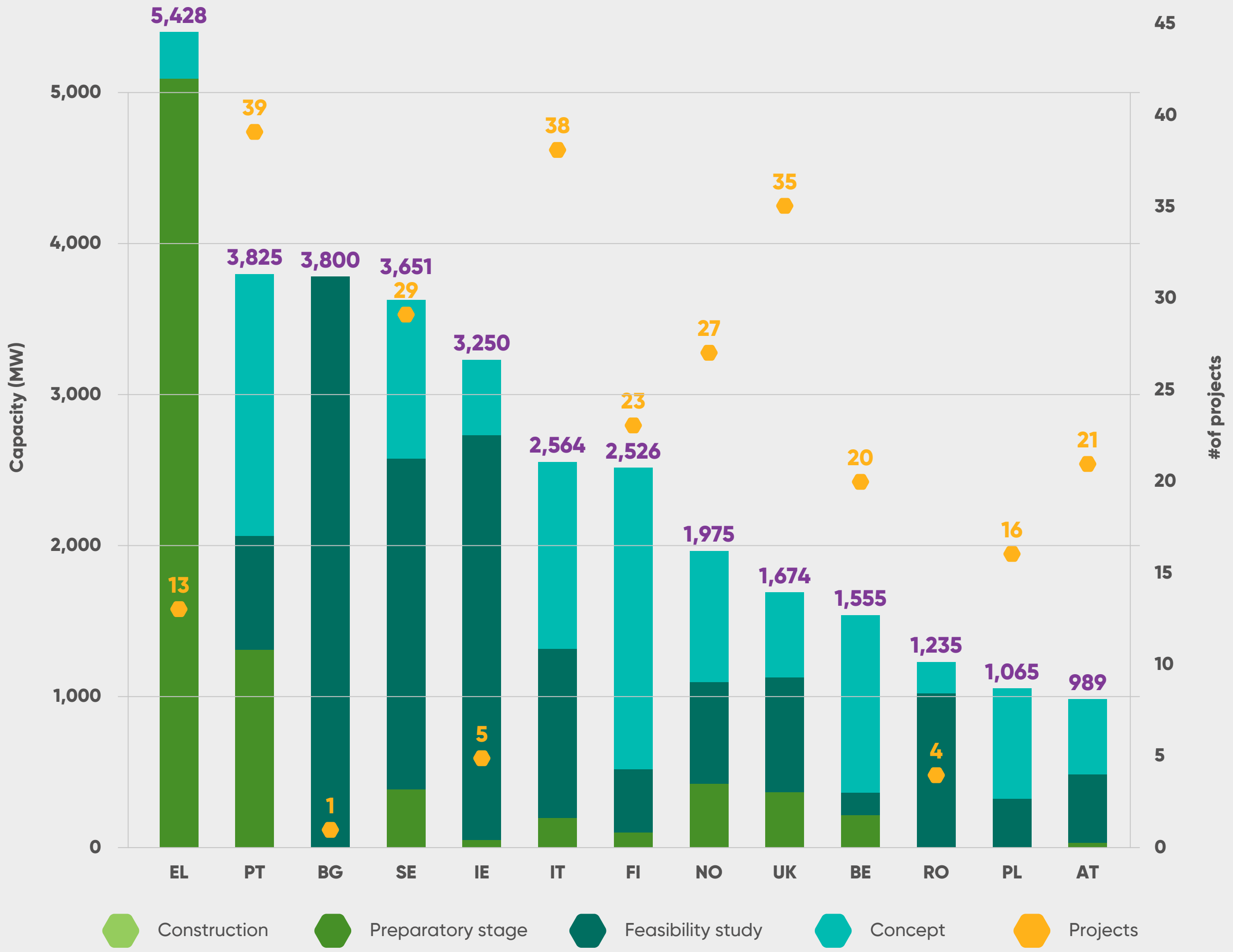
3 / Spain remains the outlier in our project tracking due to a single project with multiple phases that plans to deploy 67 GW of electrolysis by 2030 alone.

There are 13 other countries with planned PtH capacity over ~1 GW by 2030. These range from Greece with 5,428 MW to Austria with 989 MW. The project perspective markedly differs between different countries. The best comparisons are Portugal and Bulgaria. Portugal has a diversified project pipeline of 39 projects amounting to 3,825 MW by 2030, with over 1.3 GW in an advanced preparatory stage. Bulgaria's 3.8 GW is due to a single project undergoing a feasibility study.

Spain's more than 74 GW are primarily due to a single large project with multiple phases aiming to deploy almost 70 GW of electrolysis by 2030. In addition, there are also

FIGURE 8

Planned PtH capacity additions by project stage of countries with more than ~1 GW of planned PtH capacity by 2030

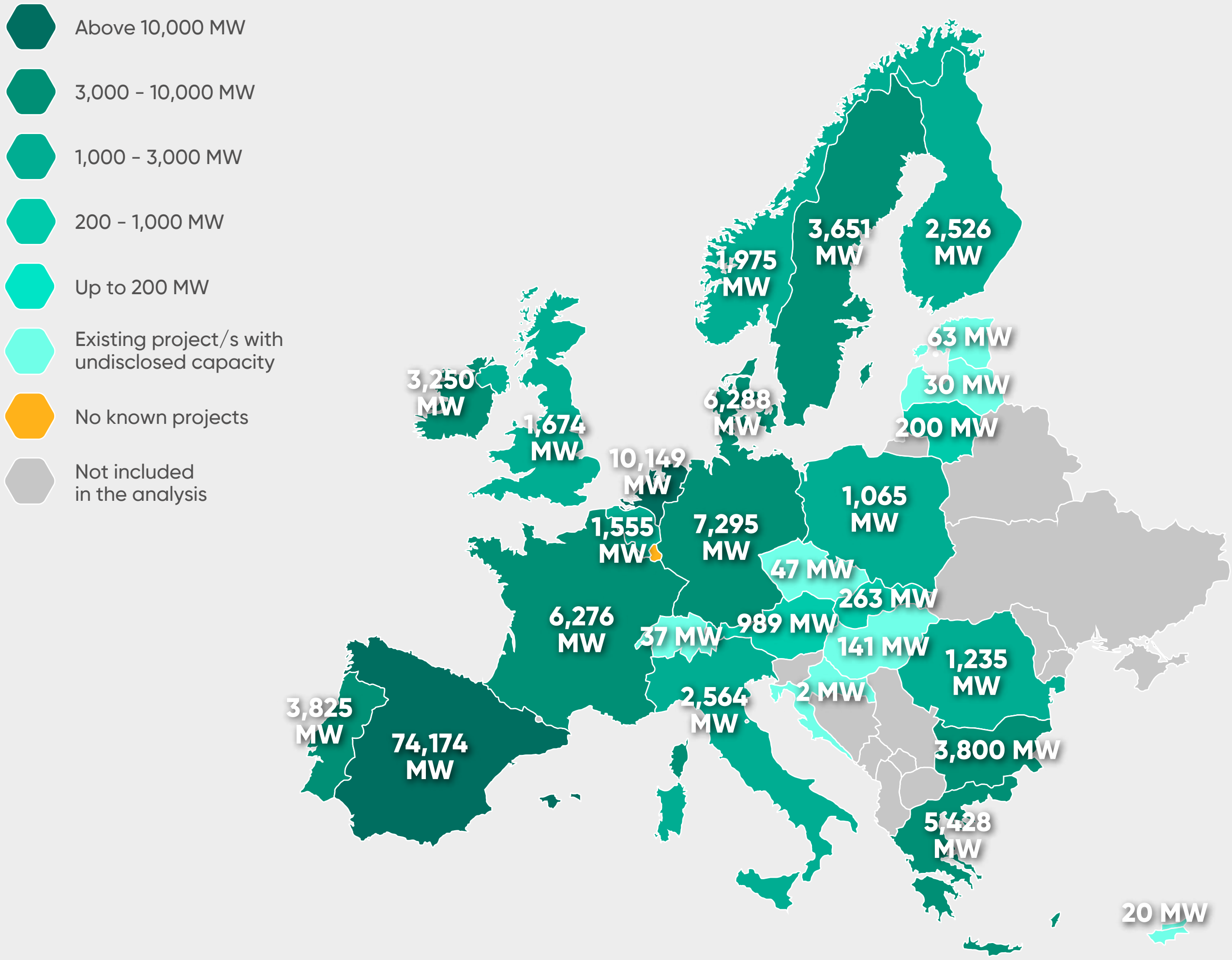


Source: Hydrogen Europe.

several 100+ MW projects focused on industrial clusters. The second largest project pipeline by 2030 is in the Netherlands, with 10 GW of electrolysis compared to the objective in its hydrogen strategy of 3-4 GW by 2030. Germany's current project pipeline of 7,295 MW by 2030 sets Germany at 73% of its revised 10 GW 2030 target. At the time of writing of this report, Denmark had the fourth highest planned PtH pipeline by 2030, with 6,288 MW to be deployed, split between 33 projects.

FIGURE 9

Map of planned PtH capacity additions by country 2022 - 2030 in MW



Source: Hydrogen Europe.

The plans for future PtH projects differ country by country, especially regarding the size and number of projects. The most significant planned PtH addition by 2030 is planned in Spain, where its 74,174 MW split between 87 projects results in an average project size of 853 MW. This is markedly different from Germany, whose 7,295 MW split between 82 projects results in an average project size of 89 MW.

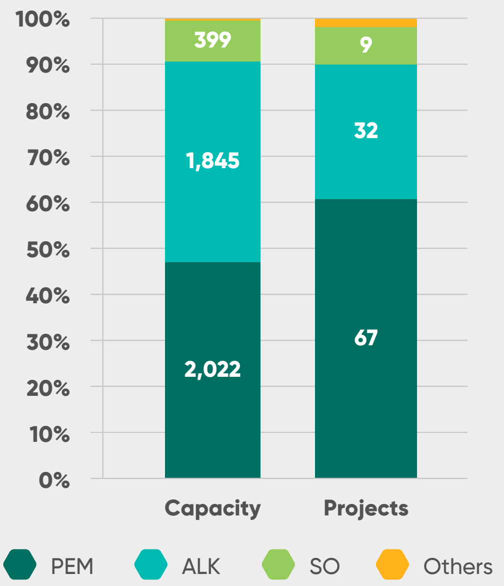
Electrolyser technology

110 out of 379 planned projects by 2025 and 4,267 MW capacity out of 31,170 MW have announced their electrolyser technology. 47% of the available capacity and 61% of those projects plan to use proton exchange membrane electrolysis at an average project size of 30 MW. Larger projects slightly prefer alkaline technology as it is planned to be used in 43% of the known capacity and 29% of projects at an average project size of 57 MW. Solid oxide electrolysis has been earmarked to be deployed in 8% of the known projects and would capture 9% of the planned PtH capacity by 2025.

For the longer-term outlook by 2030, electrolyser technology is known for only 138 out of the 628 projects and 13,572 MW out of 138,554 MW of electrolyser capacity. Like last year, alkaline technology has stayed in the lead regarding capacity even though its share decreased from 75% to 61%

FIGURE 10

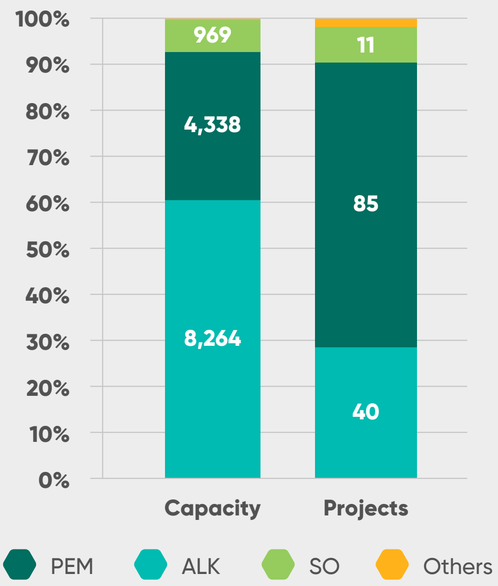
Available electrolyser composition of planned projects in MW and # of projects by 2025[4]



Source: Hydrogen Europe.

FIGURE 11

Available electrolyser composition of planned projects in MW and # of projects by 2030



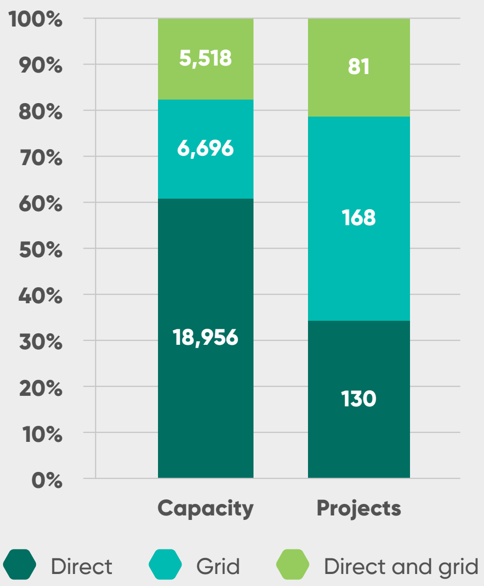
Source: Hydrogen Europe.

4 / Authors have not been able to collect sufficient individual information about planned AEM, and other water electrolysis technology deployment, but will strive to include them in the next iteration.

of the capacity and from 35% to 29% of the projects. The average size of an alkaline electrolysis project by 2030 is 206 MW. Based on available data, proton exchange membrane electrolysis is slated to capture 32% of capacity and 62% of the projects. An average project size of 51 MW suggests its use for smaller projects. These numbers represent a snapshot of the future based on available information. Still, they should not be regarded as an outlook or a forecast. Future deployments, cost reductions across electrolysis technologies, and future development of emerging electrolysis technologies will shape the deployments and likely differ from the snapshot presented today.

FIGURE 12

Planned electricity supply connection in MW and # of projects by 2025



Source: Hydrogen Europe.

Electricity connection

One of the critical considerations for every PtH project developer is the electricity supply. That means whether the project has a direct connection to its electricity source, a grid connection, or both.

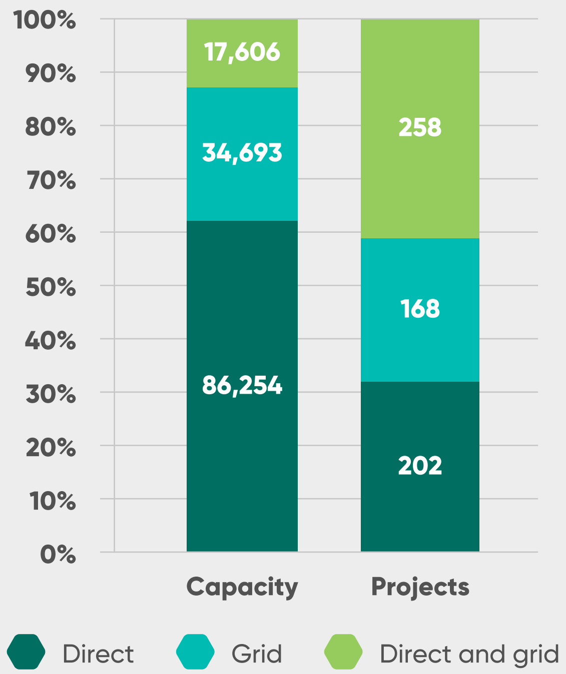
For the 31,170 MW currently planned by 2025, 18,956 MW or 61% of the capacity and 130 or 34% of the projects are connected directly to its electricity source.[5] 6,696 MW, or 21% of the capacity and 168 or 44% of the projects are planning only to have a grid connection. By 2025, planned projects with direct and grid connections are planned for 5,518 MW or 18% of the capacity and 81 or 21% of projects. In total, 39% of the planned capacity and 66% of the projects plan to connect to the grid. While large-scale PtH capacity increases will go hand in hand with additional large-scale development of renewable generation capacities, these figures continue to point to the importance of grid-connected electrolysis, at least in the short to medium term.

The situation slightly changes when looking to announced projects by 2030. For the planned 138,554 MW by 2030, 86,254 MW or 62% of the capacity and 202 or 32% of the planned projects indicate to have only a direct connection to their electricity source. 34,693 MW, or 25% of the capacity and 168 or 27% of the projects are planning to have both a direct and a grid connection. 17,606 MW, or 13% of the capacity and 258 or 41% of projects planning to come online by 2030 are planning only to have a grid connection. While developers plan to rely heavily on grid electricity by 2025, 76% of capacity aims to have either direct and grid connection or purely a grid connection. To increase their utilisations and lower the costs, future deployments of large-scale PtH installations plan to develop significant renewable generation capacities for their own use. The average project size by 2030 is 427 MW for directly connected projects, 207 MW for projects with both a direct and a grid connection, and 68 MW for grid-connected projects.

5 / 16 GW of this directly connected capacity is tied to a single project in Spain. Should these 16 GW not materialise, direct and grid and purely grid-connected projects would be dominant. By 2024, purely grid-connected with direct and grid-connected projects accounted for 4.7 GW or 76% of the capacity.

FIGURE 13

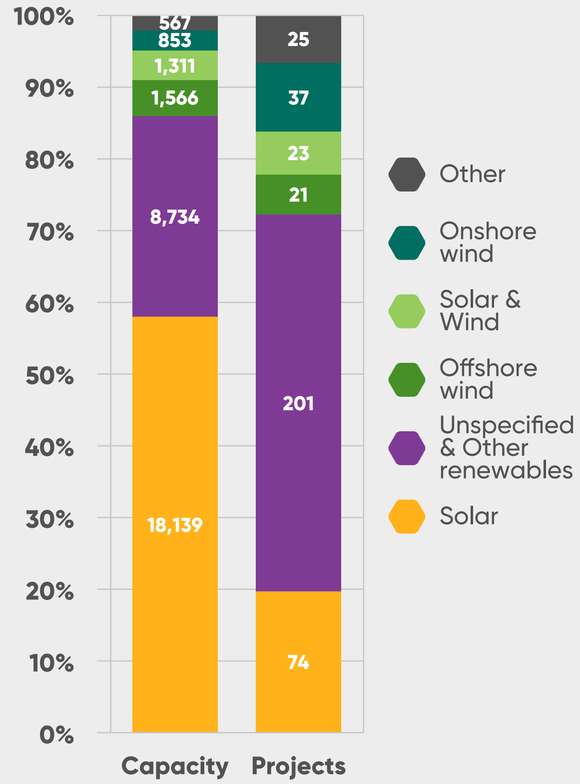
Planned electricity supply connection in MW and # of projects by 2030



Source: Hydrogen Europe.

FIGURE 14

Electricity source for projects in MW and # of projects by 2025



Source: Hydrogen Europe.

Electricity source

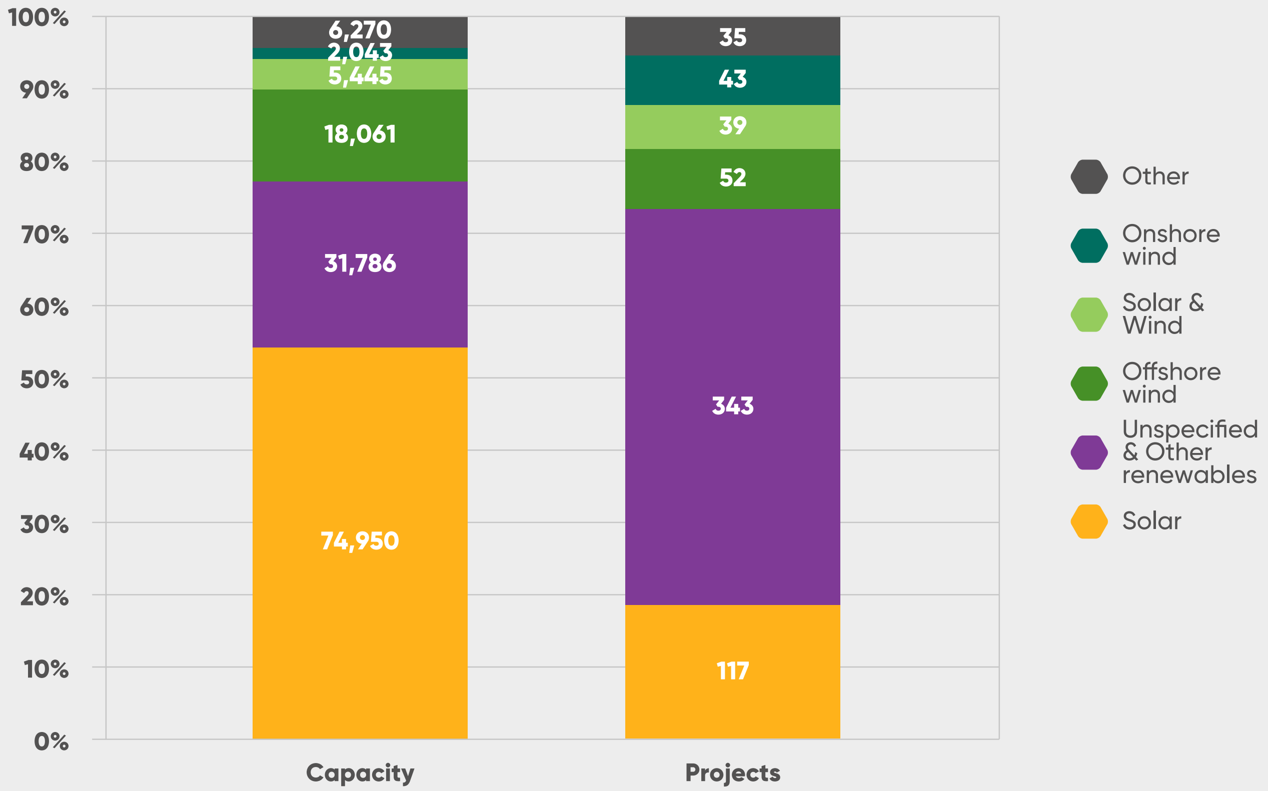
In terms of electricity sources, the capacity of the projects planned for 2025 is dominated by solar energy, with 58% of the capacity and 20% of the projects planned. Unspecified and other renewables follow it with 28% of the planned capacity and 53% of projects.[6] Most of the grid-connected projects fall in this category. The grid-connected projects plan to secure power purchase agreements with RES developers, while directly connected projects are either developing new electricity generation capacity as a part of the project or are locating the PtH facility close to an existing/under development/planned renewable generation site. The third largest electricity source powering new PtH capacity by 2025 will be offshore wind projects with 1,566 MW or 5% share of capacity and 5% projects. The remaining 9% of capacity is split between combined solar and wind renewable developments, onshore wind, and others.[7]

6 / The category Unspecified and other renewable includes unspecified renewable sources as well as hydro, biomass, geothermal, and ocean energy
7 / Other includes waste, grid mix, nuclear, and unknown.

Similar to the 2025 split, the 2030 perspective is dominated by PtH capacity connected to solar generation capacity, mostly directly connected. The 75 GW represents 65% of the 2030 capacity and 19% of the projects. While these are impressive numbers, it is essential to point out that they are dominated by a single large and very ambitious project in Spain that accounts for 67 GW of electrolyser capacity alone. The second largest category are Unspecified and other renewables representing 31,786 MW or 23% of the capacity and 343 or 55% of all projects. This represents an average size of 93 MW per project and outlines a trend that many of the PtH projects in the lower hundreds of MW have not finalised their direct electricity supply or are planning on signing a grid PPA. Offshore wind has the third largest capacity, with over 18 GW or 13% capacity and 52 or 8% of projects.

FIGURE 15

Electricity source for projects in MW and # of projects by 2030



Source: Hydrogen Europe.

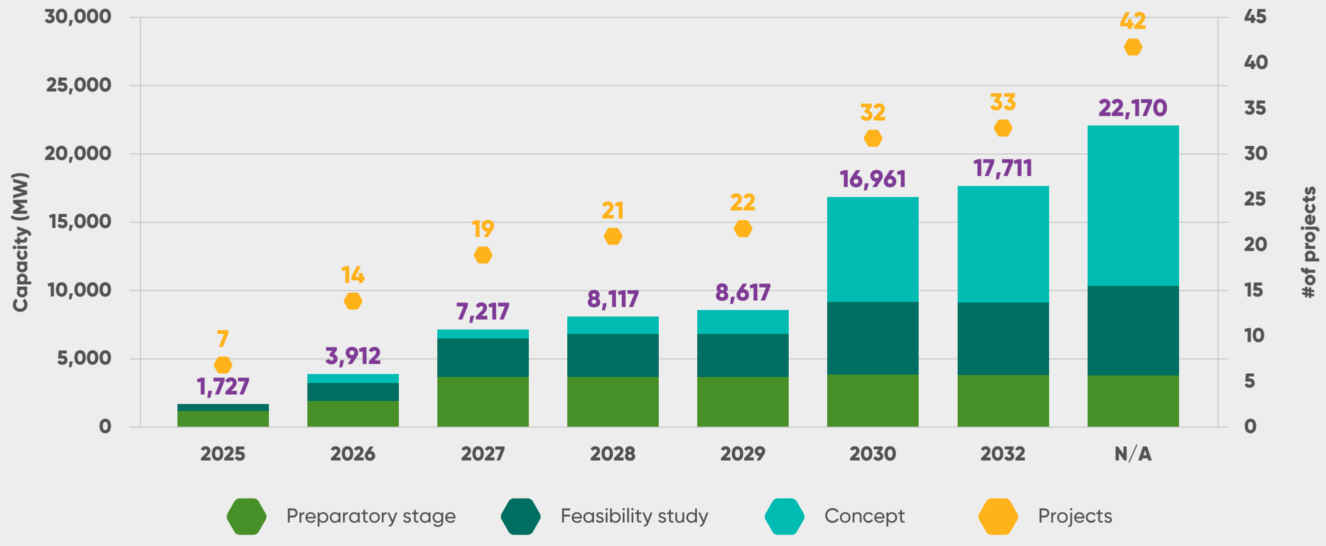
3.1.2. Reforming with carbon capture

The last two editions of the Clean Hydrogen Monitor have presented a selection of planned projects intending to reform natural gas and capture the associated emissions. Last year, 18 projects were highlighted. **Chapter 1** presents the three operational projects in Europe that produce hydrogen using this process. This section of the report gives an aggregated perspective of all identified projects intending to produce hydrogen via the reforming of natural gas combined with carbon capture (RwCC).

By August 2022, this report identified 16,961 MW[8] $_{LHV}$ of RwCC capacity planned to come online by 2030 and up to 22,170 MW_{LHV}, including projects that have not announced a commercial operation date spread among 42 projects[9] in various stages of development ranging from concept to preparatory stage. **Figure 16** illustrates the currently announced plans of companies developing RwCC in Europe. There are not any projects in construction, but several projects amounting to more than 1 GW of production capacity are in a preparatory stage and are planning to come online by 2025. The total RwCC capacity slated to come online by 2030 is 3,869 MW. There are several projects across Europe, mostly UK and NL, that enjoy government and strong industry support and have been steadily progressing. The most advanced projects are all located in and aim to decarbonise large industrial clusters with developed natural gas infrastructure and space to develop CO2 transport

FIGURE 16

Planned projects by announced start year based on reforming of natural gas with carbon capture



Source: Hydrogen Europe.

8 / Please note that the capacity values for power-to-hydrogen and reforming with carbon capture-based hydrogen production are not comparable. The capacity for power-to-hydrogen projects refers to the electrical input of electrolysers as of MW_{el}. The capacity for gas reforming with carbon capture hydrogen projects refers to the potential output of that production unit in MW based on hydrogen's lower heating value, MW_{LHV}.

9 / The term "project" refers to an individual project or a project phase. One project can have multiple phases that gradually enlarge its capacity. For the purposes of this report, each phase of a project with three phases of 10 MW, 100 MW, and 300 MW in the same location and with the same project partners is counted as a separate project.

infrastructure. It is where local production of hundreds of thousands of tonnes of electrolytic hydrogen is not expected in sufficient quantities in the near future.

Among the available projects, there is a strong geographical focus on Western Europe. This report identified over 12.5 GW from 18 different phases/projects planning to be deployed in the UK by 2030. Most of these are in industrial clusters identified by the UK government and are competing for project funds. These include Humber/Teeside areas with multiple projects, the Liverpool-Manchester area between the Northwest of England and North Wales, South Wales, Northeast Scotland, and others. The produced hydrogen would primarily decarbonise local industry and provide initial hydrogen infrastructure for mobility. Some industrial end-uses include refining, ammonia production, chemical production, industrial heat, and power generation.

Projects in Norway, the Netherlands, and Germany have smaller announced capacities than the UK, totalling about 2.5 GW in all three countries by 2030, but many are advanced and quickly maturing. There is significantly more capacity under development in these three countries, but both capacities and planned commercial operation dates have not yet been publicly announced. As in the UK, they are located in industrial hubs, clusters, or ports, already consume large amounts of hydrogen, and have access to natural gas and, in some cases, already existing hydrogen infrastructure. There is a strong focus on developing local hydrogen infrastructure. Some of these projects develop their CO2 infrastructure, but many are parts of more extensive CO2 infrastructure plans that will be used to capture CO2 from industrial processes.

There are additional RwCC projects in France, Belgium, Italy, and Greece, as well as additional projects in the countries mentioned in previous paragraphs without available start dates or capacities and additional capacities after 2030.

10 / For PtH projects connected to the electricity grid, an electrolyser capacity factor of 68% was assumed. Country-specific utilisation factors for different electricity sources have been used to calculate expected production for directly connected projects. The values can be underestimated as they do not consider increasing electrolysis efficiency up to 2030, increasing renewable generation utilisation up to 2030, and oversizing renewables directly connected to electrolysers, which are expected to constitute almost 62% of the current planned capacity by 2030.

Conclusion

The project pipeline of hydrogen production projects keeps steadily growing even though projects are delayed, and deployment lags behind announcements, especially on the PtH side. There are 138 GW_{el} of planned PtH capacity by 2030 and almost 17 GW_{LHV} of reforming with carbon capture capacity by 2030, amounting to approximately 10 Mt of electrolytic hydrogen and 4 Mt of hydrogen produced by reforming natural gas and capturing associated emissions.[10]

Projects planning to produce hydrogen by reforming natural gas and capturing associated emissions continue to focus on major industrial clusters, ports, and other areas that need 100,000s tonnes of hydrogen. UK remains an outlier in terms of planned capacity and number of projects.

On the PtH side, the planned water electrolysis capacity has increased from 118 GW_{el} in the 2021 report to 138 GW_{el} this year planned to be deployed by 2030. Some PtH projects are being pushed back due to regulatory uncertainty and expectations of financial incentives. 2020 report referred to 523 MW_{el} to come online in 2022, but the 2021 report only referred to 253 MW_{el} for the same year. A similar trend can be observed for 2023, as the 2021 report referred to 1.6 GW_{el} to be deployed in 2023, while this year's report refers to only 1.2 GW_{el}.

From the country perspective, 17 countries have project pipelines exceeding 1 GW_{el} but significantly differ in project maturity. Some countries such as Spain, Netherlands, Germany, Denmark, France, Portugal, and Sweden have maturing projects following their project pipelines. In contrast, some of other countries' planned capacities consist of a few large concepts or are in the early stages of executing feasibility studies.

By 2030, electrolyser technology will be known for only 13,572 MW_{el} out of 138,554 MW_{el} of electrolyser capacity. Based on this smaller statistical sample, alkaline is planned to be used for 61% of the capacity and 29% of the projects. PEM would capture 32% of capacity and 62% of the projects, with the average project size being 206 MW_{el} for ALK and 51 MW_{el} for PEM by 2030. Solid oxide and other technologies constitute a smaller part of the planned capacities, but their share will continue to grow as the technology matures and reaches commercial technology readiness levels.

38% of capacity by 2030 is aiming to have either direct and grid connection or purely a grid connection while future large-scale PtH installations plan to develop significant renewable generation capacities for their use, often directly connected. The average project size by 2030 is 427 MW_{el} for directly connected projects, 207 MW_{el} for projects with both a direct and a grid connection, and 68 MW_{el} for grid-connected projects.

Methodological note

The list of power-to-hydrogen and reforming of natural gas with carbon capture projects that form a basis for the analysis have been collected by ***Hydrogen Europe*** from both public and confidential sources.[11] They provide a potential future snapshot based on current developments and announcements. The authors collected this information to the best of their abilities but cannot guarantee the absolute completeness or accuracy of the collected data. If only estimate ranges have been given for capacity or start dates, the authors adopted the average provided value. The authors never made their conclusions about the start date, capacity, technology, or other project information.[12] Different phases of the same project with separate FIDs are being considered as separate projects.

The authors have adopted an inclusive approach when compiling this list of projects to develop the most exhaustive compilation of European power-to-hydrogen and reforming with carbon capture projects. The authors are not judging the feasibility of announced facilities but reporting various public and private data points. As a result, this list includes projects in all stages, including concept, feasibility studies, FEED, detailed design and permitting, and construction.

If the authors of this report refer to specific projects and provide any project details, this information is either public or relevant project partners have given explicit permission.

Geographical coverage of the database consists of EU 27, European Free Trade Association, and the United Kingdom. Results in this chapter may purposefully exclude some countries depending on the quantity and quality of the collected information.

11 / This analysis excludes any other hydrogen production methods such as biomass reforming, gasification, thermolysis, etcetera.
12 / In very occasional cases when the project start date has not been made public, but it was almost certain that the project is planning to be online by 2030, authors used 2030 instead of N/A.

3.2.

International hydrogen and hydrogen derivatives supply: export-oriented projects with the potential to ship to Europe

An expected increase in hydrogen demand and geographical imbalances related to clean hydrogen production resulted in hydrogen projects with export intentions having been announced all over the globe. To facilitate these exports, import mechanisms such as H2 Global, import facilitators such as the Global European Hydrogen Facility, and agreements such as Memoranda of Understanding (MoU) between importing and exporting countries or individual companies, including ports, were established. From the European perspective, the importance of imports has been underpinned by the RePowerEU target to import into the European Union (EU) 10 Mt/y of hydrogen annually by 2030.

This sub-chapter presents a selection of the largest export-oriented projects worldwide that could potentially ship renewable hydrogen or its derivatives to Europe. Included in this selection are projects announced up to August 2022, with over 1 GW of electrolyser capacity, which specifically intend to export to Europe, to multiple destinations among which Europe may be included or which do not mention a specific destination. It then reviews projects linked to MoU establishing trade routes with Europe.

A selection of the largest export-oriented hydrogen projects (with over 1 GW of electrolysis capacity) amounts to 5 Mt/year of renewable hydrogen or its derivatives to be available to be exported to Europe by 2030 and 11.5 Mt/year after 2030, representing respectively 50% and 115% of the RePowerEU target. While these volumes could be potentially available, they are highly uncertain. MoU establishing trade routes between these projects and Europe are linked to only 2.8 Mt/year, or 28% of the REPowerEU target.

© Justin Jin for Hydrogen Europe

3.2.1. Export-oriented production projects with the potential to deliver to Europe

The world's largest export-oriented projects (with over 1 GW of electrolyser capacity) with the potential to deliver to Europe amount to some 11.5 Mt/year of renewable hydrogen equivalent spread over 15 projects.[14] This includes projects with unclear timelines for commencing production and projects that specify a timeline.[15] Only about 0.6 Mt/year is expected by 2025, increasing to almost 2 Mt/year by 2028. Less than half of the volume, 5 Mt/year, outlined in these projects is expected to be produced by 2030. The remaining projects have not yet presented clear timelines.

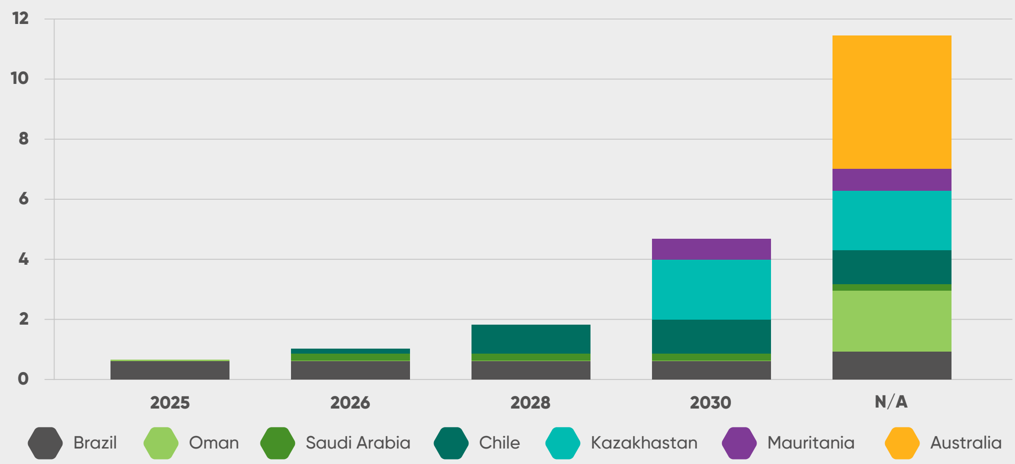
Large export-oriented clean hydrogen projects are mostly located in regions with significant renewable energy potential and close to ports to facilitate exports. The most ambitious plans are being developed in Australia with ~4.5 Mt/year of hydrogen for exports. Kazakhstan and Oman follow with 2 Mt/year of hydrogen for exports each. Chile's projects account for another 1 Mt/year of hydrogen. Announced projects in Brazil, Mauritania, and Saudi Arabia should also produce slightly less than 1 Mt/year of hydrogen for exports in each country.

13 of the 15 projects specified how the hydrogen will be marketed, i.e., whether it will be transported as hydrogen or as one of its derivatives. Out of those 13, 12 have chosen to export ammonia. A potential explanation for choosing ammonia among these early export projects is the existing infrastructure, know-how to transport it, the potential to use it directly as feedstock, and its chemical properties.[16]

Figure 17 shows a selection of the largest export-oriented hydrogen production projects in the world with the potential to ship to Europe, that is, projects that intend to export

FIGURE 17

Cumulative volume of hydrogen equivalent (in Mt/year) produced in selected export-oriented projects with over 1 GW of electrolysis capacity[17]



Source: Hydrogen Europe.

13 / Projects that mention export destinations excluding Europe are not included in the selection e.g., the Asian Renewable Energy Hub as it intends to export to countries in the Asian-Pacific region. See BP, 2022. Renewable energy hub in Australia. Available at: https://www.bp.com/en/global/corporate/what-we-do/gas-and-low-carbon-energy/renewable-energy-hub-in-australia.html
14 / For information about scope, please see the Methodological note.
15 / (IEA, 2022) identified 9 Mt of renewable and low-carbon hydrogen by 2030. This includes projects with offtake agreements with Europe, projects citing Europe as an intended destination, or projects that do not cite intended destinations.
16 / Ammonia has a high energy density of 12.7 MJ/l, and easy liquefaction at around -33°C. For reference, the energy density of hydrogen is 8.5 MJ/l, and it is liquefied at around -250°C.
17 / There are no planned additions to the hydrogen volume produced in 2027 and 2029. Potential additions may come from projects that did not yet disclose a timeline to commence production.

specifically to Europe, to multiple destinations, among which Europe, or that do not specify a destination.

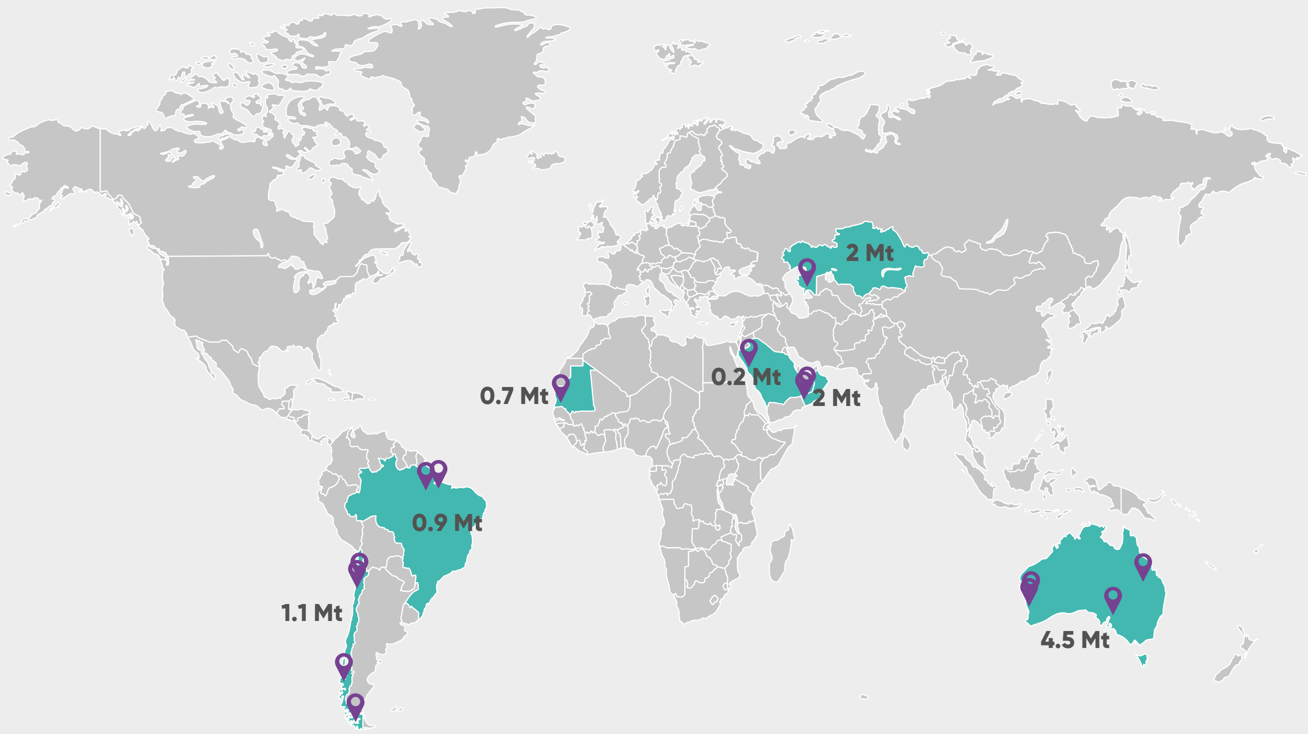
Although ambitious projects have been increasingly announced in the past few years, these projects are often still in the early stages of development. The projects presented above are almost exclusively undergoing pre-feasibility or feasibility studies or are in other early stages of development (e.g., securing land, environmental permits, the partner seeking). Only 2.4 Mt/y out of the 11.5 Mt/y are in the engineering and design or construction phases as of August 2022.

Two of the projects at the feasibility study stage are of particular importance for the expected volume of hydrogen exports (Lewis, 2021; Intercontinental Energy, 2022). The Western Green Energy Hub in Australia and the Green Energy Oman in the Duqm area of Oman could provide over 5.4 Mt/y of hydrogen or about half of the volume of all selected projects (Intercontinental Energy, 2022). A final investment decision should be taken only in 2028 and 2026, respectively, but the timeline to start production is unclear. Any changes in these projects will significantly impact the identified 11.5 Mt/y total potential exports to Europe.

Figure 18 illustrates the selection of the 15 potential export projects identified for this sub-chapter.

FIGURE 18

Graphical distribution of hydrogen equivalent (in Mt/year) produced in selected export-oriented projects with over 1 GW of electrolysis capacity



Source: Hydrogen Europe.

3.2.2. Memoranda of Understanding

Even if all these export-oriented projects come online as expected, they will still be subject to market dynamics to determine their final export destination. Therefore, agreements between countries, authorities and companies could indicate more realistic volumes of hydrogen produced in these projects that could be destined for Europe. In the early stages, MoU have been laying out several potential trade routes exporting hydrogen to Europe.

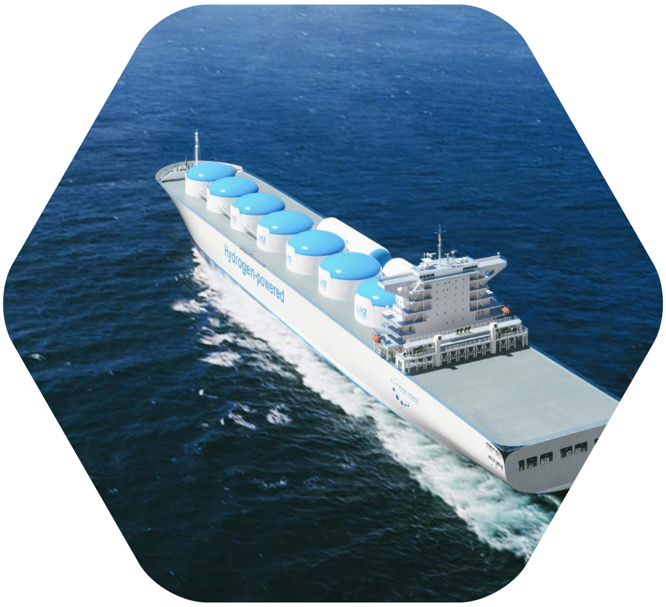
The Port of Rotterdam has signed several MoU with international partners to import hydrogen into Europe. The port is preparing to become a crucial hydrogen hub to redistribute hydrogen to European demand centres as it is well connected with industrial zones through an extensive distribution network (Port of Rotterdam, 2022). Early in 2021, the port authority signed an MoU with the Chilean minister of Energy to ensure the hydrogen supply from Chile (Port of Rotterdam, 2021). This could unlock the Chilean potential of about 1 Mt/year of hydrogen for exports by 2030. Later in the same year, the port signed an MoU with the Western Australian government. The agreement focuses on developing a hydrogen export supply chain between the two (Port of Rotterdam, 2021). An equivalent of over 4 Mt/year of hydrogen-producing projects is being developed in three projects in the state. The Western Green Energy Hub and Geraldton are both at the feasibility stage and have unclear timelines for completion (Lewis, 2021; GHD Advisory, 26). Murchison Hydrogen Renewables is under development and should finish construction by 2030 (Copenhagen Infrastructure Partners, 2022).

Agreements to directly invest in projects overseas have also been developed by the port. In 2017, the Port of Rotterdam Authority signed with the Brazilian state of Ceará an agreement that initiated a series of investment deals to develop the Pecém port, positioning itself as a hydrogen export hub. The Port of Rotterdam owns 30% of the enterprise with a say on strategic decisions (Offshore Renewables, 2018). An equivalent of almost 1 Mt/y of hydrogen is being developed in two production projects in the Brazilian state. Base One is undergoing feasibility studies and plans to start producing by 2025 (Sampson, 2021). Qair Pecém Port is at an earlier stage of development, having only signed an MoU to develop the project and does not yet have a timeline for completion (Argus Media, 2021).

Direct agreements with companies have also been established. Early in 2022, the Port signed an MoU with Chariot Energy Group to secure the supply of specific volumes of hydrogen to Europe through contracts connecting off-takers (Chariot, 2022). The Chariot Group is developing Project Nour in Mauritania, aiming to produce 0.7 Mt/y of hydrogen per year. The project is undergoing feasibility studies and should commence production in 2030 (Energy Capital & Power, 2022).

MoU establishing trade routes between these projects and Europe are linked to the production of an equivalent of 6.7 Mt/y of hydrogen per year, including projects with unclear timelines. However, considering only projects with clear timelines, only about 2.8 Mt/y are expected to be produced by 2030.

For comparison, the volume produced from projects with existing offtake agreements between companies to export hydrogen to Europe is significantly lower. The total production amounts to only about 1 Mt of renewable and low-carbon hydrogen per year by 2030, including trade between two European countries (IEA, 2022).



Conclusion

Several export-oriented projects have been announced in the past few years following an increase in expected hydrogen demand and geographical imbalances related to clean hydrogen production. A selection of the largest projects (with over 1 GW electrolyser capacity) that could potentially ship hydrogen to Europe, with or without clear timelines for commencing production, amounts to about 11.5 Mt/y with around 5 Mt/y of renewable hydrogen available by 2030. If projects planning to start production before 2030 come online as expected, there could be cumulatively almost 14 Mt of hydrogen delivered by 2030. These projects could still significantly change until an investment decision is taken, as they are mainly undergoing pre-feasibility studies, feasibility studies, or are in other early stages of development. In addition, it is highly uncertain how much of the volume announced would in fact be available for exports and destined for Europe. For these reasons, these numbers should be regarded as an upper bound of potential exports into the bloc from selected projects.

Current MoU establishing trade routes between the largest hydrogen production projects with Europe are linked to about 6.7 Mt/y of hydrogen, including projects with and without clear timelines to start production. By 2030, this number amounts to 2.8 Mt/y, or 28% of the REPowerEU target to import 10 Mt of renewable hydrogen annually into the EU (European Commission, 2022). Production linked to offtake agreements only amounts to 1 Mt/y of renewable and low-carbon hydrogen by 2030 (IEA, 2022). For the EU to achieve its ambitious goals set in the REPowerEU plan, cooperation agreements that aim to develop further export-oriented projects must be developed. More advanced agreements to secure hydrogen imports into the bloc, e.g., offtake, will also need to be in place, given the several emerging hydrogen demand centres worldwide. The Port of Rotterdam has done substantial work to secure the necessary infrastructure to import and distribute large volumes of hydrogen. However, the works will have to be intensified in the coming years if the EU is to achieve its RePowerEU targets.

Methodological note

This sub-chapter includes non-exhaustive data on the largest publicly announced export-oriented hydrogen projects that could potentially ship renewable hydrogen or one of its derivates (e.g., ammonia) to Europe. These include projects around the world with over 1 GW of electrolyser capacity that have announced they will allocate their hydrogen production completely or partially to exports (e.g., projects purely destined for exports and projects built to satisfy both local demand and international demand centres), and that have claimed an intention to export hydrogen to Europe, to multiple destinations provided that it does not exclude Europe, or that have not specified an export destination.

Both projects that specified a timeline to start production, and projects that did not specify a timeline to start production, are included. No assumptions were made when no timeline to commence production was publicly available.

Projects in all stages of development that meet the criteria above are included in the selection in this sub-chapter. However, the selection is composed almost exclusively of projects at an early stage of development. These projects might undergo significant changes until an investment decision is made, and further market conditions will determine the volume directed for exports and their final destination.

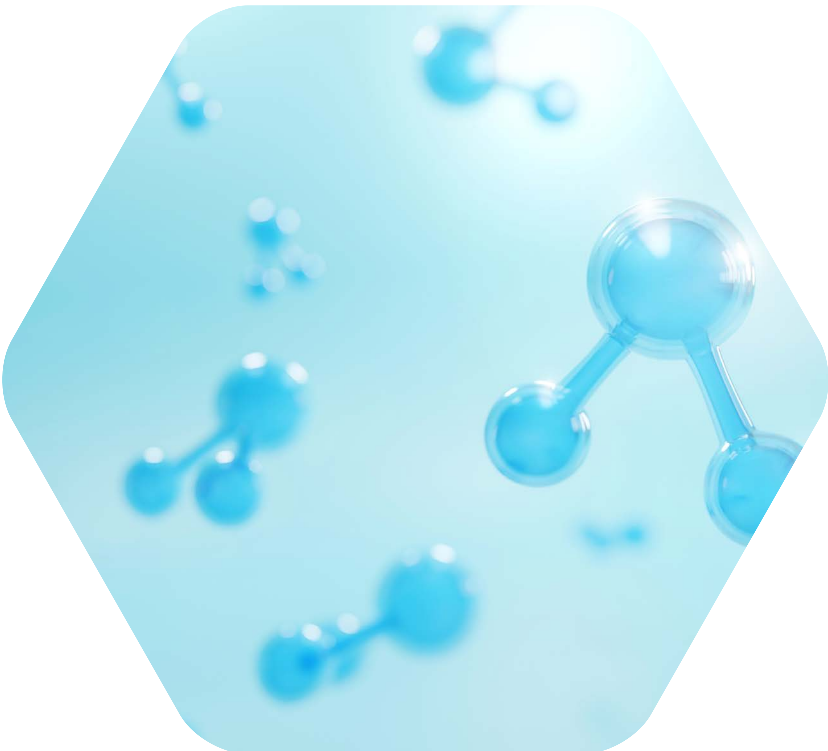
3.3.

Electrolyser manufacturing capacity in Europe

Increased hydrogen ambitions around the world will require overcoming equipment bottlenecks. One of the most cited is electrolyser manufacturing capacity. This sub-chapter presents data on operational and planned manufacturing capacity for water electrolysers in Europe and worldwide. Total planned capacity data includes manufacturers' plans at an advanced development stage, e.g., under construction, and plans still conditional on final investment decisions and further market developments, e.g., potential capacity expansions. Subsequently, the plans are broken down by stage of development. Although plans are subject to a great deal of uncertainty at initial stages and are conditional on, e.g., future demand and financing schemes, they make up a reliable indicator to show at what pace and to what capacity the market can potentially ramp up, provided adequate market conditions.

Current electrolyser manufacturing capacity in Europe amounts to 3.3 GW/year. Planned capacity could reach 53 GW/year by 2030.

If all facilities planned to be operational before 2030 come online as expected, European factories could produce 104 GW of electrolysers enabling the production of around 11.3 Mt of hydrogen per year[18] already in 2026.



18 / Provided that all planned manufacturing facilities become operational as planned, operate at a 100% capacity utilisation, and all electrolysers manufactured between 2022-2030 are subsequently deployed and installed in Europe. Tonnes are calculated assuming 5256 load hours (60% utilisation), and 69% efficiency using Lower Heating Value.

3.3.1. Operational

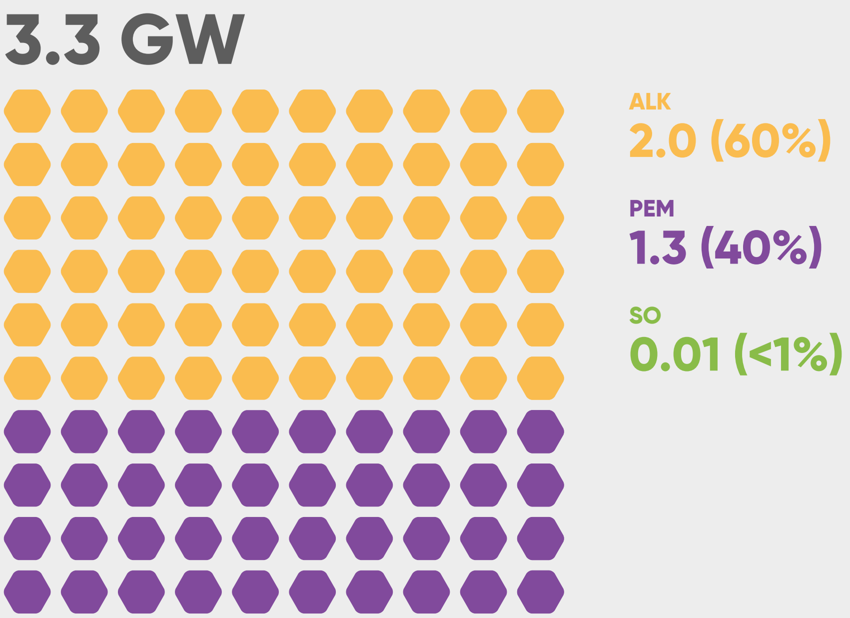
Current water electrolyser manufacturing capacity in Europe amounts to about 3.3 GW/year of operational capacity (as of August 2022). This capacity is concentrated in Germany and the United Kingdom, which host about 1 GW/year of capacity each or roughly 61% of the total capacity. Norway follows with over 0.5 GW/year, Italy with 0.3 GW/year, and France with almost 0.2 GW/year. The remaining capacity is in sites with no more than around 0.1 GW/year.

The technological breakdown of the plans shows that alkaline technologies account for 60% of the total capacity or 2 GW/year. Proton-exchange membrane (PEM) represents roughly the other 40% or 1.3 GW/year. Solid Oxide (SO) represents less than 1%, or less than 0.01 GW/year for now.[19] **Figure 19** shows the split of the electrolyser manufacturing capacity by technology type.

According to BNEF, about 12 GW/year of capacity is planned outside Europe by the end of 2022. Almost 15.5 GW/year of water electrolyser manufacturing capacity is expected worldwide by the end of 2022.

FIGURE 19

Breakdown of current water electrolyser manufacturing capacity by technology type in Europe as of August 2022 (in GW/year)



Source: Hydrogen Europe.

19 / Authors have not been able to verify manufacturing capacities for AEM, and other technologies yet, but will strive to do so in future publications.

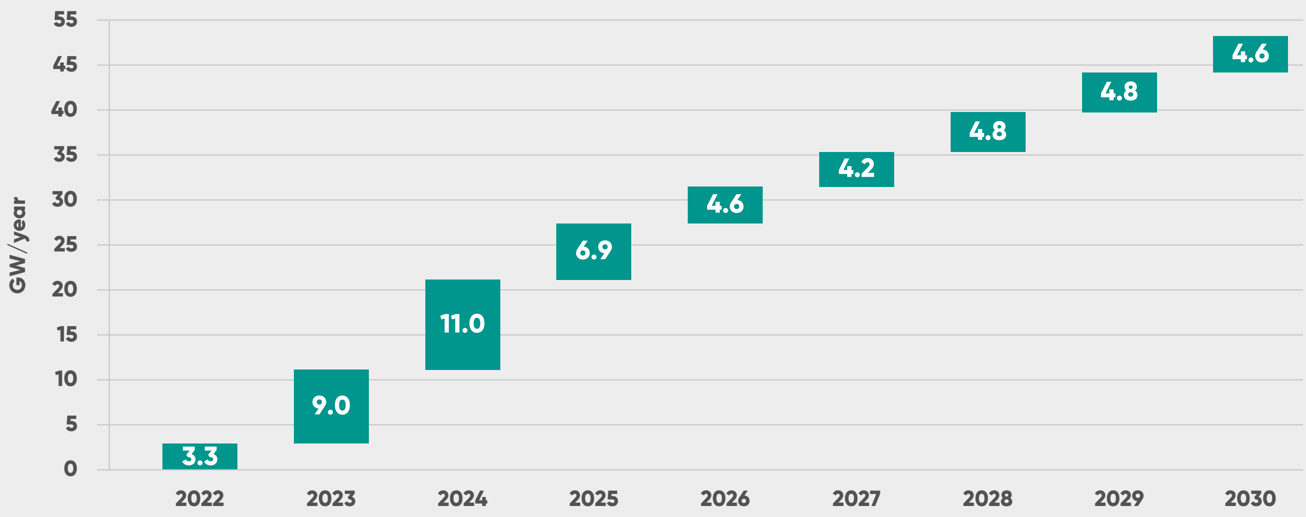
3.3.2. Planned

In the years ahead, water electrolyser manufacturing capacity in Europe is planned to increase significantly. By 2030, additions raise the total planned capacity to 53 GW/year, representing a ~16-fold increase compared to the current capacity (as of August 2022). Increases are planned to happen gradually over the next eight years, even though the next two years will see a significant ramp-up. Presumably, more capacity additions will be planned in the upcoming years to come online later in the decade (e.g., after 2027). **Figure 20** shows the increase in capacity in Europe by 2030.

If all planned manufacturing facilities come into operation, operate at a 100% capacity utilisation, and all electrolysers manufactured between 2022-2030 were subsequently deployed and installed in Europe, they would amount to 288 GW of installed electrolysis capacity in 2030, potentially producing 31.4 Mt of hydrogen.[20] In this hypothetical best-case scenario, about 104 GW could already be installed by 2026, enabling the production of 11.3 Mt/year of hydrogen, satisfying the RePowerEU target to produce 10 Mt of hydrogen in the bloc by 2030 (European Commission, 2022). However, the realisation of these water electrolyser manufacturing capacity announcements depends on business cases, regulatory certainty, and financial incentives for the whole ecosystem. Lack of financed electrolytic hydrogen production projects and subsequent concerns over future available manufacturing capacity led to the creation of the Electrolyser Partnership in May 2022 (European Commission,

FIGURE 20

Planned additions and cumulative water electrolyser manufacturing capacity in Europe by 2030 (in GW/year)



Source: Hydrogen Europe.

20 / Assumes 5256 load hours (60% utilisation), 69% efficiency using Lower Heating Value.
21 / The 25 GW is measured in terms of electrical input, as are all estimates presented in this chapter. Equivalent to about 17.5 GW in terms of hydrogen output.

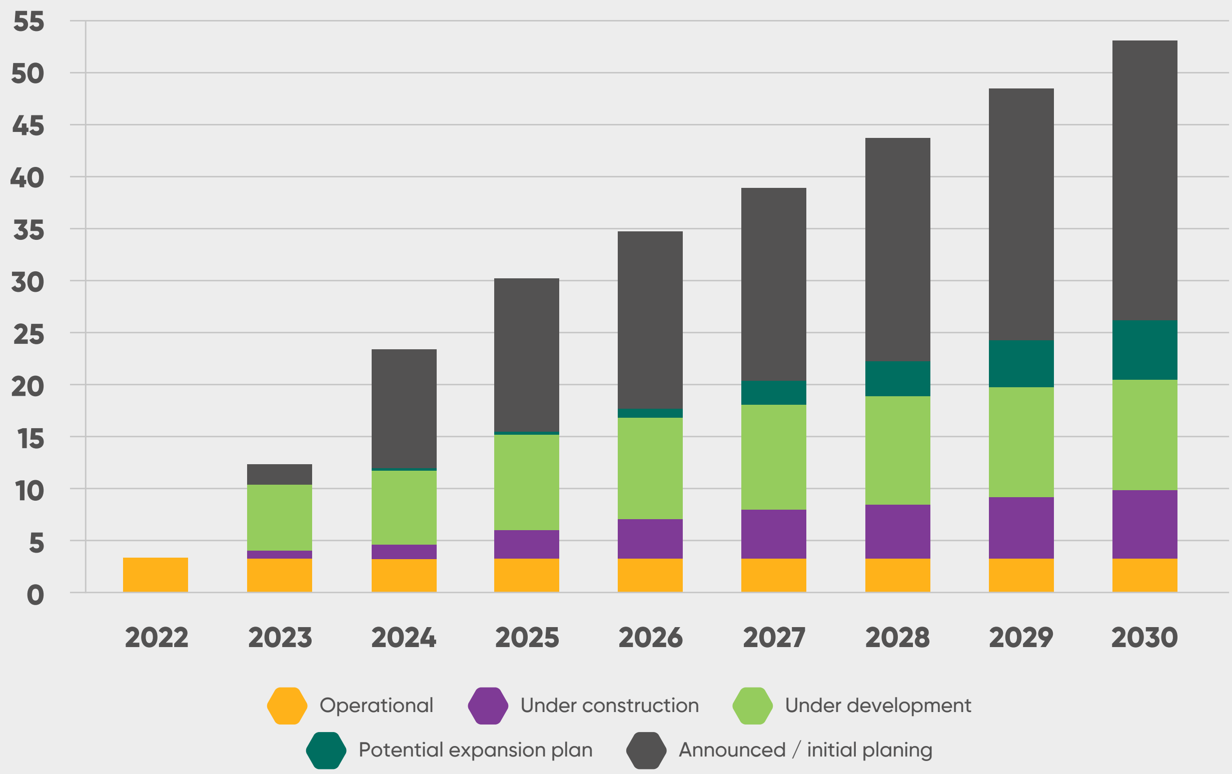
2022). It set a target to achieve 25 GW/year of manufacturing capacity by 2025. It is an ambitious but realistic target that would still allow Europe to reach RePowerEU objectives.[21]

However, around 79% of the expected capacity planned between 2023-2030 is still in the initial stages of development (e.g., announcements or plans still subject to a final investment decision) and have not started construction. Out of this 79%, on average, 45% of the planned capacity between 2023-2030 is only announced or has been initially planned; on average, 5% consists of potential expansion plans, and on average, 29% are under development (e.g., facility design, site choice). By 2030, only 12% of the planned capacity will have plans in the construction stage. **Figure 21** shows the planned cumulative electrolyser manufacturing capacity in Europe by stage of development.

Low-capacity utilisation may also be a hurdle to meeting these targets, as suggested above. ITM, which plans to have 5 GW/year of manufacturing capacity by 2024, has, as of September 2022, an effectively contracted pipeline that amounts to 77 MW of electrolysers, which would represent only 7.7% of its manufacturing capacity in 2022. Although over 340 MW in contracts are being negotiated (ITM Power, 2022), the danger for all manufacturers is that the low utilisation will not incentivise realising future expansion plans and jeopardise achieving the REPowerEU objectives.

FIGURE 21

Cumulative electrolyser manufacturing capacity by stage of development in Europe by 2030 (in GW/year)



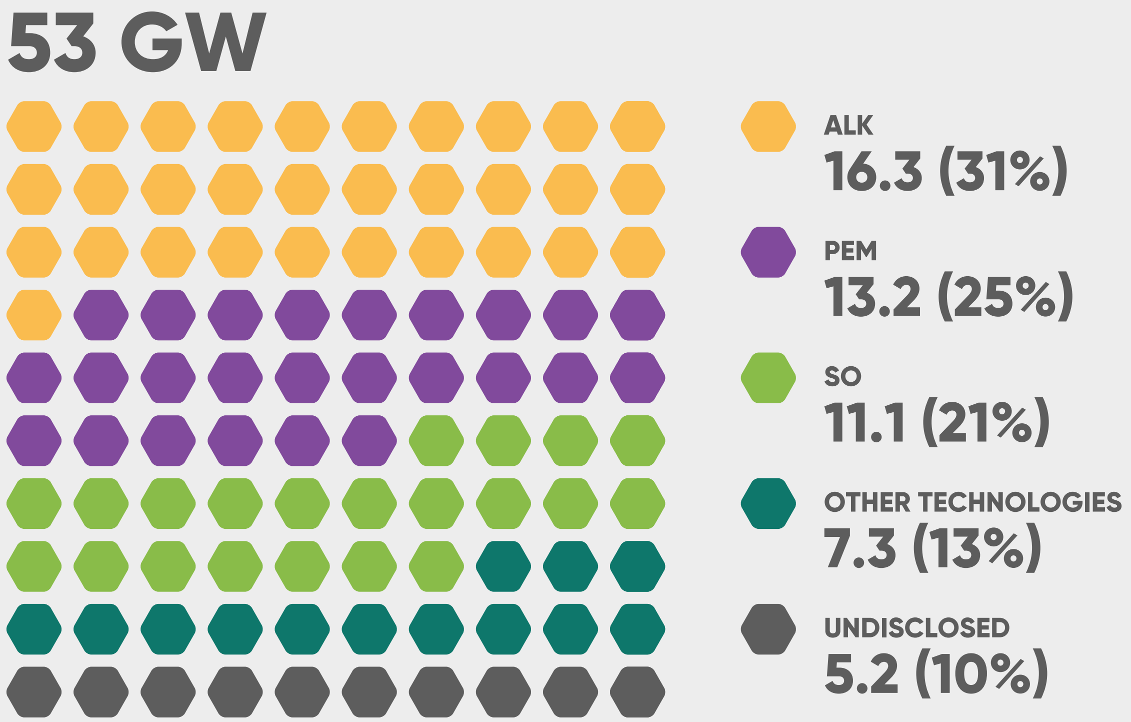
Source: Hydrogen Europe.

Information on the electrolyser technology is available for 47.9 GW/year of Europe's planned 2030 manufacturing capacity. Assuming all plans would materialise, alkaline manufacturing capacity would account for 34.1% or 16.3 GW /year. PEM would follow with 27.5% or 13.2 GW /year. SO would represent 23.2% or 11.1 GW /year, representing a significant increase from this technology's current marginal market share. Other emerging technologies, such as Anion Exchange Membrane Electrolysers (AEM), and others, represent 7.3 GW /year or 15.2%. The remaining 5.2 GW /year cannot be attributed to any technology type. **Figure 22** shows the breakdown of the electrolyser manufacturing capacity in Europe by technology type.

According to BNEF, water electrolyser manufacturing capacity outside of Europe is planned to increase to 38.9 GW /year by 2024, a threefold increase compared to 2022. Globally, that would represent 62 GW /year of planned manufacturing capacity by 2024.

FIGURE 22

Breakdown of planned electrolyser manufacturing capacity by technology type in Europe by 2030



Source: Hydrogen Europe.

Conclusion

Europe's current water electrolyser manufacturing capacity amounts to over 3.3 GW/y by August 2022. In the following years, planned capacity should increase 16-fold, reaching 53 GW/y by 2030. If facilities come online before 2030 as expected, operate at a 100% capacity utilisation, and all manufactured electrolysers are subsequently delivered and installed in Europe, they could produce about 31.4 Mt tonnes of hydrogen by 2030, or 11.3 Mt already by 2026. However, on average, 79% of the capacity planned between 2023-2030 is still conditional on final investment decisions and can change significantly. Low-capacity utilisation can also considerably reduce these numbers, especially in the near term, due to low demand for electrolysers.

Manufacturing capacity plans have been accelerating in Europe and around the world. However, if the EU is to achieve the ambitious targets set in the REPowerEU to produce 10 Mt and import another 10 Mt of hydrogen by 2030 (European Commission, 2022), there will have to be sufficient demand for electrolysers for manufacturers to realise their plans. Incentives to secure future demand for hydrogen, more regulatory certainty, and financing for the hydrogen ecosystem could significantly promote both electrolyser deployment and manufacturing.

Methodological note

The data presented in this sub-chapter includes water electrolysis manufacturing capacity in factories located in Europe, as planned by electrolyser manufacturers. Hydrogen Europe did not make any projections about potential capacity increases.

The data is collected from public announcements, complemented by Hydrogen Europe's confidential information. Whenever timelines are unclear but credible to be operational by 2030, it is assumed that facilities will become operational by 2030. This potentially underestimates manufacturing capacity shortly before 2030 and overestimates capacity in 2030. The data is reported assuming 100% utilisation capacity.

The total planned capacity is also reported, including plans in all stages of development, e.g., initial ambitions set out in business plans and facilities under construction. Then, it is followed by details on the stage of the plans. Although plans at the initial stages of development are still dependent on several market conditions, e.g., future demand, and can significantly change or even be cancelled, they compose a reliable indicator of potential ramp-up speed and capacity.

References

Argus Media. (2021, July 8). Fortescue, Qair expand green H2 plans for Brazil. Argus Media. Retrieved September 28, 2022, from https://www.argusmedia.com/en/news/2232532-fortescue-qair-expand-green-h2-plans-for-brazil

BloombergNEF. (2022). Hydrogen. Retrieved September 28, 2022, from BloombergNEF: bnef.com/core/sectors/hydrogen (paywall)

Chariot. (2022, April 6). Green Hydrogen MoU with the Port of Rotterdam. London, United Kingdom. Retrieved September 28, 2022, from https://www.chariotenergygroup.com/wp-content/uploads/2022/04/Green-Hydrogen-to-Rotterdam-MOU_Chariot-Limited.pdf

Copenhagen Infrastructure Partners. (2022). Murchison Hydrogen Renewables Project. Retrieved September 28, 2022, from Murchison Renewables: https://www.murchisonrenewables.com.au/

Energy Capital & Power. (2022, may 5). Chariot's $3.5 billion Mauritania Based Green Hydrogen Project Secures European Export Route. Retrieved September 28, 2022, from Energy Capital & Power: https://energycapitalpower.com/chariots-3-5-billion-mauritania-based-green-hydrogen-project-secures-european-export-route/

European Commission. (2022, May 5). Hydrogen: Commission supports industry commitment to boost by tenfold electrolyser manufacturing capacities in the EU. Brussels, Belgium. Retrieved September 28, 2022, from https://ec.europa.eu/commission/presscorner/detail/en/IP_22_2829

European Commission. (2022, May 18). REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition. Retrieved September 28, 2022, from European Commission: https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131

GHD Advisory. (26, March 2022). Renewable Hydrogen and Ammonia Feasibility Study. Perth, Australia. Retrieved September 28, 2022, from https://arena.gov.au/assets/2021/08/bp-ghd-renewable-hydrogen-and-ammonia-feasibility-study.pdf

IEA. (2022). Global Hydrogen Review 2022. IEA. Retrieved September 28, 2022, from https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf

Intercontinental Energy. (2022). Green Energy Oman. Retrieved September 28, 2022, from Intercontinental Energy: https://intercontinentalenergy.com/green-energy-oman

Intercontinental Energy. (2022, April 5). Green Energy Oman takes key project development steps to progress the world leading green fuels project. Muscat, Oman. Retrieved September 28, 2022, from https://intercontinentalenergy.com/announcements/ICE-Announcement-20220407.pdf

Intercontinental Energy. (2022). Western Green Energy Hub. Retrieved September 28, 2022, from Intercontinental Energy: https://intercontinentalenergy.com/western-green-energy-hub

ITM Power. (2022, September 14). Results Presentation: Full Year to April 30. Retrieved September 28, 2022, from https://itm-power-assets.s3.eu-west-2.amazonaws.com/Final_Results_Presentation_14_September_12d9f972ef.pdf

Lewis, J. (2021, July 13). Giant 50GW green hydrogen project proposal launched Down Under. upstream. Retrieved September 28, 2022, from https://www.upstreamonline.com/hydrogen/giant-50gw-green-hydrogen-project-proposal-launched-down-under/2-1-1039186

Offshore Renewables. (2018, October 26). Port of Rotterdam Investing USD 85 Mn in Port of Pecém. Offshore Renewables. Retrieved September 28, 2022, from https://www.offshore-energy.biz/port-of-rotterdam-investing-usd-85-mn-in-port-of-pecem/

Port of Rotterdam. (2021, March 17). Ministry of Energy in Chile and Port of Rotterdam Authority sign MOU on green hydrogen. Retrieved September 28, 2022, from Port of Rotterdam: https://www.portofrotterdam.com/en/news-and-press-releases/ministry-energy-chile-and-port-rotterdam-authority-sign-mou-green-hydrogen

Port of Rotterdam. (2021, November 30). Western Australia and Port of Rotterdam to collaborate on renewable hydrogen. Retrieved September 21, 2022, from Port of Rotterdam: https://www.portofrotterdam.com/en/news-and-press-releases/western-australia-and-port-of-rotterdam-to-collaborate-on-renewable

Port of Rotterdam. (2022). Import of hydrogen. Retrieved September 28, 2022, from Port of Rotterdam: https://www.portofrotterdam.com/en/port-future/energy-transition/ongoing-projects/hydrogen-rotterdam/import-of-hydrogen

Sampson, J. (2021, March 17). Black & Veatch to conduct feasibility study for $5.4bn green hydrogen hub in Brazil. H2 View. Retrieved September 28, 2022, from https://www.h2-view.com/story/black-veatch-to-conduct-feasibility-study-for-5-4bn-green-hydrogen-hub-in-brazil/

© Justin Jin for Hydrogen Europe

04

Hydrogen transport and storage infrastructure

The hydrogen economy is an eco-friendly alternative to the current fossil fuel economy. A renewable energy future will need to build along with the hydrogen economy, and hydrogen will be the bridge maker to match supply and demand.

Introduction

The following chapter contains information on current hydrogen infrastructure developments in Europe. The lack of official and accurate hydrogen statistics makes the hydrogen market non-transparent and difficult to track. Thus, Hydrogen Europe tries to give an indicative overview of ongoing developments.

Since renewables have an advantage due to their intermittent nature, periods of surplus renewables will be used in symbiosis to produce hydrogen (power-to-X), which is a green and sustainable energy vector.

Thus, hydrogen is seen as the most promising energy vector to bridge the gap between intermittent renewable energy production and secure and stable consumption needs. Electrons get converted into multitalented molecules by using surplus renewables in symbiosis to produce hydrogen through electrolysis. This way, when renewables are unavailable, hydrogen can be used as an energy storage vector to provide the power required and decarbonise hard-to-abate sectors that cannot be electrified. At the same time, power cannot be transported economically over long distances from regions where renewable energy production is more favourable. This makes hydrogen the most promising energy vector for long-distance energy transport.

The key to exploiting the many potential advantages of hydrogen is understanding why it is better to use than electricity. Hydrogen molecules are the smallest molecules that can exist in the universe and are incredibly abundant. In fact, there are more hydrogen molecules in the atmosphere than atoms in all the elements on the periodic table combined. Consequently, hydrogen has a wide range of potential applications, particularly for hard-to-abate sectors and energy-intensive industries, including powering cars and homes, providing heat, and producing energy.

According to estimates from SNAM, transporting power from North Africa to Italy in the form of hydrogen via pipeline would cost approximately USD 2.5-5 MWh, or about 13% of the cost of using a UHV power line and roughly 8% of the cost to produce and ship green ammonia.

The critical advantage of hydrogen over electricity is its energy density. A single kilogram of hydrogen contains the same energy as 3 kg of oil or a ton of coal, making it a vector for transport and storage. Additionally, hydrogen does not release pollutants when burned, making it a clean energy source. Another essential aspect to consider, based on the above, is that trading molecules is cheaper and easier over long distances than for electricity. A physical necessity for the realisation of this trade is the transport of hydrogen over long distances.

A few things need to happen for the hydrogen economy to take off.

First, renewable energies need to be developed in addition to hydrogen.

Second, transport and storage infrastructure must be developed to store the hydrogen.

Third, the technology needed to convert renewable energy into hydrogen needs to be perfected.

The economics of efficient hydrogen transport is depicted in **Figure 1,** followed by an overview of the main hydrogen network initiatives.

Hydrogen transport and storage infrastructure will play a crucial role in developing the hydrogen economy. Although pipelines are the cheapest way to transport hydrogen, refurbishing or building new infrastructure takes time. Therefore, developing the necessary transport and storage infrastructure is critical. As in figure 3, a simplified overview can be made when looking into hydrogen transport and the associated infrastructure needed.

Liquid, solid, and gaseous are three main ways to transport and store hydrogen. Each has its benefits and drawbacks.

- **Liquid hydrogen.** The hydrogen molecules are cooled to -253°C at port terminals before being loaded onto highly insulated tanker ships

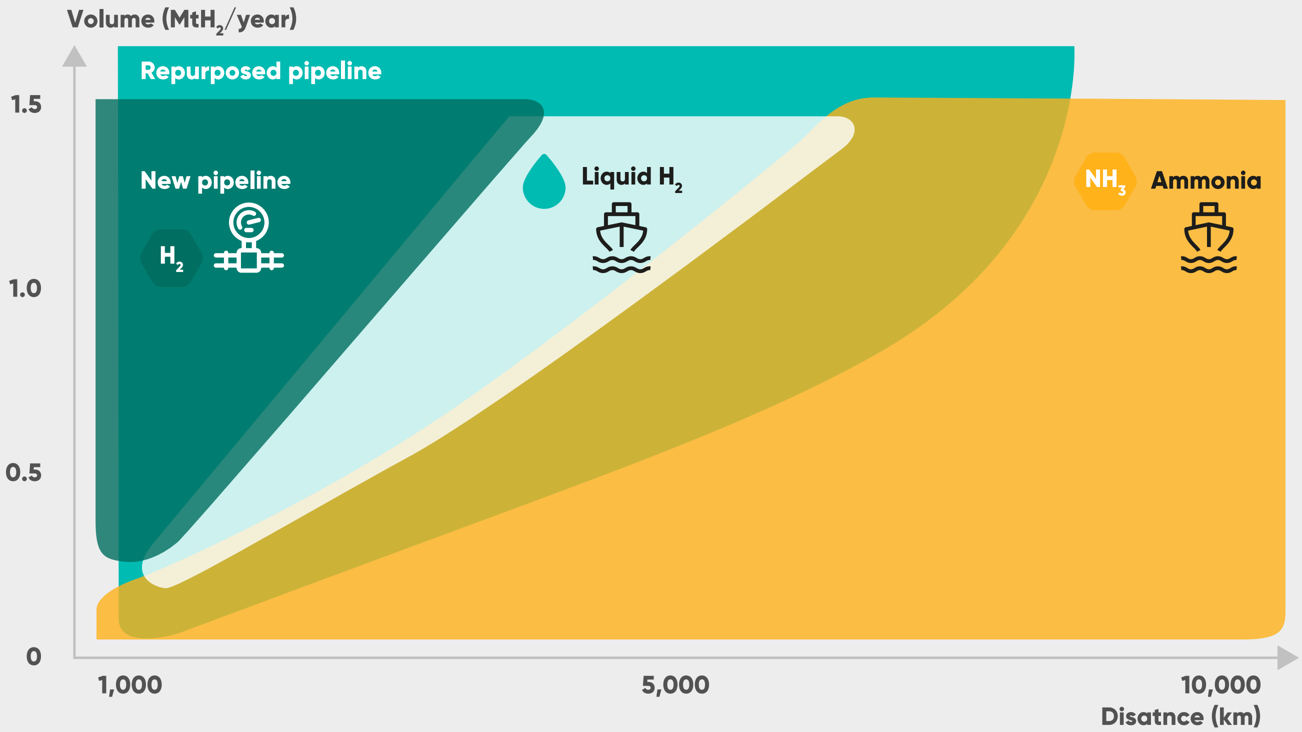
- **Liquid hydrogen carriers and liquid organic hydrogen carriers (LHC/ LOHCs).** A slate of different (most often organic) compounds can absorb and release hydrogen through a chemical reaction. LHCs & LOHCs can serve as a storage and transportation medium for hydrogen and can be transported as liquids without cooling. LOHCs are very similar to crude oil and oil products, so the existing oil transport infrastructure could even be adapted to transport LOHCs.

- **Ammonia.** Hydrogen can be converted into ammonia by reacting with nitrogen, requiring only electricity, water, and air. Ammonia has a much higher energy density than hydrogen; therefore, more energy can be exchanged. There is a well-established international trade in ammonia that can be leveraged.

- **Solid Inorganic Hydrogen Carriers** (SIHCs) bond hydrogen to other materials (borohydrides) in an energy-intensive chemical reaction. The result is an inert, coffee-like powder that can be stored under ambient conditions and retains its hydrogen for years. To release the hydrogen, the high-energy powder is mixed with water, and by immersing a catalyst plate in the liquid, a strong exothermic reaction (at 40°C-80°C) is triggered that not only releases the hydrogen molecules contained in the powder but also splits the added water - with the result that the amount of hydrogen originally contained in the powder is doubled. This makes the volumetric energy storage density of SIHCs superior

FIGURE 1

Cost efficiency of transport options when considering volume and distance



Source: IRENA (2022) Geopolitics of Energy Transformation: The Hydrogen Factor.

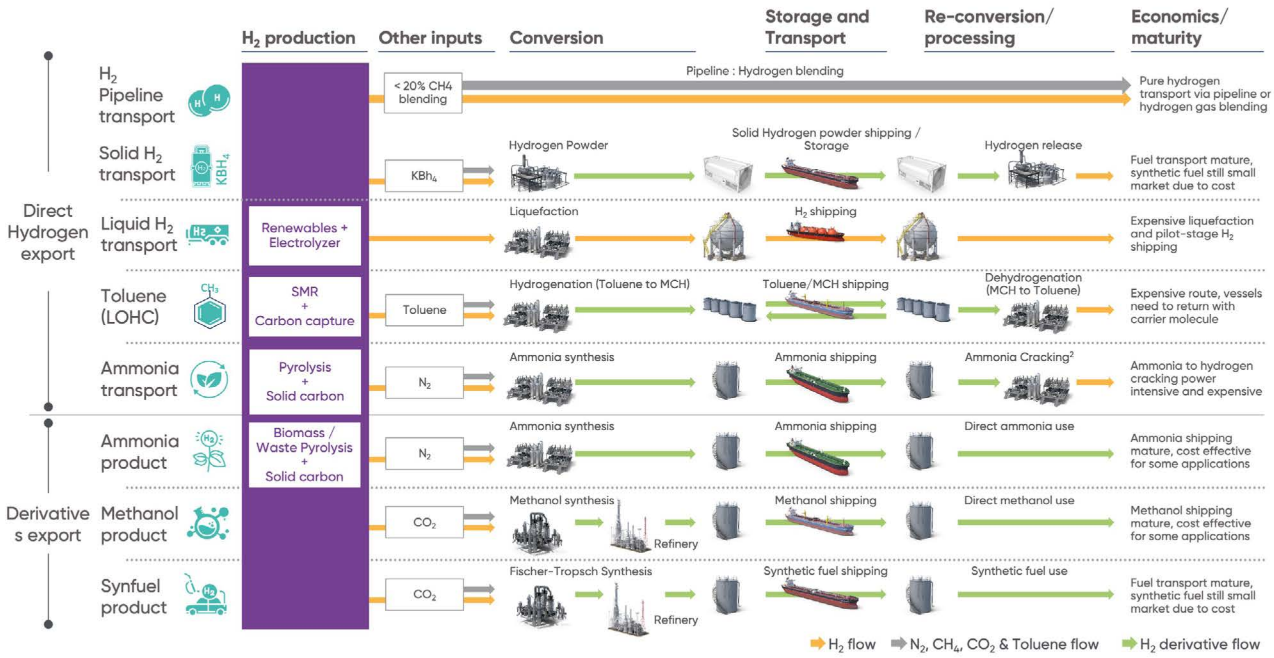
to alternative hydrogen storage options. The process is a cycle - the dehydrated material is a liquid (metaborate) re-hydrogenated to produce fresh borohydride. The added value of SIHCs lies in the high energy density of the powder, the simple and self-acting release process and the fuel cell conformity of the released hydrogen (purity, pressure and temperature).

In addition to the above it is also possible to use methanol, e-LNG or even synthetic gasoline as hydrogen carriers. However, since these need a carbon molecule and, as a consequence, are generally more expensive to produce, they will most likely be used rather as end products and less likely only as hydrogen carriers.

In principle, the following hydrogen export pathways are usually considered:

FIGURE 2

Hydrogen export pathways



Source: Hydrogen Europe based on industry data.

4.1.

Infrastructure: Pipelines

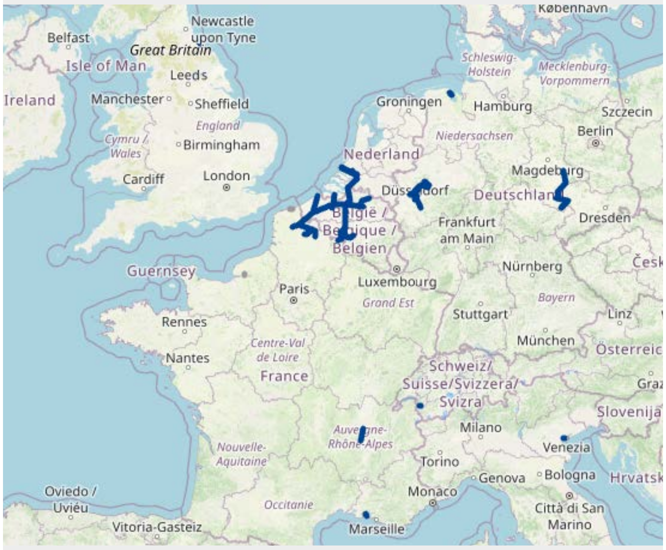
While hydrogen export via pipeline is the cost-effective option, it makes only sense for certain distances. In general, transporting hydrogen through pipelines is an inexpensive and robust method for distances up to 2,000 km, dependent on several factors, like the volume of hydrogen transported. **(Figure 1).** For the utilisation of existing gas pipelines, hydrogen blending has the potential to provide partial decarbonisation of an existing natural gas network whilst allowing for hydrogen production to be scaled up. By blending hydrogen with natural gas in relatively small quantities, the grid will not need to be retrofitted with more expensive, clean hydrogen infrastructure. This will also allow for more flexibility for the power grid, as it can take advantage of the natural variability in renewable energy production. In addition, hydrogen blending can reduce the carbon intensity of the overall energy mix by replacing fossil fuels with a more sustainable energy source.

Hydrogen production from renewable energy sources, such as wind and solar, can be used in conjunction with the existing natural gas network. By doing this, we can help to reduce carbon emissions and improve air quality. Hydrogen blending is a good transitionary option in jurisdictions with existing gas networks. It will allow for partial decarbonisation of the existing natural gas network whilst allowing for hydrogen production to be scaled up. Today, already, there is about 4,500 km of dedicated hydrogen pipelines worldwide, according to IRENA. Within Europe, the longest pipelines are in Belgium and Germany, at 600 km and 400 km, respectively. In total, there is roughly 1,800 km of hydrogen pipelines in Europe.

In the future, there are two feasible scenarios for creating a European hydrogen infrastructure: conversion of the existing natural gas grid to accommodate hydrogen or building a new hydrogen network parallel to the existing gas grid. A project completed by DNV and Carbon Limits (2021), called Re-Stream, concluded that most offshore pipelines could be reused for pure hydrogen based on the current state of knowledge and standards (Carbon Limits, 2016). Based on European pipelines, about 70% of the total pipeline length could be reused for onshore pipelines. The remaining 30%

FIGURE 3

Existing hydrogen networks



Source: Fuel Cell and Hydrogen Observatory (2022) Hydrogen pipelines.

could conceivably be retrofitted, although more testing and/ or updated standards are required.

Blending could occur relatively early in developing the low-carbon hydrogen market, even before regional markets fully develop. Studies worldwide examine the feasibility of blending hydrogen with natural gas up to 20% by volume, which is about the limit for domestic boilers in Europe. Hydrogen blending at low percentages (2- 5%) can be implemented more widely across Europe almost immediately, displacing natural gas volumes. Furthermore, regulators are investigating its impact on the safe operation and maintenance of distribution and transmission infrastructure and the compatibility with end-user appliances.

The difficulty in supplying a range of consumer segments through a single network is that different hydrogen blending limits may apply to the different appliances and equipment using the gas (including industrial and commercial users).

The safe limit for hydrogen blending is essential because a gradual increase is not technically feasible beyond this point, and a gradual change to 100% hydrogen in the network is required. This change means that a gradual transition over time is not an option and governments need to present a clear strategy on if, how and when they will move from a mixture of natural gas and hydrogen to 100% hydrogen. This will not be a trivial task, considering how many end-use appliances need to be converted or replaced, especially regarding space heating. Such a fundamental changeover will require years of planning and implementation.

The amount of hydrogen allowed in natural gas infrastructure is determined by regulations that vary from country to country. Issues to be considered concerning blending include:

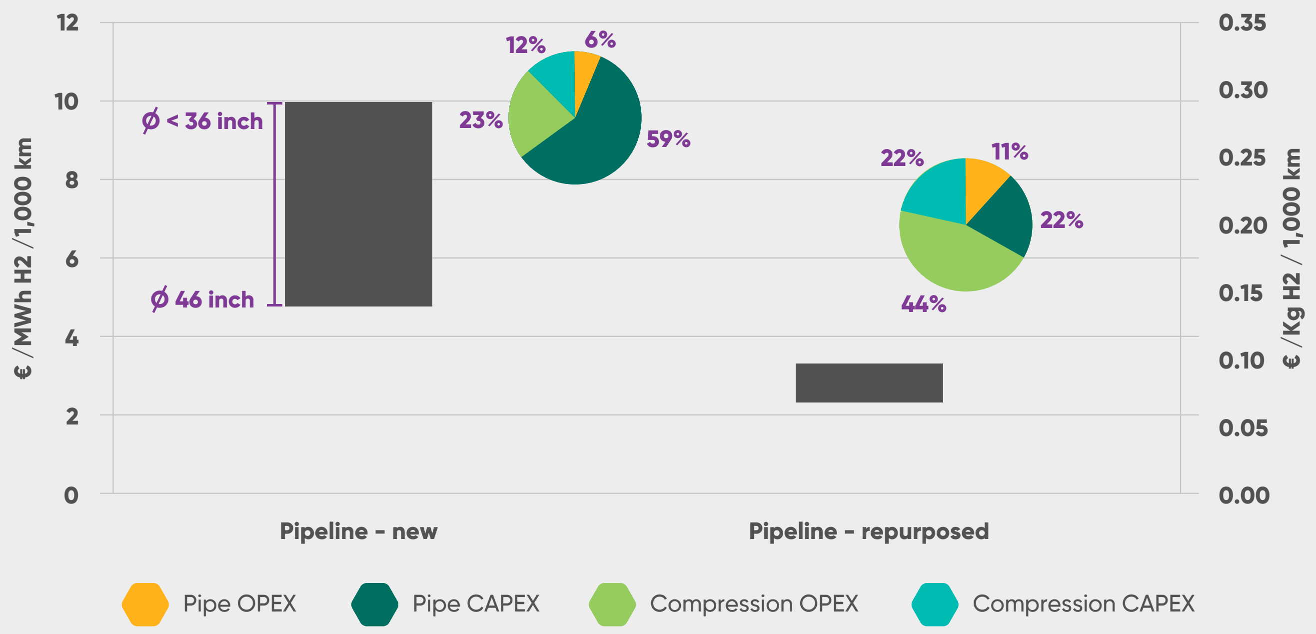
- **Hydrogen Embrittlement**
- **Appliance Tolerances**
- **Leakage/Safety**
- **Lower Heating Value**
- **Downstream Extraction**

In recent years more Blending Pilots occurred, while the use of hydrogen in the gas grid is not an entirely new phenomenon. Since the 1970s, hydrogen has made up about 12% of the gas mixture in Hawaii Gas' pipelines on Oahu and is part of the synthetic natural gas produced on the island. Trials are also underway in Northwestern Europe and the UK.

In addition, **section 4.4** discusses the planned European Hydrogen Backbone (EHB) in greater detail.

FIGURE 4

Cost comparison of new and retrofitted hydrogen pipelines



Source: German Federal Ministry for Economic Affairs and Climate Action, Ministry of Energy Saudi Arabia (2022) Hydrogen cooperation potential between Saudi Arabia and Germany.

4.2.

Infrastructure: Hydrogen at local gas distribution (DSO)

For decades European local gas distribution networks have shown the ability to deliver cost-effective, reliable, and safe pipeline gas distribution and delivery.

One project to mention here is the Ready4H2 alliance, which represents 90 European gas distribution companies (DSOs) and aims to combine their hydrogen expertise and experience. The alliance believes that local gas distribution networks, in solid coordination with gas transmission and storage infrastructure, are essential to achieve hydrogen's colossal growth and carbon reduction potential. The Ready4H2 alliance will deliver a faster energy transition and deeper emissions reductions to support Europe's decarbonisation ambitions (Ready4H2, 2022).

© Martin Adams

4.3.

Infrastructure: Large scale seasonal gaseous hydrogen storage

Developing energy storage infrastructure will be crucial to tackle the challenges of the systemic change of national energy systems. This is due to the variability and remoteness of renewable energy generation, which bring network bottlenecks due to limited grid capacity and the need to transport new energy carriers. Furthermore, storage infrastructure will be necessary for the security of supply, especially for hydrogen imported from outside of the EU, as well as in order to help to maintain the efficiency and affordability of entire systems (TNO, 2021, p. 14).

With the development of regional hydrogen markets, demand-side applications and local conditions will create demand for a variety of storage solutions **(Table 1).** Nonetheless, hydrogen storage infrastructure will be a key component of energy systems, as hydrogen can provide large-scale and centralised energy storage, which in turn provides essential social services such as strategic energy reserves, balancing and seasonal storage (TNO, 2020, p. 9).

Several options for large-scale storage infrastructure exist; these were analysed within the scope of the HyUnder project, which benchmarked the different storage options based on their safety, technical feasibility, investment costs and operation (HyUnder, 2019).

The outcomes of the benchmark, summarised in the table above, show that for large-scale hydrogen storage, the best options are salt caverns, followed by depleted natural gas reservoirs. Consequently, these types of infrastructure will be the focus of this section.

Salt caverns

Salt caverns have been used for hydrogen storage for several decades. They have outstanding properties such as high integrity (tightness of gas), inertness (limited reactions), increased flexibility (multiple annual cycles) and moderate investments and operating costs. The disadvantages of salt caverns in the EU are related to their geographical distribution.

TABLE 1

Hydrogen storage technologies and associated considerations

ENERGY STORAGE TYPE	HYDROGEN STORAGE OPTION	STORAGE CAPACITY (TWH)	RESPONSE /TURN-AROUND TIME	DURATION	TECHNOLOGY READINESS LEVEL	DEPLOYMENT TIMEFRAME	DEMAND SIDE APPLICATIONS	CENTRALISED OR DE-CENTRA-LISED SOLUTION	HAZARD / TOXICITY
Geological	Repurposed salt cavern	-	Fast response (1 hour)	Multiple annual cycles	Medium	Medium	Multiple users across power, industry and heat	Centralised	Low
	New salt cavern	1.5[a]			High	High			
	Repurposed hydrocarbon reservoir	9[b]	Slow response (12-24 hours)	Single seasonal cycles	Low	High	Large scale seasonal heat demand		Medium
	New offshore fields	-			Low	High			
Surface	Compressed	0.00004[c]	Fast response (minutes)	Multiple annual cycles	High	Low	Limited due to size	Both	Medium
	Liquid hydrogen	1[d]	Fast response (1 hour)		Low	High	Multiple users across power, industry and heat		High
	Ammonia		Medium response (> 4 hours)[f]		Medium	High			High
	LOHC				Low	High			Low
Network	Line pack	1.2[e]	Fast response (Instant)	Within day cycle	High				Low
Import	Hydrogen pipeline	-	Fast response (instant)	-	High	Medium		Centralised	Medium
	Ammonia	-	Slow response (days dependent on shipping)	-	Medium	High	Limited due to response time, target large predictable swings in demand such as heat		High
	LOHC	-		-	Low	High			Low
	Methanol	-		-	Low	High			High
	Liquid hydrogen	-		-	Low	High			High
Supply flexibility	Flexible production (Blue Hydrogen)	-	Medium response (> 4 hours)	-	Medium	Medium	Industry and heat	Both	-
	Flexible production (Grid-connected electrolysis)	-	Fast response (1 hour)	-	Medium	Medium	Multiple users		-
Demand flexibility	Interruptible contrats	-	-	-	High	Low	-		-
	Smart heating systems	-	-	-	Low	High	-		-

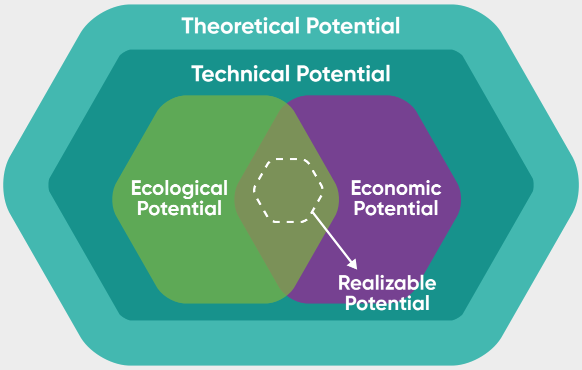
a / Salt cavern storage volume based on H21 project estimations
b / Energy based on estimated storage of re-purposed Rough reservoir
c/ Based on largest standard size metalcylinder ($50m^2$)
d / Based on H21 estimations, footprint requirements major impact
e / Based on conversation of existing natural gas network linepack to hydrogen
f / Dependent on complxity and future technology developments

Source: DNV AS (2022) Hydrogen Forecast to 2050: Energy Transition Outlook 2022 (adapted).

The most referenced study for salt cavern storage of hydrogen is Caglayan et al. from 2020, which assesses the technical potential of salt cavern storage in Europe. An important note here is that "technical potential" means the maximum storage potential that could be utilised without considering ecological, economic or social considerations **(Figure 6).**

FIGURE 5

Different types of potential



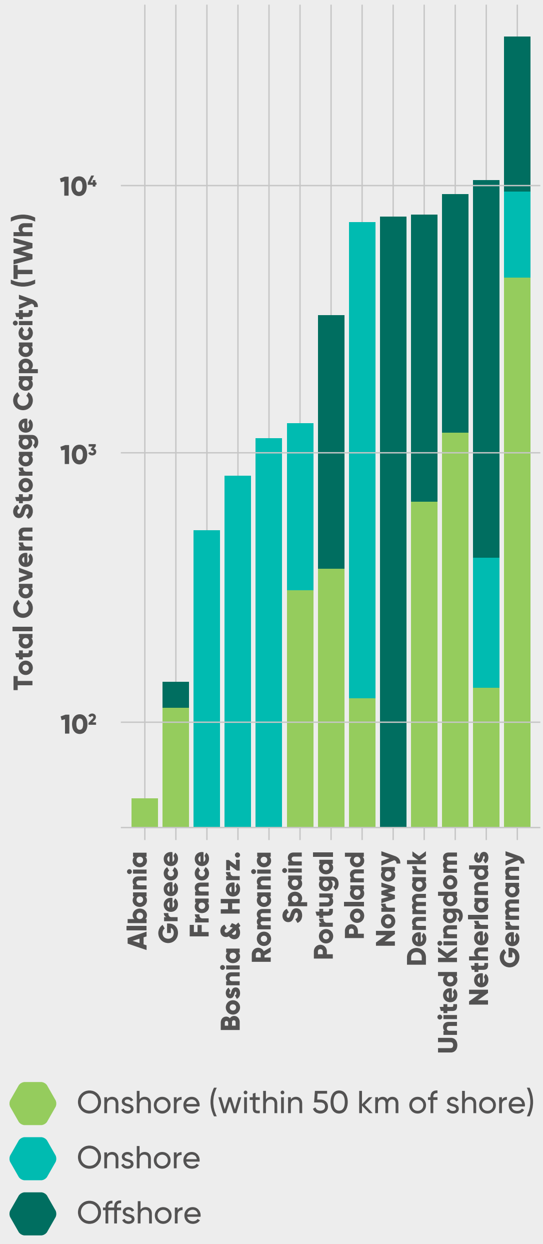
Source: Caglayan et al. (2020) Technical potential of salt caverns for hydrogen storage in Europe (adapted).

The study estimates that in caverns in bedded salt and salt domes, located outside of rural, urban and protected areas and away from major infrastructure, the potential for hydrogen storage in Europe is 2,596 Mt (84.8 PWh) of hydrogen. Onshore the potential in Europe is estimated at 703 Mt (23.2 PWh) of hydrogen. As a comparison, the pumped hydropower potential in Europe is estimated to range between 0.054 and 0.123 PWh (Gimeno-Gutiérrez & Lacal-Arántegui, 2013).

This potential, however, is not distributed evenly across European Union Member States (EU MS). Germany has the highest theoretical potential, as 42% of the total potential hydrogen storage capacity is either in Germany's onshore or the North Sea. This is the equivalent of 1,079 Mt (35.61 PWh) of hydrogen. The Netherlands is next with 315 Mt (10.4 PWh) and the United Kingdom with 272 Mt (9.0 PWh). By contrast, only 2% of the overall storage potential is located in France, estimated at 8 Mt (510 TWh) of hydrogen, as salt deposits in France are mainly located near densely populated areas.

FIGURE 6

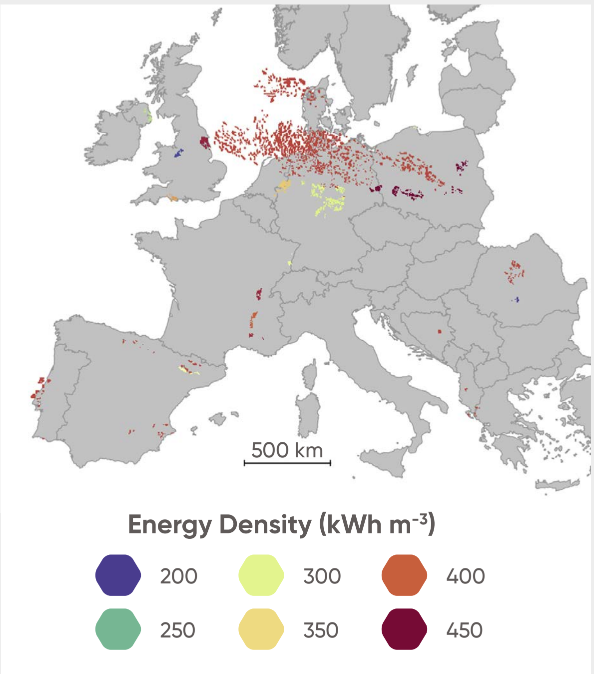
Total salt cavern storage potential in European countries



Source: Caglayan et al.(2020) Technical potential of salt caverns for hydrogen storage in Europe (adapted).

FIGURE 7

Distribution of potential salt caverns sites across Europe with corresponding energy densities



Source: Caglayan et al. (2020) Technical potential of salt caverns for hydrogen storage in Europe (adapted). Energy densities result from the cavern storage potential divided by the volume.

The study's outcomes clearly show large hydrogen storage in potential salt caverns. most of it is concentrated in Germany, the Netherlands, Denmark, and Poland. In this regard, a study by the Energy Transition Centre concludes that Member States with lower salt cavern potential where storage needs will not be as competitive will require more robust regulatory measures to guarantee non-discriminatory access to non-proprietary storage, should hydrogen markets lack sufficient integration (Energy Transition Centre, 2022, p. 132).

Depleted gas fields

Storing hydrogen in depleted natural gas reservoirs can be done by repurposing existing facilities. The advantages of this type of reservoir lie in its availability, large capacity, proven tightness for hydrocarbons and operational experience. However, the disadvantages are that their technological readiness level (TRL) is low; there is a risk of geo-chemical or microbiological reactions; higher amounts of cushion gas are needed, and the tightness of the reservoir for hydrogen needs to be examined; and lastly, gas treatment can increase the costs of storage. This means that hydrogen storage in these fields needs to be re-evaluated case-by-case (HyUnder, 2019, p. 28; Gas Infrastructure Europe, 2021, p. 46).

Currently, 80 operational depleted natural gas reservoirs are used for storage. The distribution of those is as follows: 15 in Italy, 11 each in Austria and the Czech Republic, ten in Germany, eight in Poland, six each in Hungary and Romania, four in the Netherlands, three in Spain, two each in France and Slovakia, and lastly one each in Bulgaria and Croatia. The total (technical) working gas capacity is 842.28 TWh of natural gas (Gas Storage Europe, 2021), which converted to hydrogen would be 202.14 TWh.[1]

Retrofitting existing natural gas storage to hydrogen

Another possibility for the development of underground hydrogen storage is the reconversion of existing natural gas storage facilities to hydrogen ones. As of 2021, 65 salt cavern storage facilities are either operational, under construction or planned in the EU. Of those, 48 are located in Germany, 7 in France, 5 in Poland, two in the Netherlands and Poland, and one in Denmark. Their total (technical) working capacity is 204.36 TWh for natural gas, which for hydrogen would be 49.05 TWh (Gas Storage Europe, 2021). However, not all facilities will be available for repurposing as hydrogen will compete with biomethane and existing natural gas use (Gas Infrastructure Europe, 2021, p. 39).

1 / Hydrogen energy density (at 50°C and 100 bar) is 237 kWh/m3, which is approximately 24% that of methane, which is 982 kWh/m³ (using lower heating value, LHV) (Gas Infrastructure Europe, 2021, p. 24).

4.4.

Infrastructure: Future hydrogen networks

For hydrogen to access the various end-uses across Europe, basic infrastructure will have to be developed between production and consumption points, especially since many of the most economical production locations will be far from large-scale consumption. While there are already thousands of tonnes of hydrogen traded and distributed around Europe today via local dedicated hydrogen pipelines or trucks (see **Chapter 1** and FCHO), the development of an EU-wide hydrogen pipeline network is required to jumpstart the hydrogen economy further, as this is by far the cheapest mode of transport for large quantities of hydrogen. The hydrogen economy will require a similar transmission and distribution ecosystem to the current natural gas infrastructure, complemented by trucks, rail and ships. While blending hydrogen into the existing natural gas pipelines may be an important intermediary step in the early 2020s, retrofitting existing gas infrastructure to carry pure hydrogen will be necessary in the long run. This chapter provides an overview of the plans to develop dedicated (pure) hydrogen transmission and distribution networks.

As has already been highlighted, the integration and expansion of renewable energies require large-scale storage and transport infrastructure. This is where hydrogen networks will play an essential role in the future. The definition of a demand-driven hydrogen infrastructure requires detailed information about the (natural) gas grid, the demand for molecules such as natural gas and the temporal course of all the parameters mentioned. However, such high-resolution data is currently not always available. Nevertheless, it is already clear that large-scale hydrogen imports will be needed in the future, calling for adequate infrastructure.

Along with the rapid development of national hydrogen strategies come transmission and distribution projects. Some of the largest infrastructure initiatives include the European Hydrogen Backbone (EHB) by a group of EU gas infrastructure companies and two national initiatives in Germany and the Netherlands. These plans include both retrofitting existing natural gas pipelines and partially building an entirely new hydrogen infrastructure to accommodate growing hydrogen demand.

4.4.1. European Hydrogen Backbone

The 2021 Clean Hydrogen Monitor reports that the EHB is the most comprehensive hydrogen infrastructure initiative, presenting an eponymous vision for developing a pan-European hydrogen infrastructure. In April 2022, the initiative published an updated report, followed by a detailed study in May, updating the previous version of the EHB from 2021.

The new analysis counts on the participation of 31 infrastructure companies covering 28 countries, and it identifies five pan-European hydrogen supply and import corridors presented in two development phases, 2030 and 2040. The report is based on previous EHB reports, national hydrogen strategies and plans, and announced demand and supply projects in Europe and neighbouring countries. The 2022 report and study were published before the publication of the REPowerEU Plan.

2030 and the emergence of five hydrogen supply corridors

By 2030, the EHB projects demand for hydrogen in industry, transport, power and buildings to amount to 14.7 Mt (490 TWh). While the identified supply amounts to 17.4 Mt (580 TWh), split between EU domestic supply of 12 Mt (400 TWh) and 5.4 Mt (180 TWh) of non-EU supply, with these projections to be further increased by the REPowerEU targets.

The necessity for hydrogen infrastructure comes from the imbalance of supply and demand in the different regions, with the EHB set to deliver the linking element across Europe. To link supply and demand regions, the 2030 EHB will consist of approximately 28,000 km of new and repurposed pipelines, forming five overlapping import corridors: North Africa & Southern Europe; Southwest Europe & North Africa; North Sea; Nordic and Baltic regions; East and South-East Europe.

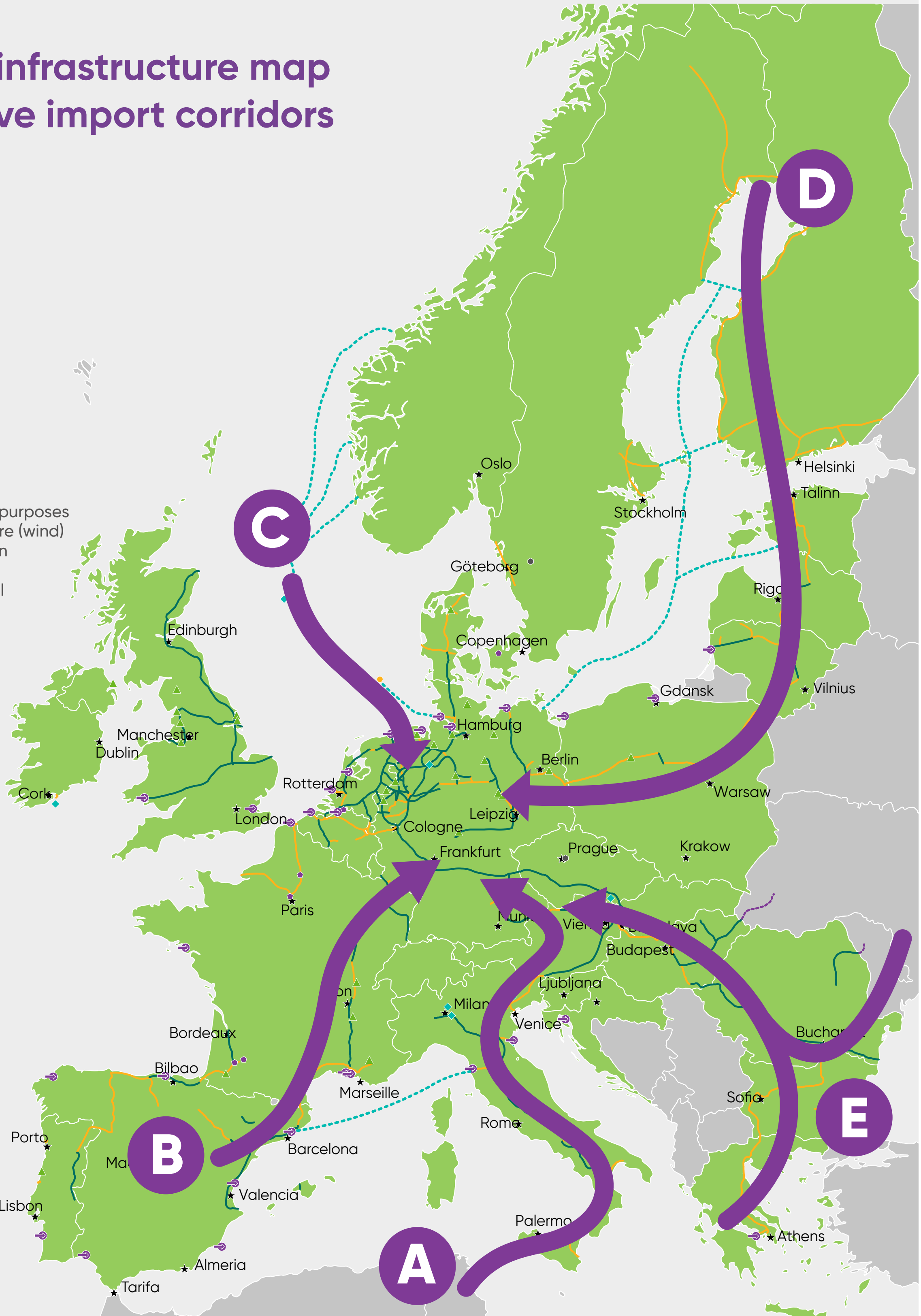
FIGURE 8

EHB 2030 infrastructure map with the five import corridors

PIPELINES
- Repurposed
- New
- Subsea
- Import / Export

STORAGES
- Salt cavern
- Aquifer
- Depleted field
- Rock cavern

OTHER
- City, for orientation purposes
- Energy hub / Offshore (wind) hydrogen production
- Existing or planned gas-import-terminal



Source: Guidehouse (2022) Five Hydrogen Supply Corridors for Europe in 2030, May 2022, (adapted).

The first corridor (A in Figure X) links North Africa and Central Europe through Southern Europe, using the potential to repurpose existing natural gas pipelines from Italy and Central Europe and pipeline interconnections with Algeria and Tunisia. The corridor could span in 2030, 11,000 km of large-scale hydrogen pipelines across Italy, Croatia, Slovenia, Hungary, Czech Republic, Austria, Slovakia, and Germany. Approximately 60% of the pipelines are to be repurposed natural gas pipelines. The hydrogen supply potential of the corridor is estimated at 97 TWh in 2030 and 340 TWh in 2040, with projected hydrogen price upon delivery at EUR 72/MWh in 2030 and EUR 42/MWh in 2040.

The second corridor - Southwest (B on Figure X), links the possibility of hydrogen imports from Morocco to the low-cost production in the Iberian Peninsula to satisfy the demand in the latter, as well as in France and Germany. Additional opportunities along the corridor include the development of a new interconnector on the Franco-Spanish border and the development of hydrogen storage in France. The corridor aligns with the Mediterranean corridor under REPowerEU, which will receive support from the EC. By 2030, it will cover 10,000 km of large-scale pipelines across Portugal, Spain, France, Belgium, Luxembourg and Germany, 60% of which will be repurposed natural gas pipelines. It is expected that it will have the capacity to supply 164 TWh by 2030 and 569 TWh by 2040, with estimated costs of hydrogen upon delivery at EUR 62/MWh and EUR 45/MWh, respectively.

Moving to the North Sea corridor (C), it links the North Sea blue and green hydrogen potential with demand from large industrial and transport clusters in the UK, Netherlands, Belgium, France and Germany. The opportunities in this corridor lie in the densely concentrated offshore and onshore natural gas infrastructure and the potential of North Sea wind resources. The development of this corridor will also receive support under the REPowerEU commitments undertaken by the EC. By 2030, it could cover 12,000 km of pipelines, with 70% of them being repurposed. The countries developing this corridor are Norway, Ireland, United Kingdom, Denmark, Netherlands, Luxembourg, Belgium, France and Germany. For 2030, the estimated supply potential is 249 TWh with the price of hydrogen at EUR 66/MWh at delivery, while for 2040, the potential reaches 852 TWh at the cost of EUR 54/MWh. Furthermore, this corridor aims to leverage the repurposing and development of new import terminals along the French, Belgian, Dutch and German shores.

The penultimate corridor is Nordic and Baltic region one (D). The impetus behind this route is based on the fast decarbonisation of the Nordic countries and the potential for surplus offshore wind in the Nordics and Baltics. It also boasts the opportunity for offshore pipelines and salt cavern storage. The corridor will link green projects in Finland, Sweden, Estonia, Latvia, Lithuania, Denmark, Poland, Germany and the Czech Republic. By 2030, the corridor should encompass 13,500 km of large-scale pipelines, with 45% of them being repurposed. Concerning capacity and price, for 2030, it is estimated that it will have the potential to supply 184 TWh of hydrogen at the cost of EUR 75/MWh, while for 2040, the potential is 501 TWh at the price of EUR 60/MWh.

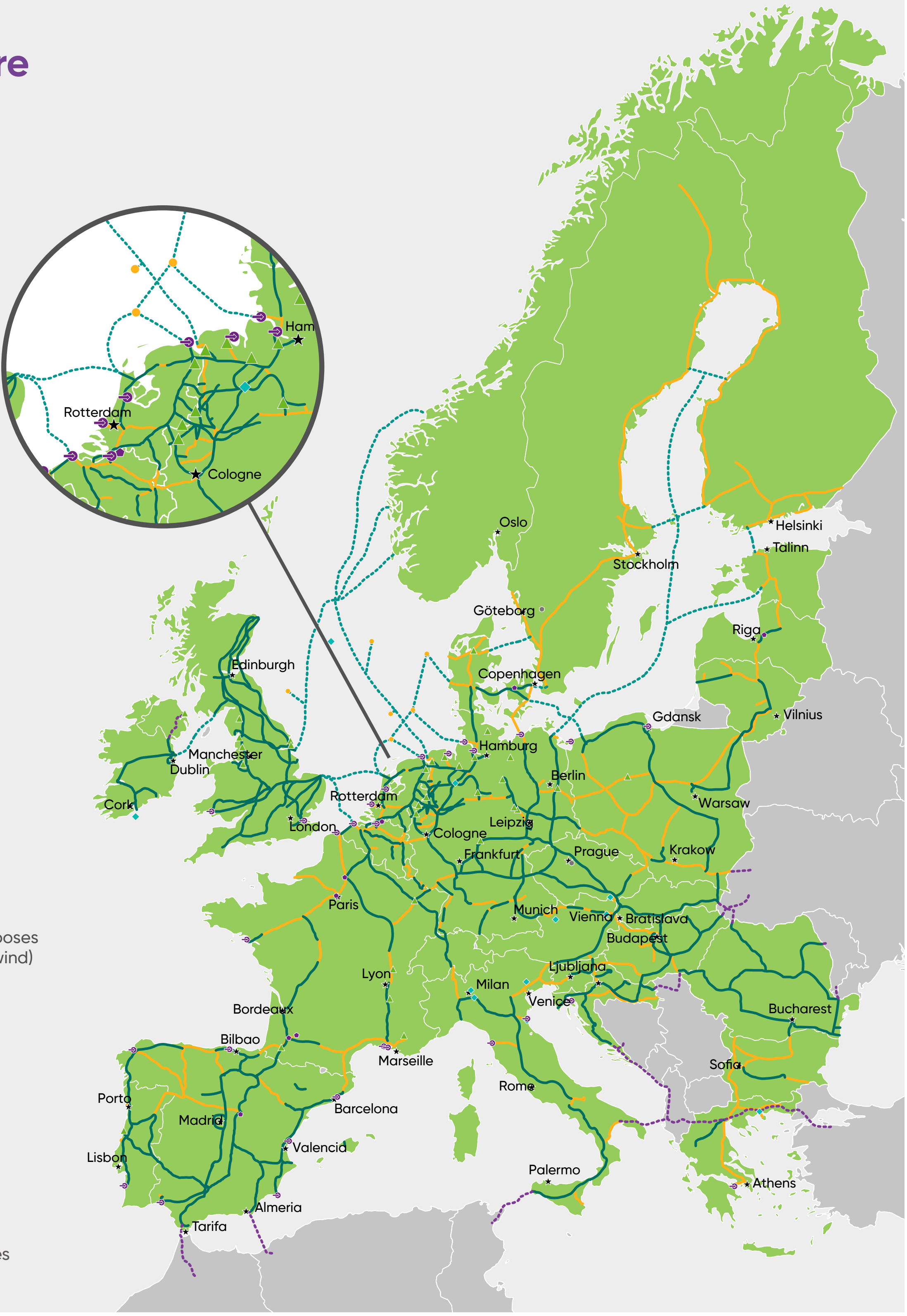
The last corridor is the East and Southeast one (E). The drivers behind it are the need to meet hydrogen demand across Eastern and South-Eastern Europe in industry, transport and power sectors. While it also has the opportunity to allow for hydrogen imports from Ukraine as soon as possible. In this last aspect, it overlaps with the third REPowerEU corridor. This corridor could reach 10,000 km by 2030, with 60% repurposed pipelines across Austria, Bulgaria, Croatia, Czech Republic, Germany, Greece, Hungary, Poland, Romania, Slovakia and Slovenia. For 2030, it has the most modest supply potential at 50 TWh at the price of EUR 75/MWh, while for 2040, the estimate is 346 TWh at the cost of EUR 54/MWh.

2040 and the emergency of a core European Hydrogen Backbone

Between 2030 and 2040, the backbone is expected to develop naturally with hydrogen demand and supply development. The vision document envisages a core European Hydrogen Backbone to be developed by 2040 with a total length of 53,000 km, of which approximately 60% are repurposed pipelines. According to the 2022 report, initially, the EHB will serve mainly industrial demand, while between 2030 and 2040, hydrogen will become a significant energy carrier in heavy transport, e-fuels production, building sector, long-term energy storage and dispatchable power generation, with the replacement of natural gas import terminals for hydrogen import terminals taking place.

FIGURE 9

EHB 2040 infrastructure map



PIPELINES

- Repurposed
- New
- Subsea
- Import / Export

STORAGES

- Salt cavern
- Aquifer
- Depleted field
- Rock cavern

OTHER

- City, for orientation purposes
- Energy hub / Offshore (wind) hydrogen production
- Existing or planned gas-import-terminal

Source: Guidehouse (2022) European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 28 Countries (adapted).

The report estimates that the cost for the 2040 EHB will range between EUR 80 billion and EUR 143 billion, covering the full capital costs for new pipelines and the repurposing of existing natural gas ones. The main explanations for the variability of cost estimates are related to compression system design, whether the project is greenfield or brownfield, the design operating pressure range, level of redundancy about system availability in the event of component failure, and compressor technology choice. As to the transport costs across the EHB, table 3 below summarises the report's estimates, focusing on only onshore or offshore transport, representing a weighted average of pipeline sizes and types.

TABLE 2

Levelised transport costs over an average of 1,000 km of EHB 2040

Onshore	Offshore
EUR 0.11 – EUR 0.21/kg H2 (EUR 3.3 - EUR 6.3/MWh)	EUR 0.11 – EUR 0.21/kg H2 (EUR 3.3 - EUR 6.3/MWh) EUR 0.17 - EUR 0.32/kg H2 (EUR 4.5 - EUR 8.7/MWh)

Source: Guidehouse (2022) European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 28 Countries

According to the report, actions are needed in five areas to develop the EHB as presented. Firstly, establishing a more integrated energy system planning at the national level to seize upcoming economic investment windows and have concrete infrastructure in place by 2030. Secondly, efficient measures to facilitate the development of dedicated hydrogen infrastructure through repurposing pipelines for natural gas. Thirdly, simplification and shortening of planning and permitting procedures. Fourthly, unlocking financing to accelerate the infrastructure deployment through flexible economic models and subsidies. Lastly, the development of international cooperation to ensure EU-wide standards, regulations, and certifications.

While the European Hydrogen Backbone is still a vision, with estimates and projections, some EU Member States are advancing with their national hydrogen infrastructure plans. Below, the focus will be on the Netherlands, Germany, and Spain, which have presented hydrogen infrastructure development plans.

Dutch hydrogen backbone

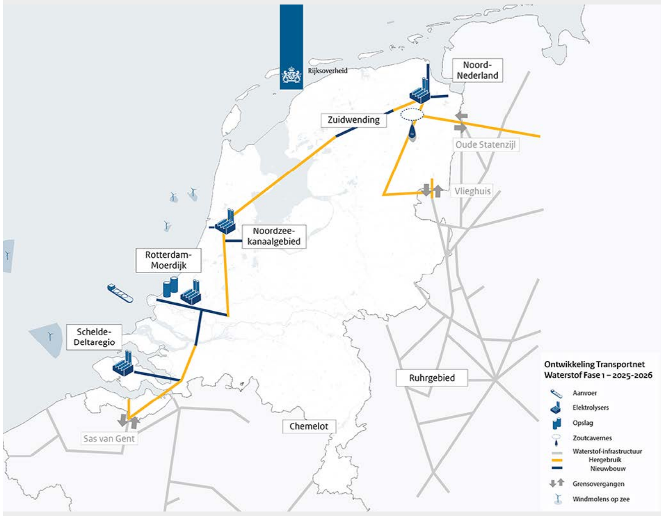
As reported in the previous Clean Hydrogen Monitor, the Netherlands is one of the first movers in Europe in relation to developing a hydrogen economy. On 29 June 2022, the Dutch minister for Climate and Energy published two letters on hydrogen infrastructure and market development. The letter on infrastructure details the plans for constructing the Dutch transport network for hydrogen.[2] The Minister's letter outlines two vital elements regarding the hydrogen transmission network development: the phases and the regulatory and state support conditions. Before describing the development phases, it is essential to note that they are subject to change as the final developments will depend on market development and the commitments of users through Expressions of Interest and, subsequently, contracts for the transport of hydrogen.

Under **Phase 1,** which is to be ready by 2025-2026, the connection between large industrial clusters on the Dutch coast and salt cavern facilities in the north of the Netherlands is to take place. According to a study commissioned by the ministry, with 3-4 GW electrolyser capacity installed, between 3 and 4 salt caverns will be needed to ensure flexibility and security of supply (TNO, 2021). While at the very early stages, demand and supply can be local, it is expected that the increase of volumes from industrial demand, together with hydrogen imports, renewable hydrogen production (from offshore wind) and reforming with carbon capture (CCUS at current fossil-based hydrogen production sites) will create the need for storage, and the infrastructure to allow for flows between clusters. In this phase, connections with Germany are envisaged at Old Statenzijl (HyPerLink project) and Vlieghuis.

2 / The text of the plan in Dutch and further annexes can be found at https://www.rijksoverheid.nl/documenten/kamerstukken/2022/06/29/ontwikkeling-transportnet-voor-waterstof

FIGURE 10

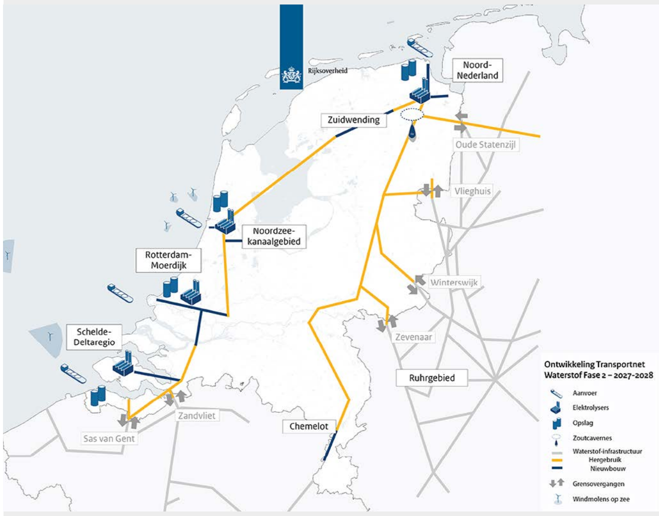
Phase 1 of the Dutch hydrogen infrastructure plan



Source: Ministerie van Economische Zaken en Klimaat (2022) Ontwikkeling transportnet voor waterstof.

FIGURE 11

Phase 2 of the Dutch hydrogen infrastructure plan



Source: Ministerie van Economische Zaken en Klimaat (2022) Ontwikkeling transportnet voor waterstof.

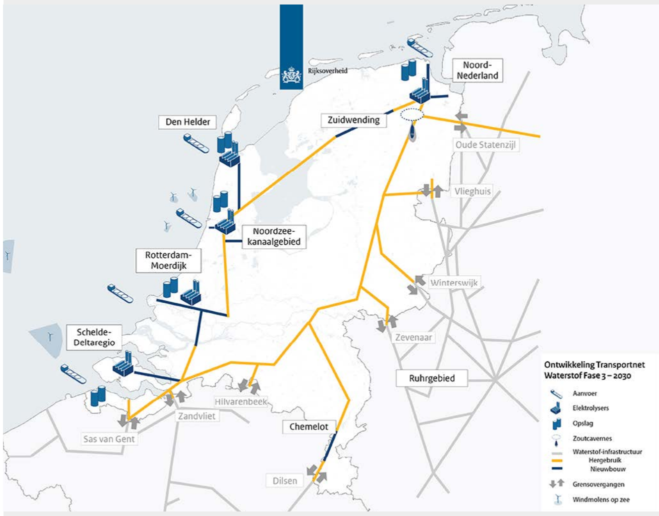
The **second phase,** to be ready by 2027-2028, envisages the connection of inland industrial clusters and other hydrogen consumers and the completion of interconnections with Belgium and Germany. As before, the timing of this phase depends on the interest of consumers, as inland connections can be realised sooner than envisaged.

The **final phase** is to be completed by 2030, as it is expected that a natural gas pipeline between Zeeland and Chemelot will become available by 2030, thus closing the loop and increasing the security of supply and capacity to transport hydrogen to Germany.

Moving to the regulatory conditions, the hydrogen network is to be operated by HyNetwork Services (HNS), a subsidiary of Gasunie. While HNS is allowed to construct and operate hydrogen pipelines, no legal conditions have been established on how it should perform its activities (tariffs, access conditions, etc.). Whilst a national regulatory framework is developed, which depends on the provisions of the Hydrogen and Decarbonised Gas Market package, the

FIGURE 12

Phase 3 of the Dutch hydrogen infrastructure plan



Source: Ministerie van Economische Zaken en Klimaat (2022) Ontwikkeling transportnet voor waterstof.

minister will entrust HNS with a service of general economic interest (SGEI) for the development and management of the transmission network. The conditions under the SGEI will be attached to the funding provided by the government. They will aim to ensure that the network is developed and operated with regard to sustainability, affordability, security of supply and spatial compatibility.

Starting with third-party access, until changed by further EU or national legislation, the applicable regime for third-party access will be a 'hybrid system of negotiated accesses'. This means that the minister will initially set guidelines based on which the network operator will have to determine its conditions and indicative tariffs for access and services. More specifically, HNS will be obliged to negotiate with any party requesting access, but that party will bear the connection costs. The conditions for access and services will have to be transparent, non-discriminatory, and reasonable, thus trying to balance the interest of network development and the interests of the parties wanting access. This system is expected to be in place until 2025 (transposition of Hydrogen and Decarbonised Gas Market package); from thereon, the ministry will work with the regulator to move towards a regulated TPA in 2030.

As for hydrogen quality, under the recommendations of KIWA and DNV, the required hydrogen purity is set at 98 mol% for both injection and withdrawal. The purchasing party must establish a purification process for end-uses requiring higher purity. This standard is to be evaluated and possibly re-defined three years after the network begins operation.

As to financial support, the estimated costs for developing the entire pipeline grid until 2030 are estimated at EUR 1.5 billion. To avoid monopolistic excess profits, the tariffs are to be based on actual costs incurred plus the reasonable return (Weighted Average Cost of Capital). However, due to the low number of users and consequently volumes to be transported in the first years of development, a subsidy of EUR 750 million is foreseen. The specific amount of subsidy granted will depend on market development and the number of users, as there will be a 'claw-back' mechanism, and excess subsidy could be recovered. It will also be possible for HNS to recover costs on investments made based on the roll-out plan until 2030 through the regulated tariffs, which are set to start applying from 2030. The decision to grant the abovementioned subsidy is subject to EC approval.

In this way, the Dutch plan for developing hydrogen infrastructure is the most advanced, having laid out clear guidelines for the infrastructure development and the much more important conditions for access to the infrastructure. This brings much-needed legal certainty for all parties involved in the development of the sector, as in the view of the Dutch minister, the transposition of the Hydrogen and Decarbonised Gas Market package will only take place in 2025.

German hydrogen network (2030-2050)

The German hydrogen infrastructure plans were first articulated in the 2020-2030 Gas Network Development Plan under the name "Start Net". However, due to a lack of the regulatory framework applicable at the time, the Bundesnetzagentur ('Federal Network Agency') rejected the inclusion of hydrogen infrastructure in the plan's final version (Savcenko, 2021). In the meantime, two other vision maps were published by FNB Gas, the Hydrogen Network 2030, and the Hydrogen Network 2050 (FNB Gas, 2022).

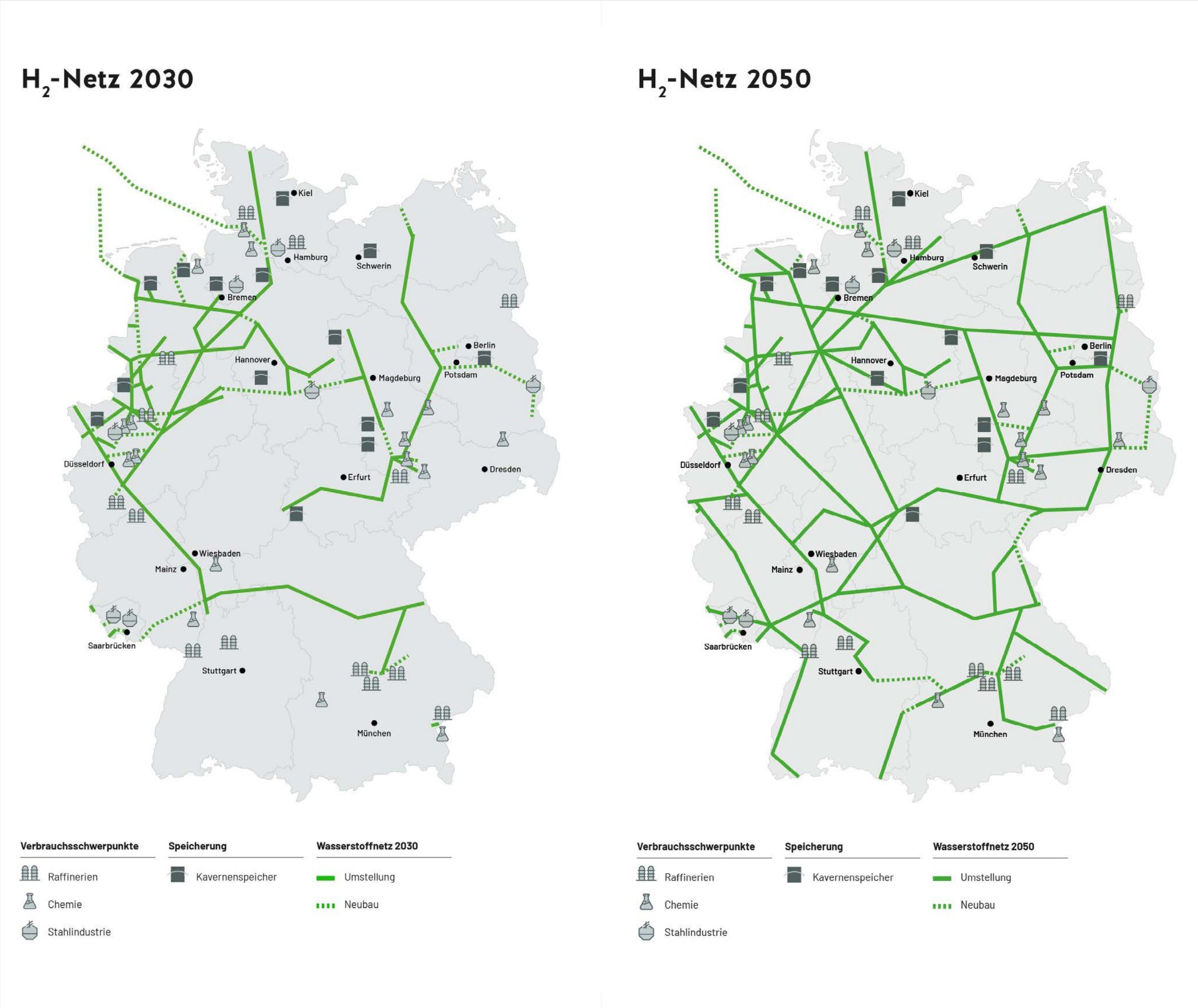
The Hydrogen Network 2030 is a more extensive development of the "Start Net", showing how transmission system operators (TSOs) can meet hydrogen transport demand on a supra-regional basis. The envisaged network is approximately 5,100 km long, with 72% of the pipelines being repurposed natural gas pipelines. It is based on a hydrogen demand of 71 TWh (calorific value) for energy and feedstock uses. Hydrogen used for methanation processes is not included in this demand. The estimated costs for the network until 2030 amount to EUR 6 billion.

The Hydrogen Network 2050 is built on the premise of climate-neutral Germany by 2050. Strong demand for hydrogen in the steel and chemical sectors is assumed, with increased demand in transport and moderate demand in power generation. At the distribution level, the assumptions are for hydrogen blending, followed by conversion of entire grid areas to pure hydrogen.

The vision estimates a total network length in 2050 of approximately 13,300 km, 82% of which are to be repurposed

FIGURE 13

Germany Hydrogen Network 2030 and 2050



Source: FNB Gas (2021) Hydrogen Network 2030: Towards a Climate-Neutral Germany.

natural gas pipelines. This is assuming that demand for "green" methane will be comparable to that of hydrogen. The network can provide an energy volume of 504 TWh (calorific value), with a peak demand of about 110 GWh/h of hydrogen. Costs are estimated at EUR 18 billion up to 2050, excluding storage conversion, offshore lines or connection lines.

In July 2021, the amendment of the Energiewirtschaftsgesetz ('Energy Industry Act') came into effect, providing the transitional regulatory framework for hydrogen networks and infrastructure. One component of the amendment is the report on the current status of the hydrogen network and the development of a future hydrogen network planning with the target year of 2035. TSOs and network operators have prepared the report, and on its basis, the Bundesnetzagentur can make recommendations for the legal implementation of a binding network development plan (NDP) for hydrogen. According to section 28q of the German Energy Industry Act, the report shall i.) be submitted three months after the gas network development plan is submitted, but no later than 1 September 2022, ii.) contain criteria for the consideration of hydrogen projects in the future network planning and requirements for identification of expansion measures, and iii.) address the interactions between the TSOs' gas network development plans, including the necessary conversion of natural gas pipelines and the electricity network development plans.

German hydrogen report

In accordance with the requirements of the Energy Industry Act, the hydrogen report (FNB Gas, 2022), submitted on September 1, 2022, provides an overview of the current status of the hydrogen network in Germany and its future planning and contains recommendations for the Bundesnetzagentur and the legislator. In addition to the legal obligations, the report presents interim results of the hydrogen network developed in the current NDP Gas 2022-2032 progress.

In brief: Currently, Germany has no hydrogen grids as defined by the Energy Industry Act. The result of modelling a Germany-wide hydrogen network in 2032 covers pipelines with a line length of 7,600-8,500 km – but it can be assumed that the demand would be even higher today. Concluding remark: the expansion of the infrastructure needs to be started as soon as possible.

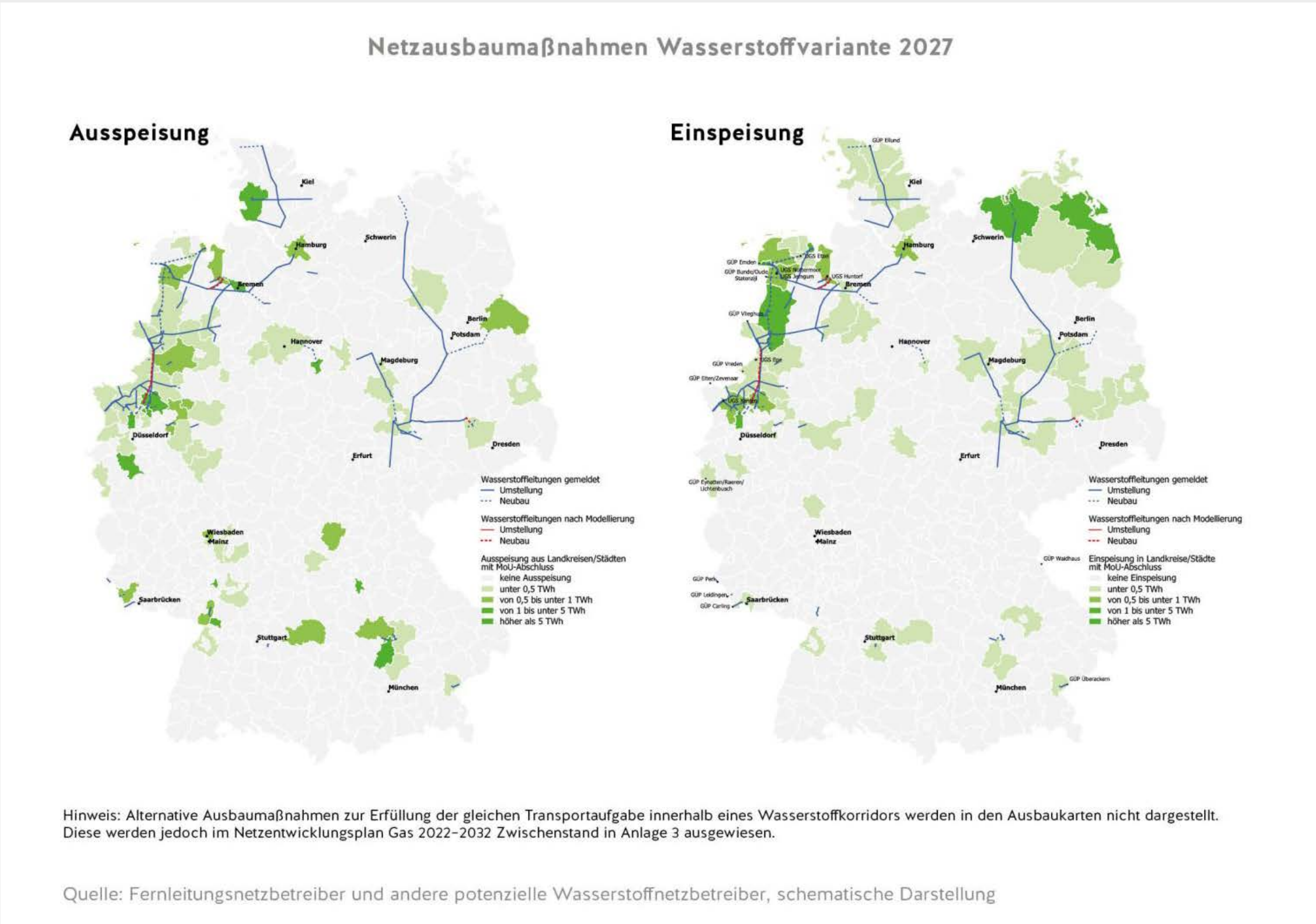
Gas Network Development Plan 2022-2032

The main input variables for the current Gas NDP 2022-2032 process are the results of the market survey of 2021 (Hydrogen demand and production). The demand for the modelling required a two-stage commitment in the form of an existing Memorandum of Understanding (MoU) for the first time. More than 250 MoU projects are included. For the modelling year 2032, the reported projects correspond to a potential feed-in volume of around 179 TWh and a hydrogen demand of 172 TWh. As a result, the transport capacity based on the WEB market survey has increased tenfold compared to the NEP Gas 2020-2030.

Figures 15 and 16 show the result of modelling a Germany-wide hydrogen network for 2027 and 2032, based on the projects for which an MoU has been signed. By 2027 this results in a hydrogen network with a pipeline length of 2,900-3,000 km.

FIGURE 14

Germany Hydrogen Network 2030 and 2050

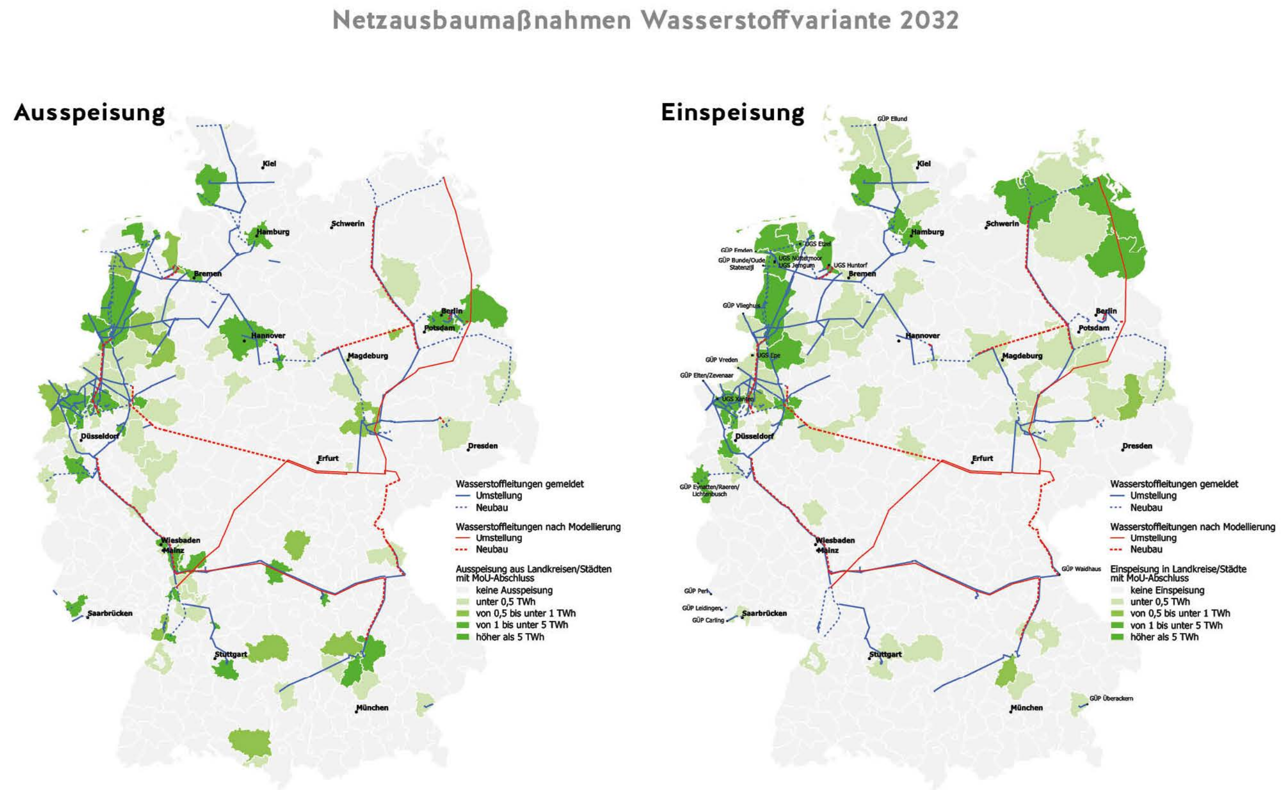


Source: FNB Gas, (2022), Wasserstoffbericht.

In 2027, the hydrogen network still consists of sub-networks, which will largely merge into one overall network by 2032. This will result in a Germany-wide hydrogen network in 2032 with a line length of 7,600-8,500 km, corresponding to a withdrawal volume of 54 TWh. It should be noted that the WEB market survey was carried out before the Climate Protection Act 2021 and does not reflect the increased customer demand after the beginning of the war. It is thus very likely that the reported demand would be significantly higher today.

FIGURE 15

Germany Network Expansion Measures 2032



Hinweis: Alternative Ausbaumaßnahmen zur Erfüllung der gleichen Transportaufgabe innerhalb eines Wasserstoffkorridors werden in den Ausbaukarten nicht dargestellt. Diese werden jedoch im Netzentwicklungsplan Gas 2022–2032 Zwischenstand in Anlage 3 ausgewiesen.

Quelle: Fernleitungsnetzbetreiber und andere potenzielle Wasserstoffnetzbetreiber, schematische Darstellung

Source: NB Gas, (2022), Wasserstoffbericht.

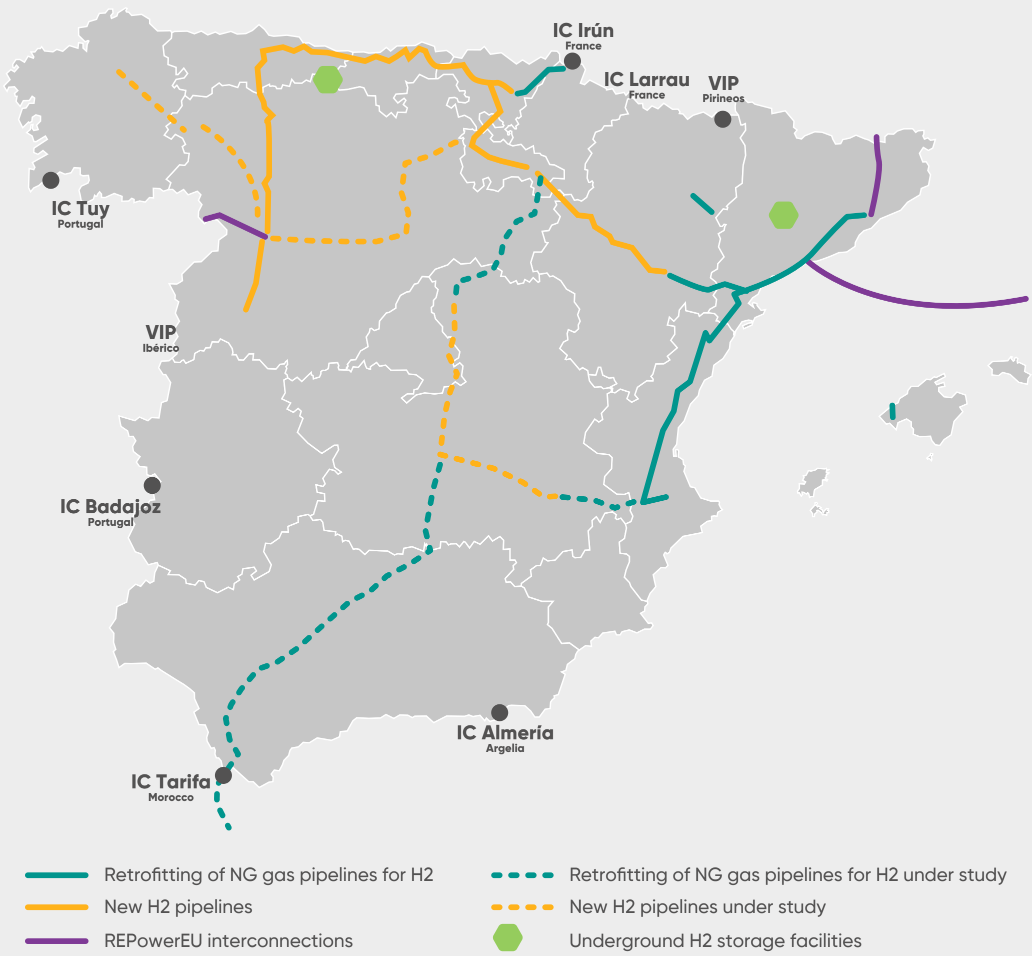
The Spanish hydrogen network

As for Spain, Enagás, as the leading Spanish TSO, has also presented a vision map for developing the Spanish hydrogen network by 2030. The plan is part of its 2022-2030 Strategic Plan: Reliable energy for a decarbonised future. The plan envisages the development of a centralised national backbone based on new and existing pipelines. The company expects that the volume of hydrogen transported via pipelines in Spain by 2030 will be approximately 30 bcm, which will be the equivalent of 60% of the transported volume of gases, with the remaining being natural gas.

Furthermore, according to the plan, the company plans to invest EUR 235 million in hydrogen in 2022-2026 and another EUR 455 million between 2027-2030. The main projects identified for the hydrogen network are Hydeal and Catalina, as well as other connections to the transmission network and new hydrogen storage facilities. However, the integration of the Iberian Peninsula also depends on developing the French hydrogen system to enable the integration of northwest Europe.

FIGURE 16

Enagás hydrogen network plan 2030



Source: Enagás (2022) 2022-2030 Strategic Plan Reliable energy for a decarbonised future: A 2030 strategy for a new stage in Europe.

Conclusion

In line with REPowerEU targets and depending on market developments, a hydrogen storage capacity of 7.5 Mt (247.5 TWh) could be necessary by 2030, split between 5 Mt (165 TWh) operational and 2.5 Mt (82.5 TWh) of strategic storage (van Wijk, Westphal, & Braun, 2022, p. 16). Between salt caverns, depleted natural gas fields and other storage means (ammonia tanks, line pack, et cetera), achieving these targets at the EU level is technically possible. Nonetheless, it will be challenging, considering the short timeframe and still evolving regulatory framework. In the future, the value of hydrogen storage in the national network is likely to be driven by similar price signals to the current natural gas market, including the spread between summer/winter hub price spreads, which determines the value of seasonal flexibility, and the spot price volatility which determines the value of short-term gas delivery flexibility. These signals tend to be highly cyclical, and declining spreads in Europe in the 2010s have made it difficult for storage owners to cover their costs. In some jurisdictions, there has been a decline in storage capacity over the past decade, which reflects this challenging market. Therefore, policy support through appropriate commercial models might be required to sustain the hydrogen storage market at a national scale in the future to ensure system resilience and meet inter-seasonal fluctuations in hydrogen demand. These storage considerations should be investigated in detail before governments make strategic decisions about whether to pursue a national hydrogen network or not.

To benefit to the maximum extent from hydrogen's advantages in the process of achieving Europe's goals of climate neutrality, infrastructure development will be fundamental. In relation to imports, multiple ways to transport hydrogen will be used to guarantee EU's security of supply in the future, such as liquid H2, ammonia, LOHCs, SIHCs, and pipelines. For intra-EU transport, hydrogen dedicated pipelines have a distinct advantage, with support from both the private sector and national governments. As hydrogen production and demand develop together with dedicated networks, so will the need for storage capacities, thus creating a market drive to harness the existing storage potential, as presented in this chapter. In this regard, several MS with more abundant resources are already active in the development of storage potential, while MS where the latter is limited, might face a challenge which will require active involvement of policy-makers to guarantee that hydrogen brings the societal benefits of a system storage solution.

Taking into account current state of affairs and considering the urgency to achieve climate neutrality, guarantee security of supply, and enable the competitiveness of the European economy, hydrogen infrastructure development should be enabled as soon as possible. Yet, to do so, policy-makers need to present clear strategies, followed by precise ground-rules for the sector. In this regard the adoption of the Hydrogen and Decarbonised Market package (see Chapter 7) is of paramount importance, as it will give guidance to national governments, which are waiting, on how to organise their national energy sectors. In this regard, the Dutch approach is to be emphasized, as it provides interim ground rules for the development of national hydrogen backbone with the definition of access conditions, tariffs, and purity requirements, while balancing private and public interests, thus enabling the development of the infrastructure system as soon as 2030.

Methodological note

TABLE 3

Identified hydrogen storage projects in Europe

Name / location	Country	Project start year	Operator/ developer	Working storage capacity (GWh)	Type	Status
Teeside	UK	1972	Sabic	27	Salt cavern	Operational
Underground Sun Storage	AT	2016	RAG	10% H2 blend	Depleted field	Demo
HyStock	NL	2021	EnergyStock	200 ready, upscaling potential to 667	Salt Cavern	Pilot
Hybrit	SE	2022	Vattenfall, SSAB, LKAB	100	Rock cavern	Pilot
Rudersdorf	DE	2022	EWE	0.2	Salt Cavern	Under construction
Jemgum	DE	2022	astroa	382	Salt Cavern	Feasibility Study (2027 operational)
HyPster	FR	2023	Storengy	0.07-1.5	Salt Cavern	Engineering study
HyGeo	FR	2024	HDF Terega	1.5	Salt Cavern	Feasibility Study
HySecure	UK	Mid 2020s	Storengy inovyn	40	Salt Cavern	Phase 1 feasibility study
Energiepark Bad Lauchstadt Storage	DE	-	Uniper, VNG, ONTRAS, DBI, TerraWatt	150	Salt Cavern	-Feasibility Study
Kosakowo	PL	2024 2027	Gas Storage, PGNiG	20,000 m^3 200,000 m^3	Salt Cavern	Demo Feasibility Study

Source: EIA, Hydrogen Europe.

References

Carbon Limits. (2016). Carbon Limits. Retrieved September 28, 2022, from Carbon Limits: https://www.carbonlimits.no/

Energy Transition Centre. (2022). The role of renewable H2 import & storage to scale up the EU deployment of renewable H2. Brussels: European Union.

FNB Gas. (2022). Hydrogen Network. Retrieved from FNB Gas: https://fnb-gas.de/en/hydrogen-network/

FNB Gas. (2022). Wasserstoffbericht. Berlin: FNB Gas. Retrieved September 28, 2022, from https://fnb-gas.de/wasserstoffnetz/h2-bericht/

Gas Infrastructure Europe. (2021). Picturing the value of underground gas storagen to the European hydrogen system. Utrecht: Guidehouse.

Gas Storage Europe. (2021, July). Storage Database 2021. Gas Infrastructure Europe.

German Federal Ministry for Economic Affairs and Climate Action, Ministry of Energy Saudi Arabia. (2022). Hydrogen cooperation potential between Saudi Arabia and Germany . Guidehouse Germany GmbH.

Gimeno-Gutiérrez, M., & Lacal-Arántegui, R. (2013). Assessment of the European potential for pumped hydropower energy storage. Brussels: Joint Research Centre.

HyUnder. (2019). Deliverable No. 3.3 Benchmarking of Selected Storage Options. HyUnder.

International Renewable Energy Agency. (2022). The Geopolitics of Energy Transformation: The Hydrogen Factor. Abu Dhabi: IRENA.

Ready4H2. (2022, September 29). Ready4H2. Retrieved September 29, 2022, from Ready4H2: https://www.ready4h2.com/

Savcenko, K. (2021, June 22). Germany's 2022-32 gas plan to integrate hydrogen: FNB. Argus Media. Retrieved from https://www.argusmedia.com/en/news/2227157-germanys-202232-gas-plan-to-integrate-hydrogen-fnb

TNO. (2020). Large-Scale Energy Storage in Salt caverns and Depleted Fields. The Hague: TNO.

TNO. (2021). Ondergrondse Energieopslag in Nederland 2030 – 2050: Technische evaluatie van vraag en aanbod. Utrecht: TNO.

Van Wijk, A., Westphal, K., & Braun, J. F. (2022). How to deliver on the EU Hydrogen Accelerator. Brussels.

© Justin Jin for Hydrogen Europe

05

Planned clean hydrogen consumption in industry

At least 6.1 Mt of clean hydrogen consumption is featured in planned industrial projects by 2030.

© Justin Jin for Hydrogen Europe

Introduction

This chapter contains information about announced projects planning to use clean hydrogen in the European Union, EFTA (European Free Trade Association), and the UK industry. Most of these projects intend to replace the consumption of fossil fuels such as coal and gas and unabated fossil fuel-based hydrogen with clean hydrogen[1].

This includes the consumption of hydrogen:

1. in the refining industry,
2. in ammonia production,
3. in the steel sector,
4. in methanol production,
5. in other e-fuels syntheses[2],
6. in industrial heating (cement, ceramics, and others)
7. as a feedstock in other chemical processes.

Hydrogen Europe has collected the data and information presented in this chapter from public and restricted sources. The database is not additional in terms of projects to the production database presented in **Chapter 3.** The data points collected around these projects, however, are different, and the scope is more restricted, including only announced plans that specifically intend to apply the production of clean hydrogen to any form of an industrial process an a clear industrial off-taker, whether it be as a feedstock or to produce industrial heat. Examples of plans not tracked in this database are projects for the consumption of clean hydrogen directly as a fuel in the mobility or energy sectors, production projects that only vaguely mention the potential uptake of the produced hydrogen by the industrial sector,

1 / This report defines clean hydrogen as the hydrogen produced from electrolysis with renewable or low-carbon electricity and natural gas-based hydrogen with carbon capture and storage or usage. Other forms of making hydrogen with reduction of emissions are not yet featured.
2 / Because ammonia and methanol are already tracked as separate sectors; they are not included as e-fuels even though they can be considered one.

and projects for the consumption of fossil-fuel based hydrogen with no carbon capture in any sector. More details on the data collection methodology can be found in the **Methodological note.**

The information reported contains projects at a preparatory, construction or operational level, announced MoUs, initial concepts and feasibility studies. As the chapter reports on aggregated planned consumption of clean hydrogen in the different sectors and countries, it should be noted that this refers only to the projects that effectively disclose enough data to estimate their yearly hydrogen consumption. This includes 211 out of the total 223 projects. The remaining 12 projects either prefer to keep this information confidential or are still in the very early stages of the process and have not defined such details yet. Hydrogen Europe makes no assumptions about the potential consumption allocated to these projects.

While the intention is to provide an accurate snapshot of planned developments, this overview likely does not reflect all projects currently planned (e.g., some may not have been made public at all). Moreover, as the projects used to generate the overview are still evolving, the numbers presented are subject to change, which is already visible when comparing values from this year with last year's edition. Although the overall planned consumption by 2030 tends to increase due to new projects that become public every year, some other plans are often cancelled or changed in the expected size/date of operation. The presented information refers to data collected by August 2022.

5.1.

Total planned clean hydrogen consumption in industry

By 2030, the total planned consumption of clean hydrogen in the tracked industrial projects amounts to 6.1 Mt H2 /year, including projects with a non-disclosed operational date. 3.4 Mt H2 /year belonging to some early industrial movers are currently planned to come online by 2025-2027. By 2030, the consumption will have increased to 5.4 Mt H2 / year, both from implementing new projects and up-scaling old ones. There is also some additional 0.78 Mt H2 /year of new consumption without an announced operational date. If these are to become online by 2030, the consumption of clean hydrogen in the industry is planned to increase at an average annual rate of 757 kt H2 /year.

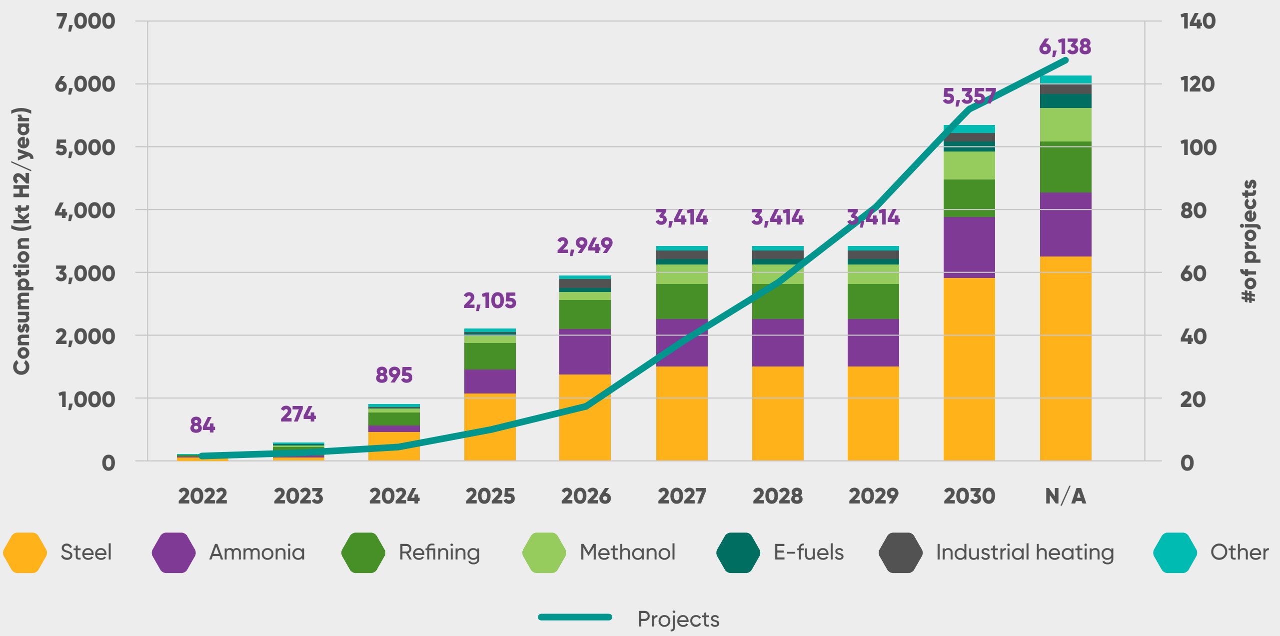
While only 21 industrial end-use projects are already in operation, the **clean hydrogen consumption in industry is expected to be, in the space of a decade, around 50 times the expected amount by the end of 2022.**

92.5% of the clean consumption projects will use electrolysis for hydrogen production. In comparison, 5% will rely on reforming with carbon capture, and 2.5% will either use both methods or rely on a different/unknown, but still clean, source of hydrogen.

Germany has the highest amount of planned clean hydrogen consumption in industry, 2,122 kt H2 /year, amounting, by 2030, to 19% of the total number of projects and 38% of the total clean hydrogen consumption. Sweden is the second largest consumer with 701 kt H2 /year, followed by the Netherlands, France, and Spain with 571 kt H 2/year, 537 kt H2 /year and 523 kt H2/year, respectively, by 2030.

FIGURE 1

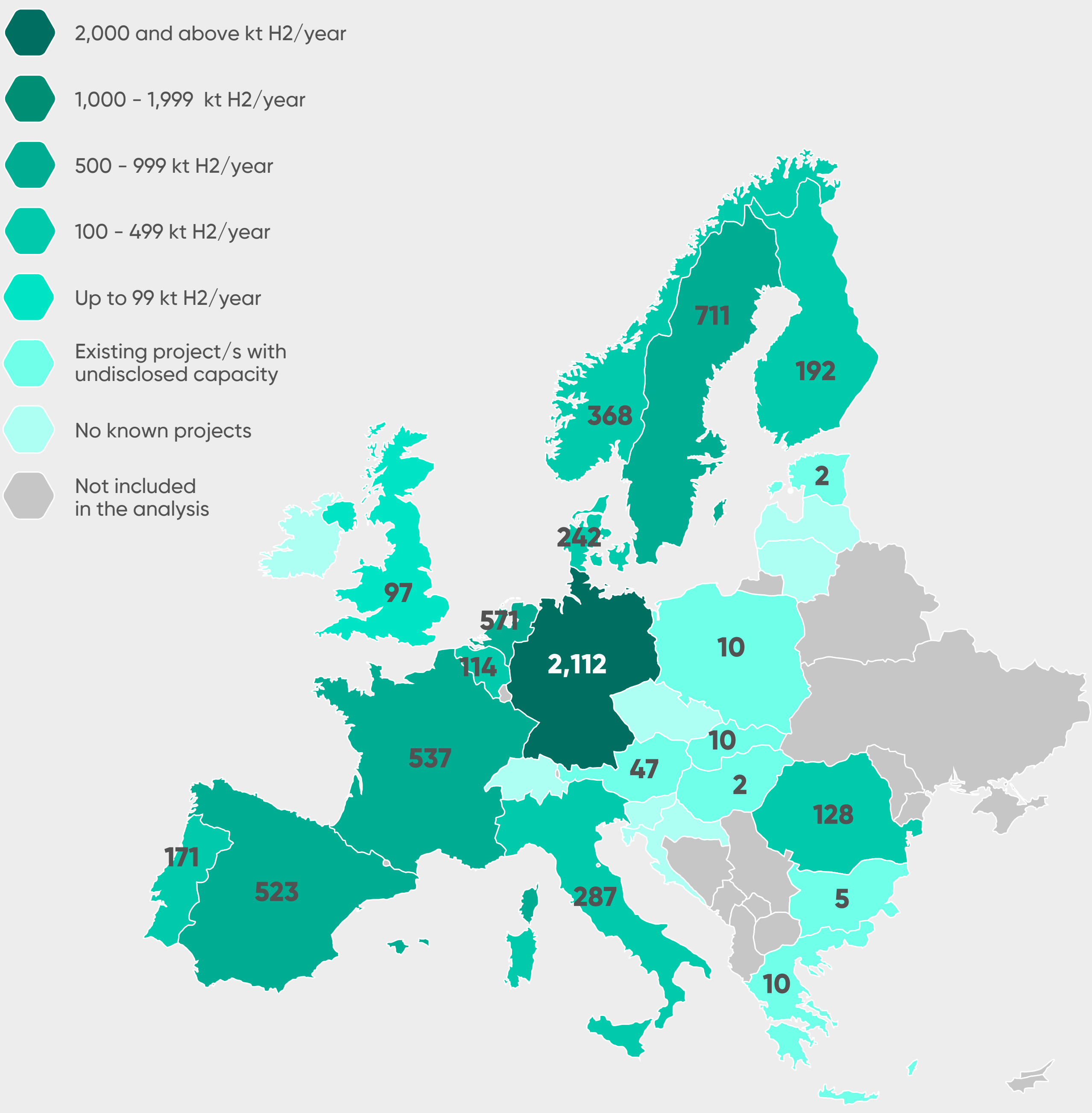
Cumulative planned clean hydrogen consumption in industry in EU, EFTA, UK in kt H2/year and # of projects



Source: Hydrogen Europe.

FIGURE 2

Map of total planned clean hydrogen consumption in industry by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year



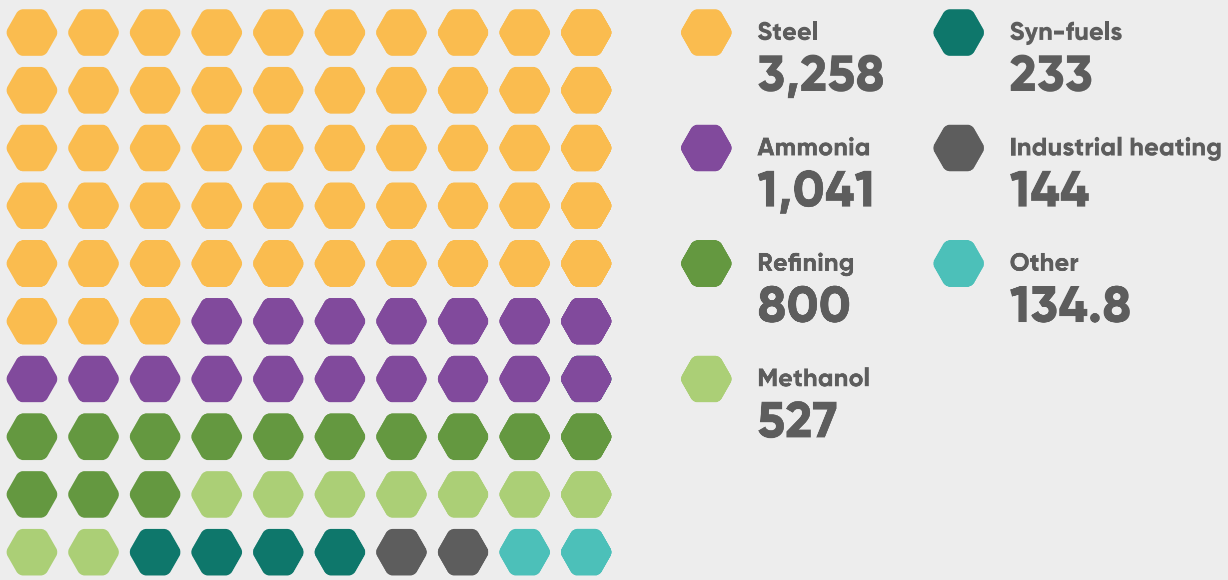
Source: Hydrogen Europe.

At 3,258 kt H2/year, the steel industry represents 53% of the total clean hydrogen planned to be consumed by the industry by 2030. Although the conventional production methods for steel are not hydrogen intensive, some new emerging CO2-free technologies are, which causes the hydrogen demand from this sector to rise. 17% of the total clean hydrogen consumption is planned to be applied in the production of ammonia, 13% to refining processes, 9% in methanol production, 4% in the synthesis of e-fuels[3], 2% in the supply of industrial heating, and 2% as a feedstock in other chemicals projects. Considering the projects announced so far, 81% of total clean hydrogen consumption in the industry could rely on on-site or dedicated contracted off-site hydrogen production, as the retail market of clean hydrogen is not yet well enough developed to supply significant quantities of it reliably. The exact hydrogen supply source is not disclosed for the remaining 19% of consumption.

Considering the total amount of clean hydrogen planned to be consumed by the different industrial sectors and the type of process that is replacing in the conventional operations, a total of 86 Mt CO2e emissions could be avoided annually in the EU, EFTA, UK region. For reference, around 720 Mt of CO2e were emitted from the industrial sector in the EU alone in alone in 2020 (Statista, 2022). Most of the CO2 avoided, 62.9 Mt CO2e /year, comes from the steel sector, not only because this is the sector where most of the hydrogen is to be consumed but also because it is where the transition can make the most significant impact per tonne of hydrogen (see **Methodological note**).

FIGURE 3

Clean hydrogen consumption planned by 2030 in kt H2/year for the different industrial sectors

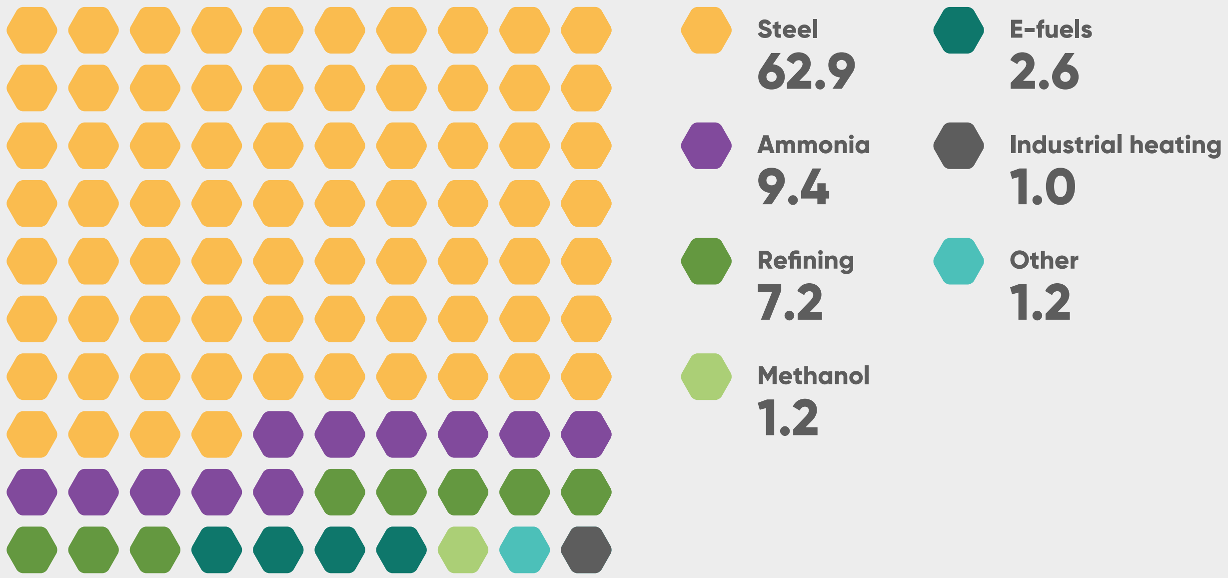


Source: Hydrogen Europe.

3 / Consumption of clean hydrogen for the synthesis of e-fuels presents quite low compared to the data in the Clean Hydrogen Monitor 2021. This is a sector where concrete information on the size of the projects or date of decommissioning is particularly hard to find and consequently, small changes in projects (cancellations, changes in size/date) result in significant changes in aggregated data.

FIGURE 4

Potential for CO2 emission avoidance in Mt CO2e/year considering planned consumption of clean hydrogen in the industry by 2030



Source: Hydrogen Europe.

5.2.

Clean hydrogen in steel

Steel is a versatile metal alloy and a basic engineering material essential in any economy. The production process of this metal is also one of the most CO2-intensive industries and is currently under immense pressure for decarbonisation. Conventionally, primary steel is produced in Blast Furnace/ Basic Oxygen Furnace (BF/BOF) factories, where coal acts as the reducing agent to transform iron ore into hot metal, and fossil fuels are burned to provide the required heat. Average emissions from this route amount to 1.9 tCO2/t steel in the EU. Secondary steel, produced from steel scrap in an Electric Arc Furnace (EAF), is already way less emitting, with an average emission rate of 0.4 tCO2/t, depending on the carbon intensity of used electricity, but the grade of steel achieved through it is more limited. In a new and greener primary process, hydrogen acts as the reducing agent to produce Direct Reduced Iron (DRI), which is then converted into hot metal in an EAF, sometimes with a mix of steel scrap. If the hydrogen used is clean and the electricity used to fuel the EAF, almost all the emissions from steel production can be abated.

H2-DRI technology is already mature enough and ready to help the sector make the transition. According to Hydrogen Europe's Steel from Solar Energy report, for a coal price of EUR 165 /t and natural gas price of EUR 80 /MWh, green steel would be EUR 126-203 /t higher in cost compared to conventional steel. For a typical ICE passenger car, this translates into an added cost of EUR 100-170 per vehicle. At a hydrogen delivery price of EUR 5.3 /kg, the estimated CO2 break-even price would be EUR 140 /t when EU ETS is currently at EUR 74 /t[4]. It should be noted, however, that coal and natural gas prices have increased since the report's release and have shown a very unstable tendency in the past year, with coal reaching prices of around EUR 400 /t and natural gas at EUR 200 /t.

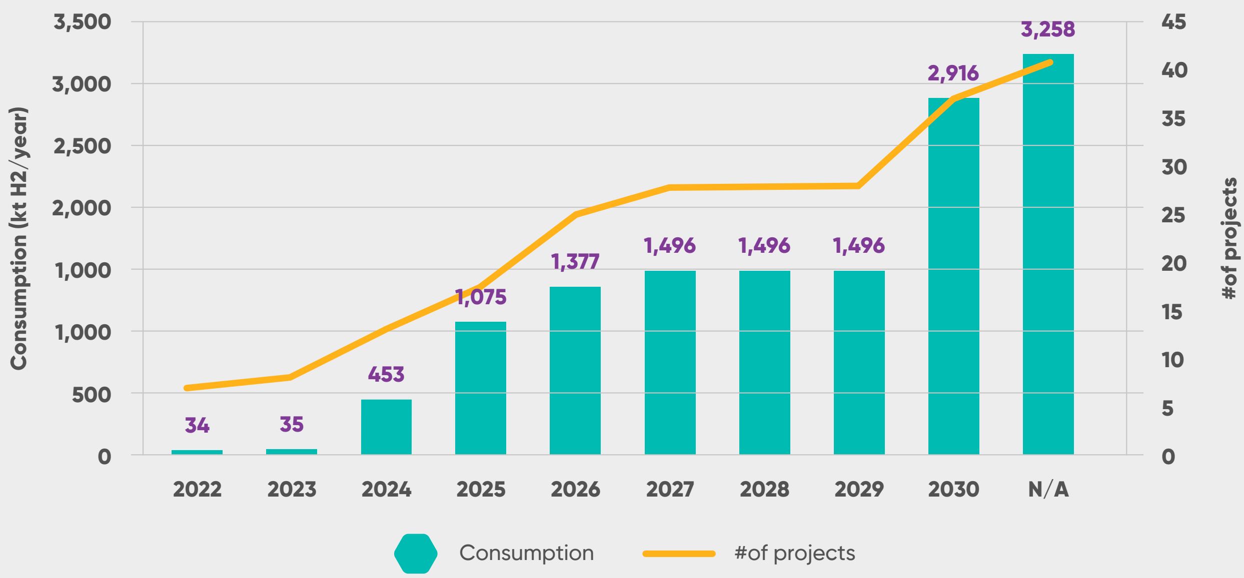
The biggest challenge for this sector's transition lies in the high capital investment and scale of renewables required, with around EUR 1.2 billion investment and 1.3 GW electrolysis running at full load needed to convert one single plant. Despite this, many green steel projects are already underway or even operational in a pilot/demonstration phase, with mostly all big names in the sector already active.

By 2030, tracked announced projects amount to 3,258 kt H2/year of clean hydrogen consumption in the steel industry, including projects with yet no announced operation date. While some projects are already operational, significant consumption of clean hydrogen in H2-DRI projects is expected to come online in 2024 and 2025. Most of the consumption is, however, to be deployed in 2030.

With a total consumption of 1,511 kt H2/year of clean hydrogen in 12 projects, Germany is planning to consume the cleanest hydrogen in the steel sector, which is not surprising considering that Germany is, indeed, the biggest steel manufacturer in Europe. Sweden plans to consume approx. 533 kt H2/year clean hydrogen in steel, followed by France, Italy and Spain with 340, 257, and 222 kt H2/year consumption, respectively.

FIGURE 5

Cumulative planned clean hydrogen consumption in the steel sector in the EU, EFTA, UK region by year in kt H2/year and # of projects

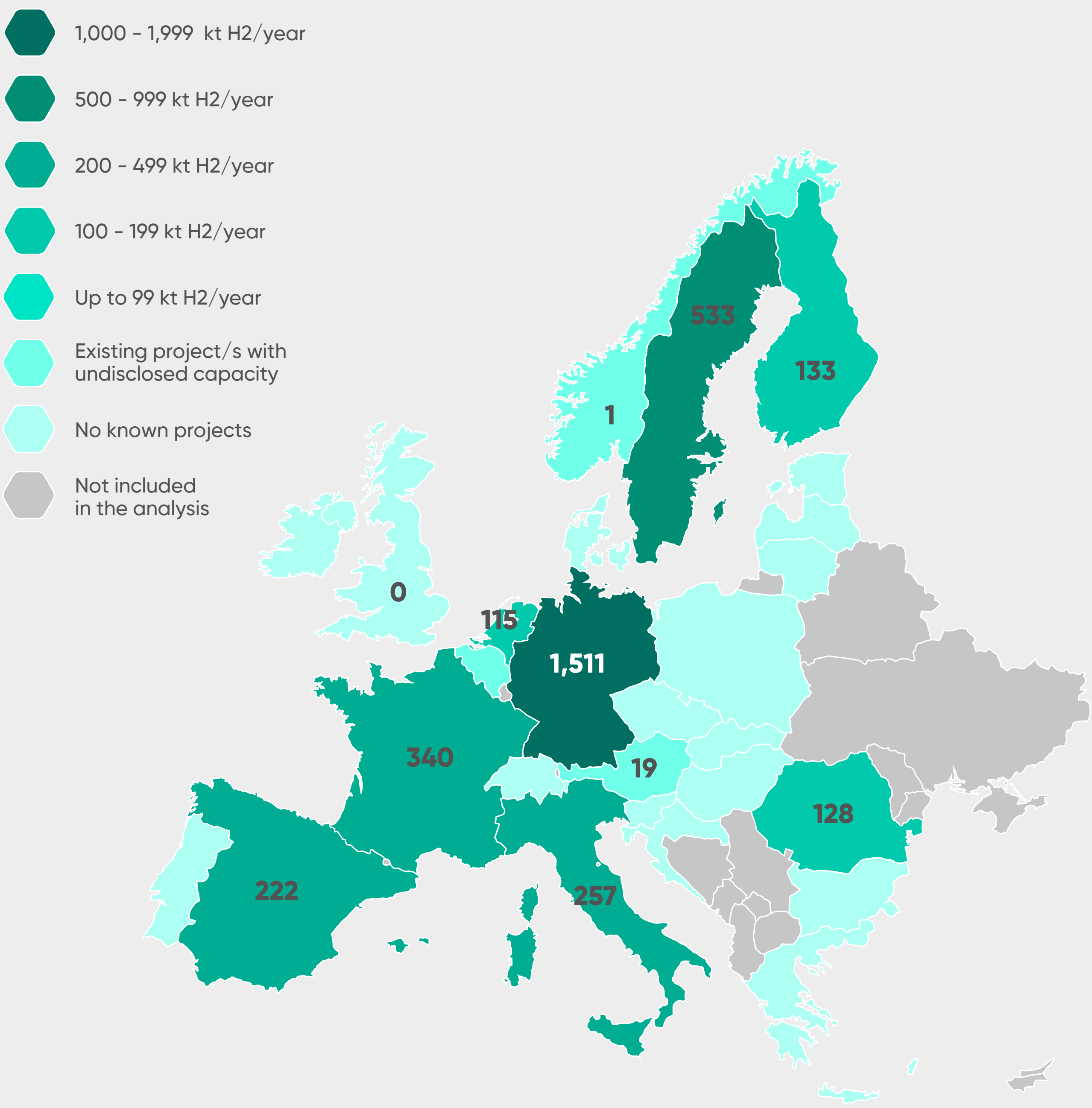


Source: Hydrogen Europe.

4 / Price consulted on 15/09/2022.

FIGURE 6

Map of total planned clean hydrogen consumption in the steel sector by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year



Source: Hydrogen Europe.

5.3.

Clean hydrogen in ammonia

The ammonia industry is the EU's second-largest hydrogen-consuming sector, with a total hydrogen demand estimated at 2.5 Mt in 2021. When producing one tonne of ammonia, 175-180 kg of hydrogen and around 820 kg of molecular nitrogen are necessary. Although it is usually used as a feedstock for a potential energy carrier and/or fuel, it is already considered a suitable e-fuel for maritime applications. This has become even more evident with the explicit intentions of the EU to start importing hydrogen from overseas, with ammonia rising as the most promising hydrogen carrier to transport at this stage, considering its already developed transport infrastructure.

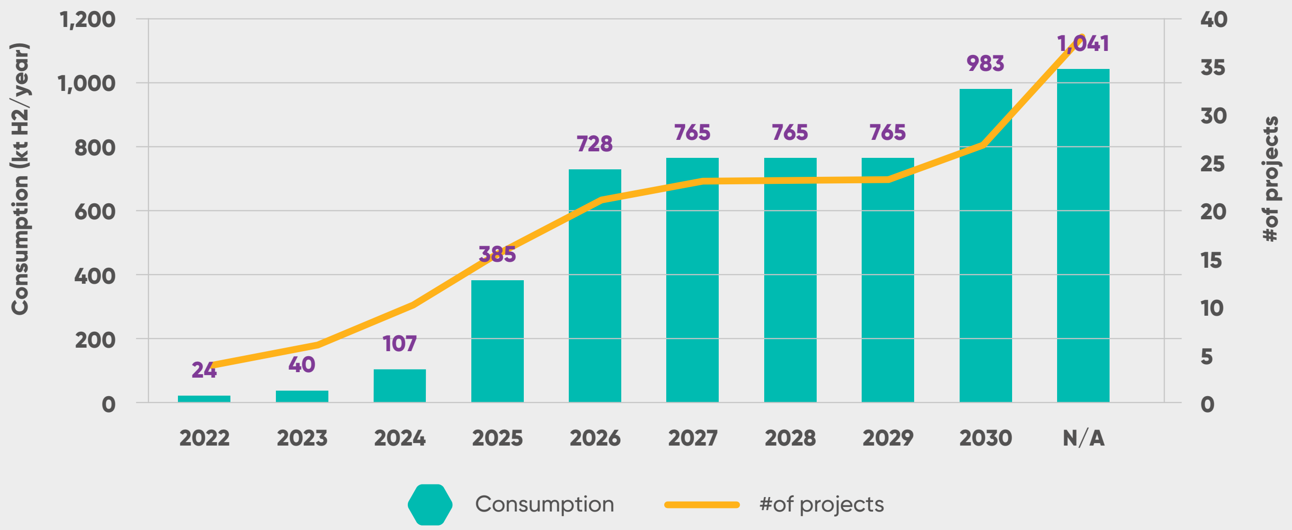
Because over 95% of ammonia production emissions are concentrated in the hydrogen production step, replacing fossil fuel-based hydrogen with clean hydrogen is crucial to decarbonise this sector. In sectors as such, reaching cost-parity between the green product and the conventional one greatly depends on the cost gap between fossil fuel hydrogen and clean hydrogen. With natural gas at EUR 190 /MWh and a carbon price of EUR 74 /t CO2e, fossil-based hydrogen could cost as much as EUR 10.3 /kg in contrast to renewable hydrogen already available for EUR 2.2 /kg.[5]

Clean ammonia projects planned to be operational until 2030 amount to a total hydrogen consumption of 1,041 kt H2/year, one-third of the total current hydrogen consumption in the sector, 70% of which will come online in 2026. Considering all ammonia production projects planning to replace fossil-fuel hydrogen with clean hydrogen, 9.2 Mt of CO2 emissions could be avoided annually by 2030 from this sector alone.

Norway, where the headquarters of the big fertilisers company Yara is located, stands out as the country with the highest planned consumption of clean hydrogen for ammonia production. The country is foreseen to consume a total of 297 kt H2/year, representing 28% of the planned clean hydrogen consumption in the sector by 2030, followed closely by Spain, with nine projects in total and 209 kt H2/year planned consumption.

FIGURE 7

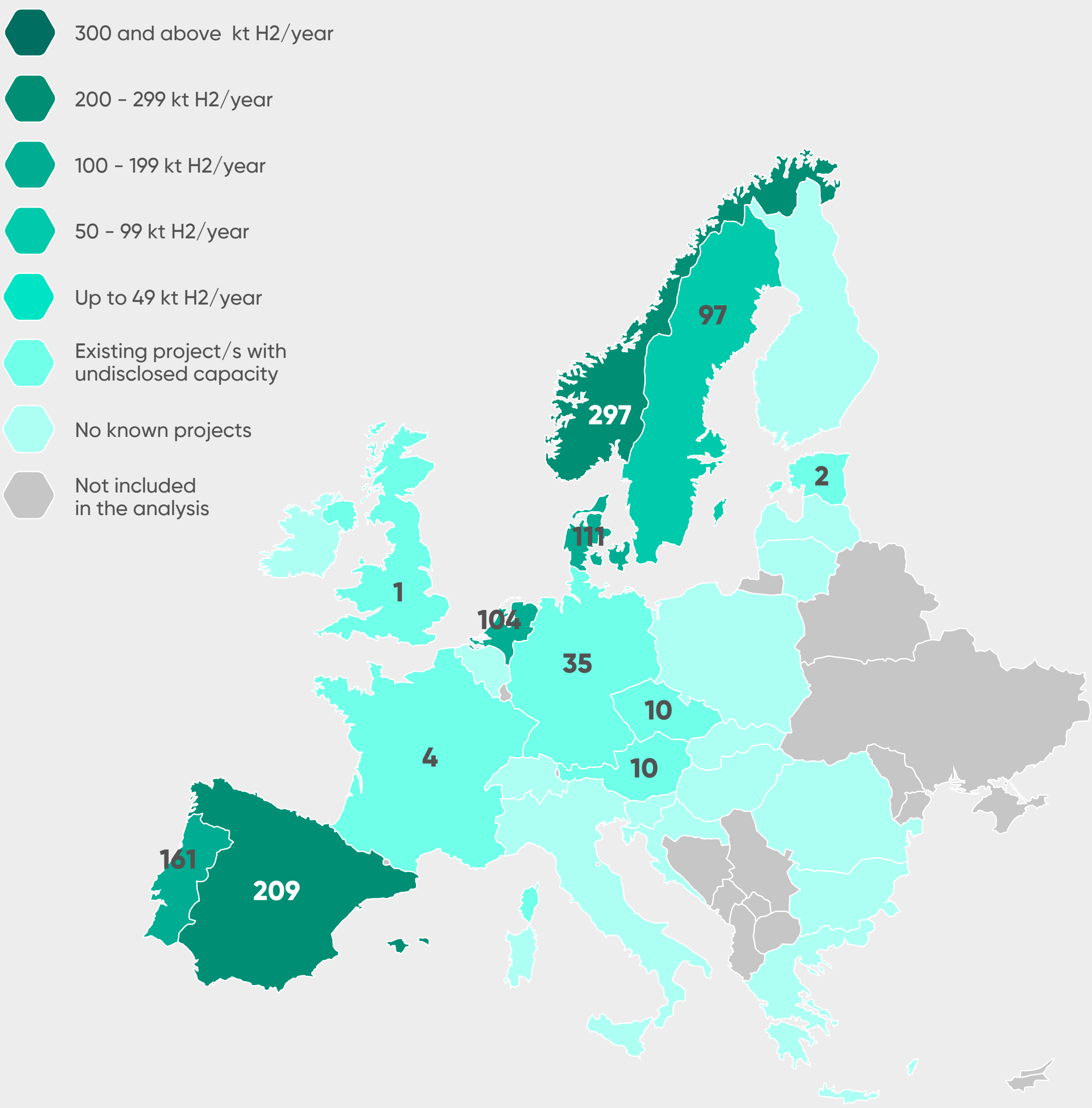
Cumulative planned clean hydrogen consumption in the ammonia sector in the EU, EFTA, UK region by year in kt H2/year and # of projects



Source: Hydrogen Europe.

FIGURE 8

Map of total planned clean hydrogen consumption in the ammonia sector by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year



Source: Hydrogen Europe.

5.4.

Clean hydrogen in refineries

Hydrogen in refining processes is used mainly for hydrotreating and hydrocracking. Hydrotreatment is one of the key stages of the diesel refining process and refers to several processes, such as hydrogenation, hydrodesulfurisation, hydrodenitrification and hydrodemetallisation. Hydrocracking involves transforming long and unsaturated products into products with a lower molecular weight than the feed.

While some by-product hydrogen is produced in refineries, they increasingly need an additional source either on-site or across the fence operated by an industrial gas company. The production method is most commonly SMR, based on natural gas.

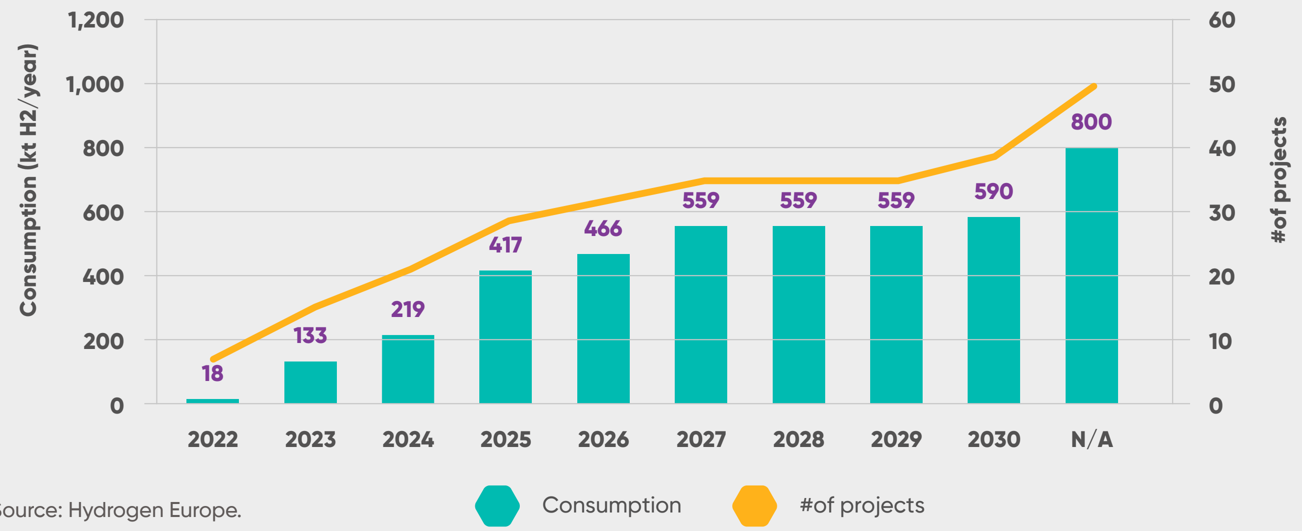
Similar to the ammonia industry, clean hydrogen is directly competing with fossil-based hydrogen as a feedstock in refineries, causing its break-even price to be tied to both natural gas and carbon prices. As explained in the previous section, rising natural gas and carbon prices have been laying out increasingly better conditions for clean hydrogen to break even.

Refining accounts for 13% of the industry's planned clean hydrogen consumption, with 698 kt H2/year consumption planned by 2030 in this sector. Significant deployment in refining is expected to start in 2023, with 133 kt H2/year cumulative consumption, and gradually increase at an average rate of 95 kt H2/year annually.

The country with the highest projected consumption of clean hydrogen in refining is Germany, with nine projects and 205 kt H2/year annual consumption, followed by the Netherlands with five projects and a 135 kt H2/year annual consumption planned by 2030.

FIGURE 9

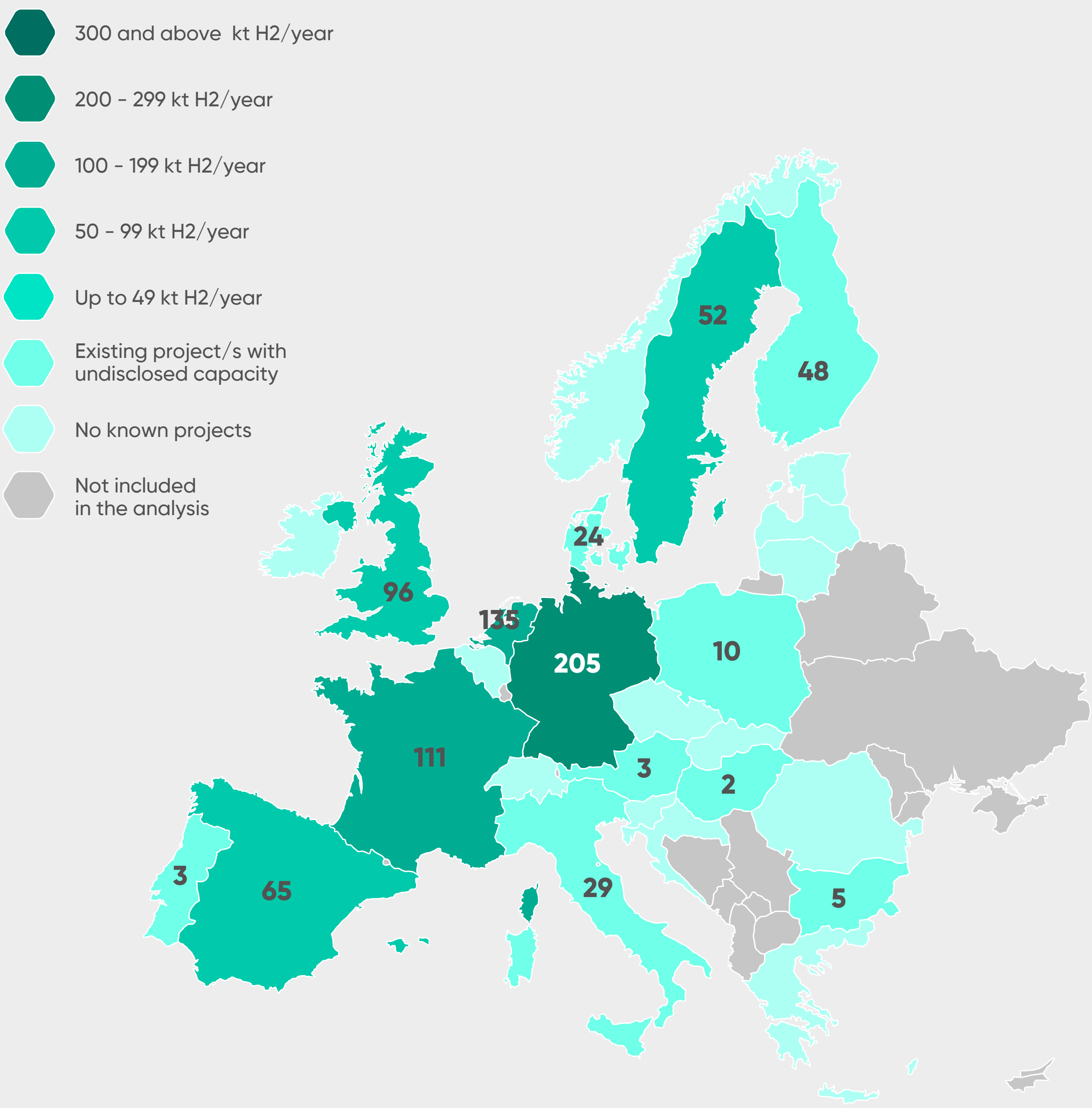
Cumulative planned clean hydrogen consumption in the refining sector in the EU, EFTA, UK region by year in kt H2/year and # of projects



Source: Hydrogen Europe.

FIGURE 10

Map of total planned clean hydrogen consumption in the refining sector by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year



Source: Hydrogen Europe.

5.5.

Clean hydrogen in methanol

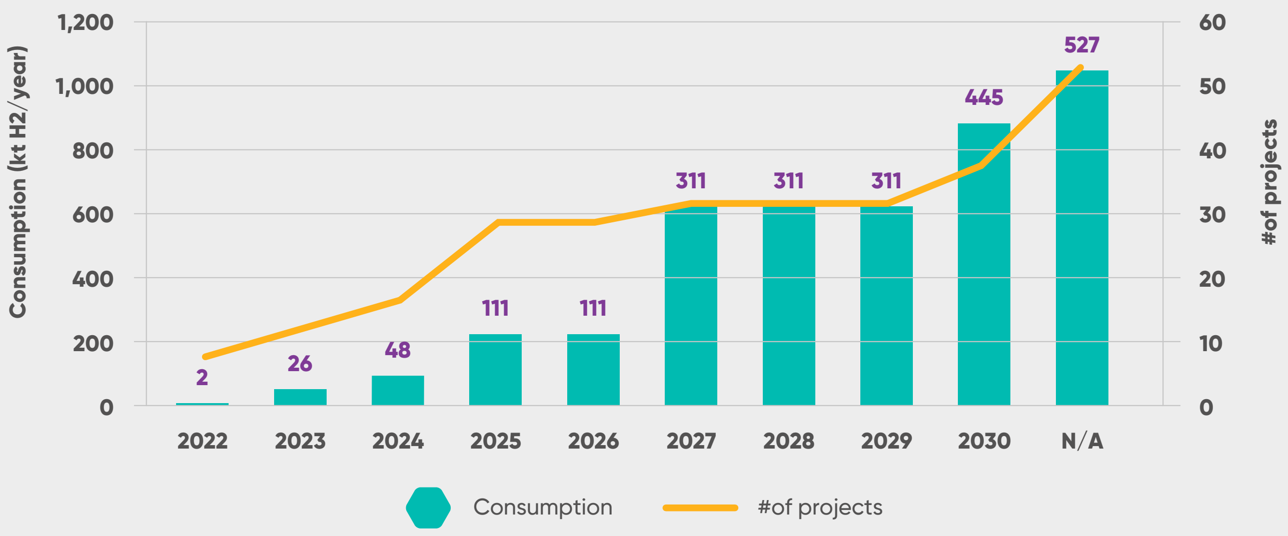
Similar to ammonia, methanol can have different uses as a chemical product, feedstock, hydrogen carrier and e-fuel. E-methanol is produced using CO2 and clean hydrogen as a feedstock, eliminating most CO2 emissions associated with the production process. Additionally, e-methanol can also help reduce emissions at the consumption level. If the CO2 used as a feedstock is obtained from direct air capture, e-methanol can be carbon-neutral even when burned in internal combustion engines.

The total amount of planned clean hydrogen consumption to produce e-methanol could amount to 527 kt H2/year by 2030, including projects with no disclosed operation date. This amounts to around 3 Mt of methanol produced, against a current demand in Europe of 8 Mt/year (Eurostat, 2022).

With a total consumption of 239 kt H2/year in six planned projects, Germany has the highest hydrogen consumption for methanol production by 2030, followed by Belgium and Denmark with 89 kt H2/year and Belgium with 81 kt H2/year, respectively.

FIGURE 11

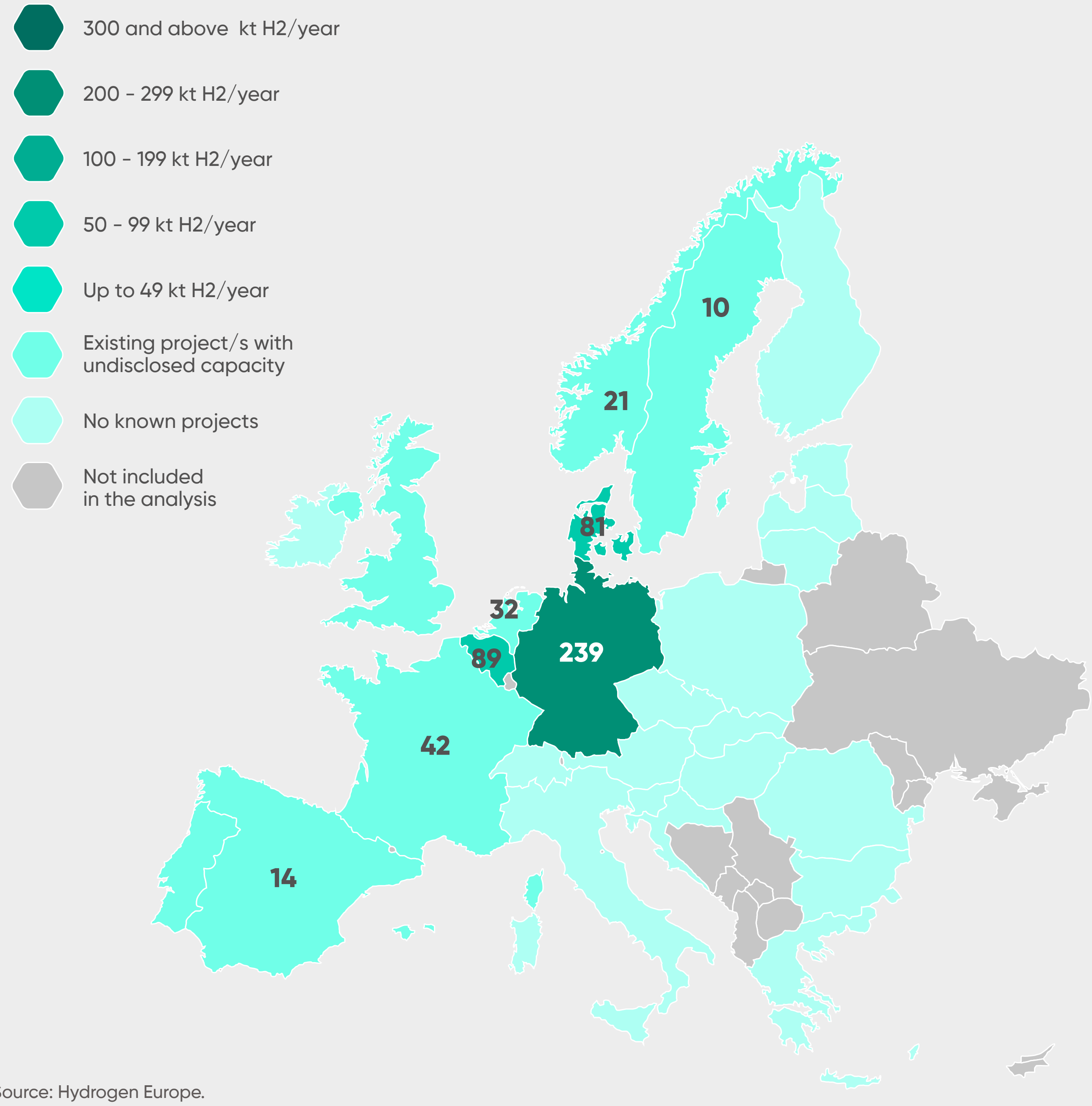
Cumulative planned clean hydrogen consumption for methanol production in the EU, EFTA, UK region by year in kt H2/year and # of projects



Source: Hydrogen Europe.

FIGURE 12

Map of total planned clean hydrogen consumption in methanol production by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year



Source: Hydrogen Europe.

5.6.

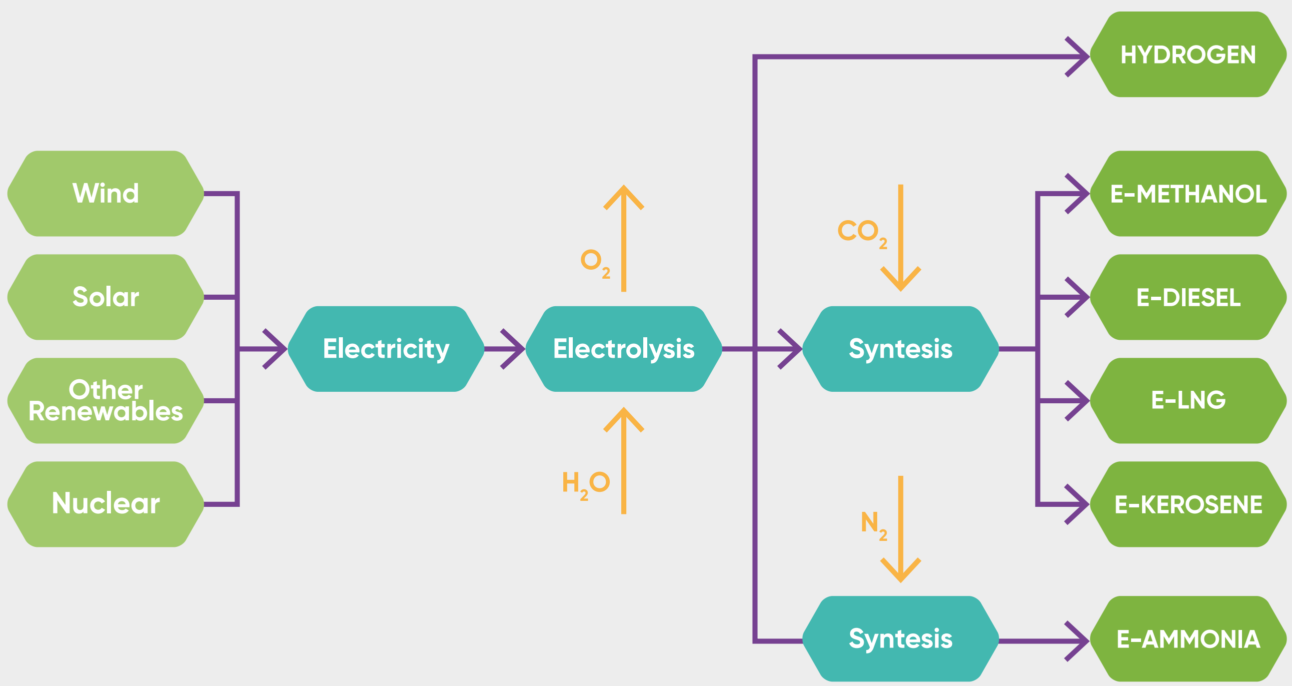
Clean hydrogen in e-fuels

With constant pressure to reduce emissions in the entire mobility sector, alternative synthetic, clean fuels are needed to help decarbonise hard-to-electrify vehicles (e.g., hydrodesulfurisation aviation and maritime sectors, heavy-duty road vehicles). E-fuels are synthetic hydrogen-based fuels that can be burned in internal combustion engines and are synthesised artificially when CO and CO2 react with H2. Provided that carbon is captured from the atmosphere or comes from otherwise unavoidable emissions and renewable electricity is used during the synthesis, e-fuels such as e-methanol, e-ammonia, e-diesel, e-LNG and e-kerosene are great low-carbon alternatives in mobility. Carbon dioxide is still emitted during the combustion of e-fuels but provided the conditions expressed above are met, CO2 emissions should be offset during production.

Since ammonia and methanol-specific projects have already been presented in the sections above, this section focuses on data concerning projects on the synthesis of other types of e-fuels, mostly e-kerosene and e-diesel. Hydrogen itself as a fuel is not considered, as this chapter represents only the plans for using hydrogen in industrial processes.

FIGURE 13

Schematic representation of the role of hydrogen and relevant e-fuels

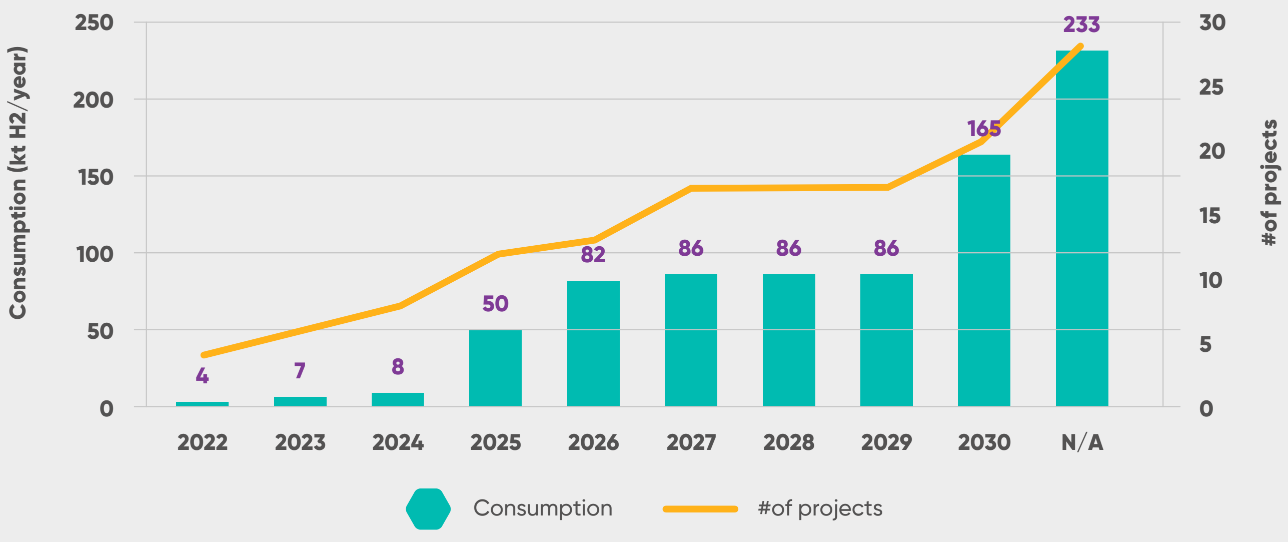


Source: TNO.

Tracked projects planning to use clean hydrogen to produce e-fuels keep to a small annual consumption. With a total of 35 projects tracked, 233 kt H2/year of total consumption in the sector is expected to be operational by 2030 if we include projects with no disclosed operational date. However, it should be noted that this is a sector where many of the identified projects still lack concrete information on their scale and timeline and are, therefore, not represented in the aggregated consumption data, even if they are in the pipeline. They still show, however, in the number of projects presented. Most of the planned production of e-fuels is concentrated in Germany, Norway, and Belgium, with a planned consumption of 93, 39 and 25 kt H2/year, respectively.

FIGURE 14

Cumulative planned clean hydrogen consumption for the production of e-fuels in the EU, EFTA, UK region by year in kt H2/year and # of projects

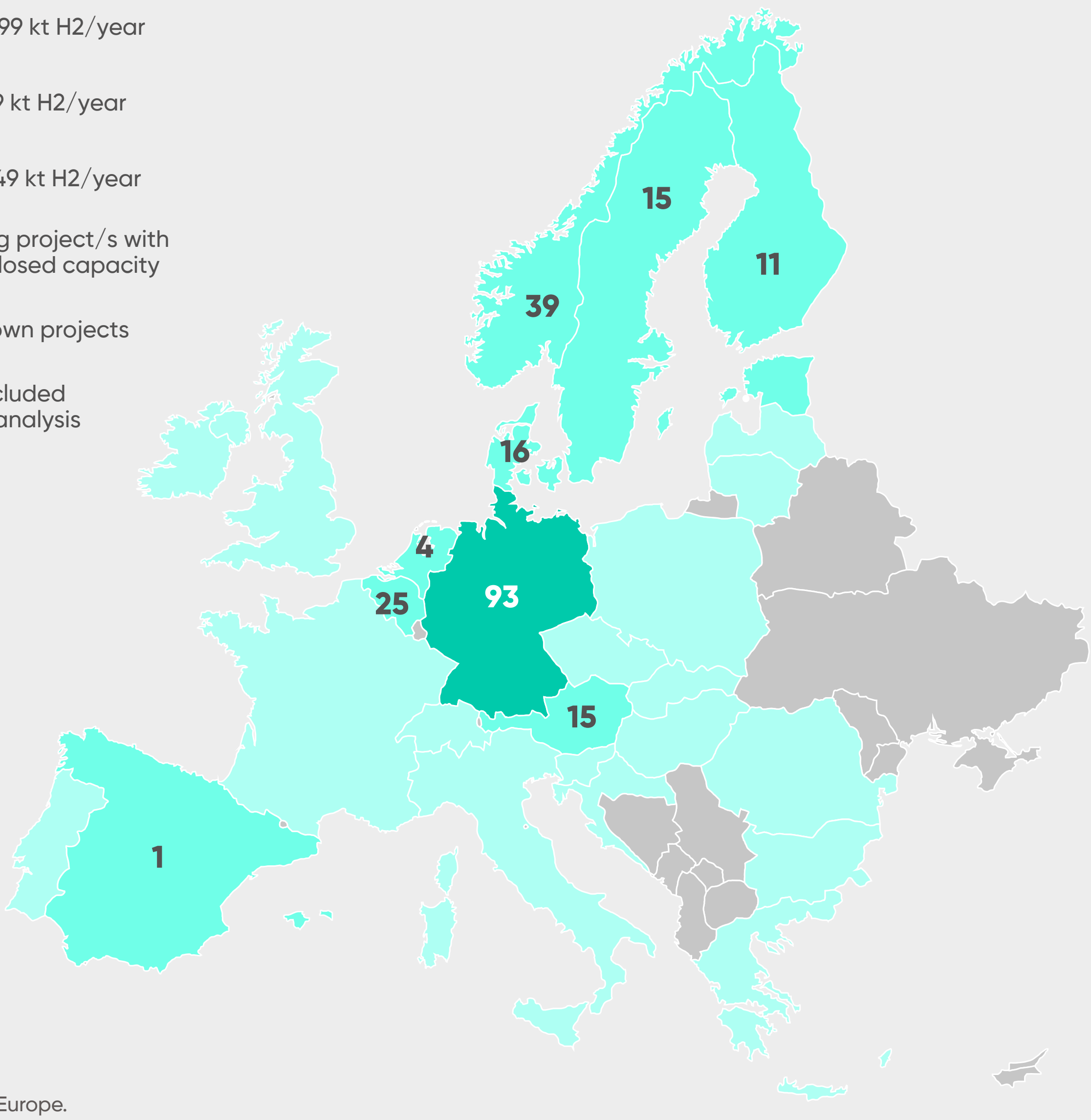


Source: Hydrogen Europe.

FIGURE 15

Map of total planned clean hydrogen consumption for the production of e-fuels by 2030 (including non-disclosed date of operation projects) in the EU, EFTA, UK region, in kt H2/year

- 300 and above kt H2/year
- 200 - 299 kt H2/year
- 100 - 199 kt H2/year
- 50 - 99 kt H2/year
- Up to 49 kt H2/year
- Existing project/s with undisclosed capacity
- No known projects
- Not included in the analysis



Source: Hydrogen Europe.

Conclusion

This chapter presents aggregated data concerning projects announced by industrial stakeholders planning to consume clean hydrogen in their processes, both as a feedstock and for the supply of industrial heating.

Tracked projects show that around 6.1 Mt of clean hydrogen consumption could come online in the industrial sector by 2030. The steel sector holds the highest share, with 53% of total consumption. 17% of the consumption is planned to be applied to the production of ammonia, 13% to refining processes, 9% to methanol production, 4% to the synthesis of e-fuels[7], 2% to the supply of industrial heating, and 2% as a feedstock in other chemicals projects. By far, Germany is the country with the highest amount of projects and consumption in the EU, EFTA, UK region, closely followed by Sweden. The industrial sector could avoid over 86 Mt of annual CO2 emissions if all announced projects are commissioned by 2030.

© Justin Jin for Hydrogen Europe

7 / Consumption of clean hydrogen for the synthesis of e-fuels presents relatively low compared to the data in the Clean Hydrogen Monitor 2021. This is a sector where concrete information on the size of the projects or date of decommission is particularly hard to find and, consequently, small changes in projects (cancellations, changes in size/date) result in significant changes in aggregated data.

Methodological note

Methodology and geographic scope

Hydrogen Europe has collected the list of projects planning to consume clean hydrogen in industrial processes from public and private sources. It provides a snapshot of the current developments.

Projects under the scope of the clean hydrogen consumption database include:

• Consumption of hydrogen produced from electrolysis from both renewable electricity or low-carbon electricity and SMR-based hydrogen with carbon capture – called "clean hydrogen" throughout the chapter.

• Clean hydrogen consumption in the industry in the EU, EFTA, UK region.

• Consumption of clean hydrogen for industrial processes with clearly committed industrial off-takers, including hydrogen used as a feedstock in chemical processes (i.e., for the synthesis of other products) and as a fuel for industrial heat production.

• Projects under the following levels of development: concept, feasibility study, preparatory, construction or operational.

The authors collected the information to the best of their abilities. However, they cannot guarantee the absolute completeness or accuracy of the collected data. The authors never made their own conclusions about any project's start date or capacity. If only estimates for the installed electrolyser capacity were given for a specific project, the corresponding amount of hydrogen was estimated, assuming a capacity factor depending on whether the electrolyser is fed by a solar panel, a wind turbine, or the grid. Moreover, if only an estimation for the annual production of the final good (e.g., annual production of clean ammonia) was given, the necessary conversion was made to estimate the amount of clean hydrogen consumed in the project.

CO2 emissions avoided

In order to calculate the amount of CO2-equivalent emissions avoided by the use of clean hydrogen in industry, the following assumptions and simplifications were made:

• In the refining and ammonia sectors, the amount of CO2 emissions avoided corresponds to the emissions that would otherwise be released during the conventional SMR process, approximately 9 t CO2e/t H2.

• 51 kg of clean hydrogen is needed to produce one tonne of steel. While almost all emissions from the BF/BOF production process could be avoided with the H2-DRI process, not all of that avoidance comes from the consumption of clean hydrogen, as the electrification of the process is also a factor. Therefore, we assumed that the consumption of clean hydrogen in one plant would decrease by 72% of the 1.9 t CO2e/t steel normally emitted by the conventional BF/BOF plant (proportionally to hydrogen input to all energy inputs to the process).

• Production of e-methanol is sourcing CO2 from direct air capture, and the CO2 emissions avoided are the ones released by the conventional method of production, 0.462 t CO2e/t MeOH. This method considers only the emissions avoided by changing the production process of the chemical, ignoring the further potential for emission reduction should it be used as a carbon-neutral alternative fuel.

• Production of e-fuels is sourcing CO2 from direct air capture, and the CO2 emissions avoided are, therefore, the ones released by the combustion of the conventional fuel, assumed to be 3.16 t CO2e/t SAF.

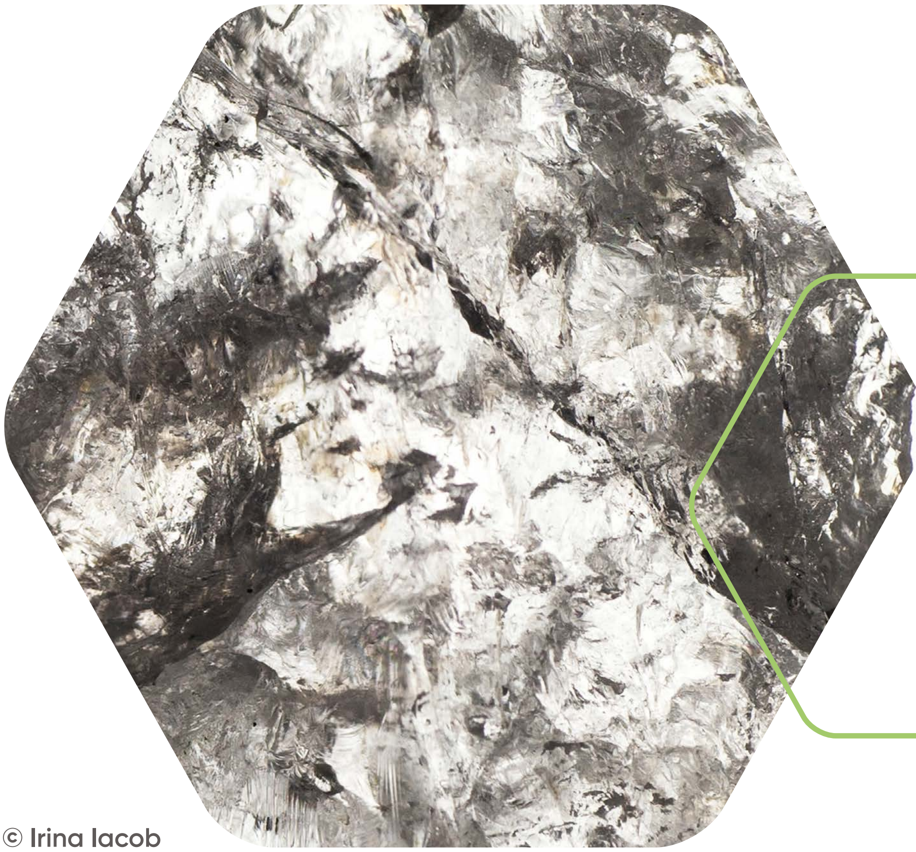
• For projects considering the use of clean hydrogen for industrial heat, it was assumed that the heat would otherwise be generated from the combustion of natural gas. If it provides the same amount of energy as natural gas does, clean hydrogen could avoid CO2 emissions at a rate of 6.7 t CO2e/t H2.

© Justin Jin for Hydrogen Europe

06

Production capacity of raw materials in the hydrogen supply chain: platinum and palladium

Annual production capacity of platinum (Pt) is 227 tonnes and of palladium (Pd) 305 tonnes. New mining capacities are expected to come online, but capacity from recycling will play a significant role in Pt and Pd production in the near and long run.



© Irina Iacob

Introduction

Critical Raw Materials (CRMs) are a group of 30 materials that, according to the European Commission, have a high supply risk and are of high economic importance for the European Union (EU). Increased supply risk is determined by the governance performance and trade dynamics with the primary supplying countries of the material. In contrast, high economic importance is based on end-use applications and value-added, corrected by substitution parameters[1]. Potential shortages of these materials can significantly impact the deployment of clean energy technologies in the EU, including hydrogen.

To ensure a successful and rapid clean energy transition, the ramp-up of hydrogen technologies and the build-up of a robust hydrogen ecosystem will require a reliable supply of critical materials, especially Platinum Group Metals (PGMs). This chapter reviews the production capacity of two PGMs[2]: platinum (Pt) and palladium (Pd), because platinum and, to a lesser extent, palladium are key materials for the current production of electrolytic hydrogen and fuel cells. This chapter presents the metals' current and future production capacity from both mining and recycling activities, presents price trends over the last 20 years, and concludes with remarks on future assessments and policies to ensure the security of supply and resilient value chains.[3]

In this and future editions of this report, the discussed materials are selected based on substitution prospects and the importance of these materials for hydrogen technologies. Technologies and their respective materials that are immediately crucial for developing a hydrogen economy are addressed first. Future editions of this report will then focus on other raw materials.

As it is difficult to measure current production capacity directly, the volume of platinum and palladium produced in 2021 is used to estimate it. Although volumes vary annually depending on operational and market conditions (e.g., mine accidents that can cause disruptions and fluctuating economic benefits of recycling scraps), volumes are fairly representative of current capacity under relatively stable circumstances. To assess future production capacity, new mining projects, reserves and resources, and future capacity from recycling are reviewed.

1 / See more information on the methodology at: https://ec.europa.eu/growth/sectors/raw-materials/areas-specific-interest/critical-raw-materials_en
2 / Platinum Group Metals (PGMs) are comprised by platinum, palladium, rhodium, iridium, osmium, and ruthenium.
3 / Future demand is purposefully outside of the scope of this chapter. For further details, please consult the Methodological note.

6.1.

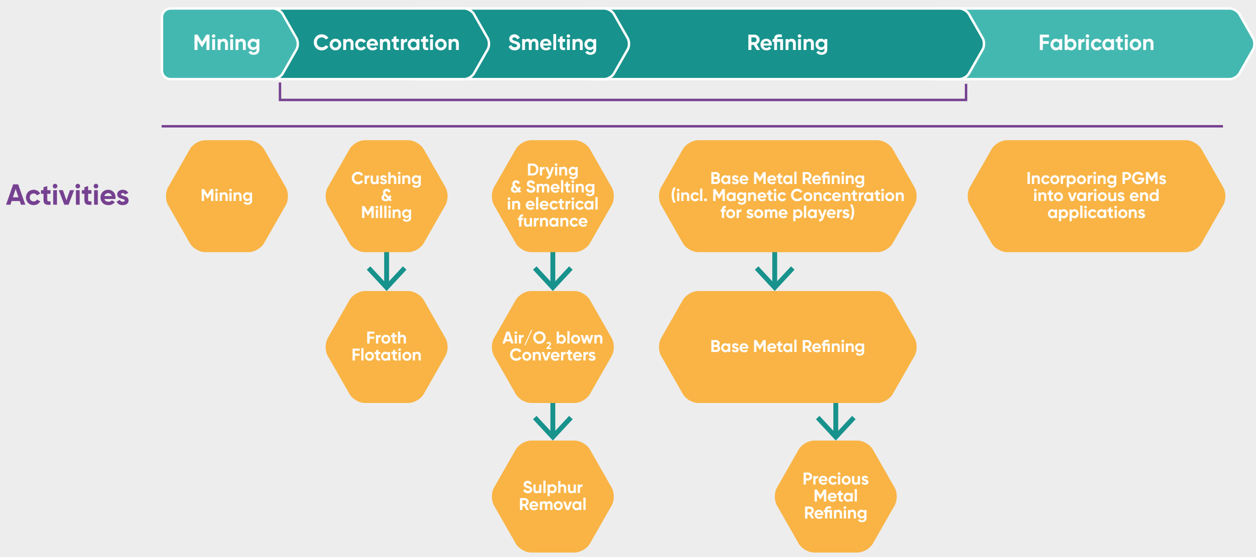
In focus: platinum and palladium

Even though PGMs are commonly aggregated as they are almost always mined together and have similar physical and chemical properties, platinum and, to a lesser extent, palladium are crucial for producing electrolytic hydrogen and fuel cells using current technologies. Pt and Pd are used in platinum or PGMs-based catalysts to facilitate electrochemical reactions and energy conversion. For instance, a PEM electrolyser requires around 0.5 mg of platinum per W, and a PEM stationary fuel cell requires 0.1 mg of platinum per W. Research has been successfully conducted to reduce material loadings in these technologies (Clean Hydrogen JU, 2022) and could potentially lead to material substitution. Historically, PGMs have been extensively used in automotive catalysts in Internal Combustion Engines (ICEs) vehicles to reduce harmful emissions.

Platinum and palladium also have a similar processing supply chain. They are concentrated, smelted, converted, and refined together. **Figure 1** describes the activity chain of PGMs, from mining to use in applications. Mining companies often have integrated processing capacity close to their mining activities. However, these metals are also sold in concentrate due to economic and technological barriers to building smelting and refining capacity. Even when processing capacity is available, miners might process the metals themselves depending on short-term conditions (e.g., electricity supply, accidents or reparations that may disrupt operations) or contract tollers to process their raw ore or concentrate[4]. Finally, platinum and palladium can also be produced as a by-product of base metals such as nickel or copper.

FIGURE 1

Simplified PGMs activity chain



Source: Anglo American Platinum, 2014.

4 / In a tolling agreement, an owner of raw materials hires a processing counterpart to process the material for a certain fee (“toll”). The final product remains property of the raw material provider.

6.1.1. Assessing current production capacity

The volume of platinum and palladium produced in 2021 estimates the current production capacity as it is hard to measure it directly. Although volumes vary annually depending on operational and market conditions (e.g., mine accidents that may cause disruptions and fluctuating economic benefits of recycling scraps), volumes are fairly representative of current capacity under relatively stable circumstances. Therefore, the estimates in this chapter should not be interpreted as a constant but rather as the best available estimate to showcase the potential availability of materials, still subject to the operational and market dynamics mentioned above.

Mining production estimates are presented in concentrate to avoid capturing dynamics from the processing market. Processing utilisation and new processing capacity strongly depend on economic and technological conditions. For instance, maintenance, accidents, and a high CAPEX required to build additional capacity can hamper the processing of metals. Even though future growth in metals` demand and prices could remove some (economic) barriers and spark processing activities to accompany production, these will depend on the abovementioned dynamics. Ensuring sufficient processing capacity will be crucial to guarantee the availability of materials promptly. For reference, industry sources estimate an average of 4 years to build additional processing capacity and about six weeks is needed to mine and process a batch of metal.

Hydrogen Europe data on mined production was collected using publicly available data from producers' reports. The estimated production capacity does not take demand forecasts into account. For further details and more information on the methodology used, see the **Methodological note** at the end of this chapter.

6.1.1.1. CAPACITY FROM MINING

The global mined output of platinum and palladium in concentrate stood respectively at around 176 and 200 tonnes in 2021. According to industry sources, these levels align with the past few years.

Platinum mining operations are highly concentrated in South Africa, representing 75% of the total mined output in 2021. Another handful of countries was responsible for the remaining volume. Russia represented 12% of the 2021 output, Zimbabwe 9% and the United States and Canada, each less than 5%.

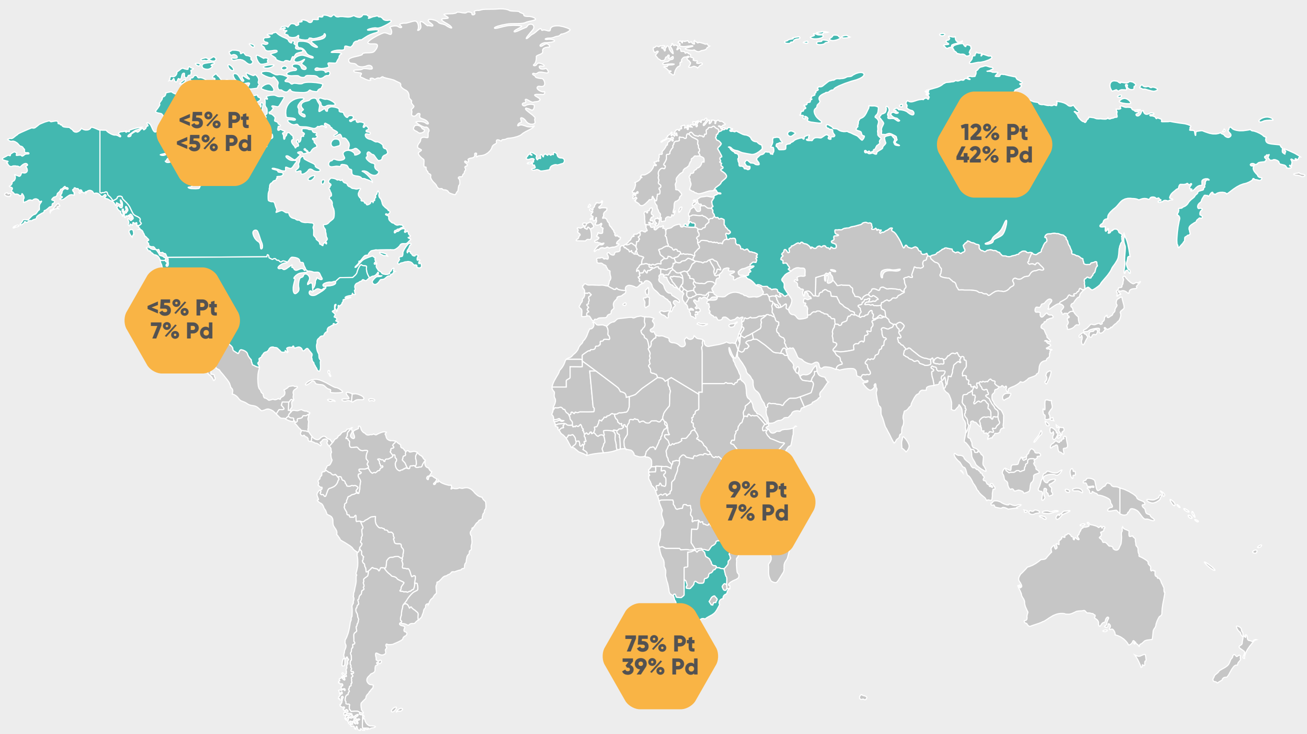
On the other hand, palladium mining operations are concentrated in Russia, which held 42% of the total mined output in 2021. Another 39% of the operations were mined in South Africa. The United States and Zimbabwe follow, each with roughly 7%, whereas Canada represented less than 5%.

Due to incomplete information, a specific volume of metals produced as a by-product of base metals mining is untraceable. These correspond to around 1% of the output in each platinum and palladium production. **Figure 2** shows the distribution of mined platinum and palladium production per country in 2021.

The significant concentration of the Pt and Pd market in a few mines means that mines with large production volumes can affect the market. In the Bushveld complex in South Africa, two Rustenburg mines produced about 34 tonnes of platinum in 2021 or almost 20% of the global production and 26% of the South African production in the same year. Also, in the Bushveld complex, the Mogalakwena mine produced about 16 tonnes of platinum or almost 9% of the global output and 12% of South African production in 2021. The Mogalakwena also produced 18 tonnes of palladium in 2021, 9% of global production and 23% of South African production.

FIGURE 2

Geographical distribution of platinum and palladium mining production in the world in 2021



Source: Hydrogen Europe based on company reports.

6.1.1.2. CAPACITY FROM RECYCLING

According to Johnson Matthey (2022), platinum and palladium refined output from open-loop recycling stood respectively at around 51.6 and 104.6 tonnes in 2021. Open-loop recycling represents recycled material from processes where the original purchaser does not retain ownership of the metal, and the subsequent recycled output is returned to the market. Overall, the past few years show a relatively stable recycled output of metal, with an annual variation of roughly ± 10 tonnes compared to 2021 volumes for both platinum and palladium. By far, the most significant contributor to the production of recycled platinum is the automotive sector (74%), followed by jewellery (23%) and electrical and electronics (3%). The automotive industry is also the biggest contributor to palladium recycling (80%), followed by electrical and electronics (14%) and jewellery (less than 1%). Closed-loop recycling is also an essential source of platinum and palladium but is not included in the market figures as it is difficult to track. In closed-loop recycling, the original purchaser keeps ownership of the metal and typically uses it again in a new product.

In the EU, end-of-life recycling rates (EOL-RR) currently stand at 54% for platinum and 47% for palladium-containing waste (European Commission, 2021). In the automotive industry, 50-60% of the PGMs are recycled, while in industrial catalysts, this share rises to 95% (European Commission, 2021). The EOL-RR indicate the efficiency of recycling in the EU, determined by collection and recovery efficiencies across applications. Despite their rarity, collection losses are the largest losses in the recycling cycle of platinum and palladium. On the contrary, recovery losses can be minimal, e.g., recovery rates in certain platinum applications can be as high as 99%.[5]

Currently, there are no dedicated binding targets for the recyclability of PGMs in the EU, only for general "waste" (see Waste Framework Directive 2008/98/EC[6]), and PGMs in the form of waste have been commonly traded with third countries. Since 2004, the EU has been mainly a net importer of waste containing precious metals, including platinum and palladium. In 2021, it exported 71,000 tonnes of waste containing precious metals, and it imported 118,000 tonnes (EUROSTAT, 2022).

The Critical Raw Materials Action Plan[7] stresses the importance of recycling CRMs waste in the EU instead of exporting it to contribute to the diversification of sourcing and security of supply for the European industry. Even though a net importer, the extent to which imported waste is destined for recovery and is efficiently recovered in the EU is unclear, as well as how much of exported waste is destined for recovery and efficiently recovered in third countries. It is also unclear how much platinum and palladium are contained in traded precious metals waste, in which silver scraps are the most common scraps (European Commission, 2021).

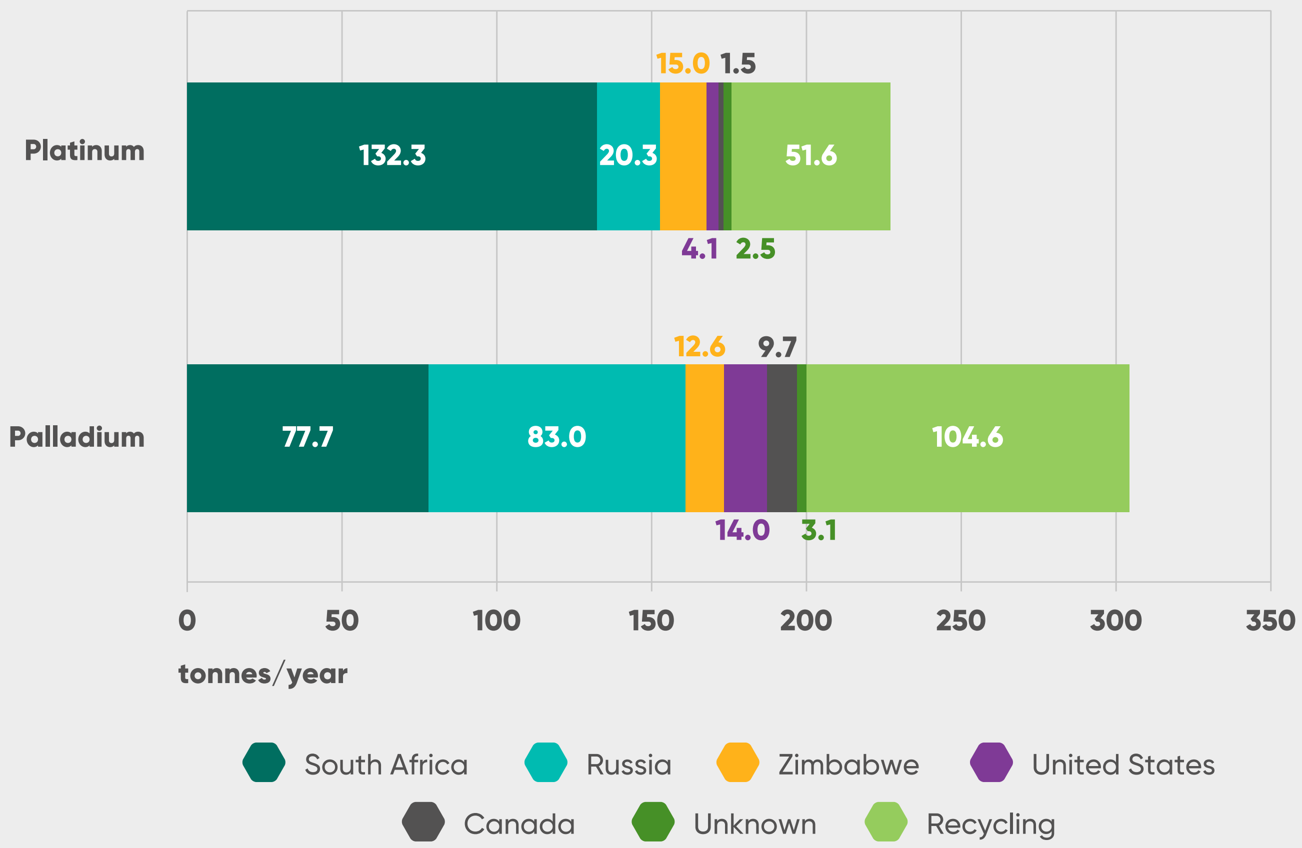
6.1.1.3. TOTAL PRODUCTION CAPACITY

Based on current mining and recycling volumes, the total production capacity of platinum is estimated at 227 tonnes and palladium at 305 tonnes[8], of which 23% and 34%, respectively, is from recycling. As mentioned at the beginning of this chapter, this capacity is subject to dynamic conditions and should be interpreted as a reference for production capacity under stable conditions. **Figure 3** shows the production capacity of platinum and palladium by the country where mining takes place and the worldwide recycling capacity. Due to incomplete information in companies' reports, some volume of metals produced as a by-product of base metal mining is untraceable.

5 / Recovery rates can be very high in certain cases, however, they may vary significantly depending on the application and quality of the scrap.
6 / See European Commission, 2018. DIRECTIVE 2008/98/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02008L0098-20180705
7 / See European Commission, 2020. COM(2020) 474: Critical Raw Materials Resilience: Charting a Path towards greater Security and Sustainability. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0474
8 / Mined volumes are in concentrate. Further losses from processing the metals should reduce the values used in the calculation by around 2%.

FIGURE 3

Distribution of platinum and palladium capacity from mining and recycling[9]



Source: Hydrogen Europe based on company reports and Johnson Matthey (2022).

6.1.2. Future production capacity

6.1.2.1. NEW MINING PROJECTS

New mining activity is essential to maintain current production levels at the end of Life of Mine (LoM). Future mining activity could also increase mining output, thus contributing to increased production of these materials. However, time plays a vital role in the industry's ability to ramp up capacity in a timely manner. Industry sources estimate that roughly ten years are needed to develop a new PGMs mining project of average capacity, from exploration to commencing production.

Currently, several PGMs exploration activities are being carried out worldwide, and some projects are expected

9 / Unknown volumes refer to metals produced as a by-product of base metals mining. These volumes are not traceable in companies` reports due to incomplete information.

to start production in the next few years. For reference, platinum and palladium are the most frequent metals in PGMs mining. In South Africa, the prill split[10] is often around 60% for platinum and 25% for palladium, but splits can vary significantly.

There are several new mining projects, some of which are not connected to existing operational mines. The Platreef project in South Africa is located on the Northern Limb of South Africa's Bushveld complex. It is expected to start production in the second half of 2024, producing around 3 tonnes of palladium, platinum, rhodium, and gold per year in the first phase. Future expansions could make it one of the most extensive PGMs operations in the world, potentially producing about 31 tonnes per year[11]. In Zimbabwe, the Darwendale project, located at the Great Dyke, could produce at peak around 24.4 tonnes of PGMs per year. The project was expected to start production in 2021 and become the country's largest PGMs mining operation. However, Darwendale is delayed due to funding issues and is being technically and financially reassessed after the recent exit of its Russian counterpart, Afromet, from its joint venture with Kuvimba, due to sanctions against Russia[12]. Also, at the Great Dike, the early-stage Karo project is expected to start producing, in its first phase from 2024, on average, 4.2 tonnes of PGMs a year for 20 years. The project's first phase is being planned with the possibility of increasing the scale even further[13].

As the projects above are not connected to operational mines, funding issues, further feasibility studies (evaluating, e.g., reserves, mining design, and production rate and schedule), and other economic assessments (based on, e.g., mining costs, LoM, metal prices, and taxes), can significantly change original plans and affect the expected production volumes and proposed timelines.

In contrast, projects connected to existing operational mines are subject to fewer uncertainties due to pre-existing evaluations. In Zimbabwe, the Mupani mine is being developed to replace operating mines in the same geological setting close to depletion and should maintain and potentially increase current production volumes from 2025.[14] In South Africa, the re-start of the Bokoni mine, on maintenance since 2017, is expected in the coming years following its sale in 2022[15]. Bokoni should produce about 9 tonnes of PGMs per year.[16] Several other expansion projects are being developed worldwide, including LoM extension projects.

If all the projects above come online as expected, including resuming Darwendale, about 40 tonnes of PGMs could be produced annually from 2024, roughly 10% of current PGMs production[17]. This volume will be essential to maintain current production levels and potentially increase mined output.

Accompanying processing capacity will also need to be built to ensure a timely and successful increase in mining capacity to produce refined PGMs worldwide.

In the EU, future mining activity of PGMs produced as a by-product of base metals will depend on developing EU-level environmental regulations and sustainability standards, funding and financing mechanisms, and permitting schemes. New legislation could potentially make mining in the EU more attractive, thus increasing EU PGM by-product mining output and encouraging its reporting.

10 / The prill split indicates the proportions of the metals contained in the ore.
11 / See Ivanhoe Mines, 2022. Platreef project. Available at: https://www.ivanhoemines.com/projects/platreef-project/
12 / See local reports e.g. Mining Zimbabwe, 2022. VI holdings GDI exit: Time to remodel the Darwendale Platinum project. Available at: https://miningzimbabwe.com/vi-holdings-gdi-exit-time-to-remodel-the-darwendale-platinum-project/. See also NS ENERGY Business, 2022. Russia's Afromet pulls out from Darwendale platinum project in Zimbabwe. Available at: https://www.nsenergybusiness.com/news/afromet-pull-out-darwendale-platinum-project-zimbabwe/
13 / See Karo Mining, 2022. Karo Platinum. Available at: https://www.karomining.com/karo-platinum.php. See also Tharisa, 2022. 31st March Announcement. Available at: https://www.karomining.com/pdf/investors/sens-rns-announcement-karo-31mar22.pdf. Tharisa, 2022. KARO PGM PROJECT. Available at: https://www.tharisa.com/pdf/investors/presentation/2022/tplc-karo-announcement-presentation-final.pdf
14 / See Zimplats, 2021. CREATING A BETTER FUTURE THROUGH THE METALS WE PRODUCE. Available at: https://www.zimplats.com/data/2021/11/ZIMPLATS_Corporate_Brochure.pdf
15 / See Anglo American Platinum, 2021. 20th December Announcement. Available at: https://www.angloamericanplatinum.com/media/press-releases/2021/20-12-2021
16 / See African Rainbow Minerals (ARM), 2021. Bokoni Platinum Mine Acquisition. Available at: https://arm.co.za/wp-content/uploads/2021/12/Investor-Presentation-Bokoni-Platinum-Mine-Acquisition.pdf
17 / For a reference of current PGMs production see International Platinum Association (IPA), n.d. THE PRIMARY PRODUCTION OF PLATINUM GROUP METALS (PGMs). Available at: https://ipa-news.com/assets/sustainability/Primary%20Production%20Fact%20Sheet_LR.pdf

6.1.2.2. RESERVES AND RESOURCES

PGMs' geological deposits in the world have long been mined. Extensive PGMs deposits are concentrated in the Bushveld complex in South Africa. While geological deposits are assessments based on the metals in an ore body, "reserves and resources" have been broadly used in a techno-economic context to specify the amount of metals that can be reasonably extracted worldwide.

Resources are an umbrella term that generally indicate reasonable economic prospects for extraction, currently or eventually. Reserves indicate a part of the resources that meet further criteria that increase the confidence at which the mineral can be economically extracted at the time of the reporting. Reserves often have a well-developed operational mining plan. For detailed definitions and further explanations, see the South African Code for the Reporting of Exploration Results, Mineral Resources and Mineral Reserves (SAMREC, 2016) for reporting operations in South Africa.

Reserves and, to a lesser extent, resources are dynamic, even though PGMs are well-explored. Reserves and resources are often developed according to companies` strategies. These strategies are limited to many conditions, such as prices, demand, and extraction costs, and depend on companies` medium-term perspectives. Therefore, reserves and resources` levels are significantly affected over time by resource extraction, technological developments, and changes in the economic feasibility of extraction. In the same way, reported levels can be increased by further discovery, exploration, and development of deposits.

Companies typically report reserves and resources according to further confidence levels for extraction, e.g., based on the extension of evidence and sampling. **Table 1** below summarises the main terms used in reports.

TABLE 1

Summary of the main terms used to report PGMs

Term	Definition
Geological deposits	Metals contained in an ore body.
Resources	Metals with reasonable economic prospects for extraction, currently or eventually.
Measured and indicated	Potentially economically extractable metals at a maximum level of confidence.
Inferred	Potentially economically extractable metals at a minimum level of confidence.
Reserves	A part of the resources that meet further criteria, that increase the confidence at which the mineral can be economically extracted at the time of the reporting.
Proved	Economically extractable metals at a maximum confidence level in the reporting moment.
Probable	Economically extractable metals at a minimum confidence level in the reporting moment.

According to company reports, proved and probable reserves of platinum and palladium worldwide stood at 14,500 tonnes in 2021, with about 6,000 tonnes of platinum and 8,500 tonnes of palladium. Measured, indicated, and inferred platinum and palladium resources worldwide, in addition to reserves, stood together at 43,700 tonnes, each of which represents almost 22,000 tonnes. Due to the inclusion of inferred resources and probable reserves that depict the highest possible level of uncertainty in each category, these estimates should be interpreted as the upper bound of reported reserves and resources. At current production levels, companies' reserves and resources of platinum so far amount to another 159 years of mining production. In contrast, palladium reserves and resources amount to another 151 years of mining production.

Even though platinum and palladium are often the most prevalent metals in PGMs mining and typically represent high revenues for producers, worldwide reserve levels identified and assessed exclusively by mining companies are significantly lower than other estimates that do not use company reports solely. Only PGMs reserves estimated by the U.S. Geological Survey (USGS 2022a, but see methodology on 2022b) currently stand at 70,000 tonnes, or about another 175 years of current PGMs production[18]. On the other hand, resources are underestimated compared to company reports and stand at an additional 30,000 tonnes, bringing the total PGM reserves and resources level to 100,000 tonnes, or around another 250 years of current PGMs production[19]. The USGS reserves methodology consists of several sources, some of which apply the same criteria to different geographical deposits. If these are not available, it uses government reporting, or at last, company reports and scientific articles.

6.1.2.3. FUTURE CAPACITY FROM RECYCLING

Future production capacity of platinum and palladium from recycling can be increased by general improvements in recycling rates, proper disposal, and collection of a growing volume of scraps from long-life products, and new demand, such as from the hydrogen sector.

Recycling rates can be improved through logistics (e.g., better infrastructure to collect scraps), higher economic benefits of recycling (e.g., with increased demand), and technological improvements (e.g. research and innovation can increase recovery rates at a market scale and across applications).

Future volumes of scraps available for recycling could also increase metals production from recycling, should they be appropriately disposed of and collected. In the automotive sector, the gradual replacement of ICE vehicles with alternative drivetrains will lead to increased amounts of platinum and palladium-containing waste available for recycling and re-use in other applications, potentially electrolysers and Fuel Cell Electric Vehicles (FCEVs). For instance, if nearly 10 million gasoline passenger cars are produced in the upcoming years; each car contains about 5 grammes of PGMs (FVV, 2021) [footnote20]; they are correctly disposed of; they are not replaced by a new ICE vehicle; and the PGMs are recovered at a 97% rate; there would potentially be 47 tonnes of platinum or palladium available for use in other applications, or about 15-21% of each metal`s current production capacity. This is expected if ICE vehicles' demand ceases in the market or closed-loop recycling. In the hydrogen sector, research targets for the recycling of metals from electrolysers and fuel cells at end-of-life have been set up until 2030 in the EU, aiming to recycle 99% of their platinum content and 50% of the other PGMs content, such as palladium (Clean Hydrogen JU, 2022).

In the EU, upcoming legislation could also increase recycled output in the near term. The "Ecodesign requirements for sustainable products"[21], proposed by the European Commission in March 2022 as a review of the Ecodesign

18 / For a reference of current PGMs production see International Platinum Association (IPA), n.d. THE PRIMARY PRODUCTION OF PLATINUM GROUP METALS (PGMs). Available at: https://ipa-news.com/assets/sustainability/Primary%20Production%20Fact%20Sheet_LR.pdf
19 / Ibid.
20 / FVV (2021) estimates there will be about 5 grammes of PGMs per gasoline car in the future. In this case, the PGMs are: platinum, palladium or rhodium.
21 / See European Commission, 2022. COM(2022) 142 final: Proposal for establishing a framework for setting ecodesign requirements for sustainable products and repealing Directive 2009/125/EC. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52022PC0142
22 / See European Commission, 2009. DIRECTIVE 2009/125/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL. Available at: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:285:0010:0035:en:PDF

Directive[22], promotes more sustainability over the whole life cycle of goods placed in the market. It could boost demand for recycled goods, increase their recycled content, and generally increase recycling rates in the EU.

The revision of the "Waste Shipment Regulation" proposed in November 2021[23], tightens restrictions on exports of several raw materials in the form of waste. However, in general, PGMs containing waste may continue to be traded with third countries. The proposal should also facilitate shipping waste destined for recovery in the EU.

In addition, the "Critical Raw Materials Act", announced in September 2022[24] and expected to be published in March 2023, could support raw materials recycling projects in the EU, by e.g., ensuring better access to finance, promoting sustainability standards, and potentially introducing targets setting demand for recycled materials in the legislation. Potential amendments to the current waste legislation[25] mentioned in this Act could also promote recycling of strategic raw materials and demand for recycled materials.

6.1.2.4 TOTAL PRODUCTION CAPACITY

Increased prices are a vital signal for investment decisions in the industry. Therefore, the future production capacity of platinum and palladium will depend on new mining activities investments to maintain current production levels and increase mining capacity above current levels. Especially in the near term, future capacity will also depend on recycling developments such as improvements in recycling rates (e.g., by improving collection rates) and large-scale disposal and collection of scraps from long-life products from the automotive sector and of new demand, such as from hydrogen applications. Increased prices and demand for recycled products, potentially promoted by legislation, are crucial to boosting recycling activities.

6.1.3. Price trends

As mentioned, prices are an important signal for the development and sustainability of future production capacity and can cause temporary disruptions in supply chains. Price volatility captures these metals' long-term fluctuation and price sensitivity to market conditions.

Platinum prices in the last 20 years have ranged from the low of 410 USD per troy ounce in 2001 to the high of 2,276 USD per troy ounce before the 2008 crisis, indicating volatility of approximately six times between the highest and lowest price. In 2021, the price varied between 894 and 1,293 USD, averaging 1,088 USD per troy ounce.

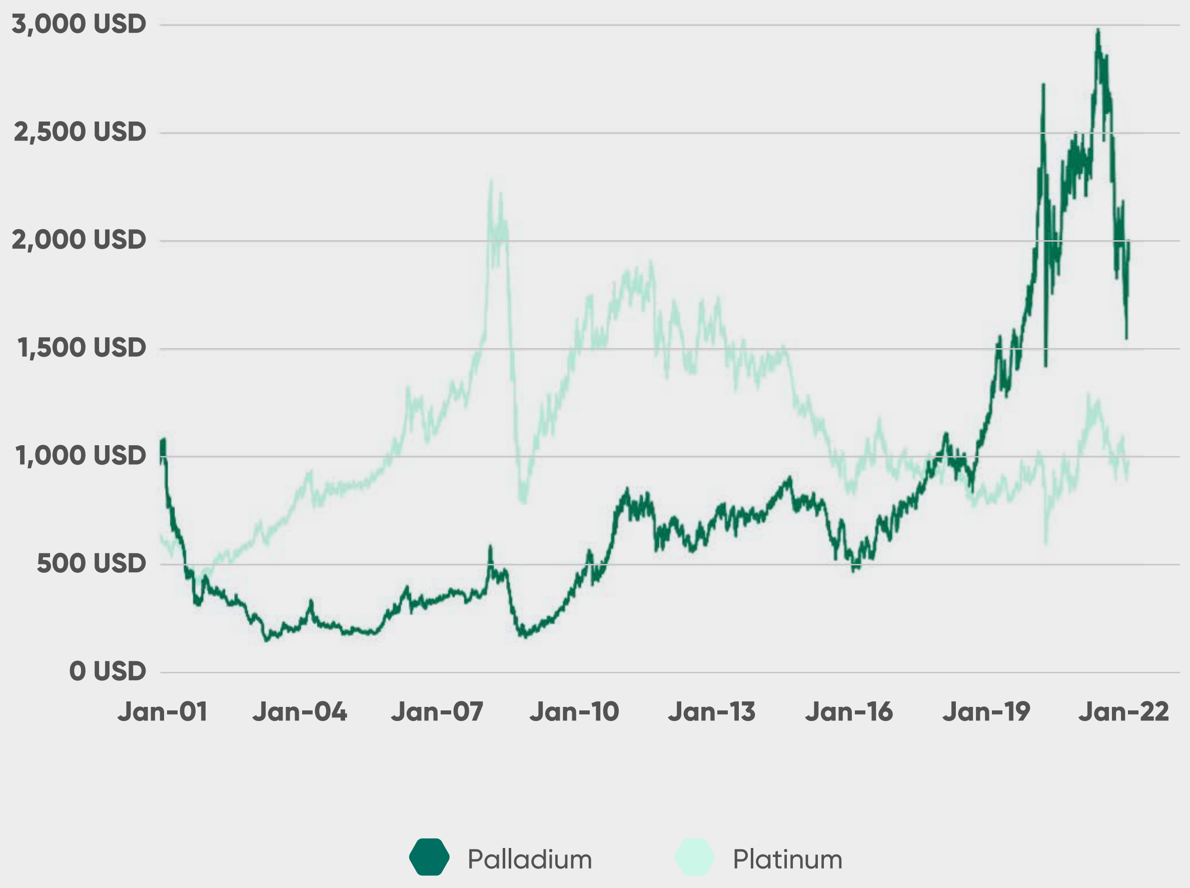
Palladium has experienced even higher price volatility in the last 20 years. With the low of 148 USD per troy ounce in 2003 and the high price of 2,981 USD per troy ounce in 2021, following disruptions caused by the Covid-crisis, price volatility was around 20 times between the highest and lowest price. In 2021, the price varied between 1,552 and 2,981 USD, with an average of 2,388 USD per troy ounce. **Figure 4** shows the price of platinum and palladium over the last 20 years.

Overall, the high price volatility of both metals in the last 20 years exemplifies relatively limited market liquidity. This is a typical market condition for precious metals, which are rare and often used as an investment. Even though palladium has a larger market size, it is subject to substantially higher price volatility than platinum. It has historically been used as an alternative to platinum (e.g., in gasoline automotive catalysts) when platinum prices were too high. However, palladium has now long been broadly used in gasoline catalysts. In contrast, platinum has been limited to diesel catalysts, making palladium prices particularly sensitive to demand changes from automotive catalysts. As a result, following an increase in environmental regulations around the world that sparked demand for automotive catalysts to reduce harmful emissions from vehicles, palladium prices have been significantly higher than platinum in the past few years.

23 / See European Commission, 2021. COM(2021) 709 final: Proposal on shipments of waste and amending Regulations (EU) No 1257/2013 and (EU) No 2020/1056. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0709&qid=1642757230360
24 / See European Commission, 2022. [Statement]. Critical Raw Materials Act: securing the new gas & oil at the heart of our economy. Available at: https://ec.europa.eu/commission/presscorner/detail/en/STATEMENT_22_5523
25 / See European Commission, 2018. DIRECTIVE 2008/98/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02008L0098-20180705

FIGURE 4

Platinum and palladium prices in USD per troy ounce



Source: Hydrogen Europe using data retrieved from Macrotrends (2022).[26]

26 / Macrotrends, 2022. Platinum/Palladium prices. Available at: www.macrotrends.net

Conclusion

Current production capacity of platinum is estimated at 227 tonnes/year and palladium at 305 tonnes/year, of which 23% and 34%, respectively, is from recycling.

Overall, the current mining capacity of platinum is geographically concentrated in South Africa (75%), whereas palladium mining is focused on Russia (42%). Zimbabwe follows as another significant producer of both metals (6-8.5%). Future mining capacity should remain concentrated in South Africa, Russia, and Zimbabwe.

Investments in new mining projects will be key for maintaining current production and increasing future production capacity. It takes roughly ten years from exploration to commencing production in a new PGMs mining project and around four years to develop accompanying processing capacity. In addition to timely investments, reserves and resource exploration are determinants when assessing future production. Typical assessments have been conducted according to medium-term market conditions and could change significantly with increased demand. In the EU, new legislation on, e.g., environmental regulations and permitting schemes, could encourage the production and reporting of PGMs produced in the bloc as a by-product of base metals.

Recycling is crucial to ensure immediate and future availability of palladium and platinum. It can contribute to a more sustainable production due to its lower environmental impact (e.g. lower carbon footprint) compared to mined production. In the EU, more targeted recycling research, dedicated binding targets for PGMs recycling, and demand stimulation are all considered to increase recycled output. Improving recycling rates can reduce the EU's dependency on imports, reliance on recovery of materials from third countries, and vulnerability to waste trade restrictions (e.g. export restrictions). Better statistics on the exports of potentially recoverable PGMs, and recovery rates in third countries, could also contribute to increasing production capacity.

There is much uncertainty about the future of PGMs production, but there is also significant potential for increases. To avoid potential temporary disruptions in value chains, future assessments and policies must consider the pace at which production can be ramped up and the size and speed at which future demand increases. These factors will be essential to ensure the security of supply and resilient value chains.

Acknowledgements note

We thank Alison Cowley, Margery Ryan, Rupen Raithatha, and Silvain Buche from Johnson Matthey for the valuable discussions and comments on the chapter. We also thank for numerous insights Matthew Turner and David Jollie from Anglo American, Javier Dufour from the Madrid Institutes for Advanced Studies in Energy (IMDEA Energy), and Julian Köhle and Gabriele Randlshofer from the International Platinum Group Metals Association (IPA). Any errors in this chapter are our own and should not be attributed to our contributors.

Methodological note

As it is difficult to measure current production capacity directly, the volume of platinum and palladium produced in 2021 is used to estimate it. Even though volumes vary yearly depending on operational and market conditions (e.g., mine accidents that may cause disruptions, operational events causing temporary closures, depletion of old shafts and development of new shafts, fluctuating economic benefits of recycling scraps, or logistics disruptions in waste collection), volumes are fairly representative of capacity at relatively stable circumstances. Therefore, the estimates in this chapter should not be interpreted as a constant but rather as the best available estimate to showcase the potential availability of materials, still subject to the operational and market dynamics mentioned above.

The processing market also has its dynamics. It is difficult to assess as it does not follow the same reporting structure as mining. It depends on complex economic and technological conditions, e.g., high CAPEX required to build additional capacity and the quality of the processed ore. Even though future growth in metals` demand and prices could remove some (economic) barriers and spark processing activities to accompany production, these will depend on the abovementioned dynamics. To avoid capturing them, mining production estimates are presented in concentrate. However, ensuring sufficient processing capacity will be crucial to guarantee the availability of materials on time. For reference, industry sources estimate an average of 4 years to build additional processing capacity and about six weeks is needed to mine and process a batch of metal.

Hydrogen Europe data on mined production was collected using publicly available data from producers' reports and adjusted, whenever necessary, for average refining losses, which typically represent less than 2% of the mined volume. Production was allocated to when and where the mining activity took place, regardless of posterior processing activities. The estimated production capacity does not take demand forecasts into account.

Finally, the volume of metal available in the market will further depend on usual supply, demand, and storage dynamics. Increasing prices and resulting stocking decisions by producers or consumers might increase market volumes and vice-versa. The production estimates presented in this chapter may be significantly different from market supply estimates. For a supply reference, see, e.g., the "PGM market report" from Johnson Matthey (2022).

References

Anglo American Platinum, 2014. OVERVIEW OF PGM PROCESSING. Available at: https://www.angloamericanplatinum.com/~/media/Files/A/Anglo-American-Group/Platinum/investor-presentations/2014/standardbankconference-anglo-american-platinum-processing-111114.pdf

Clean Hydrogen Joint-Undertaking (Clean Hydrogen JU), 2022. Strategic Research and Innovation Agenda (SRIA) 2021-2027. Available at: https://www.clean-hydrogen.europa.eu/system/files/2022-02/Clean%20Hydrogen%20JU%20SRIA%20-%20approved%20by%20GB%20-%20clean%20for%20publication%20%28ID%2013246486%29.pdf

Die Forschungsvereinigung Verbrennungskraftmaschinen e.V. (FVV), 2021. Future Fuels: FVV Fuels Study IV. Available at: https://www.fvv-net.de/fileadmin/user_upload/medien/download/FVV__Future_Fuels__StudyIV_The_Transformation_of_Mobility__H1269_2021-10__EN.pdf

European Commission, Directorate-General for Internal Market, Industry, Entrepreneurship and SMEs, 2021. 3rd Raw Materials Scoreboard: European innovation partnership on raw materials. Available at: https://op.europa.eu/en/publication-detail/-/publication/eb052a18-c1f3-11eb-a925-01aa75ed71a1

Johnson Matthey, 2022. PGM market report. Available at: https://matthey.com/documents/161599/509428/PGM-market-report-May-2022.pdf/542bcada-f4ac-a673-5f95-ad1bbfca5106?t=1655877358676

South African Mineral Resource Committee (SAMREC), 2016. South African Code for the Reporting of Exploration Results, Mineral Resources and Mineral Reserves (The SAMREC code). Available at: https://www.samcode.co.za/codes/category/8-reporting-codes?download=120

Statistical Office of the European Union (EUROSTAT), 2021. Waste Streams: Trade in waste by type of material and partner. Available at: https://ec.europa.eu/eurostat/databrowser/view/ENV_WASTRDMP__custom_3151812/default/table?lang=en

U.S. Geological Survey (USGS), 2022a. Mineral Commodity Summaries: PLATINUM-GROUP METALS. Available at: https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-platinum.pdf

U.S. Geological Survey (USGS), 2022b. Mineral Commodity Summaries: APPENDIX C. Available at: https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-appendixes.pdf


© Frederic Köberl

07

EU policies and incentives

Introduction

The EU sees a vital role for hydrogen in reaching its ambitious climate objectives for 2030 and 2050. To achieve this, the European Commission has initiated one of the most fundamental revisions of key legislation in the energy, transport, and industry sectors in the ‘Fit for 55’ package. In addition, recent developments in Ukraine have demonstrated that hydrogen is also key in ensuring the EU’s energy security. In the REPowerEU Communication and Plan, published in 2022, several initiatives were outlined which aim to accelerate the production, import and use of renewable hydrogen in Europe.

This chapter will present key policy and legislative developments, specifically focusing on the period between September 2021 and September 2022. It will cover the REPowerEU Plan and the legislative proposals within the ‘Fit for 55’ and ‘Hydrogen and Decarbonised Gas Market’ packages.

7.1.

REPowerEU Plan and the Hydrogen Accelerator

On 18 May 2022, the Commission presented the REPowerEU Plan. The Plan responds to the energy market disruptions caused by the Russian invasion of Ukraine and seeks to rapidly reduce the EU's dependence on Russian fossil fuels. It aims to complement and accelerate several ongoing EU legislative initiatives, first and foremost the 'Fit for 55' package. This is done, among others, by further raising several targets initially proposed in the 'Fit for 55' package. For example, REPowerEU seeks to increase the target for renewable energy to 45% by 2030 compared to the 40% proposed in the Commission's draft revision of the Renewable Energy Directive (RED II) from July 2021. This specific proposal indicates the Commission's intent to massively accelerate and scale up renewable energy for power generation, industry, buildings, and transport.

Hydrogen has been identified as one of the six components of this effort, which is to be realised through a combination of short- and medium-term measures. These measures cover four main pillars: energy savings, diversification of energy sources, acceleration of the clean energy transition and smart investments. For instance, **Table 1** outlines important measures to be implemented to accelerate the clean energy transition, which directly impacts the future development of the hydrogen sector.

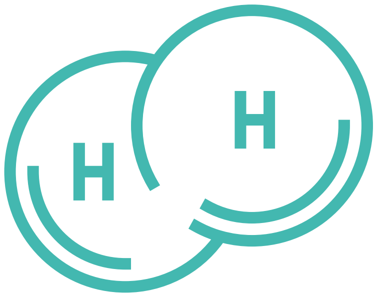
TABLE 1

Substituting Fossil Fuels and acceleration the clean energy transition

Boosting Renewable Energy (EU Solar Strategy, Permitting)	Accelerating Hydrogen	Bio-methane and R&I	Developing a European Hydrogen Grid	Reducing Fossil Consumption in Hard-to-Abate Sectors
• 45 % RES target • RES a public interest (RED changes) • Permitting guidance • Double the sale of heat pumps in 5 years	• RED targets (from 5.6 Mt to 9 Mt by 2030) • Two Delegated Acts • IPCEIs acceleration • EUR 200 million for H2 Valleys (Clean Hydrogen Partnership) + EUR 200 million from industry • Hydrogen demand report as of 2021	• Production target of 30 bcm • Biogas and Bio-methane partnership • EUR 19.1 billion for R&I in other partnerships (aviation, steel, rail, waterborne)	• TEN-E: by March 2023, a preliminary H2 infrastructure needs • PCI and PMI list by end of 2023 with access to CEF by 2024	• CCFDs • Innovation Fund calls up to EUR 3 billion: Clean tech manufacturing and H2 in industry

Source: Hydrogen Europe.

Hydrogen Accelerator



The Commission has devoted an entire section of the REPowerEU to hydrogen, setting an indicative, non-binding target of 10 million tonnes of domestic hydrogen production and 10 million tonnes of imported renewable hydrogen by 2030.

To achieve this, the Hydrogen Accelerator includes:

Call for action to the Parliament and the Council to align the sub-targets for renewable fuels of non-biological origin (RFNBOs) in industry and transport in the revised RED II with the REPowerEU ambitions. In the Plan, the **Commission proposes raising the target for industry from 50% to 75% and for transport from 2.6% to 5%.** It also calls on the institutions to rapidly conclude the revision of the Hydrogen and Decarbonised Gas Market package.

Top-up of Horizon Europe investments in the Clean Hydrogen Partnership with **EUR 200 million to double the number of Hydrogen Valleys.**

Finalising and publishing the two Delegated Acts on the definition of RFNBOs and the methodology for **accounting for their GHG emissions.**

Accelerating the assessment and approval of IPCEIs on hydrogen (the Commission has published the first wave of hydrogen technology ICPEIs in July 2022, and the second wave of projects dedicated to production, hydrogen-related infrastructure, and innovative hydrogen technologies in end use sectors in September 2022). Two more waves are being prepared on infrastructure and mobility.

Call for action to industry to accelerate the work on missing **hydrogen standards,** particularly for hydrogen production, infrastructure, and end-use applications.

Commitment to regularly report on hydrogen uptake and the **use of renewable hydrogen in hard-to-abate applications in industry and transport.**

In addition, the Commission has recognised that accelerated efforts are needed regarding infrastructure development for producing, importing, and transporting 20 million tonnes of hydrogen by 2030. To improve the domestic hydrogen infrastructure, the EU can count on the revised Trans-European Networks for Energy (TEN-E) Regulation which allows the identification of hydrogen storage and transport projects as early as 2024. For the import infrastructure, the Plan identifies three major hydrogen import corridors (Mediterranean, North Sea area and, as soon as conditions allow, Ukraine) and provides the industry with dedicated platforms where major players within these corridors can connect, partner up and work towards the imports' target set by REPowerEU. One of the corridors will be addressed by the Mediterranean Hydrogen Partnership; it will be developed by the EU and Egypt and will promote investments in renewable electricity generation, strengthening and extension of electricity grids, including trans-Mediterranean interconnectors, the production of renewables and low carbon hydrogen, and the construction of storage, transport, and distribution infrastructure.

Moreover, in September 2022, President of the European Commission Ursula Von de Leyen announced the creation of a new European Hydrogen bank, which role will be to "help guarantee the supply of Hydrogen" and construct a "future hydrogen market". This public bank will be able to invest EUR 3 billion using money from the Innovation Fund and aims to contribute to fill the investment gap faced by the industry. No specification was given on how this facility would relate to the various tools presented by the EC in the RepowerEU plan in May, including the Global European Hydrogen Facility and its targeted support to imports. Together the future European Hydrogen Bank and the Green Hydrogen Partnerships should deliver a framework to ensure that partnerships established by the Members States and by the industry provide a level-playing field between EU production and third country imports and that these are not set up in isolation.

Furthermore, the REPowerEU highlights the need to strengthen Europe's industrial competitiveness and support international technology leadership. It estimates that energy efficiency, fuel substitution, electrification, and enhanced uptake of renewable hydrogen, biogas and biomethane by the industry could save up to 35 billion cubic metres of natural gas by 2030, in addition to what is already foreseen in the 'Fit for 55' package. As such, the Commission outlines additional measures to support the adoption of hydrogen and electrification in the industrial sectors.

Finally, in the context of the REPowerEU efforts, the Electrolyser Partnership was launched in September 2022. The Partnership is a dedicated platform under the

TABLE 2

Additional measures in REPowerEU Plan to support hydrogen uptake and electrification in the industry

REPOWEREU MEASURES TO SUPPORT HYDROGEN ADOPTION AND ELECTRIFICATION IN THE INDUSTRY
• The rollout of carbon contracts for difference (CCfD) and dedicated REPowerEU windows under the Innovation Fund to support a complete switch of the existing hydrogen production in the industry from natural gas to renewables and the transition to hydrogen-based production processes in new industrial sectors. • Double the funding available for the 2022 Large Scale Call of the Innovation Fund to around EUR 3 billion and create a dedicated window for hydrogen in the industry and a window for Electrolyser and Fuel Cells manufacturing. • Develop a technical advisory facility under the InvestEU Advisory Hub, in cooperation with the EIB, to support PPA-financed renewable energy projects.

Source: Hydrogen Europe.

European Clean Hydrogen Alliance which brings together electrolyser manufacturers and suppliers of components and materials. It is the result of the Electrolyser Summit, which took place in May 2022, jointly organised by the Commission and Hydrogen Europe. At the Summit, 20 industry CEOs and the Internal Market Commissioner Thierry Breton signed a joint declaration outlining the commitment of the electrolyser industry and the Commission to realise the ambitious REPowerEU goals. With support from the Commission in removing regulatory, financial, and supply-chain roadblocks, electrolyser manufacturers aim at achieving 17.5 GW of combined annual electrolyser manufacturing capacity by 2025.[1] To this end, the Commission has already eased access to financing from its Innovation Fund (IF) for electrolyser manufacturers. The third Large-Scale Call, to be opened in November, with a budget of EUR 3 billion, will have a dedicated window supporting innovative clean tech manufacturing, including electrolysers. (See **Chapter 8**).

7.2.

Legislative acts and proposals adopted and presented in 2021 and 2022

The Commission presented its 'Fit for 55' package in July 2021, aiming to completely overhaul key climate, energy, and transport legislation to reach its ambitious climate objectives for 2030 and 2050. This was followed by a publication of the 'Hydrogen and Decarbonised Gas Market' package in December 2021, aiming to facilitate the integration of renewable and low-carbon gases into the existing gas network **(Table 3).** In addition, several other important legislations for the sector have been published, including the TEN-T Regulation setting the framework for investments into hydrogen refuelling stations (December 2021) and a proposal to revise the Industry Emission Directive (April 2022).

TABLE 3

Overview of the state of play of the 'Fit for 55' package as of 29.09.2022

	EC Proposal	Council (GA)	EP Committee	EP Plenary	In Trilogues	Final legislation
AFIR	Fit-4-55	2 Jun	3 Oct	10 Oct		
CO2 standards	Fit-4-55	29 Jun	11 May	8 Jun		
REFuelEU Aviation	Fit-4-55	2 Jun	27 Jun	7 Jul		
FuelEU Maritime	Fit-4-55	2 Jun	10 Oct	Oct		
RED II	Fit-4-55	26 Jun	13 Jul	14 Sep		
Energy Taxation Directive	Fit-4-55		26 Sep	Oct		
Energy Efficiency Directive	Fit-4-55		13 Jul	13 Sep		
EPBD	Fit-4-55	25 Oct / 19 Dec	26 Oct	Dec		
ETS	Fit-4-55	29 Jun	24 May	22 Jun		
CBAM	Fit-4-55	15 Mar	25 May	22 Jun		End Nov
REPowerEU	May 2022	Partial – 4 Oct				
TEN-T	Dec 2021		Jan 2023	Feb 2023		
Gas&H2 Directive	Dec 2021	19 Dec	28 Nov			
Gas&H2 Regulation	Dec 2021	19 Dec	28 Nov			
IED	April 2022		Apr 2023	May 2023		
ESPR						
CPR						

Source: Hydrogen Europe.

Past Future

1 / Measured in terms of hydrogen output; 25 GW if measured in terms of electricity input and assuming electrolyser efficiency of 70%.

Several discussions on the 'Fit for 55' package have already taken place both in the European Parliament and in the Council of the EU. They are expected to intensify in the second half of 2022. At the time of writing this report, none of the 12 legislative initiatives in the 'Fit for 55' package put forward by the Commission have yet been adopted.[2] Given the sheer size of the task, it is highly likely that the work on these files will continue well into 2023. More so as the Commission has revisited its proposals and placed even higher targets and stronger measures in the REPowerEU with a direct impact on several policy files in the 'Fit for 55' package, including the revision of RED II. These now must be addressed by the Parliament and the Council in their respective positions.

The work has most advanced in the case of CBAM and ETS, where the Parliament and the Council have already entered into trilogues with the Commission and could reach a final compromise at the end of 2022. As for the rest of the files, the level of progress differs. The Council still has to finalise its position on most files, including the Energy Performance of Buildings Directive (EPBD) and the Energy Efficiency Directive (EED). The European Parliament will also have a busy autumn agenda as it has only adopted positions on four files: CO2 standards for cars/vans, Carbon Border Adjustment Mechanism (CBAM), ETS, and ReFuelEU aviation.

For the hydrogen sector, the revisions of the Renewable Energy Directive (REDII) and the EU Emissions Trading Scheme Directive (ETS), the adoption of the Alternative Fuel Infrastructure Regulation (AFIR) and Hydrogen and Decarbonised Gas Market package are of crucial importance. An overview of the latest developments on these files will be presented in greater detail in the following sections. However, it should be noted that every single piece of legislation in the 'Fit for 55' package will impact the sector's future. Take, for example, the REFuelEU Aviation Regulation, which, once adopted, will require fuel suppliers to increase the distribution of sustainable aviation fuels (SAF), including synthetic aviation fuels, driving the demand for hydrogen over time. Similarly, FuelEU Maritime Regulation which will set mandatory greenhouse gas (GHG) emission reduction targets, will increase the use of hydrogen and hydrogen-based fuels in the sector.

7.2.1. Spotlight on REDII targets revision

In the REPowerEU, the Commission has further revised its own proposed target set in the draft revision of the Renewable Energy Directive (RED II) for the share of renewable energy sources by 2030, along with several sectorial targets in transport, buildings, and industry to ensure the expansion of renewables beyond the power sector. It proposed to raise the renewable target from 40% to 45% by 2030. On hydrogen, it proposed increasing the binding targets in industry and transport to 75% and 5%, respectively, from the previously proposed 50% and 2.6%. These new targets, if adopted, would result into an estimated demand of renewable hydrogen of 6.2 million tonnes for industry (excluding refineries) and 4.2 – 4.8 million tonnes for transport (including refineries), depending on market developments (Staff Working Document to the REPowerEU Plan, 2022).

The Parliament has followed the Commission's recommendations with its Committee on Industry, Research and Energy (ITRE) calling for a 45% renewable target by 2030. Regarding the sectoral targets, it calls for an industry binding target of 50% by 2030 and 70% by 2035, an RFNBO target of 5.6% for transport, and a sub-target for maritime transport of 1.2% by 2030. These proposals were adopted by the Parliament's Plenary on 13 September. The industry and fuel suppliers are worried about whether there will be sufficient renewable hydrogen at a competitive cost to meet these binding targets. This will very much depend on the delegated act on additionality for RFNBOs. With that in mind, the Parliament proposes a review clause in 2026 to adjust the target to future developments. While a review clause might seem like a good compromise, it might further delay efforts on hydrogen uptake, casting doubts on the level of ambition needed.

On the other hand, the Council did not follow the Commission's recommendations outlined in the REPowerEU and has

2 / European Commission, European Green Deal Press release, available at https://ec.europa.eu/commission/presscorner/detail/en/ip_21_3541.

instead supported the original proposal of a 40% renewable energy target. In its position, reached during the French Presidency of the EU, it also came out with a proposal for a 35% binding industry target for hydrogen. While this is below the initial expectations, the Council still endorses a binding target for the industry. The same cannot be said for the transport target, where the Council drastically reduced the Commission's ambitions by not supporting a binding target for RFNBOs in the sector but an indicative one of 5.2%.

The final targets will be negotiated in the trilogues, expected to start in the second half of 2022. However, the Council's lowering of the ambition for hydrogen in transport puts the entire sector's transformation at risk. It also doubts countries' readiness to move beyond biofuels in maritime, aviation and heavy-duty transport.

7.2.2. Delegated Acts on RFNBOs

The two delegated acts on RFNBOs - one defining the methodology for assessing GHG savings from RFNBOs and from RCFs and another one setting the rules on electricity use for RFNBO production to be counted as fully renewable - are seen as "make it or break it" for the industry. As the RED II revision will most likely set mandatory and ambitious targets for RFNBOs in industry and transport, defining what can be counted as RFNBO will be fundamental to achieving these. The fact that the Commission has delayed publishing the draft delegated acts for almost a year further speaks to the issue's complexity and the relevance of these criteria for the hydrogen industry.

The Commission had to adopt the two delegated acts in 2021 to supplement the Renewable Energy Directive (RED II). Article 25(1) of the RED II mandates Member States to set obligations on fuel suppliers to ensure that the share of renewable energy within the final energy consumption in the transport sector is at least 14%. To calculate this share, they must also consider RFNBOs when they are used as intermediate products for conventional fuel production and may consider Recycled Carbon Fuels (RCF).

This section provides an overview of the key features of the draft two delegated acts, which were published for consultation in May 2022, with the disclaimer that the rules contained within are subject to change until their final adoption.

Draft delegated act establishing a Union methodology setting out detailed rules for the production of RFNBOs

This Delegated act sets the regulations on electricity use for RFNBO production to be counted as fully renewable. It is better known as the Delegated act on additionality, and while implementing the 'additionality' principle, it should also allow for sector development. To achieve this, four scenarios are provided for:

TABLE 4 **1/2**

Possible scenarios for RFNBO production to be counted as fully renewable under the draft delegated act on additionality

SCENARIO 1

- RFNBO production facility and the RES electricity plant must be connected via a direct line or within the same installation.
- RES plant should become operational no earlier than three years before the RFNBO facility.
- RFNBO facility could increase its capacity in the next 24 months while still being considered the same installation. The combined facility should not be connected to the grid or behind the same smart metering point, which measures all electricity flows, to ensure that no grid electricity is used for RFNBO production.

TABLE 4 **2/2**

SCENARIO 2

• Allows electricity to be counted as fully renewable if the RFNBO facility is in a bidding zone, where the average proportion of RES electricity in the preceding calendar year exceeds 90%. A limit on the operating hours of the RFNBO production is imposed in this case, where it does not produce for more hours than the hours derived from the multiplication of the total number of hours in the calendar year times the share of RES electricity reported for the bidding zone.

SCENARIO 3

• Where the average proportion of renewable electricity does not exceed 90%, fuel producers may count electricity taken from the grid as fully renewable if it complies with the conditions on additionality, temporal correlation and geographic correlation in accordance with Articles 5, 6 and 7.

SCENARIO 4

• Where electricity is consumed during an imbalance settlement during which the fuel producer can demonstrate, based on evidence from the national transmission system operator, that power-generating installations using renewable energy sources were downward redispatched and the electricity consumed is reducing the need for redispatching by a corresponding amount.

SCENARIO 5

Scenario 5 is more complex than the previous two, aiming to regulate projects where renewable electricity is sourced under one or more power purchase agreements (PPA).

Four criteria are set:

(1) The RES power plant has started operation no earlier than 36 months before the RFNBO facility. If this is the case and the PPA has ended, any new PPA between the two is considered to be in accordance with this criterion. If new production capacity is added to the RFNBO facility in the following 36 months after its initial start of operations, this new capacity is considered part of the same installation.

(2) The RES plant has not received any CAPEX or OPEX support.

(3) RES electricity generation under the PPA(s) and RFNBO production should take place either in the same one-hour period; or through storage behind the same network connection point that has been charged during the same one-hour period; or during a one-hour period, where the clearing price of electricity resulting from a single day-ahead market coupling in the bidding zone is lower or equal to EUR 20/MWh or lower than 0.36 times the price of an ETS allowance for 1 tCO2.

(4) The last criterion is related to the bidding zone location of the electrolyser. Three possibilities are available: (i) the RES plant is located or was located at the time of the start of operations in the same bidding zone as the electrolyser; (ii) the RES plant is located in a neighbouring bidding zone, where day-ahead electricity prices for the same hour are equal or higher than in the bidding zone where the RFNBO plant is located; (iii) RES plant is located in an adjacent offshore bidding zone to the RFNBO facility.

Member States may decide that all bidding zones located in the Member State should be considered as one bidding zone and may introduce additional criteria concerning the location of electrolysers.

Source: Hydrogen Europe.

Furthermore, the Commission has proposed a transitional phase during which the 36-month period for a RES plant to become operational before the RFNBO facility and the prohibition of receiving CAPEX/OPEX support would not apply. Instead, they would be applicable only as of 1 January 2027. This is further strengthened by the 'grandfathering' provision, which benefits early investors, where these two derogations are extended to RFNBO installations that start operation before 1 January 2027 for their operational lifetime. Additionally, in this transitional phase, the above-described obligation on the same one-hour correlation between electricity generated and RFNBOs produced are subject to a relaxed regime until 31 December 2026, applying a requirement of monthly correlation.

Draft delegated act establishing a minimum threshold for greenhouse gas emissions savings of RCFs and specifying a methodology for assessing greenhouse gas emissions savings from RFNBOs and RCFs

This delegated act establishes the minimum threshold for GHG savings of RCFs and specifies the methodology for assessing the GHG savings from RFNBOs and RCFs. The emissions reduction threshold set for RCFs is 70%. The fossil fuel comparator for hydrogen used to produce RFNBOs and RCFs is 94 gCO2eq/MJ. This would mean that with a 70% required reduction, the GHG footprint threshold for hydrogen is 3.38 tCO2/tH2 before all other emissions, such as emissions for liquefaction and from fuel transportation, are accounted for, except emissions related to compression.

Concerning CO2 accounting, the delegated act sets that captured CO2 can be deduced from the carbon footprint of RCFs and RFNBOs in some instances. Firstly, if the CO2 is captured in industries covered by the ETS, it could be counted only if the full CO2 price was paid under the scheme and until 2035. Secondly, if it comes from Direct Air Capture. Thirdly, if it is captured from biofuels/liquids or biomass production. Lastly, if it comes from non-sustainable sources, but only until 2035.

Concerning the carbon footprint of electricity used to produce RFNBOs or RCFs, it can be either zero, when it is fully renewable according to the delegated act on additionality, or one of the three approaches for its calculation has to be followed:

Taking the average carbon intensity of the grid of the Member States (including upstream emissions);

Or, where the number of full load hours in which electrolyser is producing is equal or lower than the number of hours in which the marginal price of electricity was set by installations producing renewable electricity or nuclear power plants in the preceding calendar year, grid electricity can also be counted as zero-emission. Where this number is exceeded, electricity from the grid used in producing RFNBOs and RCFs shall be attributed to a GHG value of 183 gCO2eq/MJ.

Or when the GHG emission value of the marginal unit generating electricity at the time of production of the RFNBO in the bidding zone may be used if this information is publicly available from a reliable source.

The Commission published the two draft delegated acts in May 2022, alongside the REPowerEU Plan. Under normal circumstances, in the case of delegated acts, once the Commission adopts the final version, it must notify the Parliament and the Council. The acts will then be enforced within two months of notification if the two institutions have not objected. However, given the reactions to draft delegated acts, particularly the one on additionality, and their relevance for the hydrogen industry, the process could drag well into 2023. In its current form, the draft Delegated act on additionality could hamper the nascent hydrogen industry in Europe. It would impose an unnecessary financial and technical burden on the growing but small green hydrogen production. Not overregulating hydrogen production is becoming even more relevant when Europe's competitors put clear and straightforward rules for renewable energy production, making it easier than ever for renewable energy projects to develop. Therefore, it is crucial that the European Commission, in close conversation with the industry, finds less bureaucratic and complex approaches to ensure the ramp-up of hydrogen goes along with additional renewable energy sorces.

7.2.2. Spotlight on afir debate

The Alternative Fuels Infrastructure Regulation (AFIR) is a crucial piece of legislation for developing hydrogen mobility, as it sets mandatory national targets for deploying hydrogen refuelling stations (HRS). The proposed Regulation is a big step forward compared to its predecessor, the Alternative Fuels Infrastructure Directive (AFID), which had placed a low priority on deploying hydrogen infrastructure by letting Member States decide whether to invest and deploy HRS towards the 2020 timeline. That said, the AFIR proposal only focuses on hydrogen for road transport. It does not include HRS requirements for other modes of transportation, such as waterborne transport, where hydrogen and its derivatives are poised to become the main fuels to lead its decarbonisation.

The Parliament and the Council have nearly concluded their respective positions on AFIR (summarised in **Table 5**. They will start with the negotiations on the file towards the end of the year. While the Commission and the Parliament are more or less aligned on the file, with the Parliament being even more ambitious and calling for a minimum distance of HRS of 100 km instead of 150 km, the Council's position differs significantly.[3] Some EU Member States do not see a strong market uptake for FCEV passenger cars and trucks, fearing that the costly infrastructure would not be utilised. Therefore, the Council's position is far less ambitious regarding HRS targets, increasing the minimum distance of HRS from 150 to 200 km, applicable only to the TEN-T Core networks. It also leaves the decisions on minimum capacities, HRS in urban nodes and deployment of liquid H2 for a potential revision of the regulation in 2024. The final legislation is expected in early 2023.

TABLE 5

Positions of the EU institutions on AFIR targets

	EC proposal	Every 200 km on TEN-T Core	EP draft position
HRS	Every 150 km along TEN-T Core and Comprehensive	Every 200 km on TEN-T Core	Every 100 km along TEN-T Core and Comprehensive
HRS in urban nodes	At least one in 424 large EU cities	Possibly, under a 2024 revision	At least one in 424 large EU cities
HRS capacity	Min. 2 t/day		Min. 2 t/day
HRS	Yes		Yes

Source: Hydrogen Europe.

3 / Proposal of the EC, available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52021PC0559. Position of the Council, available at https://www.consilium.europa.eu/en/press/press-releases/2022/06/02/fit-for-55-package-council-adopts-its-position-on-three-texts-relating-to-the-transport-sector/. Draft position of the EP, available at https://www.europarl.europa.eu/doceo/document/TRAN-PR-719568_EN.html.

TABLE 6

Estimated minimum number of HRS to be deployed across EU-27

	Clean Hydrogen JU Study: HRS needed by 2030	European Commission Impact Assessment – the absolute minimum needed for HRS	Industry minimum needs Hydrogen Europe calculation	EU Parliament TRAN Committee Draft Report	Council General Approach
Number of HRS for EU-27	~ 4,800 across the EU	798	1,915	1,491	**233**

Source: Hydrogen Europe.

Looking at the minimum number of HRS to be deployed, the difference between the three positions is rather drastic **(Table 6).** The Commission's proposal would lead to the deployment of about 1,388 stations, the Parliament's draft position would lead to nearly 1,780, while the Council's position would result in a mere 233 HRS. These differing opinions will complicate the upcoming negotiations on the final version of this critical piece of legislation. The lack of ambition the Council expresses is particularly worrying as it sends a wrong signal to car and truck manufacturers deciding on their investments in technology development and industrial scale-up.

7.2.4. Spotlight on ets and cbam

The revision of the ETS and the new CBAM is at the core of the Commission's efforts to reform the EU's carbon market (Hydrogen Europe, 2021). After months of deliberation, the Council and the Parliament have adopted their respective positions. Whereas the position of the Council is aligned closely to the Commission's proposal on the revision of ETS, the Parliament aims to raise the ambition. It proposes strengthening the annual emissions cap reduction, which would translate into a higher GHG emission reduction for all sectors under the ETS, increasing CO2 prices and sending a stronger price signal to operators and investors.

For hydrogen, the main change under the Commission's ETS proposal is the extended coverage of hydrogen production: from SMR and partial oxidation to all production technologies. This will be accompanied by a subsequent revision of rules for free allowances, allowing them to be allocated to all hydrogen production types, including clean ones. While hydrogen produced from SMR and partial oxidation is already covered by free allowances to protect against carbon leakage, the proposed changes could provide a 'bonus' to clean hydrogen producers through the allowances, which are sellable on secondary markets. This change would induce that the switch in production from carbon-intensive to clean hydrogen does not imply loss of free allowances anymore.

The Commission has also suggested extending the ETS to cover maritime transport emissions for ships over 5,000 gross tonnages. While both the Council and the Parliament support this proposal, the latter wants to go further by adding coverage of smaller ships between 400 and 5,000 gross tonnages as of 2027 and accelerating the full auctioning of allowances for ships over 5,000 gross tonnages from 2024. By extending the EU ETS to maritime transport, the Commission hopes to provide further opportunities for clean fuels, including renewable and low-carbon hydrogen.

The proposal to cover emissions from buildings and road transport under a new, separate ETS (also known as 'ETS II') might lead to the same goal. Despite some stakeholders contesting ETS II amidst fears of political discontent, the Council and the Parliament have endorsed the scheme, with Council asking for a one-year delay for the surrender of allowances under the new scheme. The Parliament wants to differentiate between commercial and private emitters on this issue. While commercial emitters, based on the Parliament's position, would start surrendering emissions as of 2025, private ones would do so as of 2029 and only if bolstered by a further impact assessment.

Closely linked to the ETS revision, the Commission proposed introducing CBAM as an alternative to free allowances, replacing them gradually for the sectors covered. These include steel, aluminium, cement, fertilisers, and electricity. Once CBAM becomes operational as of 2026, it will mean a drop in free allowances allocated in those sectors, further incentivising a switch to clean processes based on renewable and low-carbon hydrogen. For instance, putting a price on the carbon content of imported steel would disincentivise imports of carbon-intensive steel. Both the Parliament and the Council have adopted their respective positions on CBAM. The three EU institutions entered negotiations on CBAM and ETS in July 2022.

The Parliament has proposed adding hydrogen and several other products to the list of sectors covered by CBAM. If the Commission and the Council agree on this issue, it would result in a carbon price on the embedded emission of hydrogen imports and accelerate the phase-out of free allowances for hydrogen production. The final legislation is expected by the end of 2022.

7.2.5. Hydrogen and Decarbonised Gas Package

In December 2021, the Commission published the Hydrogen and Decarbonised Gas Markets Package, containing three legislative proposals, of which the Proposal for a recast Regulation on the internal markets for renewable and natural gases and hydrogen ('Gas Regulation') and the Proposal for a recast Directive on common rules for the internal markets in renewable and natural gases and hydrogen ('Gas Directive') are the most relevant for the hydrogen sector. The two proposals intend to create a level-playing field based on EU-wide rules for the hydrogen market and infrastructure while also removing barriers that hamper their development. They also aim to make the right conditions for decarbonising natural gas infrastructure through hydrogen blending and repurposing existing infrastructure for pure hydrogen.

The Parliament has started discussing these legislative proposals, with a vote in the Plenary expected in December 2022. The Council is also planning to adopt its position on the package by the end of 2022. The ongoing legislative process will be an opportunity to communicate to the Parliament and the Council the position of the industry to ensure that the proposals mentioned above will be adopted in a way to facilitate the deployment of a dedicated hydrogen transport infrastructure across Europe (Hydrogen Europe, 2022). In case of no delays, trilogues with the Commission would start in 2023, with the final proposal adopted by mid-2023.

7.2.6. Regulation on trans-European energy Infrastructure (TEN-E) and Revision of the Regulation on the trans-European transport network (TEN-T)

The Regulation on trans-European energy Infrastructure (TEN-E) was adopted in May 2022 in alignment with the EU's new and more ambitious climate and energy policy. The Regulation now includes hydrogen infrastructure and electrolysers as essential infrastructure categories, along with electricity, gas and oil infrastructure. It also ended access to financial support for new natural gas and oil projects. However, funding will still be available if those gas pipelines are upgraded (retrofitted or repurposed) to integrate renewable and low-carbon gases, such as hydrogen. This revised framework on public support for energy projects presents a massive opportunity for the hydrogen sector. It can unlock significant investment opportunities for cross-border hydrogen infrastructure projects and pushes gas system operators to consider hydrogen as the natural evolution of their business and infrastructure. The upcoming 6th list of Projects of Common Interest will be based on the new TEN-E Regulation, including hydrogen projects for the first time. It will be published at the end of 2023.

The Regulation on the Trans-European Networks (TEN-T) is also being updated to match the new climate realities and the EU's ambition to reduce GHG emissions in transport by 90% by 2050. It is one of the main initiatives of the Efficient and Green Mobility Package proposed in December 2021.

It introduces new transport infrastructure requirements and aims to modernise and complete the TEN-T Core and Comprehensive network by 2030 and 2050, respectively. The text also calls for establishing multimodal freight terminals, including alternative refuelling infrastructure, among others.

The revised TEN-T and TEN-E Regulations will inform the investment priorities of the EU's Connecting Europe Facility (CEF), an EU funding programme supporting cross-border energy and transport infrastructure projects. More details on the CEF are provided in **Chapter 8.**

TABLE 7

Key provisions for hydrogen in the Gas Directive and Gas Regulation

GAS DIRECTIVE	GAS REGULATION
Proposal for precise terminology and a system for the certification of low-carbon hydrogen and low-carbon fuels, complementing rules proposed for renewable hydrogen under the Renewable Energy Directive.	Regulated third-party access (TPA) is envisaged as the long-term default rule for hydrogen networks, but Member States can allow negotiated TPA until the end of 2030. Whereas TPA to hydrogen terminals is to be organised via negotiated access, only regulated access is envisaged for hydrogen storage.
An ownership unbundling (OU) requirement for vertically integrated companies to prevent potential conflicts of interest between hydrogen producers, suppliers, and network operators. The Member States will be able to choose an independent system operator (ISO) model or an independent transmission system operator (ITO) model if the hydrogen network belongs to a vertically integrated company, the latter only until the end of 2030.	Obligation for gas TSOs to accept a hydrogen blend of up to 5% at interconnection points from 1 October 2025 and cross-border coordination on gas quality.
New horizontal unbundling requirements to restrict the ability of hydrogen network operators (HNOs) to engage in gas/electricity TSO/DSO activities and vice versa. Under the Commission's proposal, gas/electricity TSOs and DSOs may be part of the same undertaking as HNOs, as long as legal and information unbundling is ensured.	Creation of a new European Network of Network Operators for Hydrogen (ENNOH) tasked with formulating an independent 10-year network development plan for hydrogen.
Two "grandfathering" provisions to allow Member States to derogate from unbundling requirements to some extent in respect of "existing hydrogen networks" and "geographically confined networks". Both until 2030.	

Source: Hydrogen Europe.

TABLE 8

Key points about hydrogen in the proposed TEN-E regulation and TEN-T proposal

TEN-T PROPOSAL	TEN-E (ADOPTED)
Align the TEN-T and AFIR Regulation to ensure HRS are deployed across the relevant transport corridors for road transport, air, maritime, and urban nodes.	Introduction of mandatory sustainability criteria for all projects.
The networks and their completion timelines: core network by 2030, extended core network by 2040, and comprehensive networks by 2050.	Possibility of receiving EU financial support for projects that blend hydrogen up until the end of 2027.
Member States will have to support and promote the decarbonisation of transport through the transition to zero- and low-emission vehicles, vessels and aircraft;	Inclusion of electrolysers with a capacity of at least 50 MW.
Member States will have to make possible the decarbonisation of all transport modes by stimulating energy efficiency, introducing zero and low-emission solutions, including H2 and electricity supply systems, and other new solutions such as sustainable fuels, and providing the corresponding infrastructure. Such infrastructure may include facilities necessary for the energy supply. Transport infrastructure may serve as an energy hub for different transport modes (e.g., ports).	Planning of offshore hydrogen pipelines.
A requirement for urban nodes (424 major cities) on the TEN-T network to have Sustainable Urban Mobility Plans (SUMPs) by 2025 to align their mobility developments on the TEN-T network.	A stronger role for ACER and stakeholders (including the hydrogen sector) in designing the 2024 and subsequent Ten-Year Network Development Plans.
Focus on electrifying most of the railway infrastructure and develop alternative fuel technologies for railways, such as hydrogen for specific sections exempted from the electrification requirement.	Introduction of mandatory sustainability criteria for all projects.

Source: Hydrogen Europe.

7.3.

Industry value chain alliances

7.3.1. European Clean Hydrogen Alliance

In 2022 the European Clean Hydrogen Alliance (ECHA) has focused its work on providing support to implement further the Alliance's pipeline of projects identified in November 2021. These 750 hydrogen investment projects will help create an integrated European hydrogen value chain, including investors' support. This has been mainly done with the settlement of partnerships with the European Investment Bank, the Breakthrough Energy Catalyst, the EIT Green Hydrogen Acceleration Center and the Hydrogen Financing Forum, whose aim is to facilitate advisory activities and financing for the Alliance's projects. In parallel, the Alliance has launched the tHrive initiative, led by the European Commission, to connect private and public stakeholders in key hydrogen areas (pilot projects in Estonia, Auvergne-Rhône-Alpes and Asturias) and has organised several matchmaking sessions on key topics or strategic projects.

Building on the Reports on barriers and mitigation measures put forward by the six Roundtables in October 2021, the ECHA has pursued an intense dialogue with the European Commission on the regulatory framework. It focused on the challenges of the Fit for 55 and the Hydrogen and Gas Package. Since March 2022, an additional effort has been ensured to align with the new vision and objectives of the REPowerEU Communication.

In addition, specific attention has been provided to the permitting and standardisation issues by creating two dedicated Working Groups. The Permitting WG has released a report with valuable inputs for the Commission's Recommendation on speeding up permit-granting procedures and facilitating Power Purchase Agreements. The Standardisation Working Group prepares a roadmap of priorities to contribute to the new EU Strategy on Standardisation.

The REPowerEU Communication and its Hydrogen Accelerator have also provided new momentum to the works of the Alliance. A European Electrolyser Summit was organised on May 5 with Commissioner Breton and 20 key industry players to assess the implications of doubling the renewable hydrogen production target in terms of equipment and components installation. On that occasion, a Joint Declaration was adopted stressing the need to achieve the REPowerEU target of renewable hydrogen production of 10Mt. This led to the creation of an Electrolysers Partnership in the context of the Alliance, supported by the European Commission and Hydrogen Europe. The first meeting of the Partnership took place in September.

7.3.2. The Renewable and Low Carbon Fuels Value Chain Alliance

The Renewable and Low Carbon Fuels Value Chain Alliance (RLCFA) is an initiative launched by the European Commission on 6 April 2022 to address the availability and affordability of renewable and low-carbon fuels in transport. The Alliance focuses on synthetic fuels and biofuels to be used in the maritime and aviation sectors following the FuelEU Maritime and RefuelEU Aviation proposals.

More particularly, the Alliance is set to address sustainable feedstock and production pathways and their enabling conditions, establish synergies with other transport modes and sectors, and build a pipeline of investment projects, including high TRL-level R&D activities. Therefore, the assessment of public and private financing opportunities for scaling up the production, transport, and use of renewable and low-carbon fuels will be crucial.

With more than 150 members, the RLCFA brings together stakeholders of the fuels supply and demand side of aviation and waterborne transport, including other connected sectors and value chains.

The works of the RLCFA were kicked off by the first General Assembly of July 12, where the members endorsed the Alliance 2022-2023 Work Programme. This document organises the operational works of the Alliance in four roundtables dedicated to relevant aspects of the development of the value chain: feedstock and synergies between transport modes, aviation, waterborne transport, and funding and financing. The call for applications to the Roundtables is expected in September to organise the first meetings before the end of the year.

The overall coordination of the RLCFA is steered by the European Commission-DG Move supported by the chairs of the aviation and waterborne chambers of the General Assembly, Safran and Fincantieri, as well as Hydrogen Europe and Fuels Europe as secretariat organisations.

© Henri Lajarrige

Conclusion

The ongoing legislative review is one of the most significant overhauls of EU legislation undertaken so far. The 'Fit for 55' package and REPowerEU target not only the energy sector but also mobility, buildings, and regional development, with expected spill-over effects across the entire economy, thereby placing Europe on track to achieve climate neutrality by 2050. In other words, European policymakers are working towards building a future-proof energy and mobility system that will be climate neutral while still being competitive. This is already a challenging task in normal circumstances, but the EU is under growing pressure to ensure its energy security, especially following the recent Ukraine events.

In this, hydrogen will have a pivotal role to play. However, legislation must create legal certainty through clear and precise rules to ensure that it becomes a cornerstone of the future European energy system. It needs to be designed to not hinder the growth of the hydrogen sector by placing an additional administrative burden on the industry. Furthermore, considering recent global events, the adoption of these rules ought not to be excessively delayed, as the security of the supply of energy resources in Europe is threatened.

It is time for Europe to create a policy framework to ensure it keeps its leadership position in the emerging hydrogen economy.

References

European Commission. (2020). Trans-European Transport Network (TEN-T), from European Commission: https://transport.ec.europa.eu/transport-themes/infrastructure-and-investment/trans-european-transport-network-ten-t_en

Hydrogen Europe. (2021). Clean Hydrogen Monitor 2021. Brussels: Hydrogen Europe.

Hydrogen Europe. (2022, June). Hydrogen Europe Position Paper: A regulatory framework fit for a European hydrogen market. Retrieved September 29, 2022, from Hydrogen Europe: https://hydrogeneurope.eu/position-papers/

© Jorgen Hendriksen

08

Funding and financing ecosystem

© Mathieu Stern

Introduction

The following chapter aims to illustrate the current funding opportunities for hydrogen technologies. It is structured into three sub-chapters covering the following topics:

- EU funding programmes and auction mechanisms.
- Updates on relevant investments under the Recovery and Resilience Facility (RRF) and national recovery plans (RRPs).
- Private investments, including insights on financial markets for the hydrogen economy.

8.1.

H2 investment needs in Europe

The European Commission estimates that a total of EUR 86-126 billion will need to be invested in key hydrogen infrastructures to achieve the EU's ambition of producing 20 million tonnes of hydrogen by 2030, as outlined in the RePowerEU Communication. The table below summarises the investment required for different types of hydrogen infrastructure.

However, the Commission's estimates are considerably lower than those in other available studies and reports. According to the Hydrogen for Europe study (Deloitte Finance – IFPEN - SINTEF, 2021), EUR 480 billion to EUR 890 billion needs to be mobilised between the early 2020s and the mid-2030s to finance the hydrogen value chain. This excludes required investments in electrolysers manufacturing lines, which the study estimates between EUR 0.6 trillion and EUR 1.5 trillion by 2050. Furthermore, according to the European Hydrogen Backbone Initiative, which brings together thirty-one energy infrastructure operators in Europe, between EUR 40 and 70 billion are needed for pipelines and interconnectors to make the 53,000 km of European Hydrogen Backbone operational by 2040. This figure is considerably higher than the EUR 28-38 billion envisaged by the Commission. Despite differing estimates, what is clear is that the sector will require a combination of public and private funding sources to ensure its development.

TABLE 1

Capital needed for hydrogen infrastructure according to the RePowerEU

EU-internal pipelines	EUR 28 - 38 billion
Storage	EUR 6 - 11 billion
Electrolysers	EUR 50 - 75 billion
Upscaling of manufacturing capacities	EUR 2 billion

Source: RePowerEU Communication, 2022.

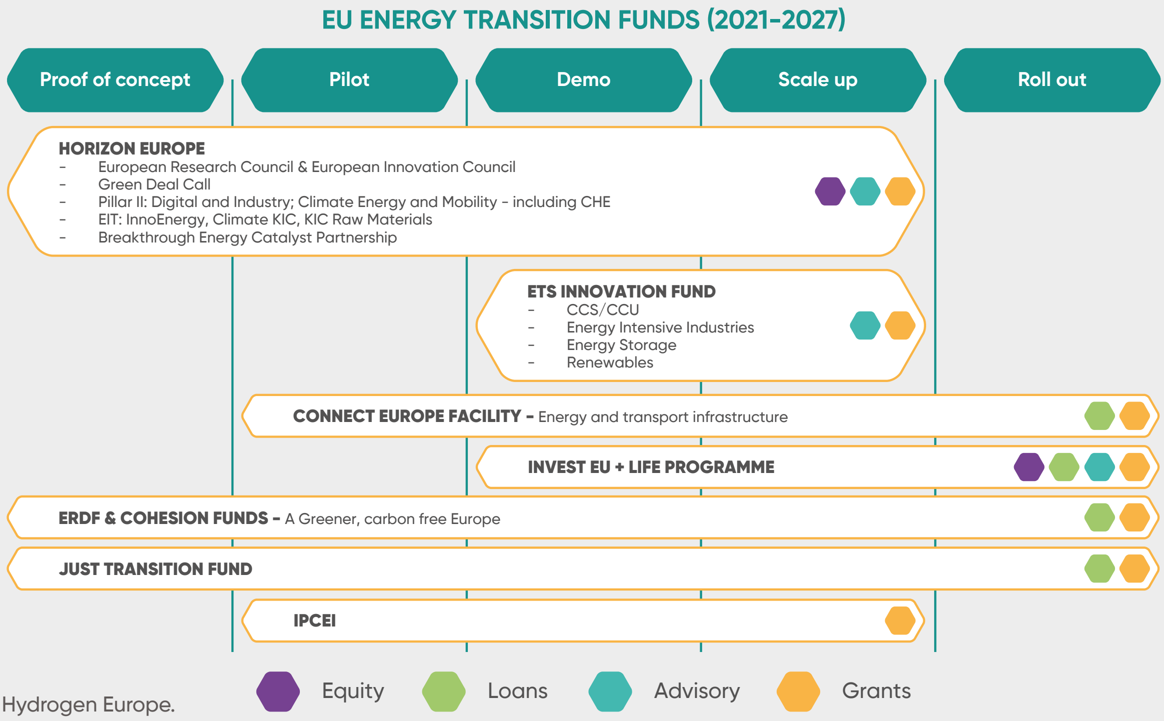
8.2.

EU funding opportunities

8.2.1. Overview

FIGURE 1

Mapping of the EU Funding Programmes supporting hydrogen applications



Source: Hydrogen Europe.

Figure 1 shows that several EU funding programmes offer support for hydrogen applications. They differ in their objectives and beneficiaries in the financing type and the technology readiness level they support. The 2021 Clean Hydrogen Monitor[1] offers a detailed overview of all these funding opportunities, focusing on their applicability to the hydrogen sector.

In addition, the Commission has planned to unlock up to EUR 300 billion by 2030 to implement the RePowerEU energy objectives, most of which will be allocated through existing EU funding programmes. As a result, in this edition of the Clean Hydrogen Monitor, the focus is on the direct impact of the RePowerEU Communication (May 2022) on the sources of financing mentioned above. Moreover, it also outlines the new economic mechanisms developed within the EU to sustain the hydrogen economy, including the German H2 Global mechanism and the European Global Hydrogen Facility.

1 / The 2021 Clean Hydrogen Monitor is available for download on Hydrogen Europe's website for members.

8.2.2. EU Funding Programmes

8.2.2.1. HORIZON EUROPE & PUBLIC PRIVATE PARTNERSHIPS

Horizon Europe is the primary funding instrument for research and innovation (R&I), with a budget of EUR 95.5 billion between 2021 to 2027 to promote the EU's competitiveness and growth while boosting the Sustainable Development Goals. The programme supports hydrogen projects through three pillars:

PILLAR I – Excellent Science aims to strengthen and develop the excellence of the European Union's science base by supporting the development of research infrastructures and basic research projects through a EUR 25 billion budget.

PILLAR II – Global Challenges and European Industrial Competitiveness are established through clusters of research and innovation activities to maximise integration and synergies across the respective thematic areas. It is endowed with EUR 53.5 billion. Through Pillar II, the Commission, together with the hydrogen, waterborne, rail, aviation, steel, and process industries, is co-investing EUR 13.1 billion in Horizon Europe Partnerships to decarbonise those industries and development of the hydrogen ecosystem. A comprehensive list of all the relevant European partnerships under Horizon Europe can be found on the European Commission's website[2]. The Clean Hydrogen Joint Undertaking (Clean Hydrogen Partnership) is the successor of the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) and was established in November 2021 with the adoption of the Council Regulation on establishing the Joint Undertakings under Horizon Europe. The EU supports the Clean Hydrogen JU with EUR 1 billion for the 2021-2027 period, complemented by at least an equivalent amount of private investment (from the private members of the partnership), raising the total budget to above EUR 2 billion. The Clean Hydrogen Partnership is the EU's flagship hydrogen research and innovation initiative that aims to accelerate the development and deployment of the European value chain for safe and sustainable clean hydrogen technologies, strengthening its competitiveness and support, notably SMEs, accelerating the market entry of innovative competitive clean solutions. As part of RePowerEU, the Commission has topped-up Horizon Europe investments in the Clean Hydrogen Partnership with EUR 200 million. This additional funding will be released in 2023 to double the number of Hydrogen Valleys. In the meantime, through its 2022 call for proposals, the Clean Hydrogen Partnership will support the deployment of two Hydrogen Valleys (small and large scale). The results of the call are expected in early 2023.

BOX 1

European Hydrogen Valleys

Hydrogen Valleys are ecosystems linking hydrogen production, transportation, and various end uses such as mobility or industrial feedstock. They are an important step towards enabling the development of a new and sustainable hydrogen economy. Currently, the Mission Innovation Hydrogen Valleys Platform has identified 23 European Hydrogen Valleys at different stages of development. Mission Innovation members have committed to delivering at least 100 large-scale integrated clean Hydrogen Valleys worldwide by 2030.

Source: H2Valleys | Mission Innovation Hydrogen Valley Platform.

PILLAR III – Innovative Europe aims to foster all forms of innovation, including non-technological innovation, mainly in SMEs, particularly start-ups, by facilitating technological development, demonstration, and knowledge transfer. It features the European Innovation Council, the European Institute of Innovation and Technology and the European Innovation Ecosystems, endowed with a total budget of EUR 13.6 billion.

2 / https://ec.europa.eu/info/research-and-innovation/funding/funding-opportunities/funding-programmes-and-open-calls/horizon-europe/european-partnerships-horizon-europe_en

8.2.2.2. ETS INNOVATION FUND (ETS IF)

The ETS Innovation Fund is one of the world's most extensive funding programmes for demonstrating innovative low-carbon technologies, with a budget of EUR 38 billion until 2030 (with a carbon price of EUR 75). The funding covers up to 60% of the costs of the relevant projects. It is allocated once a year via calls for proposals for large-scale projects (> EUR 7.5 million in CAPEX) and small-scale projects (between EUR 2.5 million and EUR 7.5 million in CAPEX).

Two large-scale calls and small-scale calls have been launched so far. The second large-scale call had a budget of EUR 1.5 billion, which was a 50% increase compared to the first. The call results were announced in July 2022, where three of the 17 projects selected for grant agreement preparation were hydrogen-related **(Figure 2).**

HOLLAND HYDROGEN: this project is led by Rotterdam Hydrogen Company B.V. and Shell. It consists of a 400 MW electrolyser with Dutch offshore wind power by 2027. The hydrogen produced will be supplied to the Pernis refinery via a new high-capacity "open-access" 40 km pipeline.

FUREC: FUREC will process non-recyclable solid waste streams and transform them mainly into hydrogen in

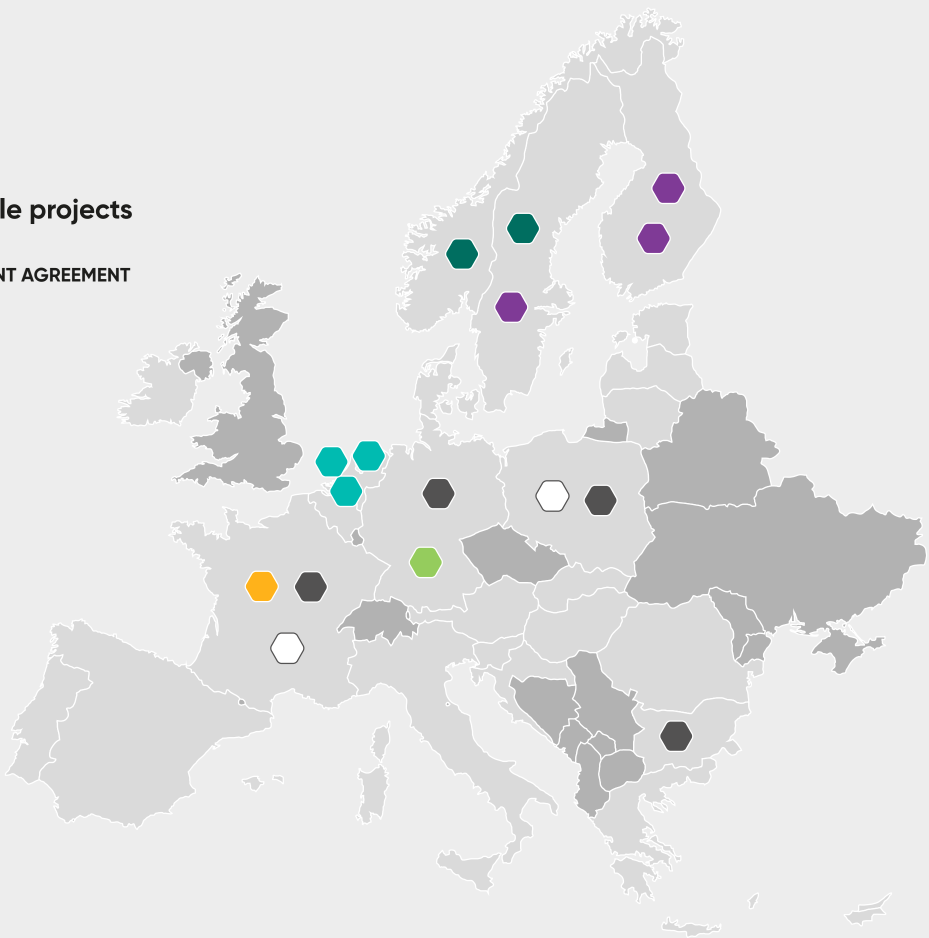
FIGURE 2

Selected projects for the ETS IF Second Large-Scale Call (July 2022)

INNOVATION FUND
Second call for large-scale projects

PROJECTS PRE-SELECTED FOR GRANT AGREEMENT PREPARATION (17 PROJECTS)

- Chemicals
- Hydrogen
- Refineries
- CO2 transport and storage
- Wind energy
- Manufacturing of components for solar energy
- Cement and lime
- Manufacturing of components for energy storage



Source: CINEA.

Chemelot, Geleen (the Netherlands), a significant chemicals cluster. The project led by RWE Generation NL will produce 54 kt of hydrogen per year during the 10-year duration of the project.

ELYGATOR: the 200 MW electrolysis project in Terneuzen (the Netherlands) will produce 15,500 tonnes of renewable hydrogen annually. This project, led by Air Liquide, aims to demonstrate an innovative and highly flexible large-scale electrolyser, fully powered by renewable energy and fully integrated into the cross-border industrial basin.

All the hydrogen projects mentioned above are located in the Netherlands, building on the existing production and usage volumes of Europe's second largest hydrogen producer.

The second small-scale call was opened in March 2022 with the same budget of EUR 100 million as the first call. The results of this call are expected in the second quarter of 2023.

The RePowerEU Communication has had a broad impact on this funding programme, facilitating access to finance for hydrogen actors. The third large-scale call, to be launched in October 2022, will have a budget of EUR 3 billion, doubling the previous envelope. It will add three specific RePowerEU windows covering:

(1) innovative electrification and hydrogen applications in industry,

(2) innovative clean tech manufacturing (including renewable energy technologies, fuel cells, electrolysers, electricity storage, and heat pumps), and

(3) mid-sized pilot projects for validating, testing, and optimising highly innovative solutions.

RePowerEU plans to provide the ETS IF with the capacity to help projects fund the green premium associated with renewable hydrogen use and production through the deployment of Carbon Contracts for Difference (CCfD). At the time of writing this report, the definition of the architecture of CCfDs is still under discussion (e.g., how to avoid detrimental interaction with the ETS, the compatibility with EU financial regulation, what level of support is justified, et cetera.).

BOX 2

Hydrogen Europe engagement in the ETS IF new Large-Scale Call

Hydrogen Europe is collaborating with the Commission in the preparation of the next the large-scale call planned for October 2022, providing recommendations on the terms of reference (scope, eligibility, award criteria, and methodologies) for the new window category for electrolysers, fuel cells and related components manufacturing, as part of the new RepowerEU second window.

8.2.2.3. CONNECTING EUROPE FACILITY (CEF)

The Connecting Europe Facility (CEF) is the key funding instrument for targeted infrastructure investment at the European level. Over the period 2021-2027, CEF is endowed with EUR 33.71 billion, divided into three main sectors: transport (EUR 25.81 billion), energy (EUR 5.4 billion), and digital (EUR 2.07 billion). The primary funding for the hydrogen sector comes from CEF-Transport and CEF-Energy, supporting the implementation of the Trans-European Transport Network (TEN-T) and the Trans-European Energy Network (TEN-E) policy.

CEF-Transport

Most of the funding under the CEF-Transport envelope for hydrogen applications is allocated via the Alternative Fuel Infrastructure Facility (AFIF). The facility has a budget of EUR 1.575 billion and is allocated via an ongoing call for proposals running until 2023[3]. It supports the deployment of re-charging, liquified natural gas (LNG) and hydrogen refuelling stations (HRS) for all modes of transport.

3 / https://cinea.ec.europa.eu/funding-opportunities/calls-proposals/cef-transport-alternative-fuels-infrastructure-facility-call-proposal_en

BOX 3

List of Implementing Partners

For the implementation of AFIF, the Commission relies on Implementing Partners (IPs). These are financial institutions that have signed an administrative agreement with the European Commission and are responsible for the deployment of at least two-thirds of the budget. In addition, up to one-third of the AFIF budget is implemented in cooperation with any other public or private financial institution established in the EU. Those interested in applying to AFIF call, are advised to first contact the implementing partners.

The current implementing partners are:

• European Investment Bank (EIB)
• Caisse des Dépôts et Consignations (France)
• Slovenska Izvozna In Razvojna Banka, D.D. – SID (Slovenia)
• Bank Gospodarstwa Krajowego – BGK (Poland)
• Finnvera Plc. (Finland)
• Hungarian Development Bank Private Limited Company – MFB (Hungary)
• Participatiemaatschappij Vlaanderen NV – PMV (Belgium)
• Cassa depositi e prestiti S.p.A. – CDP (Italy)

CEF-Energy

In March 2022, the Commission launched the first call for projects seeking to obtain the cross-border renewable energy (CB RES) status, a pre-condition to access future CEF-E CB RES calls for proposals. This new list, which will receive 15% of the CEF-E budget, will be officially published by the end of 2022.

In May, together with the publication of the RePowerEU Communication, the Commission launched a new CEF-Energy call for proposals for Projects of Common Interest (PCIs). With a total budget of EUR 800 million, the call aims to support the most urgent infrastructure projects needed to reach the RePowerEU priorities. Only projects on the 5th PCI list are eligible to apply, and the funding rate can go up to 75%. The application deadline was 1 September 2022, while the results are expected in February 2023.

Furthermore, in RePowerEU, the Commission has proposed to increase the total budget of CEF-Energy by an additional EUR 2 billion to accelerate the development of cross-border hydrogen infrastructure. Simultaneously, RePowerEU commits to speed up the adoption of the 6th list of PCIs, to be communicated by the end of 2023. The new list of Projects of Common Interest will be based on the priorities in the revised TEN-E Regulation, which entered into force in June this year (see **Chapter 7**).

8.2.2.4. INVESTEU

The InvestEU Programme aims to attract additional investment to support the EU's top policy priorities. The programme consists of three building blocks: the InvestEU Fund, the InvestEU Portal and the InvestEU Advisory Hub **(Figure 3).**

FIGURE 3

The InvestEU Building Blocks

Source: InvestEU.

The InvestEU Fund expects to mobilise EUR 372 billion of public and private investment in 2022-27 through an EU budget guarantee of EUR 26.2 billion, backing the investment made by implementing partners such as the European Investment Bank (EIB) and other financial institutions. The first set of implementing partners was selected through the call for expression of interest concluded in 2021. The next call is planned for 2023. Hydrogen applications can be supported under the Fund's Sustainable Infrastructure window, which targets sustainable energy, transport, circular economy, and other environmental infrastructure projects. This window is backed by the EU guarantee of EUR 9.9 billion.

The InvestEU Advisory Hub complements the InvestEU Fund by supporting the identification, preparation, and development of investment projects across the European Union. As part of the RePowerEU Communication, the Commission created a Technical Advisory Facility under the Hub, together with the European Investment Bank, to support renewable energy projects financed by Power Purchased Agreements (PPA).

Finally, through the InvestEU Portal, the programme brings together investors and project promoters in a single EU-wide database of investment opportunities available in the EU to facilitate the matchmaking between qualified projects and financiers.

8.2.3. Auction Mechanisms to sustain the hydrogen economy

Several initiatives are being developed and implemented in Europe to leverage market mechanisms for developing the hydrogen sector. Examples of much-anticipated schemes are the German government's H2 Global, which focuses on ramping up the international market for green hydrogen, and the European Commission's Global Hydrogen Facility, aimed at accelerating the promotion of imports of renewable hydrogen from third countries.

H2 Global Initiative

The German H2 Global Initiative, officially launched in May 2021, is a support mechanism to boost the international market ramp-up of green hydrogen and its derivatives by using a double-auction model. The Hydrogen Intermediary Network Company GmbH (HINT.CO), which serves as a dedicated intermediary, concludes long-term purchase contracts on the supply side and short-term sales contracts on the demand side for green hydrogen and Power-to-X (PtX) products. Through Contracts for Difference (CfD), the difference between supply prices (production and transport) and demand prices will be compensated by HINT.CO, which various funding bodies will fund. To guarantee a flexible and dynamic mechanism, specific parameters in terms of products promoted (hydrogen, ammonia, methanol), geographic areas (country, regional, or global) and sustainability criteria are determined for each funding body, allowing the creation of tailored funding windows. The German Federal Ministry for Economic Affairs and Climate Action (BMWK) has provided the first EUR 900 million to H2 Global, constituting the first funding window. In line with the German Government's economic stimulus programme, this window focuses on establishing foreign trade partnerships with countries where green hydrogen can be produced efficiently due to their geographical location. The auction is planned for a 10-year contract for green ammonia imports during the second quarter of 2022, with the first cargo expected in 2024. The following auctions will focus on methanol and jet fuels, while future windows will target projects in specific developing markets (S&P Global, 2022).

FIGURE 4

Germany's HINT.CO to auction hydrogen imports

Source: H2 Global Foundation.

European Global Hydrogen Facility

In the RePowerEU Communication, the Commission mentioned its plans to launch a dedicated hydrogen purchasing work stream. The European Global Hydrogen Facility will be established under the EU Energy Platform to accelerate imports of renewable hydrogen from third countries, for example, North Africa. The Facility will be established in cooperation with the Member States and in line with intra-EU measures, market functioning, and trade and investment policy objectives. It will support the creation of a regulatory framework for renewable hydrogen partnerships, facilitate EU-wide coordination on international hydrogen projects and incentivise European and global renewable hydrogen production. The Communication mentions the possibility for the Facility to recourse to Carbon Contracts for Difference, instruments under which end users would receive a guaranteed amount from a designed institution or entity for avoiding CO2 emissions. This would consist of savings from not paying a carbon price under the ETS, plus a top-up subsidy to reach the "strike price" agreed in the CCfD.

However, it also mentions that the facility will build on the experience from the German initiative H2Global, which will deploy CfDs instead of CCfDs for green hydrogen and its derivatives.

At the time of writing, the information on the actual structure and instruments of the Facility remains limited.

8.3.

Recovery and resilience facility and national plans

The Recovery and Resilience Facility (RRF), part of the NextGenerationEU, was set up as a temporary recovery instrument to help the Member States mitigate economic and social damages caused by the COVID-19 pandemic. Among other priorities, the facility is funding investments and reforms for Europe's "green transition"[4], including hydrogen technologies.

Between 2021- 2026, EUR 723.8 billion[5] in grants and loans will be made available to the Member States, of which at least 37% of the planned allocations should be dedicated to the "green transition". To access the funds, Member States had to submit a draft Recovery and Resilience Plans (RRPs) to the European Commission, specifying the investments, reforms and targets they intend to achieve. After their submission, the Commission assesses the plans, and once the Commission's concerns and comments are addressed, it submits them to the European Council for approval.

Last year's edition of the Clean Hydrogen Monitor analysed the Recovery and Resilience Facility (RRF) and National Recovery Plans (RRPs) presented by EU countries until September 2021. This year's edition provides an updated overview of the plans until July 2022, particularly the hydrogen allocations, including a breakdown of the hydrogen value chain and the status of the instrument's financing possibilities. Since last year's analysis, six plans formally submitted to the Commission have been adopted. The Commission officially endorsed the plans of Bulgaria, Estonia, Finland, Poland, Romania, and Sweden. The Netherlands submitted its draft on 8 July 2022, while the endorsement of Hungary's RRPs is still pending.

Our analysis covers all submitted plans, including those of Hungary and the Netherlands. However, as these plans are not adopted, they are subject to significant changes. The analysis also includes funding from the Recovery and Resilience Facility, national public funds, and other EU sources, when applicable.[6]

Member States generally have different approaches to allocating investments in their plans. While some present funds specifically for hydrogen technologies, others present more general funds for certain categories that may include hydrogen, among other technologies. In this analysis, we name each type of allocation 'exclusive' and 'non-exclusive', respectively. Non-exclusive funds do not contain proportions or indications of the specific amount potentially directed to hydrogen.

At the time of writing, the cumulative amount of funds available for hydrogen, among other technologies, from all RRPs is about EUR 55 billion, of which almost EUR 12 billion is exclusively for hydrogen technologies. **Figure 5** shows the distribution of total hydrogen funds (both exclusive and non-exclusive) of the 27 EU Member States.

The Member States with the largest total funds available for hydrogen, among other technologies (both exclusive and non-exclusive), continue to be France (14.3 billion EUR), Spain (9.4 billion EUR), Germany (7.9 billion EUR), and Italy (7.8 billion EUR). Among the Member States dedicating exclusive funds to hydrogen, Italy and Germany stand out with EUR 3.6 and 2.7 billion, respectively.

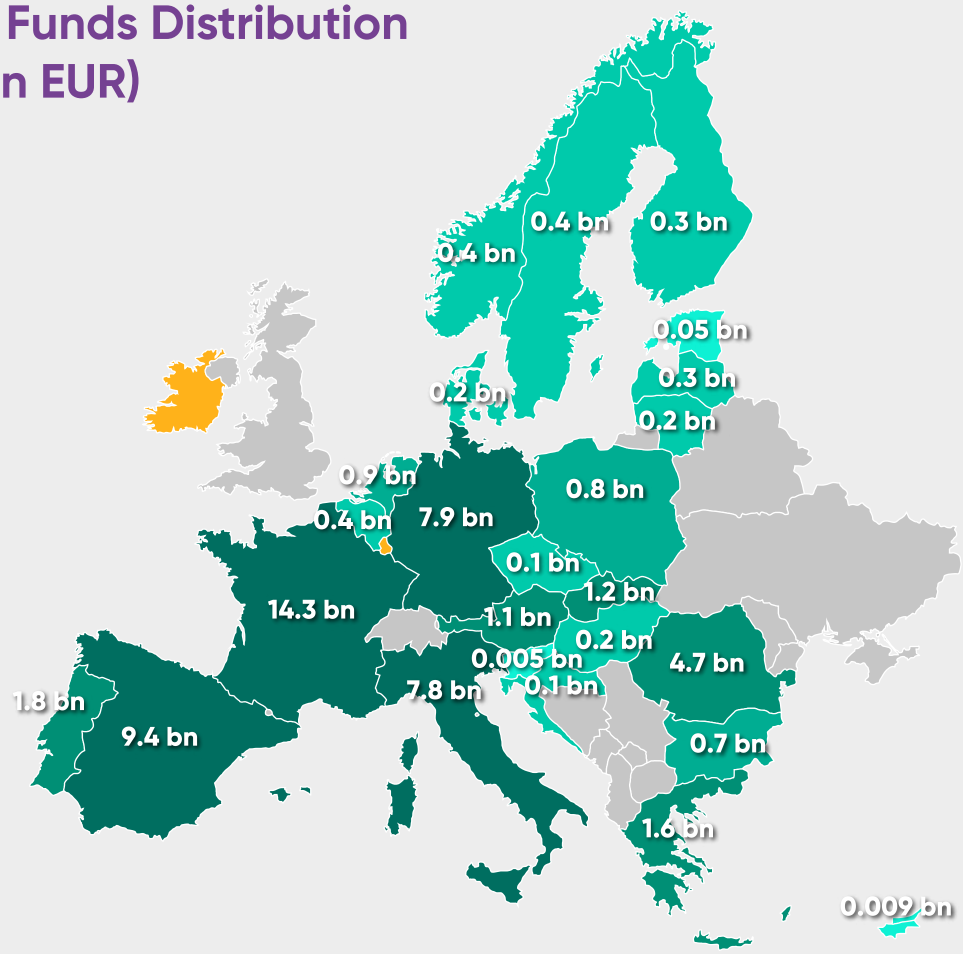
From a value chain perspective, most non-exclusive funding goes to mobility. While mobility receives 50% of the funds, research receives 14%, industry 9%, energy 5%, transmission and distribution 3%, and production only 1%. The remaining 17% goes to multiple parts of the value chain, seeking to develop hydrogen on many fronts (e.g., production, distribution and end-use in various sectors).

On the other hand, almost EUR 12 billion in exclusive funds

4 / Contributions to the "green transition" are "(...) reforms and investments in green technologies and capacities, including in biodiversity, energy efficiency, building renovation and the circular economy, while contributing to the Union's climate targets, fostering sustainable growth, creating jobs and preserving energy security", as in paragraph 11 of the Regulation, 2021/241 of the European Parliament and of the Council of 12 February 2021. For more details of the components that contribute to the "green transition" please see Annexe VI of the Regulation.
5 / In current prices.
6 / Austria, Bulgaria, Czechia, Finland, France, Germany, Hungary, Ireland, Italy and Luxembourg include national public funds and funds from other EU sources additionally to the RRF in their recovery plans.

FIGURE 5

Total Hydrogen Funds Distribution in RRPs (in billion EUR)



Source: Hydrogen Europe, 2022.

for hydrogen are widely dispersed along the value chain, with over 55% of the available funds not attributed to a specific part of the value chain. The remaining 45% is distributed as follows: industry receives 17%, research 12%, mobility 6%, transmission and distribution 5%, and production 4%, while no funds are allocated for energy applications.

As part of the RePowerEU Communication, the European Commission proposed amendments to the RRF Regulation, providing additional funding sources to finance new investments and reforms to reduce the EU's dependency on Russian fossil fuels urgently. The additional funding will come from revenues from auctioning a part of the Emissions Trading System allowances from the Market Stability Reserve. The new measures proposed by the Member States should be complementary and in line with those previously adopted under the RRF and, once approved, should not disrupt the implementation of the existing plans. An exemption from the digital target (i.e., the requirement is that at least 20% of the Recovery and Resilience Plan's total allocation is dedicated to digital transition) for new measures included in the REPowerEU chapter will also be introduced while keeping the climate target requirement, i.e., that 37 % of the Recovery and Resilience Plan's total allocation is allocated for the green transition.

8.4.

IPCEI

After the pre-notification process of nearly ten months, Member States notified the Technology IPCEI wave to the European Commission on 17 June. The Commission then approved the project, called "IPCEI Hy2Tech", on 15 July, which was jointly prepared and notified by fifteen Member States: Austria, Belgium, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Italy, Netherlands, Poland, Portugal, Slovakia, and Spain.

Under this scheme, the Member States will provide up to €5.4 billion in public funding (expected to unlock an additional €8.8 billion in private investments) to 35 companies, including SMEs and start-ups, participating in 41 projects.

The notification of the Industry H2 IPCEI should follow in August 2022 after the current fourth round of questions to project promoters and the reshuffling of the IPCEI chapeau. The Commission's decision should be released not long before the publication of this report.

The third wave, the "Regional Hubs and their Links" IPCEI or RHATL IPCEI, focuses on import and infrastructure projects. It was pre-notified in April and is currently being assessed by DG Competition. Finally, works are ongoing with the fourth wave, the Mobility and Transport IPCEI, for a pre-notification before the end of August 2022.

New waves may be introduced in the IPCEI Hydrogen process at some point in the future. One example is **H2 Capacity** ('IPCEI on European connected capacity projects for feedstock in different applications). The IPCEI process continues to create uncertainties due to timing, budget (especially for the second waves) and possible alternatives (new IPCEIs, CEEAG...) for projects that will not meet the IPCEI criteria.

8.5.

State aid

The past year has been decisive in establishing an EU state aid framework that will be instrumental for accelerating the hydrogen economy, with the entry into force of the new **state aid Guidelines on Climate, Environmental Protection and Energy (CEEAG)** at the beginning of 2022. They focus on rolling out renewable energies and technologies that reduce GHG emissions and foster energy efficiency in all sectors. Therefore, a wide range of activities from renewable and low-carbon hydrogen production to transport and distribution and mobility and industry end-use applications may benefit now more easily from state aid, previous notification to the European Commission by the Member States. In addition, the new framework includes several provisions that can be exceptionally favourable or suited to hydrogen investments (e.g., aid can go up to 100% of the funding gap when competitive bidding is foreseen, aid can cover both CAPEX and OPEX, technology-specific tenders may be possible, possibility to support integrated projects and new state aid instruments such as carbon contracts for difference…). Allocation of state aid under CEEAG is expected to intensify in the coming months under the impulse of Repower EU, implementing the Member States Resilience and Recovery Plans and as an alternative opportunity to the hydrogen IPCEI process.

The European Commission has also presented a draft revision of the state aid **General Block Exemption Regulation (GBER**) end of 2021, which complements the CEEAG. It defines the conditions under which small-size projects that largely contribute to the green transitions and digital technologies, including a large variety of hydrogen projects, could be exempted from the requirement of prior notification and Commission approval. The adoption of the GBER is foreseen before the end of 2022.

Besides, renewable hydrogen production and industry applications projects have received an additional boost through the **Temporary Crisis Framework.** The review of 20 July 2022 introduces flexibilities to incentivise companies to make the needed investments. Under this regime, which is open until 30 June 2023, state aid of up to EUR 500K benefits from a fast-track assessment but must still be notified to the European Commission.

Finally, the state aid framework relevant to hydrogen deployment has been completed with a new **Communication on Projects of Common European Interest (IPCEI),** thus impacting the H2 IPCEIs under preparation. This document, which entered into force in 2022, sets the compatibility criteria for large European integrated cross-border hydrogen projects of different TRL levels. To this end, it has extended the notion of first industrial deployment (FID) and underlined the focus of projects of great importance on infrastructure.

8.6.

National Investment Banks, development banks and sovereign funds

A sovereign wealth fund is a state-owned investment fund comprised of the money generated by the government, often derived from a country's surplus reserves, e.g., state-owned natural resource revenues and trade surpluses. Globally, they hold about USD 8.2 trillion in assets under management. Their long-term investment horizon, capacity to take on higher risk, and mandate to provide benefits for a country's economy and citizens make them perfect instruments to support the clean hydrogen sector.

BOX 4

GPFG

Norway's Government Pension Fund Global (GPFG), a sovereign wealth fund that invests the surplus revenues of the petroleum sector in its $1.4 trillion in assets, owns about 1.5% of the world's listed companies. In 2022, the Ministry of Finance envisages a change of the fund's ESG aims, replacing its environmental mandate and reference index with a climate-risk-oriented index for the entire fund. Last year under the existing threshold, the GPFG invested in Øsrsted's Borssele 1 & 2 offshore wind farm off the Netherlands, which was its first investment in renewable energy infrastructure.

National investment and promotional banks complement and leverage private capital investment and can help socialise the risks related to new green investments (Marois, 2017).

The German KfW and the French BPI are two examples of national banks' activities in the renewable and hydrogen sphere.

BOX 5

BPI and KfW

KfW is one of the largest promotional banks in Europe. The German Federal Governement holds 80% of KfW shares while the German federal states hold 20%. In 2021, out of EUR 107 billion in funding, 33% has been used for climate and environmental protection. In the same year, the bank provided EUR 40 billion debt capital to the German operator Nowega GmbH to convert around 120 kilometers of existing gas pipelines for the transport of green hydrogen as part of the GET H2 Nukleus project.

BPI France is the French public investment bank and France's sovereign Wealth fund altogether and is chaired by the French Caisse de depot et consignations (CDC). Following the announcement of the French Recovery Plan, BPI together with Banque des Territoires launched a joint 2020-2024 Climate Plan worth nearly EUR 40 billion. The plan supports initiatives in innovative clean tech and renewable energy, including hydrogen.

KfW and BPI are members of the European long-term investors association (ELTI) which represents 31 European long-term investors from 23 Member States across the European Union and Turkey. With a combined balance sheet of € 1.7 trillion, ELTI's goal is to promote long-term investment in close alignment with the objectives and initiatives developed by the European Union.

8.7.

Focus on the European Investment Bank

The EIB offers loans, guarantees, equity investments and advisory services, which could come on top of the support from the EU funding programs. Projects can be financed directly and through intermediaries within and outside the EU, with public and private promoters.

Based on the Advisory Services Agreement signed with Hydrogen Europe in July 2021, EIB is providing financing advisory support for hydrogen projects introduced by Hydrogen Europe. The two will also conduct joint market outreach (EIB, 2021).

Overview of EIB financing and advisory solutions for hydrogen

As the EU Climate Bank, the EIB provides various financing advisory solutions relevant to hydrogen project promoters. These solutions are supported, where applicable, by key mandates and partnerships, such as the InvestEU programme.

In recent years, the EIB has financed over EUR 550m in projects directly related to hydrogen. This includes research and development projects to support hydrogen technologies, financing for innovative technology developers, and funding for hydrogen mobility. Recently, the Bank has also financed the deployment of electrolysers and is observing activity in this segment.

The Bank's direct financing solutions include investment loans to corporate or public sector counterparts and project loans made out to special purpose vehicles on a limited or non-recourse basis. Beyond these tools, the Bank also offers thematic financing instruments designed to help address critical risks for demonstrating innovative energy technologies.

Indeed, with the support of the European Commission, the EIB offers thematic venture debt products that enable EU innovators to grow their businesses. These options are presented under the Action for Climate Thematic Impact

Finance ("ACTIF"). They include targeted investment tools tailored to high-risk ventures' needs in the energy innovation field. These tools allow projects presenting a higher risk for traditional bank financing to receive support.

The Bank has also partnered with the European Commission and Breakthrough Energy Catalyst to provide blended finance solutions to projects in key climate technologies, including green hydrogen.

To prepare for such financing options, the EIB also provides advisory support, helping promoters structure their investment proposals to enhance their chances of obtaining financing. The Bank also provides Project Development Assistance to eligible promoters, for example, under the Innovation Fund or NER 300 programmes, to address specific project development or financing readiness questions.

Through its Advisory Services, the Bank recently called for expressions of interest from European Clean Hydrogen Alliance members developing electrolyser deployment or manufacturing projects. Similarly, developers of hydrogen projects are invited to contact the EIB Advisory Services at innovfinadvisory@eib.org to discuss their projects and explore possibilities of support.

8.8.

Private finance

8.8.1. Overview

Nearly half a trillion euros (accordingly to the most conservative scenario) is needed to kickstart the hydrogen economy in Europe by 2030 (Deloitte Finance – IFPEN - SINTEF, 2021). As shown in the previous chapter, this financial need will only partly be financed by the public sector, highlighting the critical role that private investment will play in enabling the deployment of the hydrogen sector.

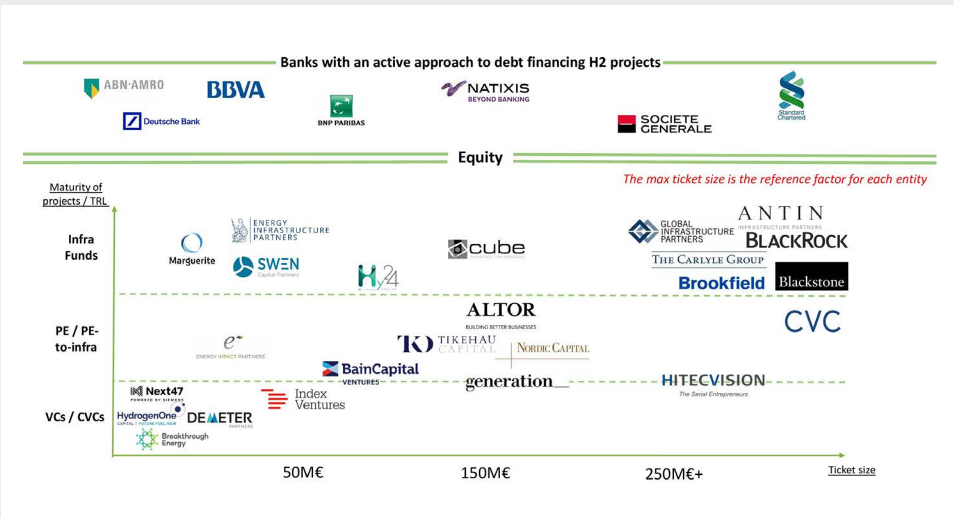
8.8.2. Leading Stakeholders

The urgency to develop a hydrogen economy to reach the ambition of climate neutrality and energy security, combined with the opportunities in terms of financial returns the sector will entail, has led a wide range of financial stakeholders, including hydrogen applications in their portfolios. **Figure 6** presents an overview of some of the largest and most influential venture capitals, private equity and infrastructure funds, and private banks currently investing in the sector.

In addition, initiatives promoted by accelerators and/ or ad hoc programmes and the support of national investment and promotional banks are also crucial for developing the sector and ensuring its attractiveness to investors.

FIGURE 6

Overview of private investors active in the hydrogen economy



Source: Hydrogen Europe, 2022.

8.8.2.1. ACCELERATORS AND PROGRAMMES

In the hydrogen sector, the identification of the most appropriate technologies is still ongoing. As such, it is essential to boost research and innovation. European and national R&I support must be completed with private initiatives to uplift ideas, innovators and technologies that will lead the hydrogen revolution towards a sustainable future. Examples of leading accelerators and networks for hydrogen include H40 Index, the HyAcceleration - powered by SNAM, and H2UB.

The H40 Index, founded in 2022 by the Task Force Hydrogen (TFH) with the support of Capgemini, GL events, John Cockerill and Natixis, offers matchmaking services to hydrogen start-ups and small caps with a capitalisation of up to EUR 250 million.

HyAcceleration entails access to Snam's Hydrogen Innovation Center, a worldwide network of research hubs interlacing SNAM's core business competencies in energy systems with ground-breaking research and facilities from academic partners. The Innovation Center offers mentoring, technical, economic, and legal support.

By providing support in arranging funding and contacts with investors, H2UB promotes both the early-stage and growth development of H2 start-ups and H2 spin-offs from companies, universities and research institutes **(Box 6).**

8.8.2.2 VC AND CVCS

Venture capital (VC) investment is crucial for developing and commercialising disruptive technologies in the hydrogen sector. VC funds can take more risk, accept longer time investment horizons, and position themselves early in the setup of industries or value chains. They usually seek returns of over 30%.

Corporate Venture Capital (CVC) is the investment of corporate funds directly in highly innovative or start-up companies. CVC funds can bring to their investees a superior knowledge of markets and technologies, a strong balance sheet, and the ability to be a patient investor, which is specifically relevant for the successful deployment of hydrogen projects.

In 2021, venture capital activity in hydrogen totalled almost EUR 2 billion. While in 2021, invested capital nearly tripled, the number of deals doubled. This significant increase in the average deal size signals that VC funds are already willing to "pay to play". The US is still leading with almost half of the global transactions in 2021; however, in Q1 2022, Europe held the highest share of capital invested in hydrogen, according to Pitchbook data (2022).

BOX 6

European Hydrogen Financing Forum

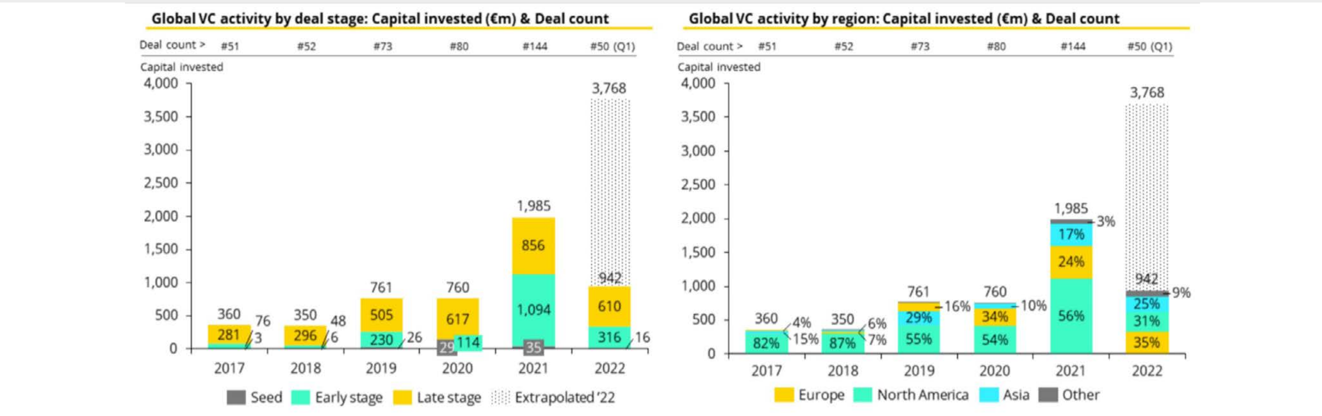
The European Hydrogen Financing Forum is a programme aimed at building a bridge between key private funding players and game changing European hydrogen projects. It includes a series of 4 events, numerous online sessions and training organised by TechTour and Hydrogen Europe. The Forum unlocks new opportunities for the sector by creating a platform for diverse financial institutions to join forces and mitigate risk through co-investment and experience sharing.

The four events include:

- European Hydrogen Investment Summit (22-23rd of June 2022, Antwerp, BE)
- European Hydrogen Transport Dialogue (20-21st of September 2022, Nuremberg, GE)
- European Hydrogen Industry Roundtable (22nd of November 2022, Duisburg, GE)
- European Hydrogen Foresight Roundtable (TBC)

FIGURE 7

Hydrogen sector - Venture Capital funding received (EURm) and deal count, 2014 - Q1 2022



Source: Pitchbook, 2022.

Examples of venture capital funds committed to hydrogen investments are Breakthrough Energy Ventures (BEV), AP Ventures, Chrysalix, and Matterwave Ventures, whereas XCarb™ Innovation Fund, Yara Growth Ventures, or Vopak Ventures are examples of the sector's leading Corporate Venture Funds.

BOX 7

Breakthrough Energy Ventures (BEV)

BEV is a decarbonization-focused VC founded in 2016 by Bill Gates, together with Prelude Ventures and Capricorn's Technology Impact Fund. With USD 2 billion in committed capital, BEV aims to invest in cutting-edge solutions including hydrogen-related technologies to accelerate the energy transition across every sector of the economy.

In 2019, together with the European Commission, the BEV-Europe was founded with a budget of EUR 100 million. The partnership between the two entities was strengthened last year with the establishment of Breakthrough Energy Catalyst that will mobilise up to EUR 820 million between 2022-2026 to accelerate the deployment and rapidly commercialise innovative technologies helping to deliver the European Green Deal ambitions and the EU's 2030 climate targets.

Example of commitments: BEV led Spanish start-up H2SITE's EUR 12,5 million Series A in June 2022. The funding will accelerate the scale up of H2SITE's integrated membrane reactor and membrane separation technologies to obtain fuel cell purity hydrogen from ammonia or methanol cracking or enable hydrogen transportation in existing natural gas infrastructure (Bloomberg, 2022).

BOX 8

XCarb™ Innovation Fund

Founded in March 2021, the ArcelorMittal's XCarb™ Innovation Fund is part of the Xcarb™ initiative, the first sustainability umbrella brand in the steel industry. The Fund will accelerate the decarbonization of the industry by investing USD 100 million per year in game changing technologies (including hydrogen) worldwide. Companies hoping to attract investment from the Fund have to develop a technology which is directly applicable to steelmaking and that is commercially scalable.

Example of commitment: USD 25 million equity injection into Form Energy for the development of an energy storage solution based on Direct Reduced Iron (ArcelorMittal, 2022).

8.8.2.3. PRIVATE EQUITY AND INFRASTRUCTURE FUNDS

Private equity (PE) firms invest when a company has gone beyond generating revenue and developed profitable margins, stable cash flow, and can service a significant amount of debt. They can usually invest larger amounts than VCs but take on a lower risk. The target return usually varies between 20 and 25%.

Infrastructure investors usually look at CAPEX-intensive assets providing steady returns and cash yields, which benefit from barriers to entry via a regulated monopoly or long-term contracts. Private infrastructure funds usually target returns between 5 to 20% and have the capacity to deploy large sums with a longer investment time horizon than PEs or VCs.

With estimates of the infrastructure financial need of around EUR 260 million by mid-2030 (without including the high investments in the electrolysers manufacturing (Deloitte Finance – IFPEN - SINTEF, 2021), infrastructure funds such as Hy24, Copenhagen Infrastructure Partners, SWEN Capital Partners, and CUBE play an essential role in ensuring that large upstream and downstream clean hydrogen projects are supported.

BOX 9

Hy24

Hy24 is the world's largest investment platform focused on clean hydrogen infrastructure with EUR 2 billion of commitments secured. The fund has been brought together by:

- FiveT Hydrogen: an investment manager specialised purely on clean hydrogen investments, and
- Ardian: a private investment house with managed assets of USD 114 billion.

Hy24 provides financial capital to fund credible, large-scale green hydrogen infrastructure projects for the production, storage, and distribution of clean hydrogen world-wide.

Example of commitments: H2 MOBILITY Deutschland has secured EUR 70 million from Hy24 to upgrade the existing network and build new hydrogen refuelling stations (Hy24, 2022). Hy24 adquired a 30% equity stake into Enagas Renovable to accelerate the development of Enagas' leading renewable-to-gas platform.

8.8.2.4. INVESTORS GROUP

To identify significant trends, improve knowledge-sharing, and co-design solutions focused on innovative financing approaches or de-risking measures, investor groups are essential to collaborate and steer capital toward priority technologies, including hydrogen-related applications.

BOX 10

FTT and GIIA

The **Financing the Transition to a Net-Zero Future (FTT)** is a collaboration between the World Economic Forum and management consulting company Oliver Wyman. Launched in 2020, FTT aims at identifying solutions that would accelerate financing towards innovative breakthrough technologies in key hard-to-abate sectors including sustainable aviation fuels, carbon capture and storage and hydrogen-based direct reduced for steel, ammonia for shipping.

The **Global Infrastructure Investors Association (GIIA)** formed in 2016 represents more than 80 leading private investors and advisors in global infrastructure. GIIA works closely with policy makers, regulators, and other industry bodies to promote policy and regulatory intervention to catalyse private sector investment in key prioritised infrastructures including the hydrogen sector.

BOX 11

Natixis

Already two years ago, **Natixis** developed a hydrogen strategy complemented with a three-pronged plan to seek out investments that could help the sector grow. These include:

- The creation of a working group to follow the sector's macrotrends.
- The participation in initiatives including Hydrogen Council and the European Clean Hydrogen Alliance.
- A strategic dialogue with players active in the entire hydrogen value to capture their fundamental needs.

Example of commitment: In 2020, HysetCo and Hype put together a group of leading financial partners, including RGREEN INVEST, Mirova (affiliate of Natixis Investment Managers), RAISE Impact and Eiffel Investment Group, thus raising more than €70 million in order to develop the most important hydrogen taxis fleet in Europe by financing the building of new hydrogen stations and by increasing the number of taxi licenses used for hydrogen vehicles through the acquisition of Slota Group (Source: Mirova, 2022)

8.8.2.5. PRIVATE BANKS

The increasing relevance of topics related to the climate crisis and the potential role that hydrogen can play in the transition to low-carbon technologies, especially in hard-to-abate sectors, is leading banks such as Natixis, Deutsche Bank, ING, ABM AMR to adapt their strategies accordingly (ING, 2021). Notably, banks are looking at industrial clusters developed around ports or close to reasonable access to renewable power where offtakes are guaranteed and risks are mitigated. Moreover, banks are willing to play a role not only in providing capital but also in advisory services (Penson, 2021).

8.8.3. Financial Markets

Despite lacking a merchant market for hydrogen, financial markets outline a vision for a mature hydrogen segment. The bond, stock and cryptocurrency markets are moving consequently to the acceleration of hydrogen solutions.

Bond Market

In November 2021, the green bond issuances stood at USD 354.2 billion YTD, with forecasts disclosing a trillion-dollar market within reach by 2023 (Climate Bond Initiative, 2021).

Green bonds are an excellent candidate for the hydrogen sector to consider, as the issuing entity's balance sheet backs them and repayments of interest and capital are not solely dependent on off-taker revenue as in the case of a hydrogen project financing (Baker, 2021). To clarify the applicability of issuances related to hydrogen, the Climate Bond Initiative is elaborating criteria laying out the requirements that hydrogen production projects must meet to be eligible for inclusion in a Certified Climate Bond and companies on a credible transition path to issue transition-labelled debt. Hydrogen Europe has been involved in this exercise by providing feedback on the concrete applicability of the proposed criteria.

Stock Market - Focus on ETFs

An exchange-traded fund (ETF) is a type of pooled investment security that operates much like a mutual fund. Typically, ETFs will track a particular index, sector, commodity, or other assets, but unlike mutual funds, ETFs can be purchased or sold on a stock exchange the same way a regular stock can.

Looking at the Exchange Traded Funds (ETFs), this space is very young, with the first ETFs launched in 2021. Currently, their combined assets under management amount to more than USD 700 million, with L&G Hydrogen Economy UCITS ETF (HTWO) having roughly USD 559 million of assets under management, followed by the VanEck Hydrogen Economy UCITS ETF (HDRO) with approximately USD 100 million AUM and the Global X Hydrogen UCITS ETF (HYGN) with around USD 3 million in AUM (JustETF).

BOX 12

L&G HTWO

The L&G Hydrogen Economy UCITS ETF (HTWO) is the world's first and largest Hydrogen Economy ETF.

This fund is designed to track the performance of the Solactive Hydrogen Economy Index. HTWO allows investors to express their view on hydrogen value chain equities: hydrogen production, hydrogen distribution, components manufacture, energy storage, transportation, and hydrogen-based applications. It invests in 30 stocks spanning five different sectors: 52.9% in Industrials, 27% in Materials, 8.3% in Consumer Discretionary, 7.3% in Utilities, and 4.5% in I.T. On the securities level, this fund is not as diversified as on the geographical level, as the top 10 holdings constitute 44.8% of the portfolio. HTWO has 28.9% of total assets invested in the United States, 12.35 in Japan, 11.0% in South Korea, 10.3% in the United Kingdom, 7% in Germany, and the remaining spread across more than five countries.

TABLE 2

Return Comparison of hydrogen ETFs, cumulative returns including dividends, in %

TF Name	1-month return in %	3 months return in %	6 months return in %	1 year return in %
L&G Hydrogen Economy UCITS ETF USD Acc	12.31%	-2.34%	-3.47%	-15.61%
VanEck Hydrogen Economy UCITS ETF	19.42%	-1.55%	0.08%	-16.81%
BNP Paribas Easy ECPI Global ESG Hydrogen Economy UCITS ETF	13.90%	6.60%	-	-
Global X Hydrogen UCITS ETF Acc USD	22.38%	0.28%	-	-

Source: justETF.com; As of 31.07.22; Calculations in EUR including dividends.

Cryptocurrency Market

Hydrogen is also gaining attention in the decentralised market of cryptocurrency, estimated to be valued at USD 1.16 trillion as of the 11th of August 2022 (CoinMarketCap). Indeed, hydrogen has been recognised as a valuable option for decarbonising the bitcoin mining process, as demonstrated by the cooperation between Caterpillar, Microsoft and Ballard Power Systems in producing reliable power from fuel cells for data centres (Caterpillar, 2021). In addition, cryptocurrency is perceived as a way to sustain hydrogen initiatives worldwide by buying linked tokens such as HydroCoin and HDGN Hydrogen Economy.

8.8.4. EIB Report: Market views on Hydrogen Investment conditions

In May 2022, the European Investment Bank (EIB) published a report on hydrogen: "Unlocking the hydrogen economy — stimulating investment across the hydrogen value chain". The report's findings are based on consultations with nearly 50 financial investors, industrial companies and sector experts. The study was conducted with the support of the European Commission under the InnovFin Advisory programme.

Overall, the analysis highlights the increasing investor interest in hydrogen, with expectations that hydrogen will play a role as a renewable energy carrier to decarbonise EU economies, especially in energy-intensive sectors. This momentum is demonstrated by the significant increase in electrolyser capacity announcements for the coming years.

However, the study also underlines how investment in hydrogen has so far been constrained, with only a low percentage of the announced electrolyser projects having reached a Final Investment Decision. This is attributed to several challenges: economic and regulatory conditions, deployment risks and value chain complexity.

The biggest issue voiced by investors is the unfavourable economics of renewable or low carbon hydrogen due to often challenging costs vs existing alternatives, whether on the production, transport or usage side. This tends to lower project returns and create a barrier to investment.

Regulatory conditions are also mentioned as a source of uncertainty by many investors, for example, in terms of the definition of renewable or low-carbon hydrogen, requirements for additional renewable energy or regulatory frameworks for transport & storage.

Beyond these issues, deploying hydrogen projects presents key uncertainties for investors. Securing offtake agreements to minimise merchant risk tends to be challenging. For example, construction and technology performance risks are noted concerning large-scale electrolyser deployment. Operational risks are also perceived, as well as uncertainties related to the life of underlying assets and the integration of multiple project building blocks.

Last, hydrogen projects depend on multiple value chain building blocks, which must be developed in parallel for projects to succeed. Without a mature market and support infrastructure, this tends to make project planning more complex and cause further uncertainties during development.

The report lays out ideas around credit enhancement and risk-sharing to address these challenges, which could help mitigate some of the risks observed and facilitate financing. Potential new advisory solutions are also highlighted to help promoters adapt to the challenges identified and improve their odds of securing financing.

The report is available at the below link: Unlocking the hydrogen economy — stimulating investment across the hydrogen value chain (eib.org)

Conclusion

The European Commission has several funds with the capacity to support the ramp-up of the hydrogen value chain, including schemes for research and development (Clean Hydrogen Partnership), commercialisation (e.g., Innovation Fund), and infrastructure (e.g., the Connecting Europe Facility). The REPowerEU communication had a broad impact on several funding programmes, opening new targeted streams for hydrogen stakeholders and topping up existing ones. Moreover, several new initiatives are being developed and implemented in Europe to leverage market mechanisms to build the hydrogen sector.

Meanwhile, the first IPCEI waves are being notified at the national level, unlocking billions of euros for leading European projects. Additionally, the current cumulative amount of funds available for hydrogen, among other technologies, from all Recovery and Resilience Plans reached around EUR 55 billion, of which almost EUR 12 billion would exclusively be for hydrogen technologies.

According to Deloitte Finance's Hydrogen for Europe study, EUR 480 billion to EUR 890 billion must be mobilised between the early 2020s and the mid-2030s to finance the hydrogen economy. Despite growing public support, private investment will play a decisive role in helping cover these colossal financial needs. Venture capital deals and invested capital are increasing tremendously, funding early technological risk, while large "pure players" infrastructure funds are being raised and helping unlock the first large-scale projects. Banks are also building knowledge and investing resources to get involved more actively in the industry. Financial markets are outlining a vision for a mature hydrogen segment, with ETFs, hydrogen bond standards, and even hydrogen cryptocurrencies being developed.

While the capital invested and several deals are rising quickly, wider involvement of various financial institutions is required to share risks efficiently and unlock the amounts necessary to scale up the value chain.

© Christian Lue

© Justin Jin for Hydrogen Europe

09

National policies and incentives

© Anthony Tyrrell

© Scott Graham

Introduction

This chapter focuses on two categories of commitments: political and economic. Political commitments take the form of hydrogen strategies that have been increasingly adopted both at the national and regional levels. The first part of this chapter focuses on these strategies, while the second part addresses selected national support mechanisms for hydrogen technologies. The **methodological note** describes the methods used to gather the data presented in this chapter.

9.1.

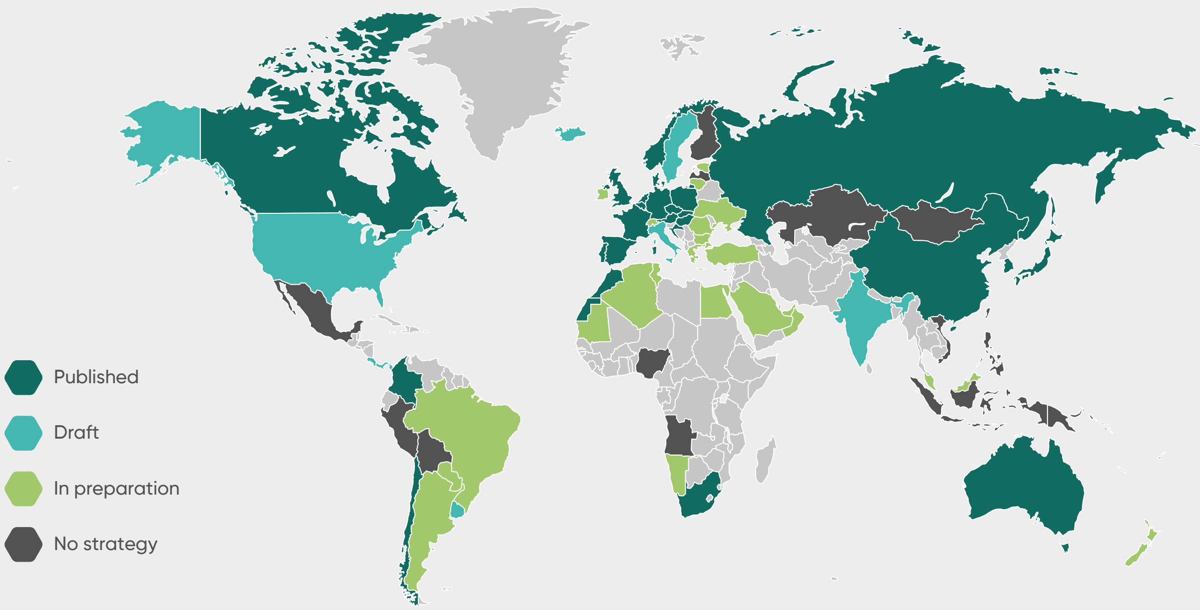
National strategies

9.1.1. Overview of hydrogen strategies

Interest in hydrogen is increasing globally, as governments across the globe continue to adopt national hydrogen strategies. In the 2021-2022 period, important regional countries that did so included China, Morocco, and South Africa, bringing the total number of countries with a national hydrogen strategy or similar strategic long-term document to 27 by August 2022. China published its first hydrogen plan in March 2022, which, while limited in terms of renewable hydrogen targets (production of 100,000-200,000 t/year by 2025), focuses on developing low-carbon and renewable hydrogen production expertise and infrastructure, as well as electrolyser manufacturing capacity. Despite the limited length of the plan, hydrogen is a technology of key interest to China, as evidenced by the investments of state-owned enterprises and the publication of hydrogen development plans by regional Chinese governments (Nakano, 2022). At the same time, as the United States continues to prepare its hydrogen strategy,[1] it has adopted under the Inflation Reduction Act 2022, a tax credit of up to USD 3/kg of hydrogen produced at a given facility, based on the carbon intensity of production (Fuel Cell & Hydrogen Energy Association, 2022). India, Italy, Sweden, and Uruguay have published their official drafts. Additionally, 27 other countries are preparing their hydrogen strategies.

FIGURE 1

Overview map of hydrogen strategies adoption status



Source: Hydrogen Europe 2022 Data by 01/10/2022.

1 / Following Hydrogen Europe methodology, the "Department of Energy Hydrogen Program Plan" is not considered a hydrogen strategy, due to its focus on research and development. Focus on research and development, and only in the end of September 2022 did the US D.O.E. published the draft DOE National Clean Hydrogen Strategy and Roadmap. For more information see the methodological note section pertaining to Chapter 9.

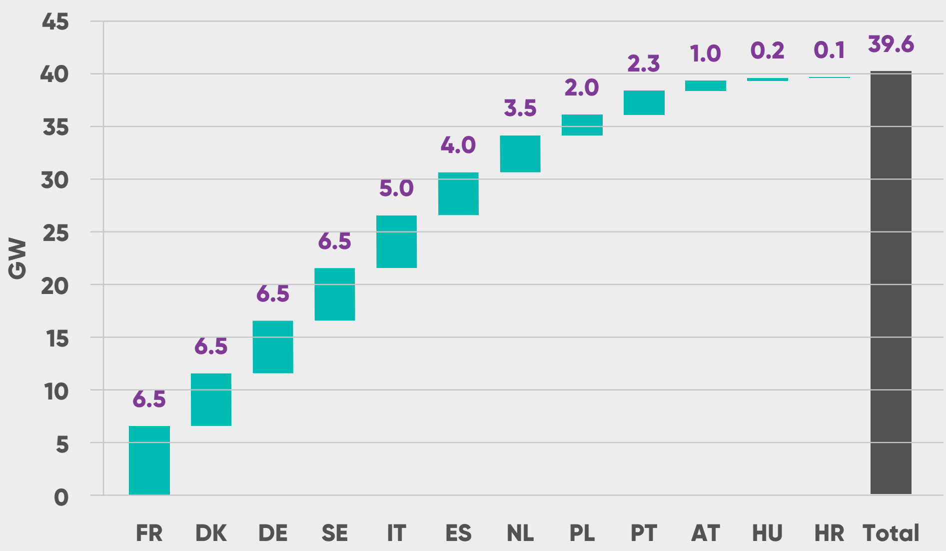
At the time of writing, Europe still remains the continent that has adopted the most hydrogen strategies: 16 in total, 14 of them in the European Union (EU). This is no surprise, as hydrogen was recognised in the European Green Deal as key to the continent's decarbonisation efforts. Hydrogen technologies were further pushed to the top of the agenda by the war in Ukraine, which renewed the urgency of reducing dependence on Russian fossil fuels.

Austria, Belgium, Croatia, Czech Republic, Denmark, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Portugal, Slovakia, Spain as well as Norway, and the United Kingdom have all published national hydrogen strategies.[2] With Austria, Croatia and Denmark having done so in 2022. Bulgaria, Cyprus, Estonia, Greece, Iceland, Lithuania, Romania, Switzerland, and Ukraine have all announced that they are preparing their national hydrogen strategies. During drafting of this report in summer 2022, Bulgaria, Estonia, Greece, and Romania are making progress on their draft strategies, which could bring the total number of strategies in the EU to 18 by the first half of 2023.

Identifying common elements in these strategies is challenging, as they reflect differing national characteristics such as levels of ambition, economic structure, and national political frameworks, among others. Thus, common elements between strategies are scarce, with the most common commitment in EU Member States' (EU MS) strategies being electrolyser capacity and public funding for hydrogen technologies.

FIGURE 2

Committed electrolyser capacity from EU national strategies by 2030 in the EU[3]



Source: Hydrogen Europe 2022 Data by 28/07/2022.

2 / The Spanish Hydrogen Roadmap and German and Austrian strategies are set for an evaluation and review in 2023, although the revision of German strategy, might take place already in 2022, as a faster market ramp-up of hydrogen is envisaged under the 2021-2025 Coalition Agreement (The Federal Government, 2020, p. 59; MITECO, 2020, p. 37; BMK; BMDW, 2022, p. 49).

3 / Only countries with specific targets for planned electrolyser capacity are included. When the target is a range, the median value of that range was used. Targets for Sweden and Italy are provisional and subject to change in the final version of the national hydrogen strategy. The target for Poland is for low-carbon emission sources, including electrolysers.

As for electrolytic hydrogen, 12 EU MS have made electrolyser capacity commitments for 2030, totalling 39.56 GW. This is below the 40 GW 2030 target outlined in the EU Hydrogen Strategy and significantly below the approximately 130 GW needed to reach REPowerEU's new target of 10 million tonnes of domestic renewable hydrogen production by 2030.[4]

Another common commitment concerns the building of hydrogen refuelling stations (HRS). Croatia, Hungary, Poland, Portugal, and Spain have committed to building a total of 267 refuelling stations by 2030, with Spain being the most ambitious MS with a target of between 100 and 150 stations.

To achieve these and other targets set out in the documents, adequate financial support provided at the national level will be critical. In their strategies, eight MS – Austria, Belgium, Czech Republic, Denmark, France, Germany, Poland, and Portugal– have committed a total of EUR 18.47 billion of public funds towards the hydrogen sector. These are mostly non-hydrogen technology exclusive funds, spread across different national funds and programmes providing support for cost reduction along the hydrogen value chain, guarantees of origin and certification, and support for research, development, and innovation. Additionally, strategies also identify funding possibilities stemming from the EU, such as under the National Recovery and Resilience plans (Belgium, France, Poland) and other funding funds or operational programmes (Denmark, Czech Republic, and Portugal).

More recently, under the Important Project of Common European Interest (IPCEI) in the hydrogen value chain, two waves of projects have been cleared from the Commission to receive state aid from the MS. The first wave Hy2Tech, comprises of 41 projects from 15 MS focusing on developing innovative technologies for the hydrogen value chain to decarbonise industrial processes and mobility. The second wave Hy2Use comprises 35 projects from 13 MS, focusing on the developing novel technologies for the production, storage, transportation and distribution of hydrogen as well as applications in the mobility sector.The IPCEI represents an important step towards maintaining EU competitiveness in the global race for leadership in hydrogen technologies.

To highlight the different national approaches and commitments, an overview of the three EU Member States' strategies adopted in 2022 is presented below. The regional strategies will then be addressed.

Hydrogen Strategy for Austria

The Austrian hydrogen strategy, published in June 2022, has from the outset a different approach to the development of the hydrogen sector, compared to other national strategies.

While the definition of renewable hydrogen is in line with that of the European Hydrogen Strategy, the Austrian strategy introduces the concept of "climate-neutral hydrogen". This is hydrogen produced from natural gas using complete CO2 separation ('blue hydrogen') or by pyrolysis ('turquoise hydrogen'). However, for 'blue hydrogen' to be classified as "climate-neutral hydrogen", it must be ensured that "CO2 capture takes place without the release of greenhouse gases, and that all CO2 emissions along the extraction, transport, and processing chains are excluded". Furthermore, 'blue hydrogen', whose CO2 capture is powered by nuclear energy [is] not sustainable and therefore do[es] not fall" into the category of 'climate-neutral hydrogen'. The same applies to 'pink hydrogen' from nuclear energy, which is not considered climate-neutral.[5] The exclusion of the use of nuclear energy for hydrogen production is explained by Austria's long-standing anti-nuclear position.

The strategy sets a target of 1 GW of installed electrolyser capacity by 2030. Production technologies based on biogenic raw materials are expected to play a secondary role. To encourage renewable hydrogen production, the strategy envisions the introduction of a renewable gas sales quota and the pricing for CO2 emissions outside of the Emission

4 / See footnote 3. For more information, see European Clean Hydrogen Alliance (2022) European Electrolyser Summit Joint Declaration, Brussels 5 May 2022, available at https://ec.europa.eu/commission/presscorner/detail/en/IP_22_2829. Electrolyser capacity is measured in terms of electricity input, assuming an average electrolyser utilisation factor of 43% and electrolyser efficiency of 70%.
5 / For more information on the definition of 'climate-neutral hydrogen' please see Wasserstoffstrategie für Österreich, p. 5, available at https://www.bmk.gv.at/themen/energie/energieversorgung/wasserstoff/strategie.html.

Trading System (EU ETS). It also includes the simplification of zoning and operating permits for hydrogen production facilities. *Transformation der Wirtschaft* will aim to incentivise market-based business models using Contracts for Difference (CfD) based instrument and provide funding for projects related to hydrogen use in industrial plants. A budget of EUR 125 million has been allocated to finance Austrian hydrogen IPCEI projects until 2026.

TABLE 1

Electrolyser capacity and projected demand for renewable gases in the Austrian hydrogen strategy

ELECTROLYSER CAPACITY 2030	1 GW	
Projected demand for climate-neutral gases 2040	**Base scenario**	**Exergy efficiency scenario**
Total demand	138 TWh	89 TWh

Source: Hydrogen Strategy for Austria, 2022, p. 13, 21-22.

The strategy contains different scenarios. The exergy scenario envisions the use of 59.5 TWh (1.8 Mt at LHV) of hydrogen in the industry with 3.1 TWh (0.09 Mt) for ammonia, 24.8 TWh (0.75 Mt) for methanol production, 22.9 TWh (0.7 Mt) for steel production, 3.7 TWh (0.01 Mt) in cement and glass production, and 5 TWh (0.15 Mt) in other industries.

In terms of infrastructure, priority will be given to the use of pure hydrogen, with on-site generation or pure hydrogen transport pipelines. To develop the hydrogen infrastructure, the strategy foresees a study on the future of gas infrastructure in 2040; a roadmap toward a pure hydrogen backbone from the existing natural gas grid; an increase of hydrogen tolerance in the gas network with a detailed plan with concrete milestones until 2040, and a study on hydrogen import possibilities.

Concerning mobility, support for R&D and demonstrations is available through *FTI-Agenda Mobilität* and Zero Emission Mobility programmes. While support for e-mobility, focusing on trucks and buses fleet conversion to zero-emission technologies (BEV, FCEV) and establishment of the associated infrastructure is available through *the Förderprogramme EBIN (Emissionsfreie Busse und Infrastruktur)* and *ENIN (Emissionsfreie Nutzfahrzeuge und Infrastruktur)* programmes.

The government is also setting up **H2Austria,** as envisaged in the strategy. The platform aims to enable dialogue between industry, local authorities, the energy sector, and civil society and to make recommendations to the strategy task force on how to implement the strategy.

Croatian Strategy for Hydrogen Until 2050

The Croatian hydrogen strategy, adopted in March 2022, is mainly qualitative and describes the different segments of the hydrogen value chain and how to integrate them into the Croatian energy, transport, heating and cooling, and industrial sectors.

The Strategy is based on four strategic areas: (1) hydrogen production, (2) storage and transport, (3) use, and (4) education and research and development. The strategy focuses on enabling low-carbon production, with a primary interest in renewable hydrogen. While in the short-term production is projected to take place at consumption sites, the country plans to convert existing gas infrastructure to transport hydrogen in the long term. It is also expected that until 2026 the main end-uses for hydrogen will be in transport and industry, although the long-term goal is to enable hydrogen use in agriculture, heating and cooling, and in backup systems for civilian and military applications. Croatia will also focus on the development and commercialisation of new hydrogen technologies. It estimates that to achieve the goals in its strategy it will need HRK 23.8 billion (EUR 3,163 billion) by 2050,[6] most of which is expected to come from EU funds.

TABLE 2

Performance Indicators of Croatian Hydrogen Strategic Objectives

STRATEGIC GOAL	PERFORMANCE INDICATORS 2030	PERFORMANCE INDICATORS 2050
Increasing the production of renewable hydrogen (Electrolyser capacity)	70 MW	2,750 MW
Increasing the use of RES potential (Share of hydrogen in total energy consumption)	0.2%	11%
Increase in hydrogen use (№ of hydrogen refuelling stations)	15	100
Encouraging the development of science, research and development of hydrogen technologies (№ patents related to hydrogen economy)	5	50

Source: Croatian Hydrogen Strategy 2022, p. 24 (adapted).

6 / ECB Exchange rate for Croatian kuna (HRK) for 12/05/2022: EUR 1 = HRK 7.5235

Croatia is also planning to create a **Regional Hydrogen Centre** to work on the expansion of the hydrogen economy in the 13 new EU Member States. The centre would serve as a forum for the scientific community, industry, and policymakers to meet while implementing projects and generating innovative ideas and solutions. A separate governmental act on the Centre is expected.

Development and promotion of hydrogen and green fuels (Power-to-X strategy) in Denmark

The Danish hydrogen strategy was agreed upon in March 2022, taking the form of an agreement between eight out of the 16 political parties represented in the Danish parliament (Folketinget, n.d.). The strategy is based on the Danish government's proposal published in December 2021 but has broader parliamentary support.[7] According to the strategy, Power-to-X (PtX) technologies should be integrated as a form of indirect electrification in a way that supports and complements existing supply sectors, focusing on fuels and chemicals that can replace fossil fuels in hard-to-abate sectors. Moreover, the surplus heat from PtX processes could also be integrated into district heating.

Denmark aims to build between 4 and 6 GW of electrolyser capacity by 2030. The strategy also emphasises the importance of EU rules on RFNBOs production (See **Chapter 7**), to ensure that the hydrogen is considered renewable. To achieve this, the government will present a plan to increase renewable energy production, so that Denmark is a net exporter of green energy by 2030. It will also set up a subsidy scheme for PtX plants, which will be funded by the statistical transfer of renewable energy from Denmark to the Netherlands under art. 8 REDII. In 2020, Denmark transferred 13.65 TWh of energy from renewable energy sources to the Netherlands (Eurostat, 2020; Morgan, 2020).[8] Following another transfer in December 2021, the total amount available for the scheme was raised to DKK 1.25 billion (EUR 167.98 million).[9] The subsidy scheme will be market-based and aimed at the cheapest and largest amount of production for the set budget. It will be granted for 10 years as a fixed price operating subsidy, paid per quantity of hydrogen produced. Only renewable hydrogen that meets EU requirements will be eligible. The earliest expected date for the tender is in 2023, subject to approval from the European Commission.

In addition, another DKK 344 million (EUR 46.22 million) from the REACT-EU was expected to be mobilized for a new investment scheme to support the scale-up of innovative green technologies in the strategy (the actual amount is DKK 244 million).[10] A first round of the scheme was open until April 2022, with the two central development tracks being CCUS and hydrogen-related technologies (including PtX), while projects for other technologies could also apply. Eligible activities included demonstration projects, R&D, building and construction investments and feasibility studies (Danish Board of Business Development, 2022).

The development of hydrogen infrastructure (pipelines and storage) is seen as a priority, especially interconnected infrastructure with neighbouring countries. Consequently, the agreement aims at establishing the necessary framework to build new or repurpose existing infrastructure for the transport and storage of hydrogen.

To facilitate the implementation of the strategy, Denmark plans to set up a **PtX task force** as part of the Ministry of Climate, Energy and Transport, which will be tasked with coordinating across government agencies, ensuring dialogue between industry and municipalities, addressing regulatory barriers and guiding project developers and authorities on permitting procedures, among other functions.

While national strategies set the general development of the hydrogen sector, at the heart of deployment are the regions and local municipalities. Thus, the focus of the next section is on regional strategies across the EU.

7 / English translation of the 2021 proposal, available at https://ens.dk/sites/ens.dk/files/ptx/strategy_ptx.pdf. Final agreement available at https://www.regeringen.dk/aktuelt/publikationer-og-aftaletekster/aftale-om-udvikling-og-fremme-af-brint-og-groenne-braendstoffer/.
8 / Amount transferred: 1173.69 ktoe.
9 / ECB Exchange rate for Danish krone (DKK) for 12/05/2022: EUR 1 = DKK 7.4413.
10 / Recovery Assistance for Cohesion and the Territories of Europe (REACT-EU) is the extension of the EU's Covid-19 response measures directly to regions, more information is available at https://ec.europa.eu/regional_policy/en/newsroom/coronavirus-response/react-eu/.

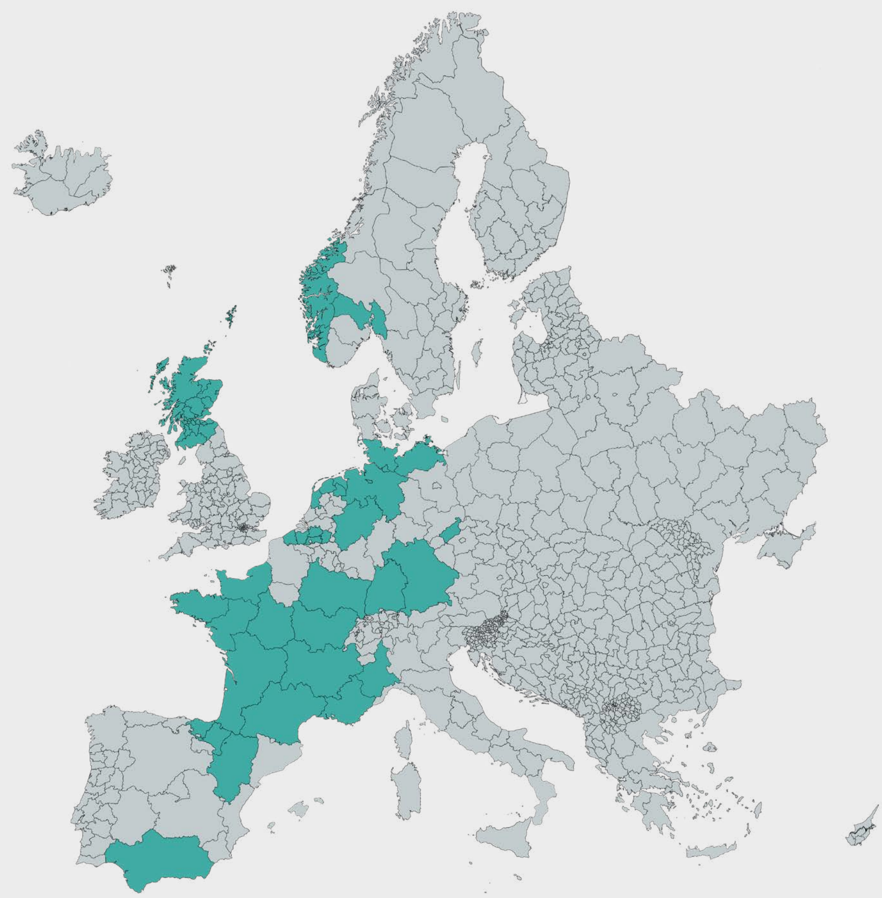
9.2.

Regional strategies

In early 2022, Hydrogen Europe launched the Regional Pillar to welcome European regions into its membership, recognising the important role that local and regional administrations play in deploying the hydrogen ecosystem. Since then, 31 regions have joined Hydrogen Europe, exchanging knowledge and best practices with each other, as well as with industry on local developments, projects, funding, and financing opportunities, while working together on preparing the workforce for the growing hydrogen economy. Several European regions have been at the forefront of investment in an emerging hydrogen sector. A notable example is the autonomous community of Aragon in Spain, which adopted its first Hydrogen Master Plan as early as 2007. The plan, now in its fourth edition, sets out priority lines of action along the entire hydrogen value chain at all stages from research and development to commercial projects.

FIGURE 3

Overview map of published hydrogen regional strategies in Europe



Source: Hydrogen Europe 2022 Data by 29/07/2022.

TABLE 3

Overview of various targets within select regional strategies in Europe

	Electrolyser Capacity 2030 (GW)	HRS 2030
Bavaria (DE)	1	
Northern Germany (DE)	5	
North Rhine-Westphalia (DE)	1-3	200
Basque Country (ES)	0.3	10
Navarra (ES)	0.15	3
Grand-Est (FR)	0.6	
Occitanie (FR)		55
Pays de la Loire (FR)		15
Provence-Alpes-Côte d'Azur (FR)		80[b]
Northern Netherlands (NL)	6	
Zuid-Holland (NL)	1	
Scotland (UK)	5[a]	

a / Target includes both electrolyser and low-carbon hydrogen.
b / By 2032.

Source: Hydrogen Europe 2022 Data by 29/07/2022.

So far, 29 European regions have adopted regional hydrogen strategies. Of these, 20 regions are members of Hydrogen Europe's Regional Pillar. The analysed regional hydrogen strategies differ in form, name, status, and content making it difficult to gather comparative data. This is not surprising, as they reflect different circumstances and priorities in regions' and countries' long-term approaches to hydrogen. Therefore, to showcase concrete hydrogen developments at the regional level, the strategies of Bavaria and Piedmont will be presented.

Bavarian Hydrogen Roadmap

Although the state of Bavaria has had a Regional Hydrogen Strategy since 2020, a Bavarian Hydrogen Roadmap was presented on 25 April 2022. The roadmap builds on the strategy, updating it and presenting the future development of the hydrogen value chain in the state.

While most European regions are orienting their hydrogen policies for a ramp-up and production of hydrogen, Bavaria lacks sufficient renewable energy generation potential limiting its local renewable hydrogen production potential. The roadmap recognises that to achieve the state's climate neutrality target by 2040, hydrogen imports will be needed, especially through a connection to the European Hydrogen Backbone.

The roadmap sets a target of 1 GW electrolyser capacity by 2030. The region will consider not only electrolytic hydrogen but also the use of biomass or other organic residues and climate-friendly alternatives. Fossil-based hydrogen is seen as a transitional measure to be kept for the shortest amount of time possible. Additionally, the state of Bavaria will strive to capture and valorise existing by-product hydrogen production (e.g. chlor-alkali process). For imports, the use of carriers such as liquid organic hydrogen carriers (LOHC), ammonia, and methanol will be explored, with initial projects starting in 2025. By 2030, there should be increased imports and the establishment of regional distribution networks.

The projected demand for hydrogen and its derivatives is expected to be between 33 and 75 TWh per year by 2040. The strategy envisions the widespread deployment of HRS and significant use of hydrogen and its derivatives for high-temperature heat supply in the industry, central power generation, and combined heat and power (CHP).

To meet this demand, the priority is to connect Bavaria to the European Hydrogen Backbone. The roadmap also seeks to build on the region's industrial ecosystem and research and development potential to move towards developing, selling, and exporting technology in the global hydrogen economy.

TABLE 4

Hydrogen related Milestones for Bavaria

	2025	2030
Electrolyser capacity	300 MW	1 GW
Buses	500	
Trucks	500	

Source: Hydrogen Roadmap Bavaria 2022, p. 29 (adapted).

The Regional Hydrogen Strategy of Piedmont

Adopted on 1 July 2022, the Piedmont strategy has five objectives:

Contribute to the achievement of European and national, energy and environmental hydrogen objectives.

Encourage the development of local businesses and attract new ones.

Facilitate access to EU and national funding.

Support research and development.

Establish a dialogue between institutions, academia, and businesses.

To achieve these objectives, the strategy outlines actions in four areas.

1. Hydrogen production, distribution, and energy use: support for green and sustainable hydrogen production plants, including the simplification of authorisation procedures, is envisaged. The planning and construction of dedicated hydrogen pipelines and hydrogen blending will be considered. Co-generation for industrial, civil, and agricultural users will also be supported.

2. Mobility and transport: support will be given for fleet replacement with hydrogen-powered vehicles for urban transport and commercial fleets, the deployment of hydrogen-powered rolling stock and the assessment of the potential of hydrogen-powered vessels for inland waterways.

3. Diversification of production, research development and innovation: this aspect focuses on the development of industrial production with a focus on hydrogen markets. Support for product diversification (systems and components), decarbonisation of hard-to-abate sectors, support for R&D and public-private partnerships, as well as support for exports of hydrogen-related products and technologies, are foreseen.

4. As part of the "transversal pillar", the roadmap will also promote skill development and training on hydrogen technologies, participation in European and national networks, associations and projects, and dialogue with stakeholders focusing on future legislation and regulation of the sector.

To implement the strategy, Piedmont will rely on a combination of EU, national and regional funding programmes such as Italy's RRP, the European Structural and Investment Funds and the regional budget. In addition, a regional hydrogen team has been set up to share information on new funding opportunities, regulatory updates, cross-sectoral project management, linkage of regional, national, and European initiatives, and reporting and possibly updating the strategy.

9.3.

National incentives for hydrogen technologies

Having analysed the national commitments, the remainder of this chapter focuses on national incentives for the development of the hydrogen ecosystem. This section presents an overview of some active policies at the national level in Europe, focusing on three segments of the hydrogen value-chain: production and transmission, mobility, and industry. The information in this sub-chapter has been collected as part of Hydrogen Europe's work for the Fuel Cells and Hydrogen Observatory.[11]

9.3.1. Incentives for hydrogen production and transmission

Hydrogen plays a key role in decarbonising hard-to-abate sectors, enabling sector coupling, and completing the decarbonisation of our energy systems. Policies that support hydrogen production and its transportation to consumers are, therefore, the launch pad for achieving climate neutrality.

There are numerous ways to support hydrogen production, with the most common measure on the national level being CAPEX subsidies. Although they vary from country to country, at the moment some form of CAPEX support exists, or is in the process of being established, in Austria, the Flemish region of Belgium, Bulgaria, Denmark, Finland, France, Italy, the Netherlands, Romania and Sweden.

In Austria, through the new renewable energy law (§62 EAG and §55 EIWOG), funding electrolysers is possible, if the installation produces exclusively renewable gases and purchases only renewable electricity. The funding rate varies: installations between 0.5 and 1 MW are eligible for up to 20% and installations above 1 MW can receive up to 45% of the investment amount directly required for the construction of the system (excluding land).

In the Netherlands, funding is available for renewable and low-carbon hydrogen production under the Stimulation of Sustainable Energy Production and Climate Transition (SDE++) scheme. It is allocated for 12 or 15 years and compensates the cost difference between the existing technology and its renewable or decarbonised alternative. In France, under *Ordonnance n°2021-167 du 17 février 2021 relative à l'hydrogène* (Hydrogen Ordinance), an OPEX, or a combined CAPEX and OPEX competitive bidding scheme, has been established for facilities producing renewable hydrogen. An implementing decree from the *Conseil d'État* (Council State) is further expected. In Sweden, hydrogen production projects can get funding under the *Industriklivet* (Industry Leap). Funding depends on enterprise size, but the programme's budget is SEK 909 million (EUR 87 million), being able to finance projects that run until 2029.[12]

In August 2022, the Romanian scheme received approval from the European Commission (EC) under state aid rules. It will support the construction of new installations for renewable hydrogen production until December 2023, to achieve at least 100 MW of electrolyser capacity by December 2025. It is open to companies active in electricity or hydrogen production, administrative or territorial units, and national research institutes.

The second most common form of subsidising hydrogen production is the exemption or reduction of electricity price components. Such schemes exist in Austria, Denmark, France, Germany, Norway, Sweden, and Switzerland. For example, in Norway, the electricity tax, which is NOK 0.1541/kWh (EUR 0.015) is reduced to NOK 0.0546/kWh (EUR 0.005) for hydrogen production.[13] In Sweden, all electricity used in chemical reduction or electrolytic processes is exempted from electricity tax, per section 9 of the Energy Tax Act.

Concerning hydrogen transportation, until dedicated hydrogen pipeline systems are built or repurposed, blending allows partial decarbonisation of the existing natural gas infrastructure. However, blending comes with its challenges. To safeguard both end-user equipment and transmission and distribution infrastructure, system operators have defined

11 / The collected information can be found at https://www.fchobservatory.eu/observatory/policy-and-rcs/national-policies.
12 / ECB Exchange rate for Swedish krona (SEK) for 11/08/2022: EUR 1 = SEK 10.36.
13 / ECB Exchange rate for Norwegian krone (NOK) for 11/08/2022: EUR 1 = DKK 9.804.

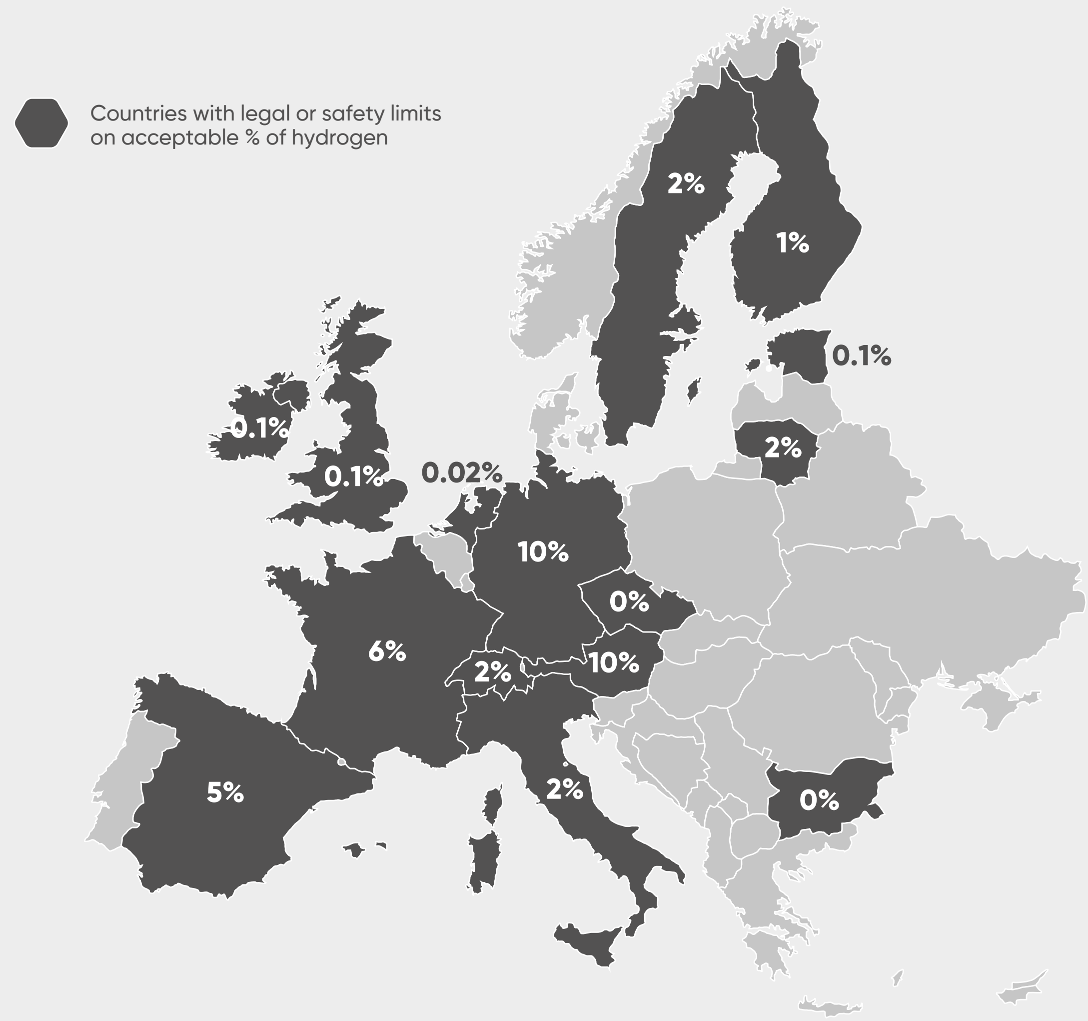
technical and safety limits for the injection of hydrogen into natural gas grids.

Austria and Germany have the highest legal limits for hydrogen concentration in the transmission networks, at 10% by volume. Estonia, Ireland, and the United Kingdom have a limit of 0.1%. In Denmark, no specific limit by volume has been set and any hydrogen injection in the natural gas network needs permission from the Danish Safety Technology Authority.

Figure 4 presents the maximum admitted percentage of hydrogen (by volume) in the transmission networks of various European countries, either legally or according to national safety regulations. In Germany, the blending of hydrogen from renewable energy sources is supported, as production plants are freed from feed-in costs for the network to which they are connected. This is only due to the current definition of biogas, which includes hydrogen and synthetic methane originating from RES.

FIGURE 4

Maximum admitted percentage of hydrogen (by volume) in various European countries' transmission networks



9.3.2. Incentives supporting the uptake of hydrogen in mobility

National support policies aimed at promoting sustainable transport via fuel cell electric vehicles (FCEV) fall into two main categories: policies focused on FCEV deployment and policies focused on infrastructure development. In both categories, the adopted schemes vary but range from investment and purchase subsidies to various tax benefits.

Support for FCEV fleets

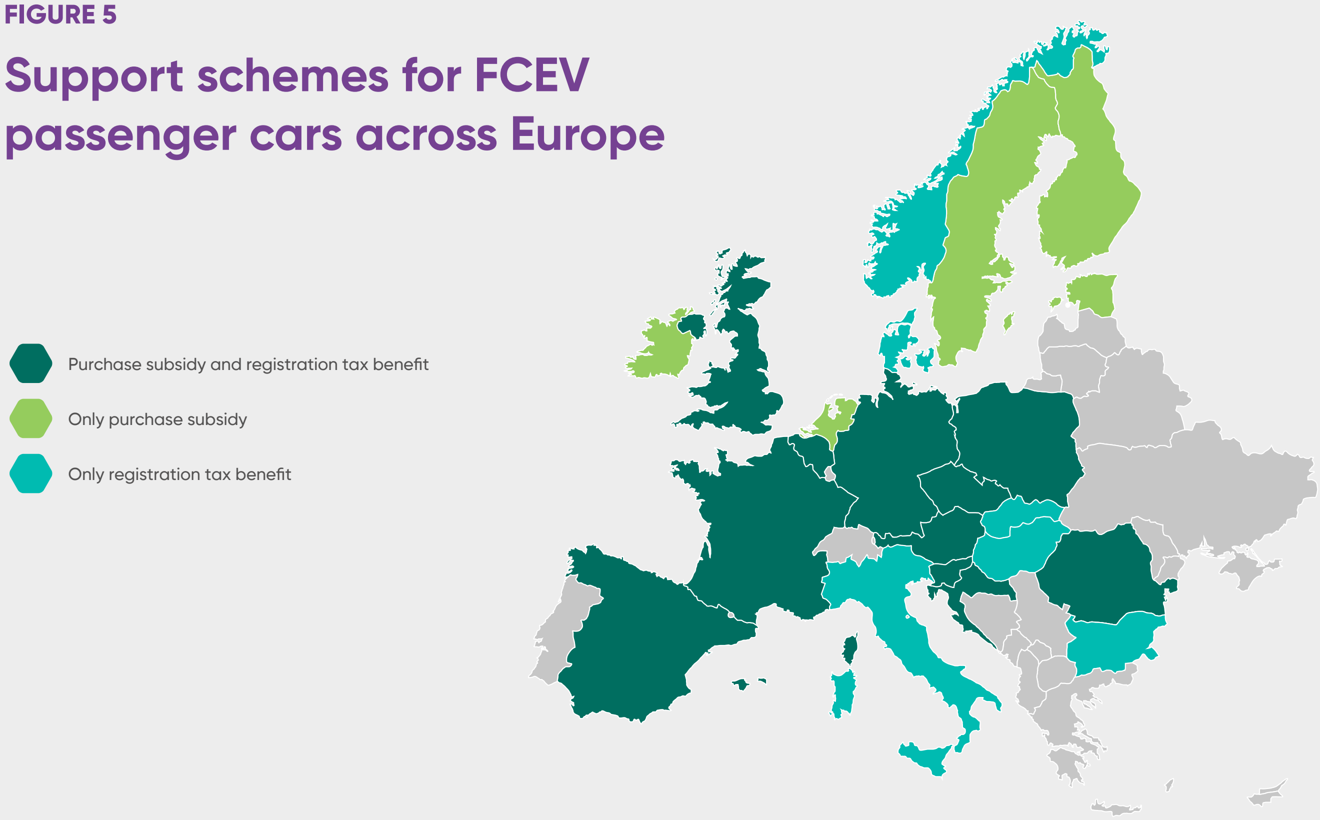
Passenger cars

Although they still represent a small share (0.01%) of the overall passenger car market in the EU, the sale of FCEVs in Europe has increased fivefold from 2017 (218 new FCEV registered) to 2021 (1,004 new FCEV registered) (ACEA, 2022, p. 6). Governments continue to incentivise their deployment with different mechanisms ranging from purchase subsidies, tax exemptions, and other financial and non-financial incentives.

One of the most common ways of incentivising FCEV adoption is purchase subsidies that aim to reduce the purchase price for end-users. 16 countries have such schemes: Austria, Belgium, Croatia, Czech Republic, Estonia, Finland, France, Germany, Netherlands, Poland, Romania, Slovenia, Spain, Sweden, and United Kingdom. The maximum amount granted varies significantly from EUR 2,000 in Finland to EUR 10,000 in Romania. Additionally, the criteria for obtaining a purchase subsidy also vary, as some subsidy schemes are limited to specific types of entities e.g., public authorities, while other schemes have limits on the cost of the car, which could potentially exclude FCEV vehicles. Examples of the latter include the Czech Republic, Estonia, Finland, and Spain. Additionally, the schemes are often accompanied by conditions regarding the location where the car is driven and the resale of the vehicle.

FIGURE 5

Support schemes for FCEV passenger cars across Europe



14 / For more information on the revised Clean Vehicles Directive, see https://transport.ec.europa.eu/transport-themes/clean-transport-urban-transport/clean-and-energy-efficient-vehicles/clean-vehicles-directive_en. For more information on Green Public Procurement see https://ec.europa.eu/environment/gpp/index_en.htm

By way of example, in Spain, under Action 1 of MOVES III, the acquisition or leasing of a new alternative energy vehicle can be supported for up to EUR 7,000, with the possibility of up to EUR 9,000 if an old vehicle is scrapped. The specific amount depends both on the type of vehicle purchased, as there are several eligible categories, and on the recipient of the aid (private, enterprise, et cetera.).

Buses and heavy-duty vehicles

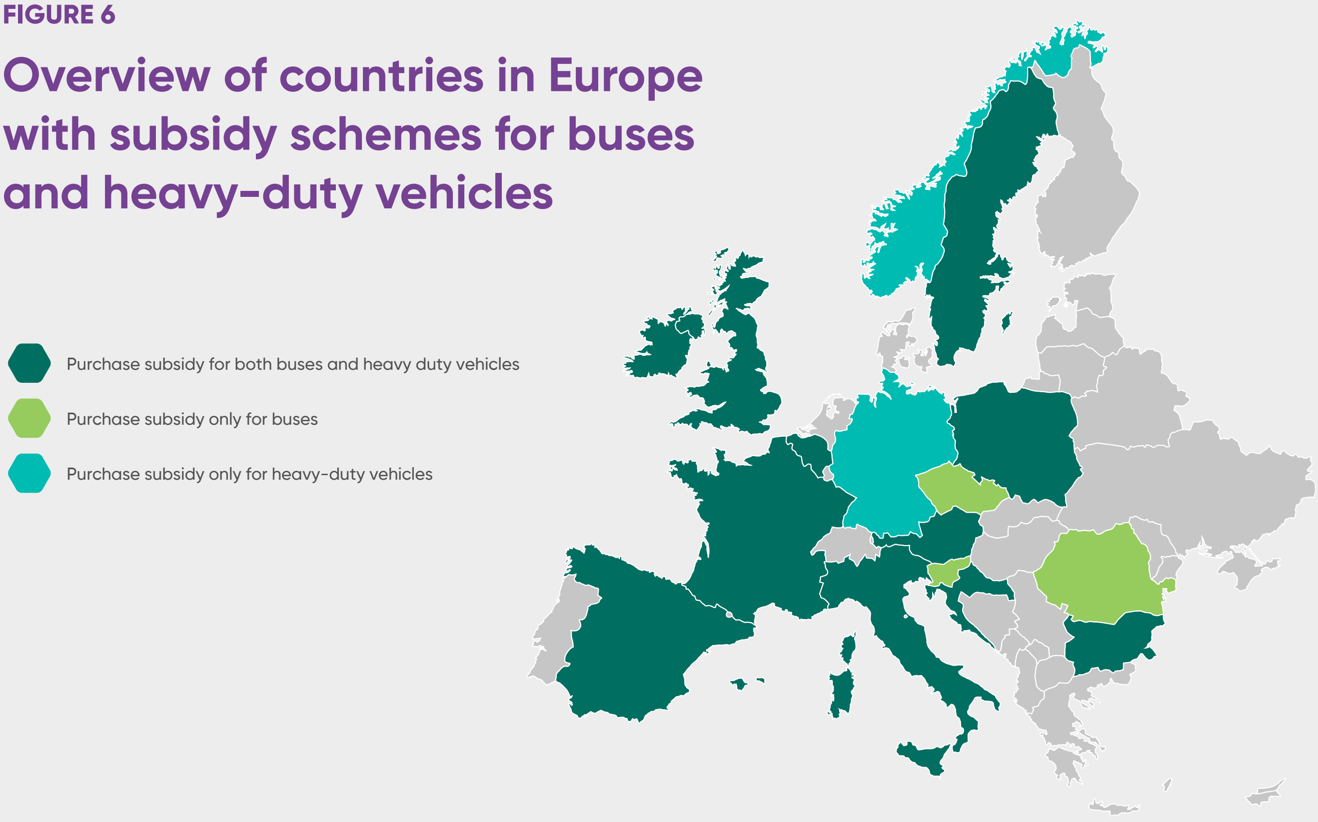
To decarbonise road transport, countries are striving to replace diesel-powered fleets with ones with lower lifecycle emissions. FCEVs in these segments offer long-range solutions, and short refuelling times, and are well suited for heavy loads and high energy use. Furthermore, in terms of public procurement, the revised Clean Vehicles Directive sets national targets on the MS for clean vehicles,[14] while the Green Public Procurement is a voluntary instrument by the EC to harness the purchasing power of public authorities to develop mass demand for sustainable goods, including FCEVs. With this in mind, the Fuel Cell and Hydrogen Observatory has identified subsidies for buses or heavy-duty vehicles in 16 countries.

Although the details of the support mechanisms vary from country to country, in general, governments periodically open calls, where mainly local authorities or public transport operators can apply for funding. Examples are the *Polish Zylan transport publiczny (Faza I)* (Green public transport Phase I) call, which co-financed up to 90% of the total costs of purchasing or leasing new FCEV buses, although the call was open only for operators of public transport (including local authorities).

Croatia had two open calls, one for the public sector and one for the private sector, for the co-financing of energy-efficient vehicles. Co-financing was also available for FCEV heavy trucks and buses with a maximum co-financing rate

FIGURE 6

Overview of countries in Europe with subsidy schemes for buses and heavy-duty vehicles



of up to 40% of the total cost. Both calls lasted until the funds were distributed.

Austria offers funding for fuel cell electric buses in the framework of the *E-Mobilität für Betriebe, Gebietskörperschaften und Vereine 2022* (E-mobility for companies, local authorities, and associations in 2022). Funding is open to both public and private persons of certain categories, and it is limited to 30% of the eligible costs. The call for applications will close in March 2023 or earlier if the budget is exhausted.

The Irish Alternative Fuelled Heavy-Duty Vehicle Purchase Grant Scheme is intended to assist the purchase of vans, trucks, buses, or coaches which are, among others, powered by FCEVs. The scheme is open to both public and private, private, or legal persons and companies can receive up to 60%, 50% or 40% of the price differential for each vehicle to be purchased, depending on whether they are a small, medium, or large enterprise. The maximum amount per undertaking is capped at EUR 500,000. The call is open until the end of December 2022 or until the funds have been exhausted.

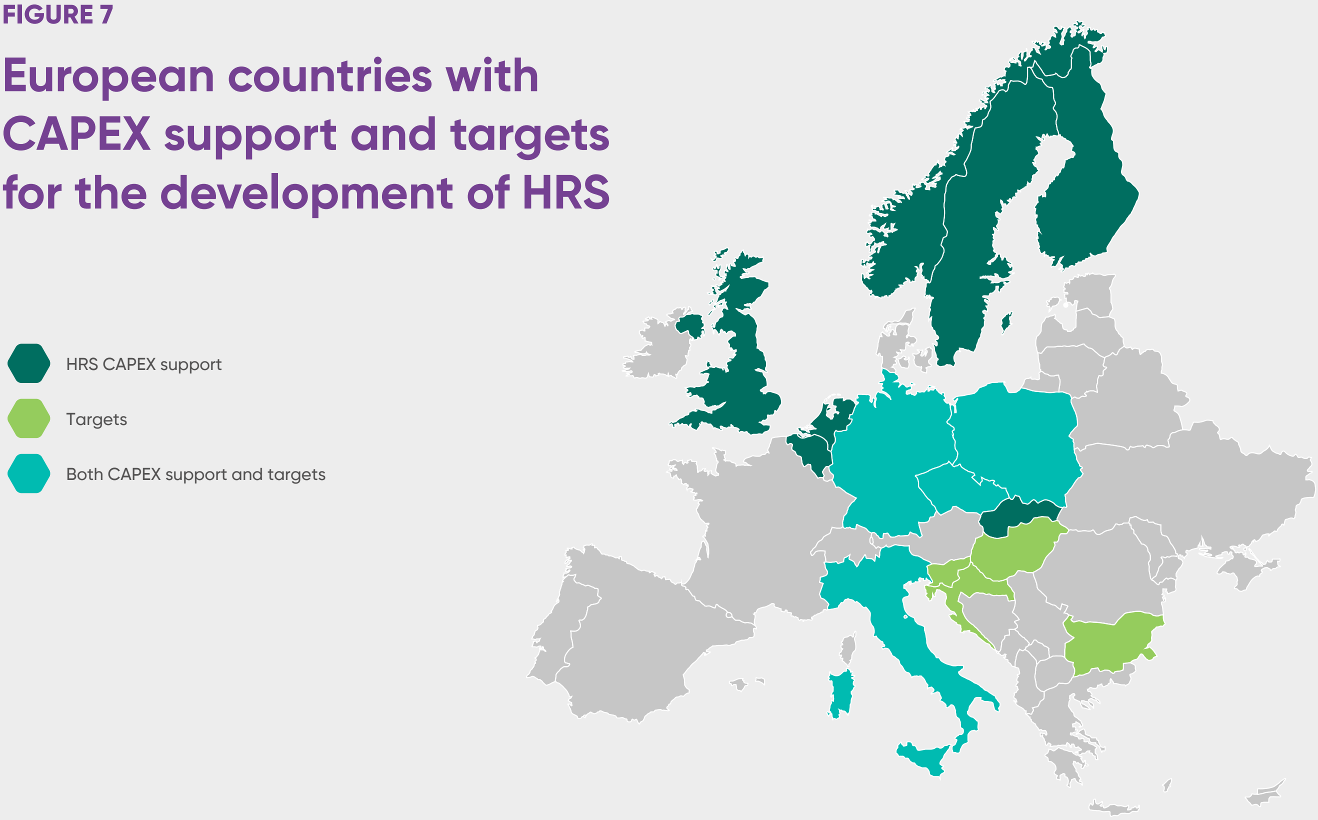
Hydrogen refuelling infrastructure

To match the increase of FCEVs on European roads and facilitate their further adoption, the availability of refuelling infrastructure is key. As a result, countries are supporting the development of nationwide publicly accessible hydrogen refuelling stations. This also includes stations with high capacity that can supply passenger cars, buses, and heavy-duty fleets. The supporting measures include targets, mandates, financial incentives in the form of CAPEX support, simplifying permitting rules, and standardization.

One of the most effective forms of support is CAPEX subsidies for the construction of HRS. Currently, 11 countries have such support mechanisms under various national programmes.

FIGURE 7

European countries with CAPEX support and targets for the development of HRS



These are Belgium, the Czech Republic, Finland, Germany, Italy, the Netherlands, Norway, Poland, Slovakia, Sweden, and the United Kingdom.

In the Netherlands, for example, CAPEX support takes the form of tax depreciation for companies that offer low- or zero-carbon transport solutions, such as HRS. The support scheme is *Demonstratie klimaattechnologieën en -innovaties in transport* (DKTI-transport) under the Dutch Enterprise Agency (RVO). In Flanders (BE), under the *Ecologiepremie+* programme, companies can obtain 15% (large companies) or 30% (small companies) CAPEX support for hydrogen refuelling stations, if hydrogen is produced on-site from renewable electricity or a residual industrial process.

Complementing direct financial support are targets and mandates that aim or direct HRS development on the national level. Often these were set through the transposition of the optional art. 5 of the Alternative Fuels Infrastructure Directive. Such targets or mandates exist in Bulgaria, Croatia, the Czech Republic, Germany, Hungary, Italy, Poland, and Slovenia. As an example, the Polish target is 32 HRS by 2030 and it is set in the 2021 hydrogen strategy, while the Hungarian target is 14 HRS by 2030 under the national policy framework that is being revised, and 20 HRS by 2030 under the national hydrogen strategy.

Another mechanism aimed at accelerating HRS deployment is the development of permitting guidelines. These can take the form of legislation as is the case in Austria, Bulgaria, Flanders (Belgium), France, Italy, and the Netherlands or the form of guidelines or standards, as is the case in the Czech Republic, Finland, Germany, Switzerland, Sweden, and the United Kingdom.

For example, VTT (Finland) has published a report providing an overview of national and EU regulations and standards applicable to fuel cell applications and HRS. It aims to inform designers, manufacturers, importers, and users on what is needed to comply with safety requirements. In Switzerland, the Swiss standardisation organisation developed guidelines for HRS construction. In Germany, various ministries and energy agencies of some federal states have prepared HRS construction methodologies which continue to slightly differ on the local level. Instead of guidelines and standards, Austria, Bulgaria, France, and Italy have adopted specific safety laws concerning the deployment of hydrogen refuelling stations.

9.3.3. Incentives supporting the uptake of hydrogen in industry

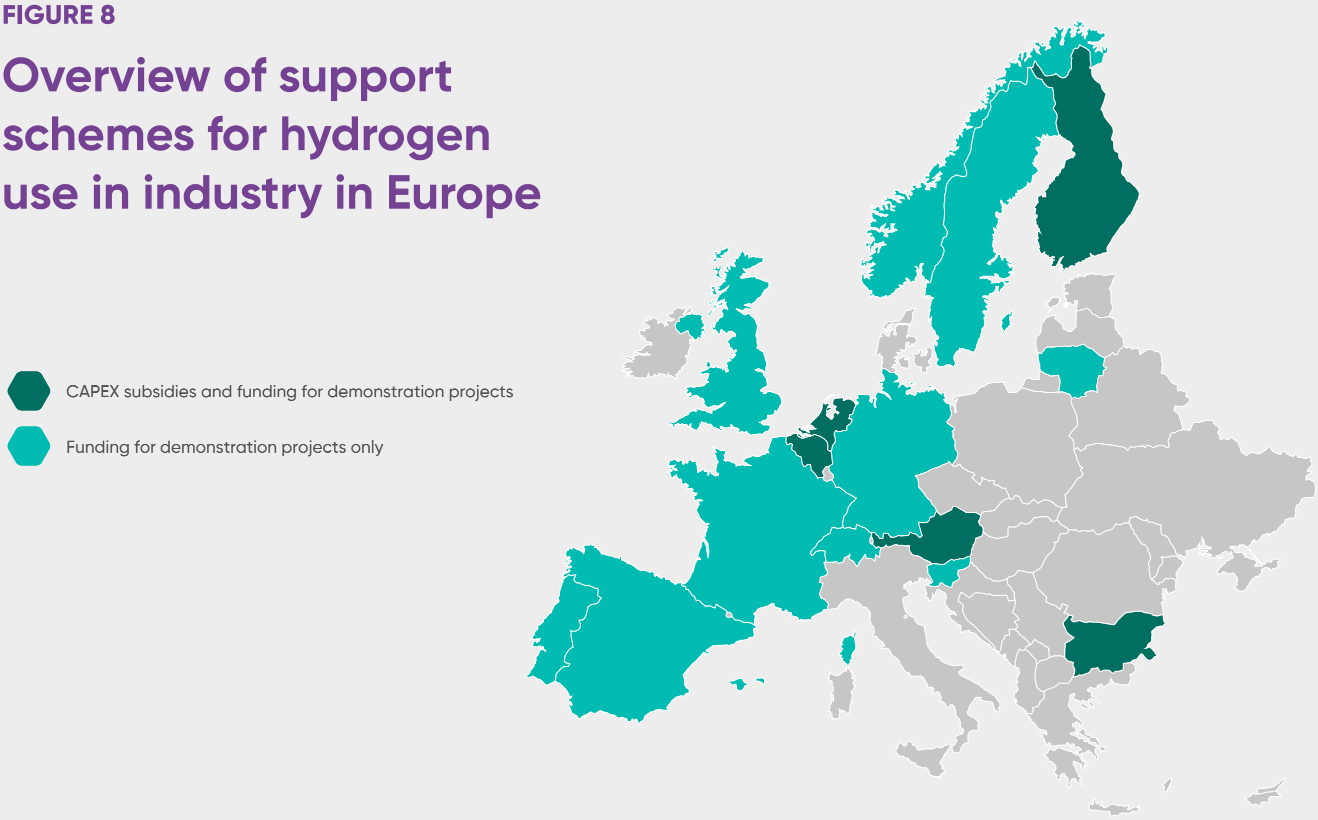
As explained in **Chapter 1**, the largest hydrogen consumer is the industry. As hydrogen is essential for refining, ammonia production, methanol production, production of various chemicals, and other industries. For these sectors to decarbonise, they will have to transition to renewable or low-carbon hydrogen. Significant future hydrogen demand will also come from the decarbonisation of other hard-to-abate sectors, either using hydrogen as a feedstock or as a source of industrial heat.

There are two main categories of instruments that countries currently use to incentivize hydrogen use in industrial decarbonisation: CAPEX subsidies for renewable or low-carbon hydrogen production plants for industry and funding for low-carbon demonstration projects in industry for renewable or low-carbon hydrogen. While funding mechanisms for demonstration projects can be found in 16 countries, investment subsidies are to be found only in five countries: Austria, Flanders (Belgium), Bulgaria, Finland, and the Netherlands.

Concerning demonstration projects, Germany provides support for pilot projects under the Environmental Innovation Programme. The projects must contribute to the reduction of process-related GHG by applying innovative processes on an industrial scale for the first time. Funding can be granted in two ways, as an investment grant of up to 30% of eligible expenditures or as an interest-reduced loan for a maximum of 70% of the eligible expenses at the discretion of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. In France, ADEME has an open call *Briques technologiques et démonstrateurs hydrogène* (Technological bricks and hydrogen demonstrators), which is open until December 2022 to support, among others, innovative industrial pilots or commercial first for the use of hydrogen. In Denmark, companies domiciled primarily in the MS can apply for funding in a variety of topics, among which hydrogen production, under the *Energiteknologisk Udviklings- og Demonstrationsprogram* (Energy Technology

FIGURE 8

Overview of support schemes for hydrogen use in industry in Europe



Development and Demonstration Programme). The focus is on the development, demonstration and market introduction of new energy technologies and support takes the form of grants, cooperation between public and private partners, and support for international cooperation.

Regarding, investment support, companies in Finland can apply for an energy subsidy covering up to 30% of eligible costs under the *Valtioneuvoston asetus energiatuen myöntämisen yleisistä ehdoista vuosina 2018–2022* (Government decree on the general conditions for granting energy subsidies in 2018–2022). The programme is open until December 2022. In the Netherlands, the *Energie-investeringsaftrek* (Energy investment allowance) is a tax deduction scheme open to entrepreneurs investing in energy-saving equipment or sustainable energy. Applicants that have invested in a list of pre-determined technologies, can claim 45.5% of the investment costs as a reduction in their yearly taxable profit (income tax or corporation tax), apart from the deduction from depreciation. The catalogue of technologies (Energy List for 2022) includes PtG, electrolysis, hydrogen cogeneration, and other hydrogen technologies.

Conclusion

Hydrogen is now widely recognised as a key technology in policymakers' toolkits to address all three challenges of the energy trilemma at once: climate and sustainability, competitiveness, and security of supply. This is evidenced by the growing number of hydrogen strategies being adopted around the world, and the increasing number of countries that are preparing such documents. Important countries that have recently adopted hydrogen strategies include China, Morocco, and South Africa. Thus, the scene for global competition for hydrogen technologies, supply, and demand is emerging.

Currently, the European Union, through the Green Deal, national and regional strategies, incentives, and increased ambition of the REPowerEU, has the most robust hydrogen policy framework. However, the variety of different EU, national, and regional approaches, as well as unclear regulatory frameworks, create the risk of stifling the emerging market. Furthermore, while the EU has been a leader in developing its hydrogen ecosystem, competition from countries such as China, Japan and the United States will increase in the coming years.

Methodological note

Methodological note on national strategies

The monitoring and analysis of national and regional hydrogen strategies are conducted on an ongoing basis as part of the work carried out by Hydrogen Europe's Intelligence team. This involves a periodical internet search for the terms "(country name) hydrogen strategy/plan/roadmap" in the official language of each country, in a pre-selected list of countries with the potential for the development of a hydrogen sector.

To qualify a "strategy" for the present analysis, a basic set of criteria has been adopted. Irrespective of the title (e.g., strategy, roadmap, action plan), the policy document must be adopted by a public body with the competence to adopt it. In the case of national strategies, examples of such are governments, ministries, or public assemblies. For regional strategies, examples are local authorities and regional energy agencies. Documents from trade associations or other private entities, or studies for potential strategies, may qualify as drafts, provided they are acknowledged by a public authority.

In the case of strategies from European countries and major economies, a content analysis focusing on quantitative indicators and targets is carried out. Qualitative and quantitative content analysis for other countries is conducted on request.

Lastly, where a strategy indicates a target or another value in a range, the median value has been used for the purposes of this analysis.

For more information, please visit Hydrogen Europe's Members Only Area.[15]

15 / https://www.hydrogeneurope.eu/members-intranet/

Methodological note on national support mechanisms

The data has been collected by Hydrogen Europe through a network of national respondents as part of its work for the Fuel Cell and Hydrogen Observatory.

Geographical scope: the geographical scope of the database consists of EU countries such as Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Lithuania, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden as well as Norway, Switzerland, and the United Kingdom. The full list of national respondents can be found at the following link: https://fchobservatory.eu/index.php/about-us. The results in this chapter deliberately exclude some countries based on the quantity and quality of information collected.

© Justin Jin for Hydrogen Europe

References

ACEA. (2022). Making the Transition to Zero-Emission Mobility. Brussels: ACEA.

BMK; BMDW. (2022). Wasserstoffstrategie für Österreich. Wien: BMK.

Danish Board of Business Development. (2022). Investeringsstøtteordning for grønne, innovative teknologier. Retrieved August 17, 2022, from Danish Board of Business Development: https://erhvervsfremmebestyrelsen.dk/investeringsstoetteordning-groenne-innovative-teknologier

European Commission. (2017). Towards the broadest use of alternative fuels - an Action Plan on Alternative Fuels Infrastructure under Article 10(6) of Directive 2014/94/EU, including the assessment of national policy frameworks under Article 10(2) of Directive 2014/94/EU. Brussels: European Commission. Retrieved from https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52017DC0652

Eurostat. (2020). Denmark SHARES detailed results 2020. Retrieved May 23, 2022, from Eurostat: https://ec.europa.eu/eurostat/web/energy/data/shares

Folketinget. (n.d.). Political Parties. Retrieved 05 13, 2022, from https://www.thedanishparliament.dk/en/political-parties

Fuel Cell & Hydrogen Energy Association. (2022, August 5). How the Inflation Reduction Act of 2022 Will Advance a U.S. Hydrogen Economy. Retrieved from Fuel Cell & Hydrogen Energy Association: https://www.fchea.org/transitions/2022/8/5/how-the-inflation-reduction-act-of-2022-will-advance-a-us-hydrogen-economy

Johansen, K., & Werner, S. (2022). Something is sustainable in the state of Denmark: A review of the Danish district heating sector. Renewable and Sustainable Energy Reviews, 158, 112117.

MITECO. (2020). Hoje de Ruta del Hidrógeno: Una Apuesta por el Hidrogéno Renovable. Madrid: Ministerio para la Transición Ecológica y el Reto Demográfico.

Morgan, S. (2020, June 22). Dutch do Danish deal to hit clean power target. Euractiv. Retrieved May 13, 2022, from https://www.euractiv.com/section/energy/news/dutch-do-danish-deal-to-hit-clean-power-target/

Nakano, J. (2022, March 25). China Unveils its First Long-Term Hydrogen Plan. Retrieved from Center for Strategic & International Studies: https://www.csis.org/analysis/china-unveils-its-first-long-term-hydrogen-plan

Rayner, J., & Howlett, M. (2009). Introduction: Understanding integrated policy strategies and their evolution. Policy and Society, 28, 99-109.

SPD; BÜNDNIS 90/DIE GRÜNEN; FDP. (2021). Mehr Fortschritt wagen: Bündnis für Freiheit, Gerechtigkeit und Nachhaltigkeit. Berllin: Die Bundesregierung.

The Federal Government. (2020). The National Hydrogen Strategy. Berlin: Federal Ministry of Economic Affairs and Energy.

Disclaimer

Hydrogen Europe Secretariat has prepared this report, and the statements in this report reflect the views of the Hydrogen Europe Secretariat and not of Hydrogen Europe's members. It is being provided to the recipients for general information only. The information contained in this report is derived from selected public and private sources. Hydrogen Europe, in providing the information, believes that the information it uses comes from reliable sources but does not guarantee the accuracy or completeness of this information. Hydrogen Europe assumes no obligation to update any information contained herein. That information is subject to change without notice, and nothing in this document shall be construed as such a guarantee. This report does not constitute technical, investment, legal, tax, or any other advice. Hydrogen Europe will not be held liable for any direct or indirect damage incurred using the information provided and will not give any indemnities.

This publication and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and the name of any territory, city, or area.