European Union Agency for the Cooperation of Energy Regulators

European hydrogen markets

2024 Market Monitoring Report

19 November 2024

ACER

European Union Agency for the Cooperation of Energy Regulators

European hydrogen markets

2024 Market Monitoring Report

19 November 2024

Find us at:

ACER

E press@acer.europa.eu

Trg republike 3

1000 Ljubljana

Slovenia

www.acer.europa.eu

Contents

EXECUTIVE SUMMARY

1 The European hydrogen market is beginning to take shape, driven by ambitious EU-wide strategies and national policies. This report marks the start of ACER's monitoring work on this emerging sector, in line with the hydrogen and gas decarbonisation package. It takes stock of recent developments and highlights key challenges from a regulatory standpoint.

Hydrogen progress and prospects

7.2 Mt

EU hydrogen (H_2) consumption in 2023

- 99.7% of it produced from fossil fuels
- EU likely to miss the consumption goal of 20 Mt renewable H_2 by 2030

62 GW

EU Member State's electrolyser capacity targeted for 2030

- 216 MW installed capacity in 2023
- EU likely to miss the 100+ GW needed for the 2030 10 Mt H_2 renewable production target

42,000 km

Length of planned EU+Norway H_2 network by 2034

Additional plans for:

- 693 GWh/d import capacity
- 49 TWh storage space

3-4 times

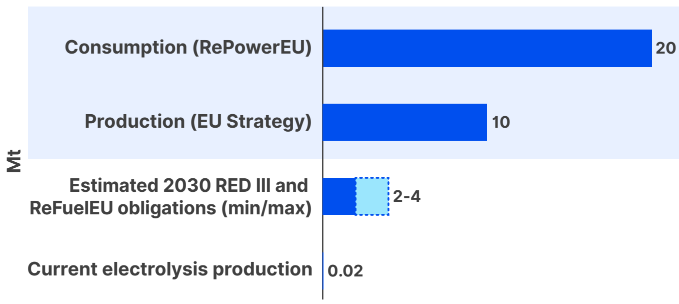
Higher production costs

- Renewable H_2 compared to fossil based H_2 discouraging early offtake

The EU must intensify efforts to meet its 2030 renewable hydrogen goals.

2 The EU has a strategic goal of 20 Mt of renewable hydrogen consumption by 2030; current consumption is 7.2 Mt, and even then, 99.7% of it comes from fossil fuels. The amount produced with electrolysis (around 22 kt) is negligible. EU renewable energy and decarbonisation targets can translate into 2-4 Mt of renewable and low-carbon hydrogen consumption by 2030, but so far renewable hydrogen uptake in industry and transport has increased slowly, making it challenging to reach the EU target.

EU strategic targets compared to current hydrogen demand and the prospect of renewable hydrogen consumption in 2030 (Mt)

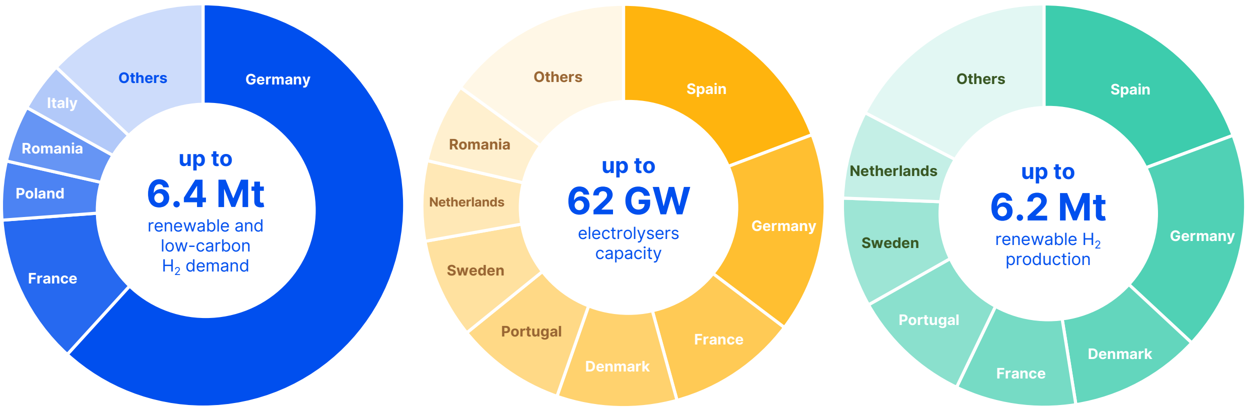


3 The total installed capacity of electrolysers in Europe is currently just over 200 MW. Projects accounting for another 1.8 GW of capacity, mostly captive to a single off-taker or industry, are under construction and expected to become operational by the end of 2026. Projects accounting for around 60 GW of capacity announced as being operational by 2030 are waiting for the final investment decision (FID). Although funding instruments are becoming increasingly available, the actual deployment of these projects remains at risk due to sector uncertainties, in particular the evolution of demand and renewable hydrogen cost prospects.

EU Member States' strategies vary, lacking full alignment with EU-wide targets.

4 Several Member States have set targets for hydrogen production, electrolyser capacities, and infrastructure expansion, with a focus on renewable hydrogen. Ambition varies across countries, leading to different paces of development across the sector, and requiring further efforts to align with the broader EU hydrogen vision.

Summary of targets based on national strategies and plans



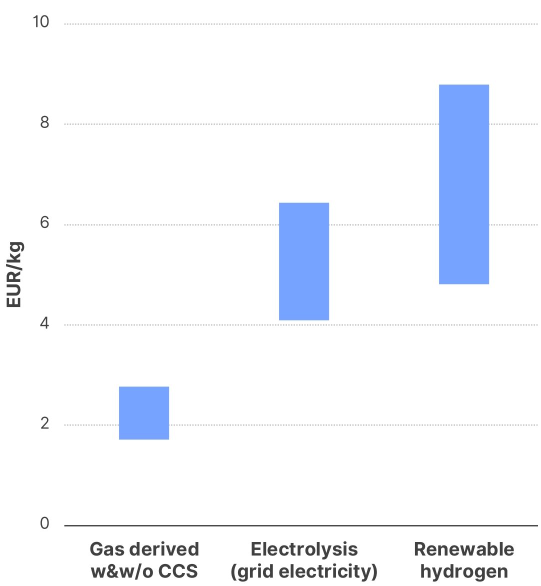
Few national frameworks under development; consistency needed for cross-border initiatives.

5 Differences in national ambitions are also reflected in the pace of regulatory developments. As the hydrogen and gas decarbonisation package has just been published, no Member State has incorporated it into national legislation yet (deadline 5 August 2026). However, some countries such as Denmark and Germany have already consulted on provisions for hydrogen network planning or access tariffs. That includes decisions on inter-temporal cost allocation mechanisms, to shift the recovery of network investment costs in time, considering the demand ramp-up. Institutional regional cooperation is key to facilitating the emergence of hydrogen initiatives with cross-border relevance. In such cases, national regulatory frameworks should be developed in coordination with neighbouring Member States.

Renewable hydrogen is three to four times more expensive than fossil-based hydrogen, discouraging early renewable hydrogen offtake.

6 The cost of hydrogen produced via electrolysis is currently two to three times higher than that of hydrogen produced from natural gas. The cost gap further increases by the EU production rules for renewable fuels of non-biological origin (RFNBOs), which aim to ensure the net decarbonisation impact of renewable hydrogen deployment, making renewable hydrogen three to four times more expensive than fossil-based hydrogen. At the same time, the first European Hydrogen Bank auction resulted in very low premiums, revealing promising instances of significantly lower costs (even lower than 3 EUR/kg) and a willingness among some off-takers to pay prices within the renewable hydrogen cost range. Yet, existing cost gaps and expectations of significant future reductions create substantial risks for first movers, prompting delays in investment decisions and hesitation in making long-term commitments. As the market evolves, increasing transparency around hydrogen costs is essential for directing investments in production and infrastructure. The European Hydrogen Bank's auction is a good example of how competitive and transparent processes can support early hydrogen uptake and enhance market clarity.

Cost ranges of hydrogen by production method based on S&P Global estimates for Jan-Sep 2024



7 The higher cost of renewable hydrogen could also impact the competitiveness of sectors like steel, though the effect on the price of final products (for example electric cars) is likely to be moderate to low, potentially increasing acceptance and viability of renewable hydrogen in the long-term.

Scaling electrolysers deployment and decarbonising electricity is essential for renewable hydrogen competitiveness.

8 Capital expenditures and electricity are the two key cost components of renewable hydrogen. Scaling up global production of electrolysers and innovation is key to bring investment costs down. Maintaining the impressive cost reduction pace of renewable electricity, however, depends on broader uncertainties such as the cost of essential commodities and innovation prospects for already mature technologies. In the longer-term, a highly decarbonised electricity sector could enable a more continuous and cheaper production of RFNBO-compatible hydrogen, increasing its competitiveness.

Clarifying low-carbon hydrogen's role is key for market development and long-term climate goals.

9 To overcome the high renewable hydrogen costs that discourages early uptake and to quickly build-up demand for hydrogen, some stakeholders call for the deployment of hydrogen produced from natural gas with carbon capture. However, such an approach might entail long-term lock-in to fossil fuel feedstocks, hindering the decarbonisation efforts in the long-term. The EU hydrogen strategy acknowledges that in the short- to medium-term, non-renewable, low-carbon hydrogen is necessary; therefore investors and hydrogen-consuming industries need more clarity on the role of that low-carbon fossil hydrogen in the European hydrogen market.

Better forecasting and planning needed to identify realistic hydrogen infrastructure needs.

10 Hydrogen infrastructure has the potential to enable sector development by linking low-cost production regions with industrial demand centres. Currently, hydrogen network development plans are mostly built around ambitions for future demand rather than specific market needs, potentially leading to infrastructure oversizing and underutilisation. To mitigate such risks, accurate demand forecasting during the planning phase, along with proper monitoring and adjustments during implementation, is essential. Market tests similar to those used for gas infrastructure development could be employed to increase forecasting accuracy. However, their effectiveness depends on the users' willingness to make long-term commitments, which might be limited given the sector's uncertainties. Leveraging comprehensive information, analysing market trends and regularly re-evaluating network expansion should become standard practice in hydrogen network development.

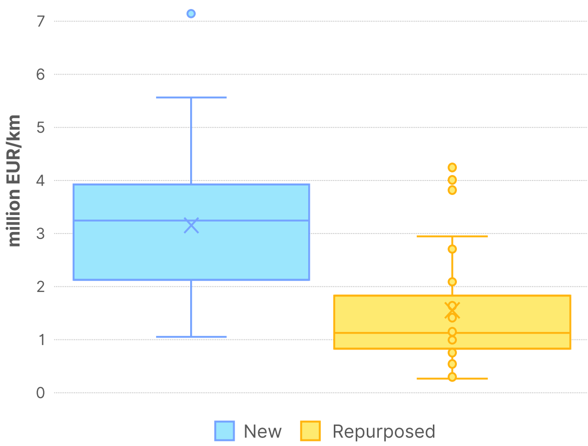
EU Member States need mechanisms to mitigate demand risk in hydrogen network financing.

11 Uncertain future hydrogen demand can lead to underutilised networks, potentially undermining cost-recovery. Proper identification of the risks associated with specific network investments is therefore crucial, together with transparent communication of their implications and a proper risk allocation among various stakeholders. The recently approved German inter-temporal cost allocation mechanism not only shifts cost recovery in time but also envisages the allocation of risk between the state and network operators. The scheme enhances the visibility of network costs for hydrogen users and aims to mitigate risks by making network costs more affordable for early hydrogen users. Regarding cross-border hydrogen networks, timely cooperation and coordination between involved Member States and regulators are essential for effectively allocating costs and risks, thereby accelerating network development and integration of hydrogen markets.

Repurposing gas networks for hydrogen could reduce costs but requires cautious regulatory decisions.

12 Using repurposed gas networks to transport hydrogen has the potential to reduce investment costs compared with building new hydrogen assets. However, the actual extent of such savings is still unclear as ranges of cost estimates are wide, and there is limited evidence so far. Repurposing also entails a set of technical challenges and economic considerations, including assessing cross-sectoral costs and benefits, and determining the value of the repurposed assets. The implications on security of gas supply should also be duly considered. This calls for a careful examination of repurposing decisions. As experience with repurposed networks grows, information coming from such new evidence shall be factored into the decision-making process.

Cost ranges of new and repurposed network as reported in the TYNDP-2024 project list



Coordination needed to develop electricity and hydrogen networks and to optimise location of electrolysers.

13 The EU target of 10 Mt of renewable hydrogen production needs around three quarters of the renewable electricity currently produced in the EU, and massive investments in electricity networks to connect renewable electricity plants and electrolysers. Such grid development needs add to those already stemming from wider electrification and renewable electricity targets. Both electricity and hydrogen operators should make rapid progress on integrated planning, coordinating choices on electrification, building up electrolyser capacity, renewable electricity uptake and electricity, and hydrogen network development.

14 Optimally locating electrolysers is also crucial to account for bottlenecks in electricity network development and to ensure that electrolysers alleviate rather than increase electricity network congestion. Proximity to renewable electricity production sites, and the use of pipelines to transport hydrogen, might reduce the need for more extensive electricity networks. Conversely, co-location of production and demand for hydrogen can reduce the need for hydrogen infrastructure and may be preferrable considering the uncertainties in the development of hydrogen demand. Integrated planning, also taking account of specific network development constraints and locational parameters, should guide decisions on electrolysers location, hydrogen network development, and electricity grid expansion and reinforcement.

ELECTRICITY GRID NEEDS

To reach 10 Mt of renewable H_2 target

- +100 GW electrolysers
- 550 TWh of renewable electricity
- Up to 180 GW of wind/solar
- Vast grid expansion

DELAYS IN ELECTRICITY GRID DEVELOPMENT ALREADY ENCOUNTERED

LOCATION OF ELECTROLYSERS

- Co-location with demand or proximity to renewable generation?
- Congestion amplifiers or alleviators?
- Central planning or market choices?
- Which role for locational signals?

INTEGRATED ASSESSMENT NOT YET IN PLACE

ELECTRICITY SERVICE PROVIDERS

- System flexibility
- Ancillary services
- Renewable curtailment

ENABLING NATIONAL FRAMEWORK NOT ALWAYS IN PLACE

Complex EU regulatory framework and funding schemes may hinder hydrogen sector development.

15 Since the publication of the EU hydrogen strategy, key EU legislation has been developed that aims to stimulate demand, establish market frameworks, and facilitate hydrogen network and infrastructure development. The hydrogen regulatory landscape comprises several interlinked policies and measures; similarly, there are numerous EU and national support schemes in place covering the full hydrogen supply chain. Navigating the hydrogen regulatory landscape is complex and further clarity would benefit the sector.

16 This report concludes that the European hydrogen market evolving fast, driven by ambitious EU-wide strategies and national policies. But meeting the 2030 renewable hydrogen targets remains critical. Accordingly, ACER provides a set recommendations for the European Commission, Member States, national regulators, electricity and gas Transmission System Operators (TSOs), and hydrogen network operators. This suite of ACER recommendations covers four areas: clarifying the regulatory framework; monitoring; network planning; and hydrogen infrastructure financing. The key recommendations are presented hereafter while more details are provided in Section 4 of the report.

Summary of ACER's key recommendations

Legislation	**Quickly transpose the hydrogen and decarbonised gas package into national legislation** and proceed with its implementation. Member States need to develop their national hydrogen markets in line with the European framework to enable infrastructure development and avoid fragmentation.
Electrolyser deployment	**Speed up electrolysers deployment and decarbonisation of electricity sector** to increase renewable hydrogen competitiveness.
Forecasting and planning	**Improve forecasting and accelerate integrated planning** to identify realistic hydrogen infrastructure needs, avoiding overinvestments and reducing cost related to under-recovery risks.
Incremental infrastructure development	When future demand is highly uncertain, consider **incremental infrastructure development** based on market needs (to avoid building too much network too fast and stranded assets).
Repurposing of gas networks	**Consider carefully the repurposing of gas networks** for hydrogen to minimise costs, while not overlooking the potential impacts on the broader gas sector.
Risk mitigation	**Address future demand risk in financing hydrogen networks.** Properly identify different risks associated with uncertain future hydrogen demand. Allocating these risks among stakeholders (considering also cross-border implications) is key to enable hydrogen infrastructure investments.
Market certainty	**Provide market certainty over the role of non-renewable, low-carbon hydrogen.** Clarity on the uptake of non-renewable hydrogen should be provided by the European Commission and Member States.

List of abbreviations

Acronym	Meaning
ACER	European Agency for the Cooperation of Energy Regulators
AEM	Anion exchange membrane
ATR	Autothermal reforming
BF	Blast Furnace
CBAM	Carbon Border Adjustment Mechanism
CCUS	Carbon Capture Utilisation and Storage
DRI	Direct-Iron-Reduction
DSO	Distribution System Operator
EU	European Union
EC	European Commission
EHB	European Hydrogen Bank
ELYS	Electrolysis technology
ENNOH	European Network of Network Operators for Hydrogen
ENTSOE	European Network of Transmission Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emissions trading system
EU	European Union
FCEV	Fuel cell electric vehicles
FEED	Front-end engineering and design
FID	Final investment decision
HCN	Hydrogen Core Network
IEA	International Energy Agency
IPCEI	Important Project of Common European Interest
JRC	Joint Research Centre
LCOH	Levelized Cost of Hydrogen
LPG	Liquefied petroleum gas
NECP	National Energy and Climate Plan
PCI	Project of Common Interest
PEM	Proton exchange membrane
PMI	Project of Mutual Interest
PPA	Power Purchase Agreement
RED	Renewable Energy Directive
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RFNBO	Renewable fuels of non-biological origin
RRF	Recovery and Resilience Facility
SAF	Sustainable aviation fuels
SMR	Steam methane reforming
SOEC	Solid oxide exchange cells
TCTF	Temporary Crisis and Transition Framework
TEN-E Regulation	Regulation on guidelines for trans-European energy infrastructure
TPA	Third party access
TSO	Transmission System Operator
TYNDP	EU Ten-Year Network Development Plan

1. Introduction

17 After the introduction of hydrogen as a key element of the European Green Deal's decarbonisation strategy in 2019, numerous EU and national policies and regulations have been put in place to shape the landscape for hydrogen market development. The hydrogen and gas decarbonisation package published in July 2024, which inter alia sets out the European hydrogen market framework, expands the competences of the European Union Agency for the Cooperation of Energy Regulators (ACER) in this market. Along with a range of other regulatory tasks, ACER is to monitor the hydrogen market focusing on market developments, access to the hydrogen network, interconnector developments and cross-border trade barriers.

18 This report marks the beginning of ACER's monitoring of the European hydrogen markets. Given the sector's nascent status, the report takes stock of the recent development and provides a concise yet comprehensive overview of the status and prospects for hydrogen markets in Europe. The report also sheds light on the sector from the regulatory standpoint and touches upon major regulatory challenges, for example in network development and financing, aiming to instigate a dialogue between the regulatory community and stakeholders.

19 The report has essentially two parts, Section 2 and Section 3. The first part of the report focuses on the regulatory and policy developments thus far at the European (Section 2.1) and national (Section 2.2) levels. It starts with an overview of the European strategies that set the objectives for the future hydrogen markets (Section 2.1.1). It then continues with a description of the European legislative acts that set the future demand for hydrogen and the rules for future hydrogen markets (Section 2.1.2). National strategies and hydrogen related targets are discussed next (Section 2.2.1) followed by the EU Member States' current regulatory frameworks (Section 2.2.2) and then the challenges of financing hydrogen networks through tariffs (Section 2.2.3). The first part of the report closes with an overview of the various schemes aiming to support the nascent sector at the European (Section 2.3.1) and national (Section 2.3.2) levels.

20 The second part of the report provides a brief overview of the current status of the European hydrogen market, assessing current demand for (Section 3.1) and supply of (Section 3.2) hydrogen. It then describes infrastructure developments (Section 3.3), focusing on projects with a wider European importance (Section 3.3.1). Two important set of challenges are analysed; the ones of using repurposed natural gas networks to transport hydrogen (Section 3.3.2), and those that hydrogen developments bring to the electricity networks (Section 3.3.3). Finally, the second part discusses the cost of producing (Section 3.4.1) and transporting (Section 3.4.2) hydrogen.

2. Regulatory and policy developments

21 The European hydrogen market framework has undergone rapid development, driven by a combination of ambitious EU-wide strategies and national policies that position hydrogen as a cornerstone of the energy transition. Over the few past years, a series of initiatives have been introduced to establish the necessary conditions for hydrogen's sustained uptake. Legislative measures, which set binding rules and frameworks, have been complemented by non-legislative efforts, including strategic plans, all aiming at fostering the use of renewable and low-carbon gases

22 The hydrogen and gas decarbonisation package, published on 15 July 2024[1], offers a structured framework to accelerate the development of hydrogen market. It aims to enable and facilitate the phase out of fossil gas and the creation of a European hydrogen market, by setting out rules on several key aspects such as unbundling and access to networks, infrastructure planning, network tariffs, and governance. It also extends the role of ACER in various domains, to ensure proper coordination and consistency of regulatory developments across the EU. Beyond the hydrogen and gas decarbonisation package, there are no less than 39 EU-wide policy and legislative acts relevant to hydrogen[2]. In addition, some Member States are also making significant efforts to develop and promote their national hydrogen markets, by taking strategic initiatives, granting specific financial incentives, and designing appropriate regulatory frameworks.

23 This section explores the key regulatory frameworks and legislative initiatives that have emerged in recent years to foster hydrogen demand and facilitate the creation of a robust hydrogen market. Starting with an overview of the EU-level strategies (Section 2.1), it addresses the specific legislative actions designed to stimulate demand for hydrogen in hard-to-abate sectors such as industry and transport. National strategies and policies are then examined (Section 2.2), highlighting their alignment with EU targets, alongside the challenges related to the financing of hydrogen infrastructure (Section 2.3). By focusing on both EU and national regulatory frameworks, this section provides a comprehensive look at the foundational elements driving Europe's hydrogen market forward.

2.1. EU-wide developments

2.1.1. Setting the objectives

24 Since 2020, various strategies and plans have paved the way towards the goals set by the Fit-for-55 package. The most relevant strategic plans are the EU strategy for energy system integration and the EU hydrogen strategy, both published in July 2020. The former identifies hydrogen, along with other renewable and low-carbon fuels, as a means of decarbonising sectors in which direct heating or electrification are not feasible or efficient. The EU hydrogen strategy sets out a more specific roadmap for hydrogen uptake. It prioritises renewable hydrogen because it is seen as the most compatible with EU climate policy, while recognising that low-carbon hydrogen will be needed in the short- to medium-term to enable the sector's development[3]. The strategy establishes an intermediate target to install at least 6 GW[4] of electrolyser capacity in the EU by 2024, able to produce approximately

1 The package is composed of the following two legal acts:
- Directive (EU) 2024/1788 of the European Parliament and the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive (EU) 2023/1791 and repealing Directive 2009/73/EC (hydrogen and decarbonised gas market Directive)
- Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen, amending Regulations (EU) No 1227/2011, (EU) 2017/1938, (EU) 2019/942 and (EU) 2022/869 and Decision (EU) 2017/684 and repealing Regulation (EC) No 715/2009 (hydrogen and decarbonised gas market regulation)

2 An extensive review is provided in the European Hydrogen Observatory's policy landscape report. The Oxford Energy Institute has also issued a comprehensive report on the European hydrogen market.

3 This document uses the definitions of renewable, electricity-based and low-carbon hydrogen as defined in the EU hydrogen strategy, unless otherwise specified. In this context, renewable hydrogen means hydrogen produced via water electrolysis using electricity from renewable energy sources only (renewable electricity) or via processing of biogas and biomass, if in compliance with sustainability requirements. The strategy also defines electricity-based hydrogen as the hydrogen produced through the electrolysis of water (in an electrolyser, powered by electricity), regardless of the electricity source. Low-carbon hydrogen means hydrogen produced in such a way that related greenhouse gas emissions are significantly reduced (at least 70%) compared with conventional production routes from fossil fuels.

4 Industry's practice is to rate electrolysers capacity in terms of electricity input capacity. ACER understands that the targets are set according to this rating.

1 million tonnes (Mt)[5] of renewable hydrogen. It also sets a target for the installation of at least 40 GW of electrolyser capacity and the production of up to 10 Mt of renewable hydrogen by 2030[6], and expects market maturity by 2050 enabling the widespread use of renewable hydrogen in all hard-to-decarbonise sectors. The REPowerEU plan (May 2022), coming in response to the Russian invasion of Ukraine, targeted the end of the EU dependency on Russian fossil fuel imports and the acceleration of the energy transition. Regarding hydrogen, the plan has increased ambitions by introducing a strategic goal of 20 Mt of renewable hydrogen consumption by 2030, of which half is to be produced in the EU (in line with the EU hydrogen strategy) and the remainder imported either as pure hydrogen or in liquid compounds such as ammonia. To that end, the plan supports the development of three major hydrogen import routes via the Mediterranean, the North Sea area and, as soon as conditions allow, Ukraine[7].

25 Fostering hydrogen supply and demand is also a target of several cross-sectoral legislative frameworks:

- Following a second revision, the Renewable Energy Directive (RED) sets the binding target for renewable energy at the EU level for 2030 at 42.5%, while maintaining the European Commission's initial proposal for a 45% target as an aspirational target[8]. Furthermore, the share of renewable energy sources in the final energy use of the industrial sector shall increase by 1.6% every year until 2030[9]. The RED also introduces the notion of RFNBOs[10] which include mainly renewable hydrogen and its derivatives, such as ammonia, methanol and other sustainable synthetic fuels. In February 2023, the European Commission issued two delegated regulations providing further technical details on the conditions for RFNBO production (see Commission Delegated Regulation (EU) 2023/1184 and Box 1 for the main points) and on the calculation of the greenhouse gas emissions saving from RFNBOs and recycled carbon fuels[11] (see Commission Delegated Regulation (EU) 2023/1185)[12]. According to the RED, certification of renewable and low-carbon hydrogen will be performed by national schemes or international voluntary schemes recognised by the European Commission[13]. The RED further establishes specific targets for RFNBOs that are directly relevant to hydrogen. First, at least 42% of the hydrogen used for final energy and non-energy uses in industry shall be labelled as RFNBO by 2030; the share increases to 60% by 2035[14]. Second, at least 1% of the fuels in the transport sector shall be of RFNBO by 2030[15]. Third, at least 1.2% of the fuels supplied to the maritime transport sector shall be of RFNBO by 2030[16].

5 It is common practice to refer to hydrogen in kilograms or tonnes and this report follows this practice. Whenever necessary to refer to energy units, the low heating value of hydrogen is used (33.3 kWh/kg). For a comprehensive overview of the conversion assumptions used in this report, please refer to Figure 24 in the Annex.

6 The 2030 target to produce 10 Mt of renewable hydrogen in the EU implies installed electrolyser capacity significantly more than the target of 40 GW. The joint declaration of May 2022 announce by the European Clean Hydrogen Alliance estimated that producing 10 Mt of renewable hydrogen in the EU would indicatively require up to 140 GW of electrolyser capacity.

7 Figure 26 in the Annex shows the hydrogen corridors as depicted in the REPowerEU plan.

8 The targets refer to renewable energy over gross energy consumption. Individual targets at Member State level are developed via the national energy and climate plans.

9 This is calculated as the annual average for 2021-2025 and 2026-2030.

10 The exact definition is provided in Article 2(36) of the Directive as: *"renewable fuels of non-biological origin" means liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass. According to Article 29a(1) of the Directive "energy from renewable fuels of non-biological origin shall be counted towards Member States' shares of renewable energy and the targets... only if the greenhouse gas emissions savings from the use of those fuels are at least 70 %".*

11 According to the RED definition "recycled carbon fuels" means liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC, or from waste processing gas and exhaust gas of non-renewable origin which are produced as an unavoidable and unintentional consequence of the production process in industrial installations. The feedstock of recycled carbon fuels is mainly industrial gases such as coke oven, blast-furnace gas and unrecyclable plastics.

12 Further guidance on the implementation of these delegated acts is also provided in a living questions-and-answers document.

13 Recognition of national schemes or international voluntary schemes is subject to the provisions of Article 30(4) of RED III. The European Commission maintains a registry of approved schemes and is launching a study to support the implementation of the framework.

14 RED (Article 22b) allows for a reduction of this target by 20% by 2030 under certain conditions. In September 2024 and while the content of this report was being finalised, the European Commission issued a guidance on the implementation of the obligation for RFNBO consumption in industry and transport sector.

15 The combined share of advanced biofuels and biogas, and RFNBOs shall be 1% by 2025 and 5.5% by 2030. Member States are encouraged to differentiate the targets by type of fuel to provide clarity on the development of each sector.

16 Notably, RFNBOs shall also be considered for the purpose of fulfilling the 2030 transport sector targets for renewable energy (29%) and greenhouse gas emissions reduction (14.5%) when used as intermediate products to produce conventional transport fuels or biofuels (Article 25(2)(a)). In reaching these targets, RFNBOs energy content is multiplied by a factor of 2; for maritime and aviation sectors, it is multiplied by a factor of 1.5.

- The revised Emissions Trading Scheme (ETS) expands the existing cap-and-trade scheme to the maritime sector and introduces a separate scheme (ETS2) for buildings, road transport and other sectors. It also makes clean hydrogen production facilities producing 5 tonnes or more of hydrogen per day eligible for free allowances. At the same time, free allocation of allowances will stop from 2034 for sectors specifically relevant for hydrogen, such as fertilisers and steel production. This means that ETS carbon prices will potentially increase the competitiveness of renewable hydrogen for these sectors.

- The Carbon Border Adjustment Mechanism Regulation (CBAM Regulation) aims to maintain the EU's industrial competitiveness with respect to non-EU countries, in a context where the EU made products follow stricter emission rules. It does so by gradually equalising the price of carbon dioxide (CO_2) emitted during the production of certain imported and EU-made products. The CBAM regulation covers products such as conventional hydrogen, ammonia and iron.

26 In addition to the strategic plans and the general emissions reduction and renewable energy policies, more specific tools are also used to trigger demand for renewable hydrogen through sector-specific targets and quotas.

- The Sustainable and smart mobility strategy sets an ambitious target to cut emissions in the transport sector by 90% by 2050, envisaging a role for hydrogen either as a direct fuel, e.g. in fuel cell vehicles, or as a feedstock for producing synthetic fuels[17]. It also aims to develop 500 hydrogen refuelling stations across the main EU corridors by 2025 and double that number by 2030.

- The FuelEU Maritime Regulation aims to further promote the decarbonisation of the maritime sector by setting average greenhouse gas emissions intensity reduction targets[18]. The reduction target starts at 2% in 2025 and gradually reaches 80% by 2050. Until the end of 2033 the energy content of RFNBOs used in the maritime sector will be counted twice, to facilitate the early deployment of such fuels; furthermore, if the share of RFNBOs is less than 1% by 2031, a sub-target of 2% RFNBOs on total maritime fuel should apply as of 2034.

- The ReFuelEU Aviation Regulation promotes the use of sustainable aviation fuels (SAFs)[19] as a means of decarbonising the sector. SAFs cover a range of fuels, including synthetic aviation fuels made from renewable hydrogen and captured carbon like synthetic-kerosene. The share of SAFs in fuel supplied to aircraft in EU airports shall increase to 2 % by 2025 and reach at least 70 % by 2050. Moreover, the share of synthetic aviation fuels (i.e. those with direct hydrogen significance) shall also reach at least 1.2% in 2030 and at least 35% in 2050 and beyond.

27 Finally, the new intermediate climate target for 2040 (February 2024), sets the reduction level of the EU's net greenhouse gas emissions to 90% by 2040 relative to 1990, implying substantial scaling efforts compared with the 55% reduction level by 2030 set out in the Fit-for-55 package. If adopted into a binding legislative act, the new target would require front-loading efforts for the development of the hydrogen sector in the next decade.

17 According to the EU hydrogen strategy, 'hydrogen-derived synthetic fuels' are gaseous and liquid fuels produced by combining hydrogen and carbon. For synthetic fuels to be considered renewable, the hydrogen part should be renewable. Synthetic fuels include for instance synthetic kerosene in aviation, synthetic diesel for cars, and various molecules used in the production of chemicals and fertilisers.

18 The Regulation applies to ships above 5,000 gross tonnage calling at European ports, regardless of their flag. It is the same category of vessels to which the ETS applies from January 2024.

19 As per the Regulation (Article 2(7)), 'sustainable aviation fuels' ('SAF') means aviation fuels that are either: (a) synthetic aviation fuels; (b) aviation biofuels; or (c) recycled carbon aviation fuels. The first and third categories are particularly relevant for hydrogen

Box 1: Defining renewable hydrogen

The delegated regulation setting out the rules for producing RFNBOs defines the criteria under which hydrogen produced via electrolysis (and its synthetic derivatives) may be considered renewable hydrogen and therefore count towards the relevant decarbonisation targets. The purpose of the delegated Regulation is to ensure that electricity used for renewable hydrogen production is renewable, the position of electrolysers minimises adverse locational effects (e.g. congestion) and renewable hydrogen production adds to actual renewable deployment. The Regulation establishes three main criteria:

- **Additionality.** For hydrogen production facilities starting operation from 2028, the electricity supply installations must be commissioned at most 36 months before the commissioning of the electrolyser. Electrolysers that become operational before 2028 are exempted from the additionality criterion for 10 years.
- **Temporal correlation.** Hydrogen production must use electricity from the grid during the same hours when the contracted renewable electricity is injected to the grid. Until 31 December 2029, monthly rather than hourly correlation applies. The temporal correlation criterion is considered complied with if electricity is supplied during periods when the electricity day-ahead price in the bidding zone of the electrolyser is lower than or equal to 20 EUR/MWh or 36% of the ETS CO_2 emissions allowance price in EUR/tCO_2. The underlying principle for this derogation is that additional demand during these hours is most likely to increase renewable electricity uptake rather than incentivise electricity generation from fossil fuels.
- **Geographical correlation.** Renewable electricity installations supplying electricity to an electrolyser must be in the same bidding zone as the electrolyser, or in a neighbouring zone with the same or higher electricity prices, or in an offshore bidding zone interconnected with the bidding zone of the electrolyser.

The Regulation distinguishes between electricity obtained via **direct connection** to a renewable electricity production facility and electricity obtained from the **grid**. In the first case the hydrogen produced qualifies as renewable if the renewable electricity facility fulfils the additionality criterion. When electricity comes from the grid, the hydrogen produced qualifies as renewable if any one of the following criteria is met:

- The electrolyser is in a bidding zone with a share of renewable electricity above 90% for at least one of the preceding 5 years, and its operating hours are fewer than the hours of the year multiplied by the renewable electricity share.
- The electrolyser is in a bidding zone with an emission intensity of electricity below 18 grams of CO_2 equivalent per megajoule (18 g CO_2e/MJ) (approximately 65 g CO_2e/MWh) for at least one of the preceding 5 years, and the temporal and geographical correlation is fulfilled.
- Hydrogen was produced during hours when renewable electricity was curtailed.
- The electricity consumed by the electrolyser leads to reduced need for redispatching.
- The electricity is sourced from a power purchase agreement (PPA) that meets the additionality, temporal correlation, and geographical correlation criteria.

28 Figure 1 summarises the main targets related to hydrogen described above. Estimates indicate that the total hydrogen needed to achieve the targets is between 2 and 4 Mt[20]. This amount represents less than half of the 2030 renewable hydrogen target set in the EU hydrogen strategy and an even smaller part of the ambitious goal of the REPowerEU plan.

Figure 1: Hydrogen related targets of key European legislation

Source: ACER.

Note: For synthetic aviation fuels the following rules also apply: (i) from 1 January 2030 until 31 December 2031 synthetic aviation fuels must make up an average of 1.2 % of all aviation fuels, of which each year a minimum share of 0.7 % must be synthetic aviation fuels; (ii) from 1 January 2032 until 31 December 2034, an average share over the period of 2.0 % of synthetic aviation fuels, of which each year a minimum share of 1.2 % from 1 January 2032 until 31 December 2033 and of which a minimum share of 2.0 % from 1 January 2034 until 31 December 2034 of synthetic aviation fuels.

20 For example see Hydrogen Europe's Clean Hydrogen Monitor 2023 (p. 85) or the 2024 state of the European Hydrogen Market Report (p. 27) by the European Roundtable on Climate Change and Sustainable Transition. The impact assessment accompanying the European Commission's proposal for the 2040 climate target suggests that the total EU consumption of hydrogen in 2030 will be around 3 Mt.

2.1.2. Designing the regulatory framework

29 The hydrogen and gas decarbonisation package, introduced in July 2024, plays a pivotal role in shaping the future of Europe's energy landscape by providing a comprehensive framework to support the transition from fossil fuels to cleaner energy sources. Its goal is to phase out fossil gas and establish a European hydrogen market, while ensuring a smooth transition from natural gas. It also broadens ACER's role to include overseeing the hydrogen market, particularly in areas such as monitoring, network codes development and implementation, infrastructure planning, tariffs, and governance. The package assumes that the hydrogen market will function most effectively through a dedicated hydrogen network, rather than by blending hydrogen with natural gas[21]. As a result, it calls for the development of a separate hydrogen infrastructure and the establishment of distinct market rules tailored specifically to hydrogen.

30 Regarding the hydrogen market design, the package follows principles similar to those of the current gas market, with an emphasis on ownership unbundling for hydrogen transmission networks, regulated third-party access, and the organisation of future markets in accordance with the entry-exit model. The hydrogen and decarbonised gas market regulation envisions the establishment of a European Network for Network Operators of Hydrogen (ENNOH) to manage market functioning and infrastructure development. Potential challenges during the early stages of developing a hydrogen network are also addressed: Member States are allowed to implement mechanisms that defer cost recovery to avoid high tariffs for early users. Financial risk coverage mechanisms can also be introduced to support hydrogen network operators if demand does not materialize as expected. In addition, while cross-subsidies between the gas, electricity, and hydrogen sectors are generally prohibited, they may be allowed under certain conditions to support the growth of hydrogen network. Complementary market rules in the form of network codes and guidelines will be developed, and hydrogen will be gradually included in the scope of the Regulation on wholesale energy market integrity and transparency (REMIT), enhancing market transparency (see Box 2).

21 Recital 74 of the Gas and hydrogen Regulation states that "*the production and use of hydrogen in its pure form and its transportation in the dedicated hydrogen system should … be prioritised*". Blending of hydrogen into existing gas networks up to 2% by volume shall be unrestricted. Member States may choose to allow blending of hydrogen at higher levels; however, such a decision shall not introduce restrictions to cross border natural gas flows.

Figure 2: Key points of the hydrogen and decarbonised gas market package

Hydrogen and gas decarbonisation package

EU Directive 2024/1788, EU Regulation 2024/1789

Market

- Organize hydrogen markets by 2033 according to the entry-exit system, similar to the European gas markets.
- Hydrogen network operators shall ensure hydrogen network capacity, transparency, safety, and efficiency.
- Max duration of capacity contracts: 20 years (infrastructure completed before 2028) or 15 years (infrastructure completed afterwards).

Unbundling

- Default option: ownership unbundling between hydrogen transmission networks and production/ supply.
- Possibility to apply Independent System Operator and Independent Transmission Operator models.
- Gas TSOs can be engaged in hydrogen production / supply, subject to conditions.
- Gas and hydrogen TSOs must be legally separated (but derogation is possible).
- Hydrogen DSOs subject to vertical legal unbundling obligations (and possible derogations), and horizontal accounting unbundling.

Governance

- National regulatory authorities become competent for hydrogen
- ACER's market oversight on hydrogen.
- Establish a European Network for Network Operators of Hydrogen (ENNOH)
- Collaborate with ENTSO-E and ENTSOG to co-develop Union-wide Ten-Year Network Development Plans (TYNDP) for hydrogen.

Third-party access

- Mandatory TPA to hydrogen infrastructure.
- For networks and storage facilities: both negotiated and regulated TPA allowed until the end of 2032. From 2033 onwards, fully regulated TPA.
- For hydrogen terminals: negotiated TPA.

Regulation and Financial Mechanisms

- National regulatory authorities could provide free access to cross-border interconnection points.
- Member States can use an inter-temporal cost allocation mechanism and provide additional support compliant with State Aid rules.
- Prohibit cross-subsidies between services and sectors. But possible financial transfers, subject to conditions.
- Derogations for existing and for geographically confined hydrogen networks, on unbundling, TPA and planning provisions.

Network planning

- Mandatory network development plans at national level (NDP) for gas and hydrogen TSOs .
- Focus on greater system integration (e.g, cooperation between gas/H_2 and ele operators).
- NDPE assessed and approved by national regulatory authorities.
- Planning requirements also on hydrogen DSOs.

Overview of ACER's competences regarding the hydrogen market

Hydrogen Market Rules and Monitoring

Network codes (NCs)
- Prepare non-binding framework guidelines.
- Review and revise NCs proposals.
- Monitor NCs implementation.

Market Monitoring
- Assess the impact of market developments on consumers.
- Evaluate access to the network.
- Review progress on interconnectors.
- Identify barriers to cross-border trade
- Publish an annual report.

Hydrogen network tariffs

- Provide recommendations on the methodologies for:
  - inter-temporal cost allocation;
  - determination of the asset transfer value;
  - financial transfers and allocation among final customers.
- Give the factual opinion on the methodology for setting the hydrogen network access tariffs or reserve prices for interconnection points.

Hydrogen network infrastructure

- Provide an opinion on national hydrogen TYNDPs to assess their consistency with the EU TYNDP.
- Give an opinion on ENNOH's draft Union-wide TYNDP, the draft annual work plan, and other related documents.
- Provide an opinion on the hydrogen PCI/PMI list.
- Monitor the implementation of PCIs/PMIs.

Governance

- Provide opinion to the European Commission (EC) on the draft statutes, member list, and draft rules of procedure of ENNOH and the EU DSO entity.
- Monitor the execution of ENNOH's tasks (and those of the EU DSO Entity) and report findings to the EC.
- Oversee the implementation of network codes and guidelines by ENNOH.

Source: ACER.

Note: DSO, distribution system operator; Entso-E, European Network of Transmission System Operators for Electricity; ENTSOG, European Network of Transmission System Operators for Gas; TPA, third-party access; TSO, transmission system operator; TYNDP, 10-year network development plan.

Box 2: Hydrogen under REMIT

In contrast to electricity and natural gas, there is currently no existing liquid market in the EU for the trading of hydrogen; hydrogen transactions are concluded on a bilateral basis for specific delivery locations and almost exclusively for industrial purposes. The buyers of hydrogen are therefore mostly final customers under Article 2(4) of REMIT, buying hydrogen for their own use. According to Article 2(4) and (5) of REMIT, supply contracts for which the buyer is a final customer with a consumption capacity of less than 600 GWh per year are not considered wholesale energy products reportable under REMIT. Consequently, as most hydrogen transactions today are with final customers, the consumption capacity of those customers will be relevant to assess whether they shall report the details of supply contracts under REMIT. The transaction type and volume also define whether market participants shall register with the national regulatory authority as per Article 9 of REMIT.

As the liquidity of the European hydrogen market grows, REMIT would enhance market transparency, prevent market abuse and insider trading, ensure fair pricing, and standardise transaction reporting, thus facilitating cross-border hydrogen transactions. To the extent that hydrogen becomes an integral part of the energy value chain, REMIT would also harmonise transparency requirements and market rules across electricity, natural gas and hydrogen. For example, REMIT's definition of inside information would require public disclosure of data on hydrogen production, storage, or consumption if it could significantly impact hydrogen prices.

2.2. National developments

31 Following the publication of the EU hydrogen strategy and the Fit-for-55 package, Member States started setting national targets and putting together strategies and plans establishing roadmaps and tools to achieve these targets. This section provides an overview of the national strategies and plans (Section 2.2.1), describes recent regulatory developments (Section 2.2.2), and provides information on approaches to hydrogen network funding through tariffs (Section 2.2.3).

2.2.1. National strategies

2.2.1.1. Overview

32 Scaling up the production of hydrogen requires a joint effort by Member States, as the EU objectives must be translated into actions not only at the European level, but also at the national level. Member States show different degrees of ambition. Understanding the different paths and strategies can be useful to make the comparison between EU goals and actual national implementation, and to monitor the development of hydrogen markets against different trajectories.

33 This section focuses on national hydrogen demand and supply targets, and their overall consistency with the EU targets. It uses information from the national hydrogen strategies, where available, and from other relevant strategic documents, including the updated 2021-2030 National Energy and Climate Plans (NECPs)[22]. ACER also ran a survey among national regulatory authorities in the summer of 2024 to complement the information available[23].

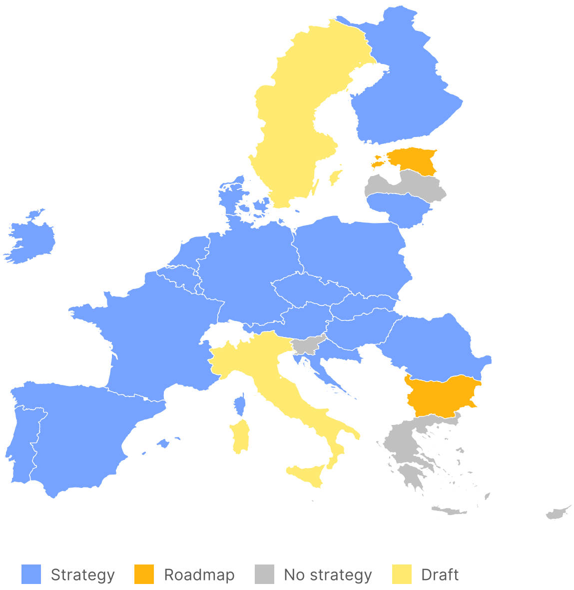
34 As of September 2024, 22 Member States have published or drafted a hydrogen strategy or roadmap. The number includes the Member States, the strategic documents of which have been labelled as roadmaps (Bulgaria, Estonia, Spain) or are still in draft form (Italy, where a formal version is expected in autumn 2024, and Sweden, where the published strategy is a proposal by the Swedish energy agency).

22 Within the NECPs, the WAM (With Additional Measures) scenarios were considered.

23 Data have also been validated against those provided in other relevant databases and reports: the Policies and Measures Database of the International Energy Agency (IEA), the Green Hydrogen Strategy from the Interanational Renewable Energy Agency (IRENA), the 2024 State of the European Hydrogen Market Report from the Oxford Institute for Energy Studies (OIES), and the European hydrogen policy landscape 2023 from the European Hydrogen Observatory.

35 Apart from the national hydrogen strategies, some NECPs also include specific targets on hydrogen. This is particularly relevant in cases where a hydrogen strategy has not been published (Greece and Slovenia) or where the NECP provides an update on hydrogen targets compared with the hydrogen strategy previously published (Czechia, Italy, Luxembourg, Poland, Portugal, and Spain). In the Netherlands, certain targets on hydrogen are also included in the Climate Agreement published in 2019. In Croatia, detailed objectives are included in the 2024 hydrogen strategy implementation document. Figure 3 depicts the availability of strategies and roadmaps across the EU, while Table 4 in the Annex provides more details and links to the documents used.

Figure 3: Overview of hydrogen strategic documents – September 2024



Source: ACER.

Note: In France, an updated strategy was submitted for public consultation in December 2023.

36 Most strategic documents provide medium-term targets (for 2030), while only a few focus on the longer term (2040 or 2050). Great variability can also be found in the types of targets: while almost all strategies set specific objectives on electrolysers' capacity, many do not provide hydrogen supply and demand targets, and only a few provide an overview of the expected import or export patterns. Finally, certain countries (e.g. Bulgaria, Estonia, Lithuania, Slovakia) have only set targets for renewable hydrogen production only; thus, it is not always possible to understand the overall potential contribution of hydrogen production potential when non-renewable hydrogen (e.g. low-carbon hydrogen) is also considered.

2.2.1.2. Summary of the targets

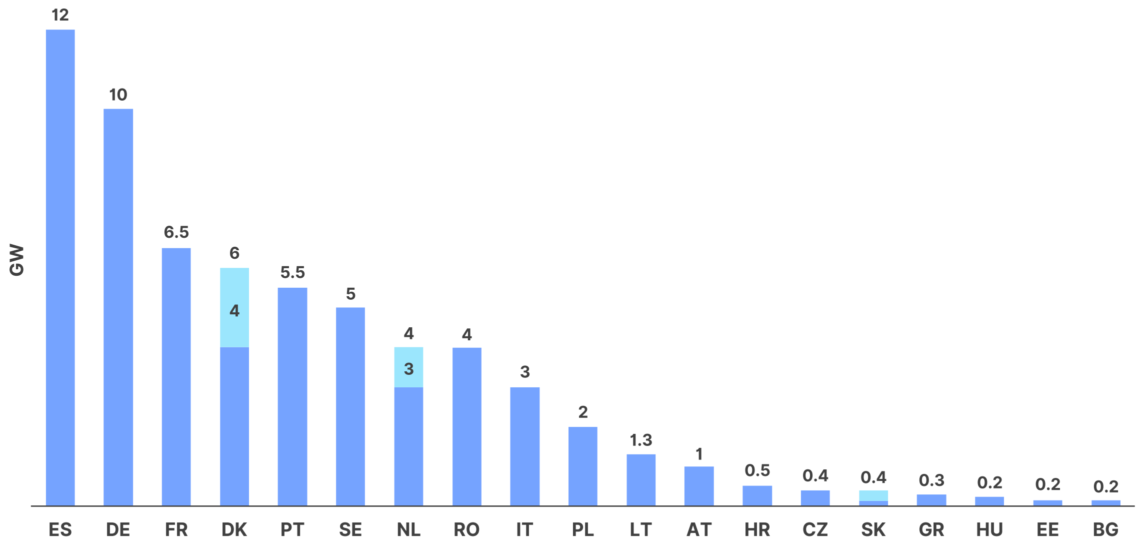
37 As further detailed in Section 3.2, almost all hydrogen in the EU is currently produced from fossil fuels, via steam reforming, normally without carbon capture[24]. To achieve the decarbonisation targets, hydrogen strategies focus on the potential for renewable hydrogen produced via electrolysis using renewable electricity, or via biomass gasification. The definition of renewable hydrogen adopted in such documents is not necessarily consistent with the one in the European legislation and the delegated regulations issued by the European Commission in February 2023[25]. This section retains the definitions of renewable (or green) hydrogen used in the national strategies.

38 Nineteen Member States provide an explicit target for electrolyser capacity in 2030, adding up to 59-62 GW of electrolyser capacity at the EU level. As shown in Figure 4, Spain and Germany have the highest target on installed electrolyser capacity (12 and 10 GW respectively). France (6.5 GW), Denmark (4-6 GW), Portugal (5.5 GW) and Sweden (5 GW) follow with a significant contribution.

24 Very few facilities with carbon capture exist in the EU, see Section 3.2 for more details.

25 See also section 2.1.1 and Box 1.

Figure 4: Targeted electrolyser capacity for 2030 in EU Member States according to the national strategies and plans – September 2024 (GW)

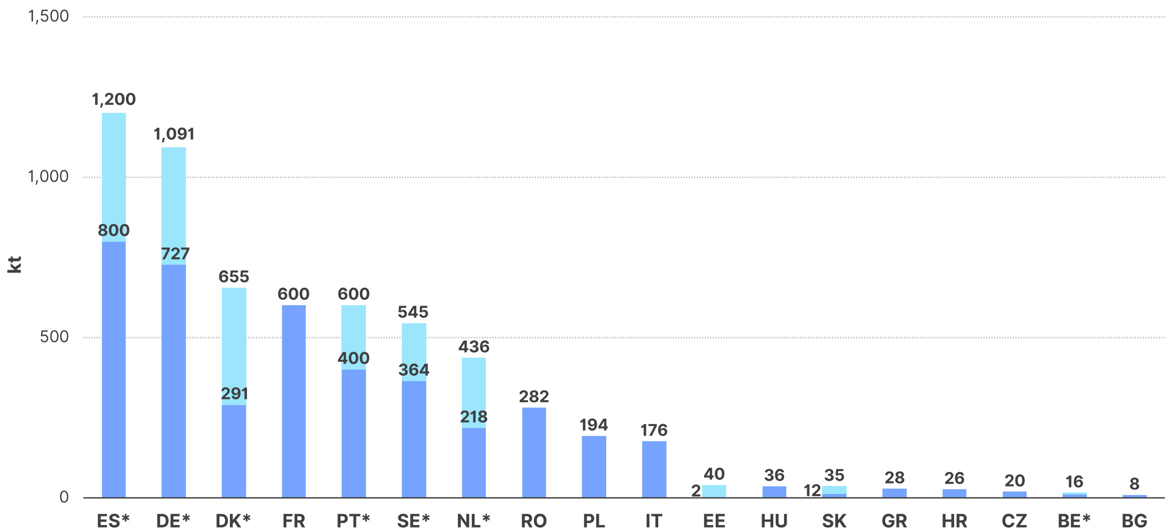


Source: ACER based on national hydrogen strategies and roadmaps, NECPs, and information provided by national regulatory authorities.

Note: Ranges (light blue column) correspond to different assumptions or scenarios in the strategies. For Belgium the target refers to 2026. For Czechia, Greece, Italy, Portugal, and Spain data taken from updated NECPs. For Lithuania, data were taken from draft hydrogen strategies. For the Netherlands, data taken from the climate agreement. For Croatia, data were taken from hydrogen strategy implementation document. For Estonia, the figure is not a target but is linked to the estimated potential for renewable hydrogen production. Finland, Ireland, and Luxemburg have published strategies but with no quantitative targets on electrolysers for 2030. For Ireland, the strategy indicates a 2 GW target of offshore wind in 2030 for the production of renewable hydrogen. For Portugal, the draft updated NECP mentions a target of 5.5 GW, while the final updated NECP mentions a target of 3 GW "output" capacity; for comparison purposes, the 5.5 GW target is presented.

39 Only a few Member States provide explicit reference to their targeted renewable hydrogen production. Figure 5 provides relevant information based on the strategies or on estimates using the electrolyser capacity expected to be installed by 2030 and general operational assumptions[26]. While this calculation is purely indicative[27], it offers some insight on the renewable hydrogen production expected in the EU based on the national targets for electrolysers.

Figure 5: Targeted renewable hydrogen production for 2030 in EU Member States according to the national strategies and plans – September 2024 (kt)



Source: ACER based on national hydrogen strategies and roadmaps, NECPs, information provided by national regulatory authorities, and own calculations.

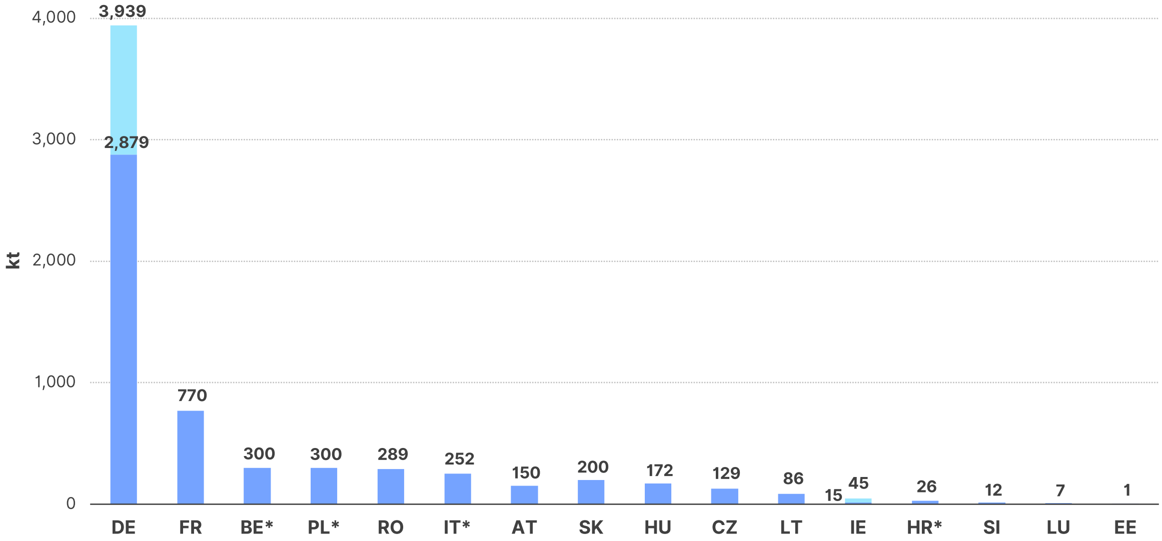
Note: Ranges (light blue column) correspond to different assumptions or scenarios in the respective strategies. (*) indicates estimates based on electrolyser targets assuming that electrolysers operate with a 61% efficiency (55 kWh / kg H_2) and a load factor of between 4,000 and 6,000 hours/year (46-68%), and that they employ renewable electricity. For Belgium the estimate refers to 2026. For France and Hungary the figure includes hydrogen produced via electrolysis using electricity from nuclear power or the grid.

26 See Figure 24 in the Annex.

27 For example, it could lead to underestimated volumes since the calculations do not consider any hydrogen produced from biomass gasification. At the same time, it could lead to overestimated volumes because it assumes that all electricity used is renewable and that the production of electricity-based hydrogen complies with the definition of renewable hydrogen.

40 As regards hydrogen demand (Figure 6), based on the explicitly set targets, Germany has by far the highest consumption goal (3-4 Mt/y), noticeably higher than the second in the row (France with 0.77 Mt/y) and nearly as high as all the other countries together (even higher if the upper end of the expected demand, 3.9 Mt, is considered).

Figure 6: Targeted hydrogen demand for 2030 in EU Member States according to the national strategies and plans – September 2024 (kt)



Source: ACER based on national hydrogen strategies and roadmaps, NECPs, and information provided by national regulatory authorities.

Note: Ranges (light blue column) correspond to different assumptions or scenarios in the strategies. (*) indicates countries that only set targets for renewable hydrogen demand. For Belgium the target refers to 2026 and is half of the total target for imported "green molecules". Countries such as Denmark, Spain and the Netherlands, with ambitious electrolyser targets or significant current hydrogen demand, are not included in the graph because they have not set explicit hydrogen demand targets. Portugal has set a target of hydrogen in final energy consumption of 1,5-2% in 2030.

41 Table 1 summarises the information available about the expected future use of hydrogen. Most strategies focus on the development of the industrial sectors, in particular the hard-to-abate ones (e.g. iron manufacturing). Mobility, in particular heavy-duty transport, maritime and aviation, is also a key area for hydrogen uptake. In a few stances, references are made to the potential of hydrogen for power production, often associated with the blending of hydrogen into the gas system. In contrast, very few Member States see a role for hydrogen in private or light-duty mobility, or residential heating. Hydrogen is also anticipated to serve as a decarbonised alternative for district heating (mostly from combined heat and power plants) in cases where other sources (such as sustainable biomass or electrification) are not available. Some strategies also mention the importance of renewable hydrogen in an integrated energy system, by offering energy storage opportunities and grid flexibility options.

Table 1: Hydrogen use according to the national strategies and plans – September 2024

Country	Industrial applications			Transport					Power generation including cogeneration for district heating
	Chemical and fertilizers	High-temperature processes (e.g. steel, iron, cement, glass)	Petrochemical	Road - heavy duty	Road - private and light duty	Public transport (trains, buses)	Maritime	Aviation	
Austria	990 kt			60 kt (2040), mainly heavy duty					390 kt (2040)
Belgium	✓	✓	✓	✓	Limited	Limited	✓	✓	Limited
Bulgaria	✓	✓	At least 80 kt	✓	✓	✓			
Croatia	21 kt (2030), 84 kt (2050) renewable H_2			5 kt (2030), 125 kt (2050) renewable H_2, mainly road transport					Potential
Cyprus									
Czechia	✓		✓	✓	✓	✓			
Denmark	✓	✓	✓	✓			✓	✓	
Estonia	Potential			✓			✓	✓	Potential
Finland	✓	✓	✓	✓		✓	✓		✓
France	✓	✓	✓	✓			✓	✓	
Germany	8,788-13,333 kt (2045)			✓	✓	✓	✓	✓	2,424-2,030 kt (2045)
Greece					✓				
Hungary	162 kt (2030), 249 kt (2050)			10 kt (2030), 212 kt (2050), mainly heavy duty					
Ireland		Up to 452 kt (2050)		30-282 kt (2050), mainly heavy duty and rail			67-79 kt (2050)	394-788 kt (2050)	109-403 kt (2050)
Italy	115 kt (2030) ren. H_2			137 kt (2030) ren H_2					Potential
Latvia									
Lithuania	77 kt (2030), 614 kt (2050)			8 kt (2030), 51 kt (2050)					17 kt (2050)
Luxemburg	4 kt (2030), 30-121 kt (2050)			3 kt (2030), 61-121 kt (2050)					30-61 kt (2050)
Malta									
Netherlands	✓	✓	✓	✓	✓	✓	✓	✓	✓
Poland	✓		✓						
Portugal	✓	✓	✓	✓	✓	✓	✓	✓	✓
Romania	59 kt (ren. H_2) + 7 kt (clean) in 2030			169 kt (2030), mostly heavy duty and public transport					54,8 kt (2030)
Slovakia	✓	✓	✓	✓	✓	✓	✓	✓	✓
Slovenia	8,0 kt (2030), 18,5 kt (2040)			3,8 kt (2030), 33,9 kt (2040)					
Spain	✓	✓	✓	Limited					
Sweden		✓	✓	✓			✓	✓	

Source: ACER based on national hydrogen strategies and roadmaps, NECPs, and information provided by national regulatory authorities.

42 The strategic documents developed at the national level mostly focus on the national dimension, and very rarely provide a picture of the potential cross-border exchanges of hydrogen. It is therefore difficult to assess the probable development of the EU hydrogen market, and to evaluate the corresponding need for cross-border infrastructures based on these documents. Austria would need to import 0.04 Mt/y by 2030 and 1.1 Mt/y by 2050. Belgium anticipates importing around 0.6 Mt/y by 2030 and 6.1-10.6 Mt/y by 2050 (that includes both renewable hydrogen and hydrogen derivatives), of which about half will be available for transit to neighbouring countries. Germany expects to import 1.4-2.7 Mt/y by 2030, corresponding to a significant share of the expected hydrogen demand (between 50% and 70%)[28]. Italy plans to import at least 30% of the renewable hydrogen it needs in 2030, corresponding to about 0.08 Mt/y. Lithuania anticipates the export of around 0.04 Mt/y.

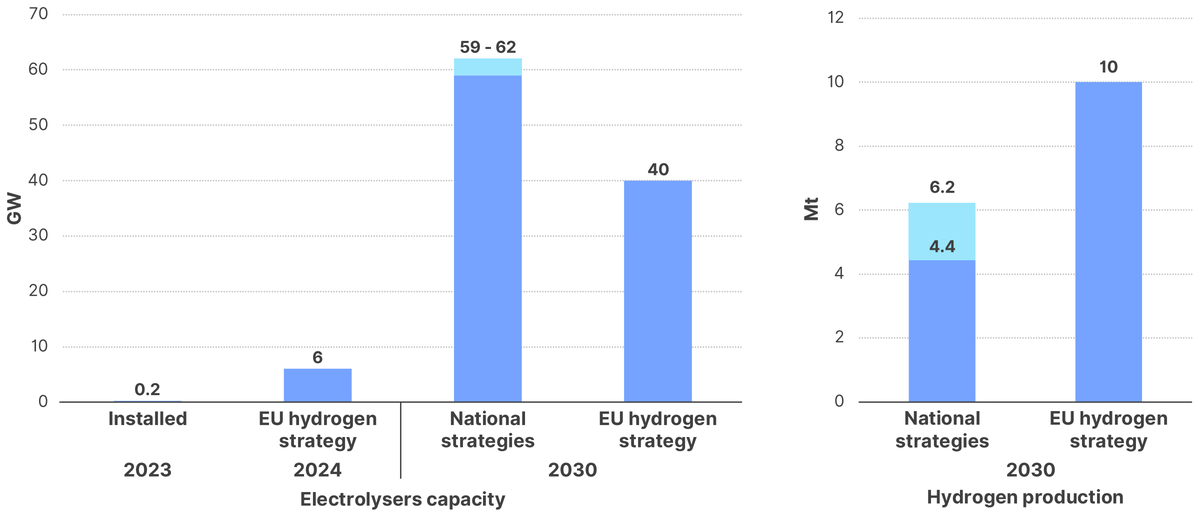
43 When comparing EU and nationally-specific objectives, only the targets on electrolysers' capacity in 2030 show a certain alignment. As shown in Figure 7, Member States envisage a total of 59 to 62 GW of electrolysers' capacity in 2030, compared with the 40 GW target in the EU hydrogen strategy. For 2050, when the EU Hydrogen Strategy sets a very ambitious goal of 500 GW, the picture is less clear since only few countries have set a long-term target. What seems particularly challenging, however,

28 See also the Import strategy for hydrogen and hydrogen derivatives adopted by the Federal cabinet on 24 July 2024.

is reaching these targets by the suggested timelines. The electrolyser capacity currently installed is 216 MW, much less than the intermediate EU target of 6 GW in 2024[29].

44 As regards hydrogen production, the target for 2030 that can be inferred from national strategic documents is estimated to be between 4.4 and 6.2 Mt of renewable and low-carbon hydrogen. Only a few countries (such as Czechia and Hungary) provide indications on the potential for the production of other types of hydrogen (e.g. fossil-based), adding up to around 0.2 Mt. Overall, the targets explicitly set at the national level fall short in achieving the 2030 EU target for the production of 10 Mt of renewable hydrogen set out in the EU hydrogen strategy, though clearly a significant contribution could also come from countries where specific targets have not yet been set.

Figure 7: Comparison of EU targets with national ones according to the national strategies on electrolyser capacity (left, GW) and hydrogen production (right, Mt) - September 2024



Source: ACER based on national hydrogen strategies and roadmaps, NECPs, and information provided by national regulatory authorities.
Note: Actual installed capacity of electrolysers in 2023 is based on data from the European Hydrogen Observatory.

45 The discrepancies between the electrolyser capacity targets (where national strategies exceed the EU goal) and between the hydrogen production targets (where, instead, the national strategies collectively aim for a lower amount) is noteworthy. Moreover, the 2030 goal to produce 10 Mt of renewable hydrogen, set out in the EU hydrogen strategy, would require an installed electrolyser capacity significantly higher than the EU target of 40 GW[30].

2.2.2. Regulatory developments

46 Before the adoption of the hydrogen and gas decarbonisation package in July 2024, only Belgium, Denmark, and Germany had introduced regulatory provisions specifically intended for the hydrogen sector. Currently, most countries are still at the stage of assessing the requirements of the package and working on its transposition into national legislation, which, as regards the hydrogen and decarbonised gas market Directive, should take place by August 2026. To a certain extent, the existing regulatory frameworks in Belgium, Denmark, and Germany will also have to be amended or complemented accordingly.

47 In Belgium, the national regulatory authority, the Commission for Electricity and Gas Regulation (CREG), is currently in charge for certifying and designating of hydrogen network operators. Fluxys Hydrogen was appointed as the first such entity in April 2024. CREG is also responsible for approving the methodology and the tariffs for access to the hydrogen network, and has an advisory role on the national development plan, while the Ministry is currently in charge of its final approval[31].

29 In a special report on the EU's industrial policy on hydrogen issued in June 2024, the European Court of Auditors, recommended a reality check and an update of the EU targets. In its reply the European Commission acknowledged that the ramping up of the hydrogen market is challenging and that advancement of projects within the EU and internationally are insufficient in view of reaching the targets.

30 See also Figure 24 in the Annex. See also footnote 6 and paragraph (90).

31 Law of 11 July 2023 on the transport of hydrogen by pipelines, published in the on 25 July 2023.

48 In Germany, a comprehensive framework on financing and access to the network is under development[32]. It includes a mechanism for inter-temporal allocation of network costs (see Section (1)), with specific provisions on the tariff levels and the way to manage under- and over-recovery. The mechanism also sets out how the risk should be taken over by the State and network operators. The German regulatory authority, the Bundesnetzagentur (BNetzA), is responsible for approving the investments of the 'core network' and the scenarios used for network planning, and it may request amendments to the plans. BNetzA is also responsible for determining the rules on access to the network, and for balancing.

49 In Denmark, the Power-to-X strategy of March 2022 implies that the two gas infrastructure companies, Energinet (gas transmission system operator) and Evida (gas distribution system operator), will own and operate the future hydrogen infrastructure. Two subsequent political agreements were issued in 2023 and 2024 related to the development of hydrogen infrastructure. The first agreement concerns the ownership and operation of Denmark's future hydrogen pipeline network. It specifies, among other things, that the hydrogen infrastructure will be developed under market conditions, based on the demonstrated specific demand. The second agreement sets out the economic framework conditions for the future hydrogen infrastructure. Regulated third party access will apply to the hydrogen transmission infrastructure, based on tariffs established in accordance with a methodology approved by the Danish regulatory authority (Danish Utility Regulator, DUR), and revenues will be established according to a revenue cap methodology. Revenue caps and through that network charges will be calculated in accordance with an inter-temporal cost allocation mechanism, designed by DUR, to spread cost recovery over time. The 2024 agreement does not specify a model for risk-sharing between the State, Energinet and network users. However, it establishes preconditions to the potential involvement of the State in providing guarantees, including capacity bookings of at least 1.4 GW (corresponding to 44% of the planned pipeline capacity) and commitments for 10-15 years. DUR has also been given competences over the topics of unbundling and certification of hydrogen operators, access to the system, terms and conditions, monitoring, and balancing. While a formal certification procedure has not started yet, both Energinet and Evida are planning to operate as hydrogen network operators.

50 Furthermore, on the certification of hydrogen operators, in Spain Enagás Infraestructuras de Hidrógeno S.L.U. has been provisionally designated as hydrogen network operator. Until the formal designation takes place it may take part in the preparations for the ENNOH statutory documents and exercise the functions of development of European projects of common interest (PCIs) under the TEN-E Regulation. In the Netherlands, Hynetwork Services, a subsidiary of the fully State owned gas transmission operator Gasunie, is the single entity being tasked with a service of general economic interest to develop and operate the national hydrogen network. A specific mechanism to support network development, defined by the Dutch government, is also in place (see Section (1)).

2.2.3. Strategies to finance the development of hydrogen networks

51 The EU hydrogen policy provides for the creation of hydrogen markets that are connected via dedicated hydrogen networks. Delivering this networks from scratch presents significant challenges: infrastructure needs to account for different national ambitions on the hydrogen sector, consider various hydrogen demand scenarios and hydrogen supply routes, and be overall consistent with European targets. Interlinkages with the natural gas (in terms of declining consumption and the option to use existing natural gas assets to transfer hydrogen) and electricity (in terms of optimum location of electrolysers and electricity network constraints) sectors need to be considered when planning the hydrogen network. While the EU policy framework aims to create significant demand for hydrogen in the coming decades, uncertainties about the cost of renewable and low-carbon hydrogen influence the pace of uptake and the expectations about the market development. Since the recovery of network costs should primarily be based on access tariffs, the risk related to uncertain hydrogen demand poses a significant financial challenge for project promoters, namely network operators, that needs to be taken into account by policy makers and regulators when designing the optimal framework. If future demand is not sufficient to recover network costs at affordable tariffs, this might further discourage the offtake of hydrogen, thereby escalating the problem of cost recovery and making investments in hydrogen networks less viable.

32 Amended Energy industry act and Regulation of costs and charges for access to hydrogen networks.

52 This challenge is acknowledged in the hydrogen and decarbonised gas market Regulation. For instance, it provides for exemptions to the general unbundling rules between the natural gas, hydrogen and electricity sectors specifying tools that, as an exception, allow cross-subsidies between sectors. It also allows for an inter-temporal allocation of network costs to end-users reflecting the evolution of demand so that costs are evenly and fairly distributed between early and future hydrogen off-takerss[33]. However, the uncertainty around the demand evolution remains in terms of both the growth rate and the total expected long-term demand levels. Such uncertainty makes it necessary to decide not only on the tariff methodology, but also on the management of demand risk, and in particular its allocation among different parties[34].

53 As shown in Section 2.2.1, Member States have different aspirations regarding hydrogen market development. For example, Germany puts the emphasis on the hydrogen use in its industrial and energy sectors and anticipates the need for substantial imports, while the Netherlands focuses mostly on becoming a hub to import hydrogen in Europe, partly addressing Germany's needs. In an interconnected market these differences highlight the need to properly allocate demand-related risks and their associated costs[35].

54 Also, as highlighted in Section 2.2.2, some Member States are already developing mechanisms to facilitate the early financing of hydrogen networks, including the design of inter-temporal mechanisms. Useful indications and suggestions on how to deal with the challenges associated with hydrogen network development can come the experience of such prime movers. The remainder of this section provides a brief overview of the approaches used in Germany and the Netherlands.

55 **The German inter-temporal cost allocation mechanism.** Germany is planning to build a 'hydrogen core network' to supply hydrogen to industrial and urban centres across the country[36]. The amended plan proposed by fifteen gas transmission operators consisted of approximately 9,700 km of pipelines. On 22 October 2024, at the time of finalisation of this report, BNetzA approved the core-network application with changes (more information here). The approved line length is reduced to 9,040 km lowering the investment cost to EUR 18.9 billion. To ease the financing of such project, the German government has also designing a specific inter-temporal cost allocation mechanism. In particular, any mismatch in demand compared with the designed capacity of the network could lead to prohibitively high fees and hinder further uptake of hydrogen increasing the chance of demand ramp-up failing. The inter-temporal cost allocation mechanism is meant to cope with this challenge, not only in the way it defines tariffs over time, but also by means of a risk sharing settlement that allocates the risk of uncovered costs of (stranded) investments in case demand expectations do not materialise. The mechanism provides for a common ramp-up tariff for all users. For the initial period of market development, the ramp-up tariff is set below the normal level of a cost reflective tariff leading to under-recovery of costs. As demand develops the tariff will become more cost-reflective; when demand is such that a cost-reflective tariff is low enough, the tariff will be set at a level whereby revenues from users will overcome network costs to balance the initial deficit. A revision of the mechanism settings is foreseen to deal with any deviations between actual and anticipated network development costs. Every three years, BNetzA will review the suitability of the tariff so that it is affordable but also enough to balance the accumulated deficit by 2055. The initial settlement of the ramp-up tariff will use cost estimates and demand projections considering different scenarios (including assumptions by network operators and official energy transition scenarios). In principle, the mechanism is set in a way that full cost recovery is achieved through network tariffs by 2055 without the need for any public support. However, if the expectations for demand prove too optimistic and demand lags significantly behind, there is a risk that affordable tariffs will not be enough to fully recover the costs. Such risk is shared between the German State and the network operators, providing an incentive for the latter to take rational economic decisions. Hence, if the accumulated deficit is not balanced by the end of 2055, 76% of the remaining deficit will be covered by the German State while the rest will be borne by network operators. If, by 2038, it is obvious that demand will not

33 ACER is tasked by the hydrogen and decarbonised gas market Regulation with issuing a recommendation on the methodologies for setting an intertemporal cost allocation. This work has commenced and is undertaken together with national regulatory authorities

34 Such risks may also have cross-border implications in the case of cross-border infrastructure. This issue was also highlighted by the Austrian regulatory authority, E-control, to its reply to the public consultation of the German Ministry for Economy and Climate Protection on the law for electricity security of supply, mentioning that to avoid unexpected and inefficient cost transfers across borders, financing solutions for cross-border infrastructure should be jointly developed.

35 Opportunities stemming from the sector's development should also be considered. For example, the high demand in Germany creates the opportunity for some countries with favourable conditions to develop their renewable hydrogen production industry or become hydrogen trade and transit hubs.

36 For more details on the German core network, please also refer to paragraph (86).

reach the levels necessary to cover the costs through reasonable tariffs, and network operators refuse to take the additional losses, the German government may decide to cancel the process and take on any losses accumulated by network operators, while gaining control of the network.

56 **The Dutch network development support scheme.** In the Netherlands, the plan provides for the gradual development of a network connecting hydrogen production sites and terminals with industrial clusters and large-scale underground hydrogen storage, and eventually linking the market with Germany and Belgium[37]. The Dutch State has reserved approximately EUR 750 million as direct support to finance the network. The rest is expected to be covered by network tariffs. The tariff setting at this stage is a prerogative of the government, that is, the national regulatory authority currently has a limited role[38]. The final amount of the State support will be determined by the actual use of the network by 2031, so that most of the risk of the demand ramp-up is undertaken by the State directly. Hence, the government will have the right to amend the development plan, while the network operator must provide access to third parties in an objective, transparent and non-discriminatory manner.

2.3. Kick-starting the market

57 As opposed to gas or electricity, hydrogen is not a commodity traded in organised multilateral markets, and there are still relevant uncertainties on future demand, in particular for renewable hydrogen. Such uncertainties are driven mainly by the current large cost gap between renewable and fossil-fuel-based hydrogen (and in general between hydrogen and other energy sources in cases where hydrogen is used as energy carrier rather than feedstock), the large investment needs and several technological challenges. The production cost of renewable hydrogen is currently three to four times higher than the cost of hydrogen produced by conventional methods from fossil fuels (see also Section 3.4.1). Investments are needed not only to scale up the market and bring down production and distribution costs, but also to expand the demand for hydrogen to new sectors[39]. The significant capital investment needs and the higher production cost of renewable hydrogen could impact the competitiveness of the sectors where hydrogen is expected to be more widely employed. Proper policies and regulations need to be accompanied by public support to bridge the current cost gap, with the aim of reaching market maturity levels that will self-sustain without the need for subsidies. This section gives an overview of the funding schemes provided at the EU and national levels and provides some further details on the European Hydrogen Bank auctions.

2.3.1. EU support mechanisms

58 According to the EU Taxonomy[40], the production of hydrogen is considered sustainable if it results in a 73.4% reduction in life-cycle greenhouse gas emissions compared with hydrogen produced using fossil fuels[41]. Similarly, the sustainability criterion for the production of synthetic fuels based on hydrogen is that it must lead to a 70% reduction in emissions. Ammonia produced from sustainable hydrogen is also considered sustainable[42]. The inclusion of hydrogen production in the EU Taxonomy is particularly important as it facilitates the financing of the production of sustainable hydrogen and its derivatives[43]. These activities may be included in the various EU financing instruments promoting the European Green Deal objectives, effectively enabling the European Commission and the Member States to support the development of the hydrogen sector through various funding instruments. Most of these instruments

37 For more details on the Netherland's national hydrogen backbone refer also to paragraph (87).

38 This is expected to change once the transposition of the hydrogen and decarbonised gas market Directive into national legislation is completed, after which the tariffs or their methodologies shall be approved by the regulatory authority.

39 For example, replacing conventional heavy-duty vehicles with fuel-cell-powered ones, or using direct iron reduction via hydrogen instead of coal fuelled blast furnaces to produce iron.

40 As described in the European Commission's website "the EU taxonomy is a cornerstone of the EU's sustainable finance framework and an important market transparency tool". It establishes criteria for economic activities that are aligned with the European Green Deal climate targets and with broader EU environmental goals and directs investments to these activities.

41 The EU Taxonomy uses a benchmark of 94 g CO_2e/MJ for hydrogen production. While the EU Taxonomy does not explicitly refer to RFNBO compliant hydrogen, the same comparator is used in the relevant delegated regulation for calculating emissions savings for RFNBOs.

42 Other relevant economic activities promoting sustainability under the EU taxonomy include: manufacturing of sustainable hydrogen production equipment; the storage of electricity in the form of sustainable hydrogen or ammonia (and re-electrification); the construction and operation of hydrogen storage facilities (including conversion of existing natural gas underground storage facilities); the transmission and distribution networks of renewable and low-carbon hydrogen (including conversion, repurposing and retrofitting of existing gas networks for that purpose); the hydrogen fuelling stations and relevant research and demonstration.

43 For example, the European Investment Bank aims at "*aligning its tracking methodology for climate action and environmental sustainability finance with the framework defined by the EU Taxonomy Regulation*". Other public or private banks and financing institutions are also following similar approaches.

provide grants for projects aiming to produce sustainable hydrogen or to enable its uptake, for example in industrial processes. Research, development and demonstration of sustainable hydrogen projects is also being funded. Table 5 in the Annex provides an overview of the key EU funding tools, while the European Hydrogen Observatory gives a comprehensive list and description of the schemes.

59 Because of the enhanced role of renewable hydrogen envisaged in the REPoweEU plan, the European Commission established the European Hydrogen Bank (EHB) in autumn 2023, a financial instrument with an objective to "*close the investment gap and connect future supply of renewable hydrogen with demand*". Using resources from the Innovation Fund, the European Hydrogen Bank has thus far focused on supporting the production of renewable hydrogen within the European Economic Area (EEA)[44]. An international pillar focusing on coordinated imports of renewable hydrogen into the European market is under development, which might consider using the German auctioning scheme H2Global as a vehicle.

60 The European Hydrogen Bank plans to hold regular auctions awarding a fixed green premium to successful bidders via 10-year contracts[45]. The first auction was held in November 2023 and selected seven projects for funding of EUR 719 million in total. Six out of those seven projects signed their respective grant agreements in October 2024. The total amount of support comes to EUR 695 million and will be disbursed over a timespan of ten years. Jointly, the six projects have the potential to produce up to 1.5 Mt of renewable hydrogen during the first ten years of their operations, avoiding more than 10 Mt of CO_2 emissions. The pay-as-bid auction awarded premiums ranging from 0.37 to 0.48 EUR/kg, much lower than the auction ceiling price of 4.5 EUR/kg. A short analysis of the results based on information provided publicly by the European Commission is presented in Box 3[46]. A second auction for domestic (i.e. EEA) renewable hydrogen production is tentatively scheduled for the end of 2024 and will allocate a maximum of EUR 1.2 billion in premiums.

61 The European Hydrogen Bank may also assist Member States in identifying suitable renewable hydrogen production projects in their jurisdictions, which can be supported via national schemes. This would enable a faster deployment of supporting tools, relying on scrutiny checks of the Bank's auctions and avoiding lengthy State-Aid approval processes. Germany has already agreed to use this "auction as a service" mechanism to support projects that did not qualify in the first auction of the European Hydrogen Bank.

62 Based on Article 52 of the hydrogen and decarbonised gas market Regulation, the European Commission has also initiated the creation of a pilot mechanism to support the market development of hydrogen. The mechanism sits under the umbrella of the European Hydrogen Bank and focuses on collecting information on market data, including individual demand and supply offers. While it is not a trading platform, it may still help connecting suppliers with off-takers, thus facilitating potential bilateral agreements. The exact types of services to be offered to stakeholders are yet to be determined. Data collection and analysis is scheduled from the second half of 2025, and the mechanism will last until the end of 2029. The European Commission will then evaluate the mechanism with a view to assessing the need for a voluntary hydrogen demand aggregation mechanism and the joint purchasing of hydrogen, similarly to what has been envisaged for natural gas.

63 Finally, hydrogen operators developing infrastructure projects with a cross-border relevance, including storage and large-scale electrolysers, may seek funding from the energy budget of the Connection Europe Facility instrument. Eligible projects are those included in the approved list of Projects of Common Interest (PCI) or Mutual Interest (PMI), developed according to the Trans-European Network for Energy regulation (TEN-E Regulation)[47].

44 The European Economic Area comprises the EU Member States, Iceland, Liechtenstein and Norway.

45 The European Hydrogen Bank's activities also include the support of imported sustainable hydrogen produced outside the EU. Dedicated green premium auctions for this purpose are currently under development. The European Hydrogen Bank also aims to increase transparency on hydrogen transactions, flows and prices and enhance coordination among various stakeholders and across different financing tools. More details can be found in the relevant communication by the European Commission.

46 A more detailed analysis is available on the Innovation Fund's website.

47 The TEN-E Regulation, which sets the framework for energy infrastructure planning at EU level, was revised in May 2022 to align with the European Green Deal objectives on climate neutrality by 2050. The revised TEN-E Regulation endorses the use of renewable and low-carbon gases, in particular hydrogen, and promotes related infrastructure PCIs/PMIs, including the conversion of existing natural gas infrastructure to supply hydrogen

Box 3: European Hydrogen Bank's first auction results

The following overview is based on the European Commission's analysis of the auction results.

The European Hydrogen Bank opened its first auction in November 2023 and received 132 bids (119 eligible) from 17 countries, oversubscribing the budget by a factor of 15. The auction resulted in a selection of seven projects to be awarded a total of EUR 720 million in the form of green premium grant agreements for up to 10 years. The capacities of electrolysers range from 35 MW to 500 MW, with four projects planning to install over 100 MW. The projects are located in countries with competitive advantage for the production of renewable hydrogen; two projects are in the Nordic countries and five in the Iberian peninsula. In October 2024, six out of the seven projects, with the potential to produce 1.5 Mt of renewable hydrogen over the 10-year period signed their respective grant agreement.

The pay-as-bid auction awarded premiums ranging from 0.37 to 0.48 EUR/kg, way lower than the auction ceiling price of 4.5 EUR/kg. Overall, bids below 1 EUR/kg represented around 5 Mt of potentially produced hydrogen, while bids for another 2 Mt were below 2 EUR/kg. This striking deviation of the bids from the ceiling price might be an indication that the gap between the current production cost of renewable hydrogen and the willingness to pay for it (e.g. considering the ETS carbon price signal or the RFNBO quotas) might be smaller than initially anticipated.

The European Commission's analysis indicates that the average levelised cost of hydrogen (LCOH) of all the submitted projects per county ranged between 5.3 and 13.5 EUR/kg, yet individual bidders' LCOHs as low as 2.8 EUR/kg were reported. In terms of technology, all but one bidder planned to use alkaline or proton-exchange membrane (PEM) electrolysers. The average LCOH of the two competing technologies is around 7 EUR/kg for alkaline and around 10 EUR/kg for PEM electrolysers.

Most notably however, the average price that off-takers seem to be willing to pay for renewable hydrogen, according to the information provided by bidders, is estimated at 5.7 EUR/kg for the industrial sector and 8.3 EUR/kg for the transport sector. This indicates that, under current EU and national policies, some buyers are willing to pay prices that are very close to (and even higher for some very competitive projects) the expected cost of renewable hydrogen production in some European locations.

In conclusion, the results of the first auction seem quite promising considering the implied low subsidy needed to kick-start the market (in combination with the other decarbonisation policies set to drive demand). Actual implementation of projects and delivery of the expected outcome is pending, with some stakeholders expressing scepticism during a workshop organised by the European Commission in July 2024. At the same time, LCOH estimates indicate that while specific regions/projects might be closing the cost gap with conventional hydrogen, further cost reductions are necessary to reach parity. The overall competitiveness of the Nordic countries and Southern Europe, compared with other regions highlights the need to develop an internal market and to plan the necessary hydrogen transportation infrastructure.

With bids from 17 Member States, the pilot auction revealed that there are a number of hydrogen production projects ready to move to operation and which do not require very high subsidies. If the entire pipeline of the projects bidding at the pilot auction could come into operation, it could deliver close to 10% of the capacity needed for reaching the 2030 EU objective for hydrogen production.

2.3.2. National funding policies

64 In addition to EU-wide funding schemes, some Member States support the development of the hydrogen sector either via hydrogen-specific support schemes or as part of wider decarbonisation support policies whereby hydrogen projects are eligible for funding. Depending on the specific features, the support schemes might need to receive State-Aid approval by the European Commission or be exempted from it based on the General Block Exemption Regulation[48]. Member States may also provide support to hydrogen projects through the Temporary Crisis and Transition Framework (TCTF) and via the Recovery and Resilience Facility (RRF) provided they have included relevant schemes in their RRF plan.

65 Hydrogen projects characterised as important projects of common European interest (IPCEIs) may also receive State support. IPCEIs are innovative projects backed up by Member States that contribute to EU objectives but which would not materialise on a pure market basis due to significant risks. Candidate projects are assessed by the European Commission for compliance with the State-Aid rules; once a project is selected as an IPCEI, Member States may proceed with providing support. Since December 2020, projects included in the clean hydrogen value chain are eligible to apply for IPCEI status. Four rounds of assessments have been completed by the European Commission so far, resulting in the selection of 76 hydrogen IPCEIs. These collectively represent more than EUR 26 billion in investments, out of which Member States will provide up to EUR 10.6 billion as public support (Box 4 provides for more details).

Box 4: Important projects of common European interest

First hydrogen IPCEI: IPCEI Hy2Tech, Hydrogen Technology: The European Commission approved the first IPCEI in the field of hydrogen in July 2022. It comprises 41 projects from 35 companies from 15 EU Member States participating in this initiative, which is organised in four Technology Fields (TFs): TF1 (Development of Hydrogen Generation Technologies), TF2 (Development of Fuel Cell Technologies), TF3 (Development of Technologies for Storage, Transportation and Distribution), TF4 (Development of Technologies for End Users). The involved Member States will provide up to EUR 5.4 billion of public support unlocking additional EUR 8.8 billion in private investments.

Second hydrogen IPCEI: IPCEI Hy2Use, Hydrogen Industry: The second IPCEI in the field of hydrogen, IPCEI Hy2Use, was approved in September 2022. A total of 37 projects involving 29 companies from 13 EU Member States and Norway will receive up to EUR 5.2 billion in public funding in the coming years, which is expected to unlock an additional EUR 7 billion in private investments. It is organised along two Technology Fields: TF1 (Infrastructure), TF2 (Development of Fuel Cell Technologies).

Third hydrogen IPCEI: IPCEI Hy2Infra, Hydrogen Infrastructure: IPCEI Hy2Infra was approved in February 2024. A total of 32 companies from 7 Member States participated in this IPCEI with 33 projects. EU Member States will provide up to EUR 6.9 billion in public funding, which is expected to unlock an additional EUR 5.4 billion in private investments. IPCEI Hy2Infra will support the deployment of 3.2 GW of large-scale electrolysers to produce renewable hydrogen and the development of new and repurposed hydrogen transmission and distribution pipelines with a total length of 2,700 km. It also includes large-scale hydrogen storage facilities with a combined capacity of at least 370 GWh and the construction of handling terminals and related port infrastructure for liquid organic hydrogen carriers (LOHCs) that can handle 6,000 tonnes of hydrogen per year.

Fourth hydrogen IPCEI: IPCEI Hy2Move, Hydrogen Mobility: IPCEI Hy2Move is the fourth IPCEI in the field of hydrogen; it was approved by the European Commission in May 2024. A total of 11 companies from seven EU Member States are participating in this IPCEI, across 13 projects. IPCEI Hy2Move will support the hydrogen technology value chain by developing new technological innovations including: (i) integrating hydrogen into transport (road, maritime, and aviation) with fuel cell platforms for buses and trucks; (ii) advancing fuel cell technologies powerful enough for ships and trains; (iii) creating next-generation hydrogen storage for aircraft, focusing on safety and efficiency; and (iv) producing hydrogen for refuelling stations with high purity. Seven EU Member States will invest EUR 1.4 billion, unlocking an additional EUR 3.3 billion in private investments, totalling over EUR 4.7 billion.

48 Any financial support provided by or involving Member States must comply with the rules of the Treaty. In general support for hydrogen projects needs to comply with the State Aid guidelines for climate, environment and energy (CEEAG).

66 Based on the European Commission's public database on competition cases, there are 52 approved schemes providing support to hydrogen projects. This number does not only refer to dedicated hydrogen support schemes, but also to broader decarbonisation schemes that could fund hydrogen among other solutions. The list includes 17 schemes supported by the Recovery and Resilience Facility in eight EU Member States promoting the creation of hydrogen valleys[49] and the manufacturing of electrolysers. Figure 8 shows the number of support schemes per Member State; the list of schemes identified is provided in Table 6 in the Annex. Most of the support is provided in the form of direct grants. Other forms of support include soft loans, State guarantees and tax exemptions, or a combination of these.

Figure 8: Number of EU Member State support schemes related to hydrogen that received State Aid approval since 2020 – September 2024

Source: ACER based on information from the European Commission's public database on competition cases.

49 A hydrogen valley refers to a regionally integrated network for hydrogen production, storage, and distribution to end-users. The European hydrogen strategy recognises hydrogen valleys as enablers for scaling up Europe's hydrogen economy. Currently there are over 60 hydrogen valleys in Europe. Based on the progress report from the Clean Hydrogen Partnership, Germany leads with 16 valleys, followed by Spain with 7, the Netherlands with 6, and France, Italy and Portugal with 4 each. The REPowerEU plan intends to double the number of hydrogen valleys operating across Europe.

3. Market developments

67 This section provides insights into the most recent hydrogen market developments using three main sources of information: the European Hydrogen Observatory, the IEA's hydrogen project database and S&P Global[50]. The section starts by presenting the status of the demand and supply of hydrogen in the EU (Sections 3.1 and 3.2)[51]. It then provides an overview of the current and planned infrastructure development (Section 3.3) and discusses the cost of renewable and low-carbon hydrogen production (Section 3.4).

3.1. Hydrogen demand

68 Currently, hydrogen is widely used in oil refining, and as a feedstock in the chemical industry to produce primarily ammonia and methanol and also numerous other chemicals. The EU decarbonisation strategy provides for the increasing use of renewable hydrogen and hydrogen derivatives in the hard-to-abate sectors of the economy, envisaging a switch from more carbon-intensive options. New demand for hydrogen is envisaged mainly in the production of steel (see Box 5 for more details on the use of hydrogen for decarbonisation of steel production), and in the transport sector, used either directly in fuel-cell engines or as feedstock to produce clean fuels, primarily for the aviation and maritime sectors. Other future applications may include high-temperature industrial heat[52], lower-temperature heat for industrial, commercial or residential applications where electrification is more difficult or more expensive (e.g. due to network availability), and even the use in the electricity sector mainly for security of supply purposes (e.g. during prolonged unavailability of intermittent renewable energy sources)[53]. In this section, this new demand for hydrogen is referred to as "novel hydrogen applications"[54]. Hydrogen might also be blended with natural gas and biomethane in the natural gas network, thereby covering a share of the energy demand supplied by natural gas. In this report, the injection of hydrogen into the gas network is not considered as demand for hydrogen and is reported separately.

69 As depicted in Figure 10, the average total hydrogen consumption during the last 5 years (2019-2023) in the EU was 7.2 Mt. In 2023, refineries were the largest hydrogen consumers, accounting for 4.2 Mt (58%) of total demand. Ammonia, methanol and other chemical industries followed with 1.9 Mt (26%), 0.1 Mt (1.4%), and 0.6 Mt (8%) respectively. Consumption in novel hydrogen applications accounted for just 23 kt (0.3%)[55], with the rest of hydrogen consumption, 0.5 Mt (6.4%), being attributed to other end-uses.

50 ACER found that the three databases are generally consistent. Still there are some differences which merely relate to the availability of primary information (e.g. electrolyser capacity expressed in GW or kt/y) and the underlying assumptions of conversion factors used.

51 Information for these two sections is derived from the data made available by the European Hydrogen Observatory, unless otherwise mentioned in the text.

52 Industrial heat generation represents hydrogen burned for its energy content, traditionally when produced as a by-product from chemical processes. However, hydrogen might also be an alternative for the decarbonisation of other energy-intensive and hard-to-abate industrial sectors for which high-temperature thermal heat is required, such as the metallurgic, glass, and ceramics sectors, among others.

53 While, from an energy efficiency point of view, the transformation of electricity to hydrogen and subsequent use of hydrogen to produce electricity entails significant losses, hydrogen can provide seasonal storage and enhance security of supply. Hence, some Member States already include hydrogen utilisation for power generation in their hydrogen strategies (see Table 1).

54 Specifically, the aggregate category "novel hydrogen applications" includes hydrogen used for synthetic fuels, mobility, power generation, and the replacement of conventional fuels in industrial and residential heat.

55 Most of the hydrogen for these new applications is produced by electrolysis, see paragraph (72).

Box 5: An industrial case study: the use of hydrogen for green steel production

Steel production stands as one of the hard-to-abate industrial sectors called to first and extensively integrate hydrogen in its production process to achieve decarbonisation. The iron and steel industry is energy and carbon intensive consuming ca 40 Mt of coal (Eurostat, 2022), accounting for about 5% of the EU's carbon emissions and over 20% of the EU's industrial emissions. Hence, policy makers and steel associations are advocating for incorporating hydrogen to reduce emissions, given favourable economic conditions and technological suitability. Indeed, the REPowerEU aims to decarbonize 30% of EU steel production by means of using renewable hydrogen by 2030.

Hydrogen can primarily be used in the iron ore reduction process, where iron ore is cleaned from oxygen and other impurities to produce clean iron. The two prevalent technologies for iron ore reduction are as follows:

- Blast Furnace (BF) technology, which is predominant in Europe (more than 60% of output) and uses coke, derived from coal, as a fuel and a reducing agent. This production technology is highly carbon intensive.

- Direct-Reducted-Iron (DRI) technology, whereby natural gas is typically used in the reduction process. From the DRI furnace, the pure iron moves to the electric arc furnace.

Hydrogen can be used as an auxiliary/supplementary reducing agent in the blast furnace route where it partially or totally reduces iron ore, thereby enhancing the process. Most importantly however, hydrogen can replace natural gas in the DRI route, reducing iron ore while in a solid state, with significantly lower carbon emissions. Green steel can then be produced via electric arc furnaces using renewable electricity and low carbon alternatives to coal (e.g. a biogenic solid carbon source) to turn reduced iron into steel.

Cost and technical challenges. As a significant share of the blast furnaces are old and needs upgrading or replacement within the decade, there is an additional incentive and opportunity to integrate hydrogen into the steel-making process. According to information from the Green Steel Tracker, 23 projects aim at introducing the DRI process using hydrogen in Europe within this decade. However, currently steel production costs using renewable hydrogen are estimated to be 30-50% higher than those using conventional methods (Figure 9). Hence, the future competitiveness of steel production based on renewable hydrogen will depend on decreasing renewable hydrogen and electricity costs, driven by technological advancements and economies of scale, and on the rise of carbon emission prices. At the same time the implications of the higher costs of green for advanced final products such as cars might be less profound. Interestingly, a recent study by Transport and Environment advocates that electric vehicles made of 40% green steel would add just EUR 57 to the price of a new car by 2030. Similarly, the IEA estimates that the impact of using green steel on the price of electric vehicles is just 1% in Europe. The automotive industry accounts for 12% of steel consumption worldwide.

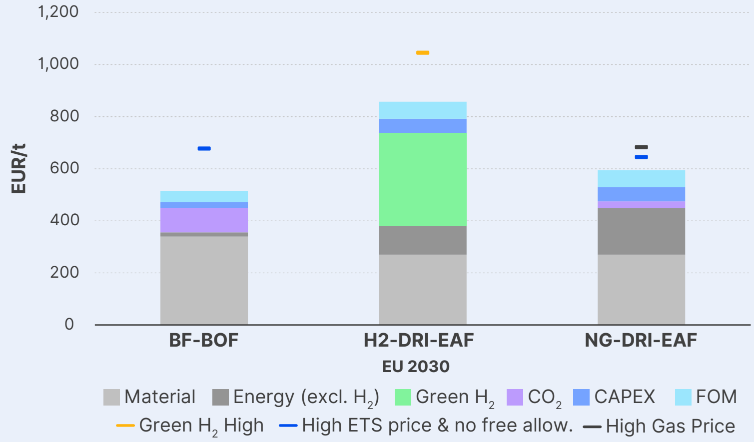
Another challenge is that green steel production requires substantial amounts of renewable electricity and hydrogen. As an illustration, according to the REPowerEU plan, decarbonising 30% of the EU's current steel production using the DRI process would require 1.4 Mt of renewable hydrogen, translating to a renewable electricity need of about 77 TWh. To produce green steel, another 30 TWh of zero emission electricity should also be used in the electric arc furnaces.

Finally, the use of hydrogen in the DRI process also poses some technical challenges, in particular those related to avoiding hydrogen embrittlement (the diffusion of hydrogen atoms into the metal), and preserving steel quality in order not to reduce its possible applications.

In summary, while hydrogen-based steel production offers significant emissions reduction potential, its competitiveness depends on economic, technological, and infrastructural advancements.

Box 5: An industrial case study: the use of hydrogen for green steel production (continued)

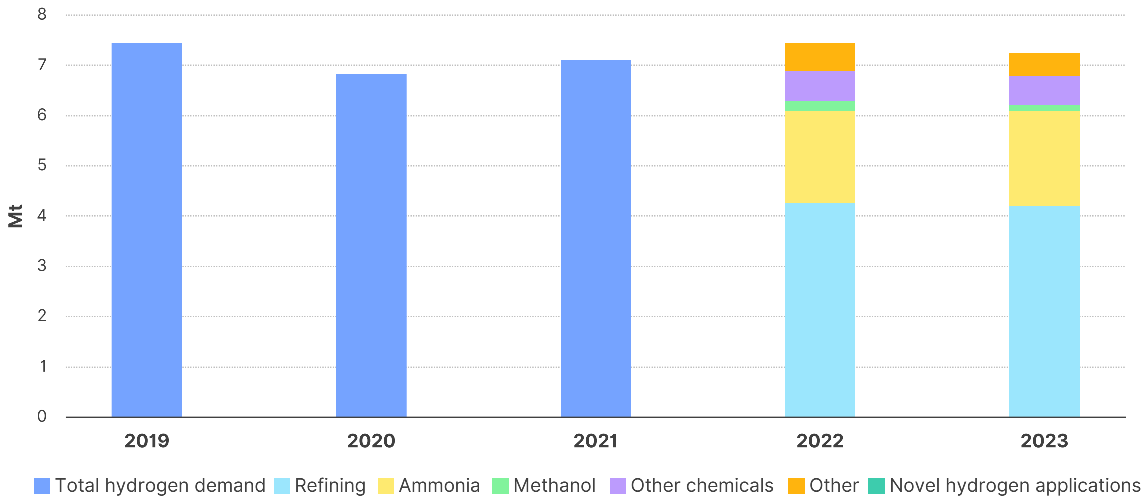
Figure 9: Estimated unit costs for steel production per category for three different production routes in 2030 (EUR/tonne of steel)



Source: [Compass Lexecon, Energy and Climate Transition: How to strengthen the EU's competitiveness, July 2024](#).

Note: The figure is a reproduction from the source report. BF-BOF: blast furnace-basic oxygen furnace, H2-DRI-EAF: direct reduced iron-electric arc furnace using hydrogen, NG-DRI-EAF: direct reduced iron-electric arc furnace using hydrogen.

Figure 10: Hydrogen consumption and breakdown by end use in the EU – 2019-2023 (Mt)



Source: ACER based on data from S&P Global (2019-2021) and the European Hydrogen Observatory (2022 - 2023).

70 All sectors, excluding the production of ammonia and mobility saw a decrease in hydrogen consumption between 2022 and 2023[56]; thus, total hydrogen consumption decreased by 190 kt (-2.5%). Notably, the consumption of hydrogen for methanol production saw a sharp decline of 50%, driven by overall reduced methanol production and the shutdown of some plants in Europe in 2023[57].

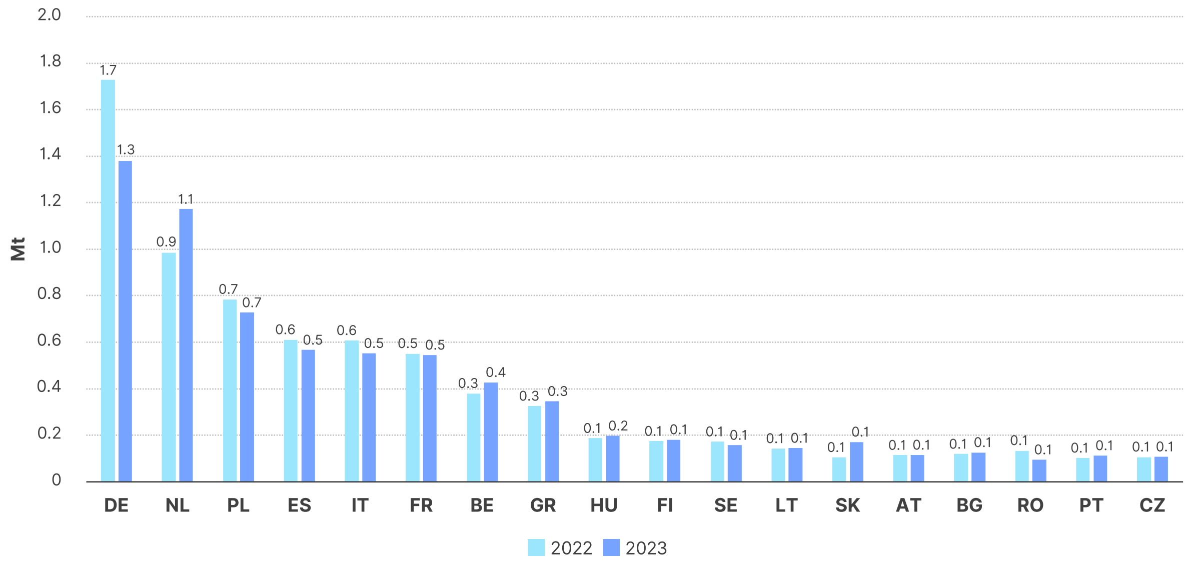
71 Most of the use of hydrogen occurs in a few Member States with large industrial capacity in the chemical and refining sectors. As shown in Figure 11, in 2023 the three largest consumers of hydrogen, Germany, the Netherlands and Poland, accounted for 46% of total demand, with 1.4 Mt (19%), 1.2 Mt (17%) and 0.7 Mt (10%) respectively. The refining industry stands out as the main driver of demand for most Member States[58]. Although very low in volume, the entire consumption of hydrogen in Latvia and Luxembourg is attributed to novel hydrogen applications, specifically the transport sector.

56 See Figure 26 in the Annex for the yearly change in conventional hydrogen demand per end-use.

57 For example, in Germany the closure of the BP Gelsenkirchen petrochemical site's methanol production capabilities is associated with the planned restructuring of the site to produce lower-emission fuels including SAFs.

58 The share of hydrogen demand per end-use for all Member States is presented in Figure 27 in the Annex.

Figure 11: Hydrogen consumption in EU Member States – 2022-2023 (Mt)

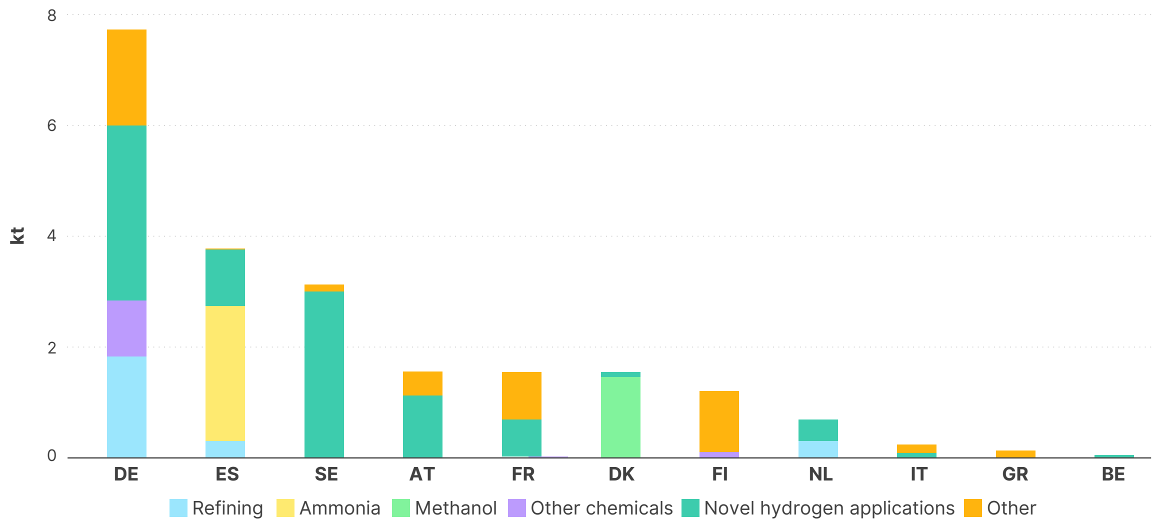


Source: ACER based on data from the European Hydrogen Observatory.

Note: Only Member States with demand higher than 100 kt are included in the figure.

72 Consumption of hydrogen produced by electrolysers (electricity-based hydrogen) increased from 16 kt in 2022 to 23 kt in 2023. Currently, this is consumed on site, or blended into the gas network. As shown in Figure 12, Germany, Spain, and Sweden are the largest consumers, together accounting for 66% of the total consumption. Consumption of electricity-based hydrogen for novel hydrogen applications doubled in 2023 reaching 10 kt, accounting for 45% of the total (Figure 13). In 2023, the use of electricity-based hydrogen for new industrial heat applications was recorded for the first time in Sweden (2.4 kt), Austria (1.1 kt), and Spain (1.0 kt) becoming the largest end-use category of the novel hydrogen applications. The use of electricity-based hydrogen in mobility has also increased significantly (+40% year on year); it was highest in Germany, the Netherlands, and France, which together accounted for 4.1 kt (92% of the total consumption for mobility). These three Member States also have the largest fleet of fuel cell electric vehicles, 3,958 out of the 4,798 at the EU level.

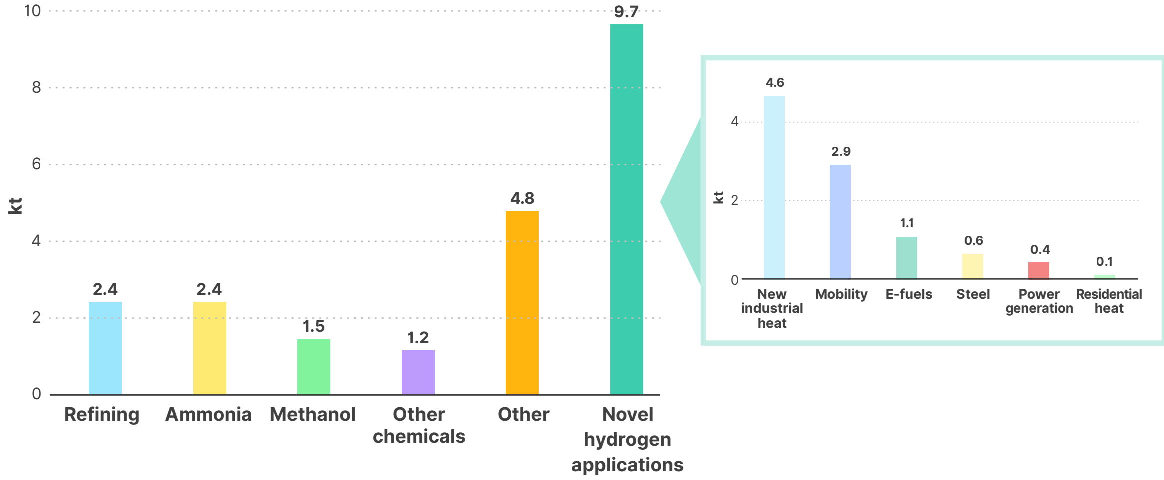
Figure 12: Consumption of electricity-based hydrogen in EU Member States by end-use – 2023 (kt)



Source: ACER based on data from the European Hydrogen Observatory.

Note: Only Member States with renewable hydrogen consumption of over 50 tonnes are presented.

Figure 13: Electricity-based hydrogen consumption by end-use (left) and breakdown of consumption in novel hydrogen applications (right) in the EU - 2023 (kt)



Source: ACER based on data from the European Hydrogen Observatory.

73 Finally, around 10% of the electricity-based hydrogen (2.4 kt) was blended with natural gas in the gas network. Germany and France already blended hydrogen in 2022 (1.9 kt), while Austria and Hungary started in 2023, with each injecting around 250 tonnes of hydrogen into their gas networks. A review of the some technical challenges associated with blending hydrogen into the natural gas system is provided in Box 6.

Box 6: Blending hydrogen in the natural gas system

According to the European hydrogen strategy, blending hydrogen into existing gas networks might be an enabler of decentralised renewable hydrogen production in anticipation for the development of a hydrogen network. The strategy recognises, however, that blending is less efficient, diminishing the value of hydrogen. As such, only few Member States include blending in their national strategies. Portugal sets a target for 10-15% of blended hydrogen to the existing network. Poland also targets a 10% blending in its strategy. While Austria does not see blending as a viable option for hydrogen development, it foresees the increase of the blending limit to 10%. Lastly, Hungary focuses on blending hydrogen up to 2% in existing gas storage facilities.

Blending comes with several technical, safety, and regulatory challenges, that limit the amount of hydrogen that can be safely blended into the gas network. Key issues include the need to preserve pipeline integrity and maintain adequate pipeline pressure, in addition to aspects more generally related to end-uses appliances compatibility. Blending hydrogen at levels between 2% and 10% by volume is generally deemed as being technically feasible with minor adjustments to the infrastructure. Some examples of the technical issues of blending hydrogen to existing gas networks are presented hereafter:

- The acceptability of hydrogen blends in network pipelines depends on the materials used and their resistance to hydrogen embrittlement. Since hydrogen leaks more easily than methane due to its smaller molecular size, leak detection and prevention systems must be tailored for it. Also, specific safety protocols are essential to address hydrogen's higher flammability. Additionally, the lower energy density and distinct flow dynamics of hydrogen may necessitate increased flow speeds and pressure differences to ensure equivalent energy delivery compared to natural gas.

- The impact of gas composition to end-use applications is also important. For example, the hydrogen tolerance of gas burners in boilers and stoves due to changes in the calorific value of the mixed gas, must be considered. Moreover, some industrial processes rely on consistent gas quality and/or temperature. In this cases blending of hydrogen might be harmful even at low percentage of blends requiring a de-blending system.

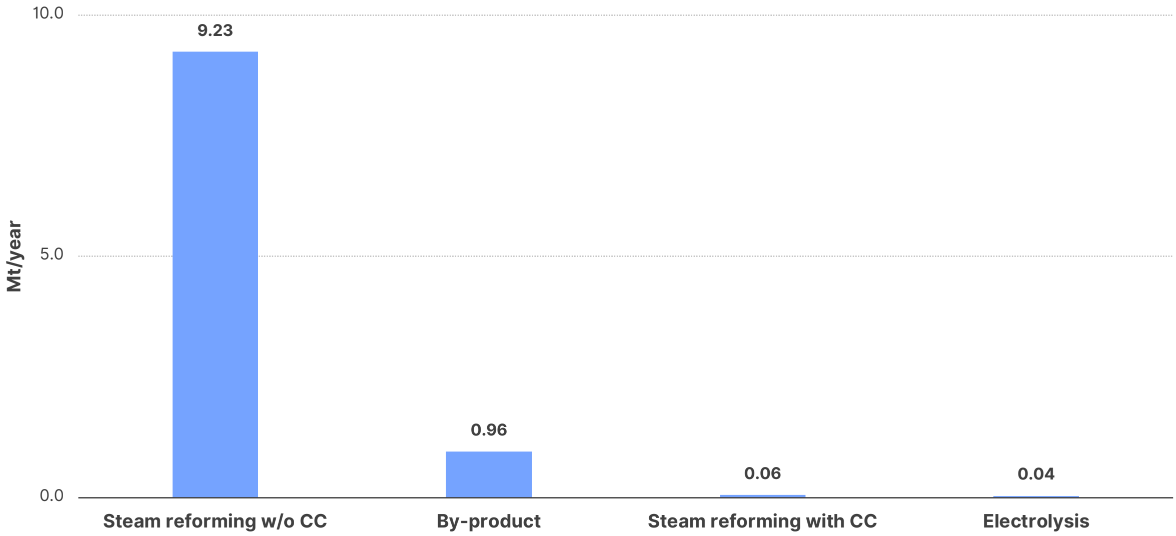
- For gas turbines the permissible blending limit varies by manufacturer, ranging from 1% to 5% by volume, but adjustments are generally needed when hydrogen blending exceeds that level. For internal combustion gas engines hydrogen blends resulting in a methane number lower than 70 (pure methane is at 100 and hydrogen normally below 5) could pose operational challenges and affect performance.

3.2. Hydrogen supply

74 The total amount of hydrogen produced in the EU in 2023 was 7.3 Mt, of which production using unabated fossil fuel accounted for over 99%. Both hydrogen production from electrolysers and steam methane reforming (SMR) with carbon capture exhibited strong year-on-year growth compared to 2022: electrolysers produced 24 kt[59] of hydrogen, while SMR with carbon capture facilities another 42.5 kt, representing a year-on-year increase of 55% and 180% respectively.

75 In total, 443 hydrogen production facilities were operational in the EU-27 in 2023 with a combined annual production capacity of 10.3 Mt. Of these, 209 produce hydrogen via SMR, three of which use carbon capture technology[60]. In 119 facilities, hydrogen is derived as a by-product of the main chemical process, and the remaining 115 produce hydrogen via water electrolysis. While the number of SMR and by-product production facilities did not significantly change compared with 2022, the number of electrolysers in the EU grew by over 50% year on year. As shown in Figure 14, SMR without carbon capture accounts for 90% (9.3 Mt/y) of the total capacity, while the combined capacity of SMR with carbon capture and water electrolysis was below 1% (56 kt/y and 36 kt/y respectively). Around 77% of the total capacity refers to hydrogen production for own use and the rest operates as merchant capacity, that is, selling the hydrogen produced to consumers via pipelines or other means of transport.

Figure 14: EU hydrogen production capacity by process type - 2023 (Mt/y)



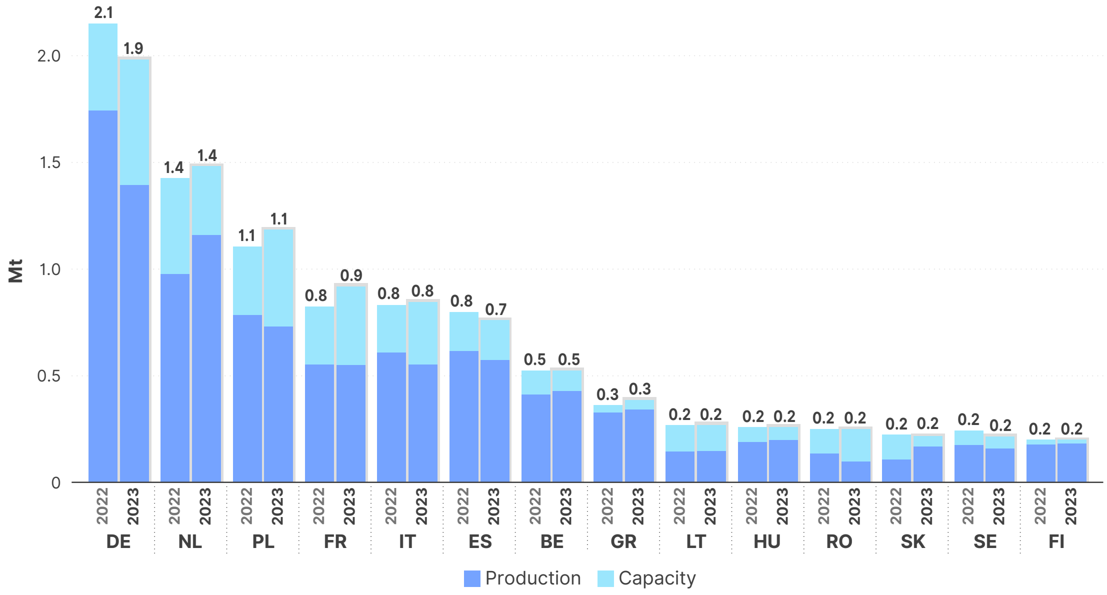
Source: ACER based on data from the European Hydrogen Observatory.

76 As trading of hydrogen is limited, hydrogen production facilities are located in Member States where the industrial demand for hydrogen is highest. Figure 15 presents the installed capacity of hydrogen production and the total production of hydrogen per EU Member State in 2022 and 2023. Compared with 2022, significant changes can be observed only in Germany and the Netherlands. In Germany, SMR capacity decreased by 135 kt/y, and production fell by 313 kt in 2023. On the contrary, in the Netherlands, the Rotterdam-Vondenlingenplaat-Pernis Shell SMR with carbon capture plant expanded its production capacity from 4.7 kt/y to 41.5 kt/y and total production in the Member State increased by 250 kt in 2023.

59 The difference between the volumes of produced and consumed hydrogen from electrolysers is attributed to process losses.

60 These are the Port Jérôme Air Liquide in France, the Mantova Sapio in Italy, and the Rotterdam-Vondelingenplaat-Pernis Shell SMR with carbon capture plant in the Netherlands.

Figure 15: Installed capacity and hydrogen production in EU Member States - 2022-2023 (Mt)

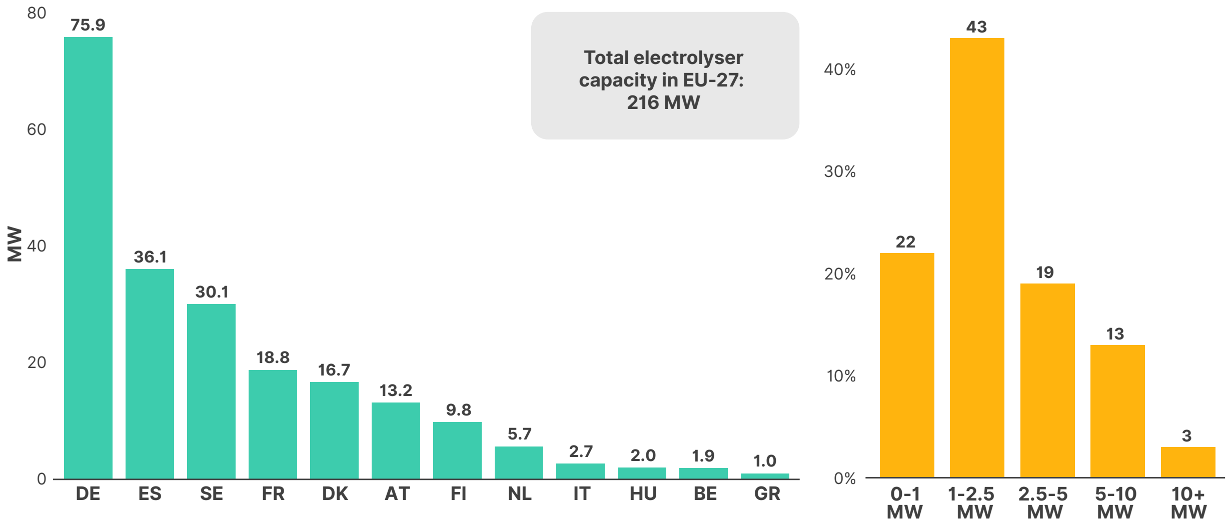


Source: ACER based on data from the European Hydrogen Observatory.

Note: Only Member States with production capacity over 200 kt/y are presented.

77 Figure 16 shows the total capacity of electrolysers by Member State in 2023. At the EU level total capacity of electrolysers in 2023 was approximately 216 MW. In terms of scaling, most of the electrolysers are in the low range of the megawatt scale. The two largest electrolysers in the EU, both 20 MW, are the Spanish "H2F (Phase 1)" used for ammonia production and the Swedish "H_2 for Ovako steel mill" used in the steel industry.

Figure 16: Installed electrolyser capacity in EU Member States (MW, left) and distribution per size (%, right) - 2023



Source: ACER based on data from the European Hydrogen Observatory.

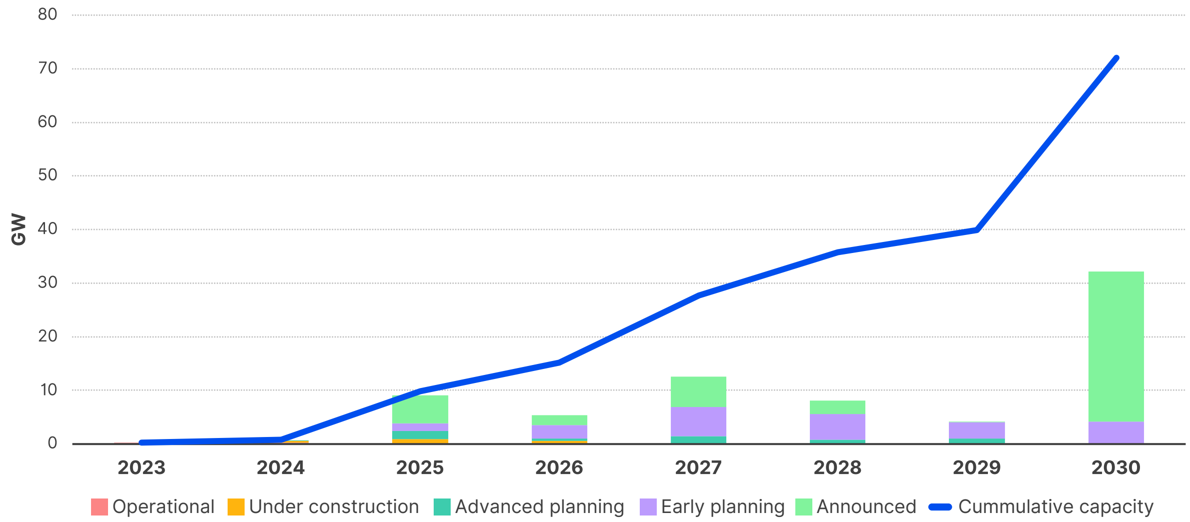
Note: Only Member States with production capacity over 1 MW are presented.

78 The future prospects of electrolyser capacity development in the EU are presented in Figure 17. In total, 52 electrolysers with a capacity of 1.8 GW are under construction, and are expected to be deployed by the end of 2026. The three largest projects alone account for 1.2 GW[61], with the remaining being relatively small projects. The projects are mostly captive, linked to uses in a specific sector. In particular, steel and refining represent together 81% of the total electrolysers capacity under construction (see Figure 29 in the Annex). This incremental growth around significant consumption centres confirms the importance of demand as a driver to initiate the market, and it may also be linked to the current scarcity of options to transport hydrogen over longer distances.

61 Specifically, Stegra (Phase 1) in Sweden with a capacity of 760 MW, Holland Hydrogen (Phase 1) in the Netherlands with 200 MW, and Normand'Hy in France with 200 MW.

79 The electrolysers under construction will bring the total installed capacity close to 2 GW by 2026. This is still one third of the intermediate target of 6 GW by 2024 set out in the EU hydrogen strategy. Using additional information from S&P Global's hydrogen production assets database[62], it follows that approximately 70 GW of additional capacity is planned to begin operation within the decade. Yet, fewer than 0.5 GW of these projects have reached a final investment decision (FID) and only 6 GW are in an advanced planning phase (see Figure 17).

Figure 17: Electrolyser projects by project status and estimated commissioning year – 2023-2030 (GW)



Source: ACER based on data from the European Hydrogen Observatory and S&P Global and own calculations.

Note: Definitions of the maturity of projects as per S&P Global are as follows: advanced planning, projects that have completed the feasibility study and are moving forward with front end engineering and design, applying for permits, issuing purchase orders for equipment, or taking an FID; early planning, projects with a feasibility study in progress or applied for funding; announced, earliest-stage projects — projects announced with very limited information on the partners and stakeholders, the capacity of H_2 production, the online date, etc.

3.3. Infrastructure development

80 The existing hydrogen networks in the EU consist of 1,569 km of pipelines, concentrated in Belgium, France, Germany and the Netherlands[63]. Such networks often serve specific industries, mainly chemical and petrochemical, and access to third parties is not open. Currently, there is no underground hydrogen storage in the EU, with the exception of four pilot projects[64], nor any hydrogen terminals are currently in operation[65].

81 Reaching the EU and the national hydrogen targets requires substantial investments in infrastructure. The REPowerEU plan estimates that the investment needs for key hydrogen infrastructure will be EUR 28-38 billion for EU internal pipelines, and EUR 6-11 billion for storage facilities. There is hence a growing interest from project promoters to develop hydrogen infrastructure projects. The section focuses on transmission pipelines, storage facilities and terminals along with some major electrolyser projects. A brief overview of the status and developments regarding hydrogen refuelling stations is provided in Box 8.

62 The European Hydrogen Observatory provides data on operational projects and projects under construction. S&P Global provides additional information on (usually pre-FID) projects in different development stages. While ACER tried to maintain consistency, combining the two databases might create small discrepancies due to different definitions and assumptions related to conversion factors (efficiencies and capacity factors when only information on output capacity is available). Whenever information from S&P was available in terms of hydrogen output (kt/y), the assumptions from the European Hydrogen Observatory were used for consistency.

63 The European Hydrogen Observatory provides an interactive map and related data of the current hydrogen network here.

64 Based on the European Hydrogen Observatory there are currently four demonstration projects in Austria, France, Germany and Sweden. Globally, there are three salt cavern underground hydrogen storage facilities, two in Texas and one in the UK in operation for years, according to a 2021 report by Gas Infrastructure Europe.

65 While there are numerous ammonia terminals in Europe, these do not imply the transformation of ammonia into gaseous hydrogen so as to be characterised as hydrogen terminals within the meaning of the hydrogen and gas decarbonisation package.

82 There is a number of information sources regarding planned hydrogen infrastructure in the EU[66]. The information collected via the EU-wide TYNDP process by ENTSOG is currently one of the most comprehensive. Hence this section primarily uses information from the most recent TYNDP-2024 project list to describe the current status of infrastructure planning and development in the EU and Norway. Smaller projects may also be developed at more local level. Visibility over these smaller scale project developments is not always ensured, as the regulatory framework for planning and monitoring is still under development in most Member States. As the transposition of the hydrogen and gas decarbonisation package progresses, better data availability and consistency is also expected.

3.3.1. The European hydrogen infrastructure

83 The TYNDP-2022 was the first EU-wide plan to include hydrogen projects and was used as a basis for the 6th list of the PCIs, also including Projects of Mutual Interest (PMIs) for the first time. The list was adopted in November 2023, and included 49 hydrogen infrastructure and 16 electrolyser projects, representing together 39% of the total 166 projects in the list[67].

84 While the TYNDP-2024 has not been formally finalised yet (the plan is not expected to be submitted to ACER for review until late 2024; for ACER's view on the infrastructure planning process see also Box 7), project collection has already been completed[68]. Hydrogen projects have increased to 202 (from 165 in TYNDP-2022), representing nearly two thirds of the 326 infrastructure projects. They include transmission pipelines, hydrogen storage facilities, terminals and hydrogen production facilities[69]. A summary of the project list, focusing on the EU and Norway related projects, is provided below, while the information is outlined in Table 2 and Table 8 in the Annex gives more details per country:

- **Hydrogen transmission pipelines**: A total of 107 projects are included under this category, encompassing over 42,000 km hydrogen pipelines of which 33,500 km is to be commissioned by 2030. Approximately two-thirds of these pipelines will be new, while the remainder refer to repurposed existing natural gas transmission pipelines. Most of these projects focus on developing national hydrogen networks in various Member States, with some also involving cross-border interconnectors. However, only two projects have reached FID stage, the National Hydrogen Backbone in the Netherlands and the mosaHYc – Mosel Saar project between France, Germany and Luxembourg.

- **Hydrogen storage**: A total of 38 projects are included, the slight majority being new developments, while the remainder involve the repurposing of existing natural gas storage facilities. Hydrogen underground storage projects with commissioning dates up to 2030 have a total capacity of 40 TWh of working gas volume (82% of the total of 49 TWh). Only two demonstration projects, H2CAST Etzel in Germany and HYPSTER in France, have advanced to FID status, both involving the repurposing of existing natural gas salt cavern storage facilities.

- **Hydrogen terminals**: A total of 20 projects are included in this category. Ammonia is the predominant importing hydrogen carrier, followed by methanol and LOHCs. No FIDs have been taken for these projects so far, and only three are at an advanced stage of development. The expected commissioning date of nearly half of the projects is 2030. If they materialise, these projects will add 540 GWh/day of hydrogen import capacity by the end of the decade[70].

- **Electrolysers for hydrogen production**: This category includes 29 projects, totalling close to 17 GW of electrolyser capacity, 14 GW of which is planned to be installed by 2030. Nearly a third of the electrolysers' capacity is planned to run on dedicated renewable electricity sources, mainly offshore wind.

66 See for instance the hydrogen infrastructure map platform, which is an effort of the industry to gather and present all relevant hydrogen infrastructure projects, and includes over 280 projects including also hydrogen demand and production. The IEA also maintains a global database of hydrogen production and infrastructure projects.

67 The adopted list can be found here and the projects are also included in the PCI interactive map. An overview is provided in Figure 26.

68 The list of projects for the TYNDP 2024 can be found here. The TYNDP project list includes also projects in countries outside the EU namely Bosnia and Herzegovina, Norway, Switzerland, Tunisia, Ukraine and United Kingdom.

69 The list also includes one project for a refuelling station for busses in Spain.

70 Assuming a 50% utilisation rate of the terminals, this translates in nearly 3 Mt of hydrogen. These terminal projects are linked to the reconversion of the hydrogen carrier into pure hydrogen to be further utilised on site or injected into the hydrogen network. It is expected that in the future a significant part of the existing liquified natural gas (LNG) terminals will most likely be transformed into multipurpose terminals dealing with decarbonised gases in different forms, such as liquid hydrogen, bioLNG, ammonia, methanol or LOHC. They could also be retrofitted to handle captured CO_2 streams to be either transported to storage sites or further utilised for the production of synthetic fuels.

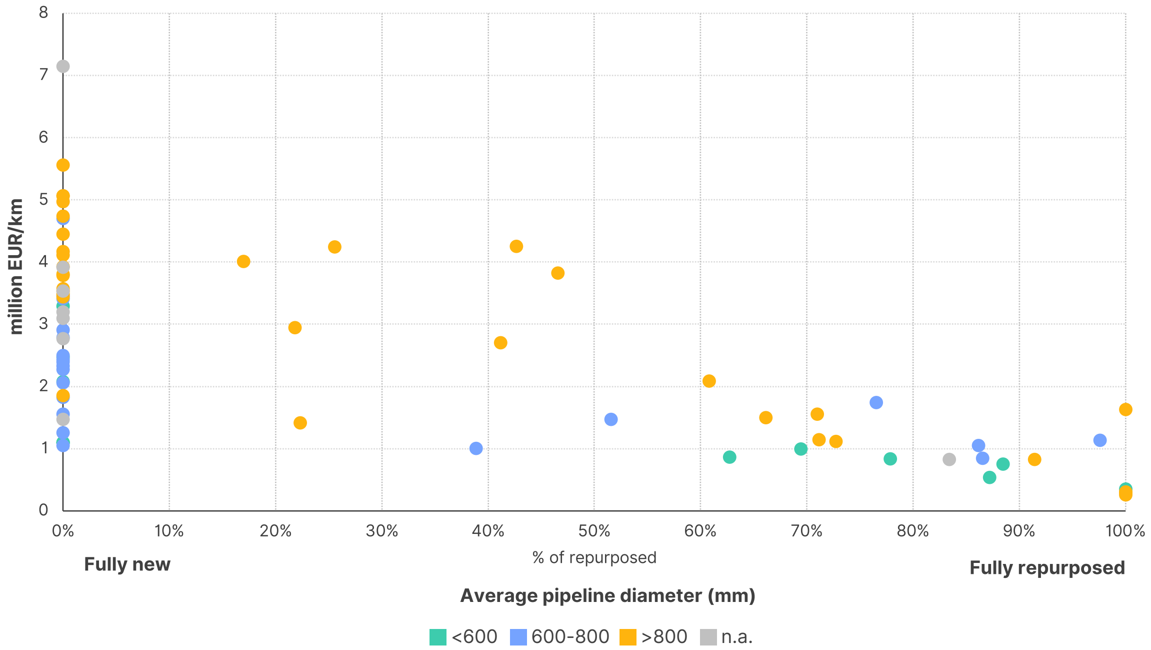
Table 2: Planned infrastructure projects in the EU and Norway based on the TYNDP-2024 project list

Type of infrastructure projects	Total number of projects	Overview	Maturity status (number of projects)		
			FID	Advanced	Less-advanced
Transmission lines	107	42,425 km of which 15,507 km will be repurposed	2	60	45
Storage facilities	38	49 TWh working gas	2	16	20
Terminals	20	693 GWh/day import capacity	0	3	17
Electrolysers	29	17 GW total capacity	0	5	24

Source: ACER based on information from TYNDP-2024 project database.

85 Figure 18 shows hydrogen network unit costs in million EUR/km based on information provided by project promoters in the TYNDP-2024. For new pipelines, cost estimates range indicatively from EUR 1-3 million per kilometre for smaller pipelines (e.g. with a diameter of up to 36 inches) to EUR 3-6 million per kilometre for larger pipelines. By contrast, costs of fully repurposed pipelines are EUR 0.3-1.6 million per kilometre. Monitoring the evolution of these cost estimates over time, along with projects advancement, is key to inform regulators and policy makers in light of future projects evaluations and investment planning decisions.

Figure 18: Hydrogen transmission projects' unit investment costs, based on the TYNDP-2024 project list (million EUR/km)



Source: ACER based on information from TYNDP-2024 project database.

Note: Only projects with cost estimates have been considered. Costs are provided at the project, not pipeline, level. For each project, the share of repurposed pipelines, as well as the average pipeline diameter, has been calculated based on the length of the respective sections.

Box 7: ACER's view on the hydrogen infrastructure development process

According to the TEN-E Regulation, PCIs and PMIs are selected from an initial list of projects included in the latest EU-wide TYNDP, and are subsequently assessed via a cost benefit analysis and an investment gap analysis. The assessment is performed for different scenarios developed commonly by ENTSO-E and ENTSOG. ACER monitors the TYNDP process and issues formal opinions on the scenarios, the methodology for the cost-benefit analysis, the report identifying infrastructure gaps, and the full TYNDP taking into account the objectives of non-discrimination, effective competition and the efficient and secure functioning of the internal markets in electricity and natural gas.

The TYNDP-2022 was the first to include hydrogen projects, and the one the 6th PCI list was based upon. The TYNDP-2024 candidate PCI projects list is not expected to be submitted to ACER for review until late 2024. In this context, it is worth highlighting the main shortcoming related to hydrogen infrastructure planning identified by ACER in its opinion on the TYNDP-2022:

- Lack of cost information for a significant number of methane and hydrogen projects.
- Lack of consideration of the interest of market players to develop transportation capacities to connect hydrogen demand and supply in the methodology for the identification of hydrogen infrastructure needs.

With regards to the ongoing TYNDP-2024 process, ACER has also provided recommendations to ENTSOG for improving the analysis. The most relevant messages are as follows:

- Increase the involvement of stakeholders including network operators in the TYNDP development process, making sure that stakeholders' engagement can influence the TYNDP methodology for the identification of system needs and infrastructure placement choices.
- Require information from hydrogen infrastructure promoters on the status of market testing and consultations on a mandatory basis and consider such information for the identification of needs of hydrogen infrastructure projects.
- Implement the electricity-gas-hydrogen interlinked model in a timely manner and analyse, jointly with ENTSO-E, electrolysers in the system needs analysis of the electricity, gas and hydrogen TYNDPs by assessing the potential impact of electrolysers on the grid.

Regarding the TYNDP-2024 joint scenarios, ACER recently issued an Opinion identifying several areas of non-compliance with the Framework Guidelines for Scenario Development. For hydrogen, in particular ACER finds that the assumptions on future hydrogen uptake (15 Mt in 2030 and 51 Mt in 2050) appear too optimistic considering current developments and should be less ambitious for one of the alternative scenarios.

86 Apart from the EU wide network development plans, several EU Member States are actively developing their national hydrogen networks as part of their broader strategy to transition to hydrogen. Germany and Netherlands are front runners in this respect and the following paragraphs provide a more detailed overview of the network developments in these two EU Member States.

87 The planned **German Hydrogen Core Network** (HCN), proposed by fifteen gas operators consisted of a 9,700 km long pipeline network supplying hydrogen to industrial and urban centres across the country[71]. On 22 October 2024, at the time of finalisation of this report, BNetzA approved the core-network application with changes (more information here). The approved line length is reduced to 9,040 km lowering the investment cost to EUR 18.9 billion. Nearly 56% of the hydrogen network is planned to be repurposed natural gas network. The HCN network will also link Germany to several other EU Member States and connect major import routes with key demand hubs, including the Ruhr area, Rhine-Main area, eastern Germany, the central German chemical triangle, and Bavaria. A distribution grid is planned for a later phase. Around 60% of the network will repurpose existing natural gas pipelines, with new hydrogen pipelines and compressor stations constructed as needed. The first major pipeline is expected to be operational by 2025, with the entire HCN completed by 2032. The core network plan, based on the joint application of 15 gas operators, was based on a hydrogen demand market survey to determine the hydrogen demand levels up to 2032. The network is then designed to accommodate 101 GW of entry capacity, of which 58 GW refer to imports, and 87 GW of demand (62 GW of which is for combined heat and power).

88 **The Netherland's national hydrogen backbone**. In October 2023, the Netherlands officially began construction of its nationwide hydrogen backbone: the full network, spanning 1,200 kilometres, is expected to be operational by 2030[72]. The first 30 km section, located in Rotterdam, is scheduled to begin operation in 2025, connecting the new Tweede Maasvlakte port to Shell's Pernis refinery. Currently, however there are delays with another major part of the hydrogen backbone that belongs to the Delta Rhine Corridor, an initiative for the coordinated construction of underground hydrogen and CO_2 pipelines and high-voltage electricity lines. The estimated total investment is EUR 1.5 billion and up to half of it may be provided as State support. The network will mostly consist of repurposed natural gas pipelines (>80%), linking major industrial clusters across the country and establishing cross-border connections with Germany and Belgium. In addition, the network will integrate import terminals at seaports, domestic hydrogen production sites, and large-scale storage facilities. Netherlands national hydrogen backbone is one of the two hydrogen transmission line projects in the TYNDP-2024 project list with FID. Along with the hydrogen network, two terminals and one underground storage facility, already part of the national plan and in an advanced state of maturity, are included in the TYNDP-2024 list with commissioning dates within or short after this decade[73]. The ACE terminal in Rotterdam and the Eemshaven hydrogen terminal will both receive ammonia cargoes; together they will account for 94 GWh/day of hydrogen import capacity and 153 kt of storage capacity. The two underground storage fields are located near the existing salt cavern gas storage in Zuidwending and together they reach 850 GWh of working hydrogen.

71 The German core network is described in detail in the joint application of fifteen gas operators to the Federal Ministry of Economy and Climate Protection.

72 According to the TYNDP-2024 project list the total length is 1,306 km and the last commissioning date year is 2035.

73 Four additional less advanced projects are also reported in the TYNDP-2024 list, one transmission line, two terminals and one large (400 MW) electrolyser project.

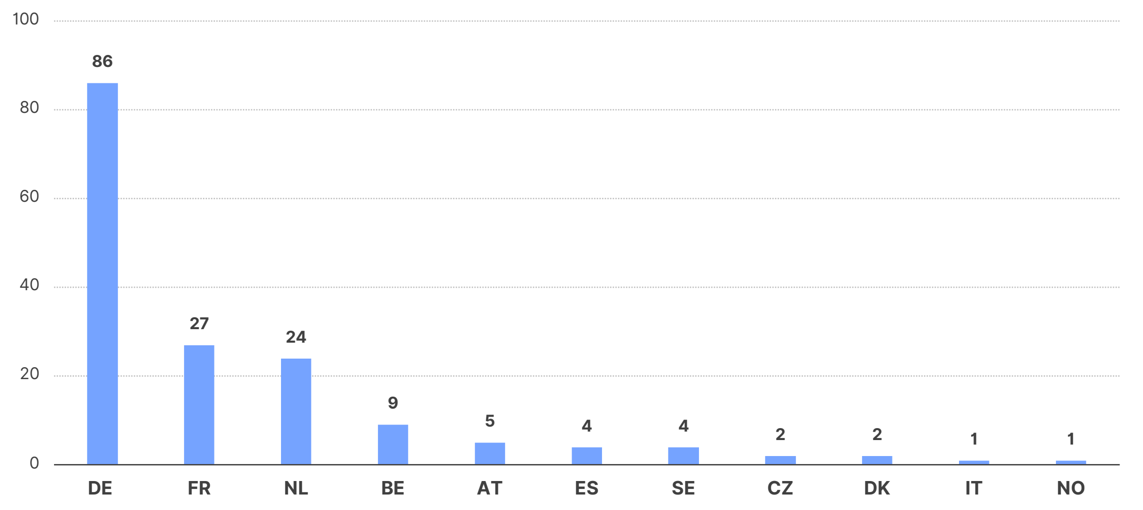
Box 8: Hydrogen refuelling stations in Europe

The EU hydrogen strategy identifies heavy duty road transport, such as long-haul road freight transport, as one of the hard-to-abate sectors for which hydrogen will be important for decarbonisation in the longer term. The EU mobility strategy sets a target of 500 hydrogen refuelling stations by 2030 while the Regulation on the deployment of alternative fuels infrastructure calls for the deployment of publicly accessible hydrogen refuelling stations every 200 km along the TEN-T core and the TEN-T comprehensive network and at least one in every urban node.

According to the European Hydrogen Observatory, in May 2024 there were already 187 publicly accessible and operational hydrogen refuelling stations in Europe. At the end of 2023, the number of hydrogen-powered fuel cell vehicles surpassed 6,000 units. Passenger cars accounted for 88% of these vehicles, followed by buses at 10%, and heavy-duty vehicles at 2%. The low rate of deployment of the last indicates that there are still challenges regarding the use of hydrogen for road freight transportation, including competition from battery powered trucks.

The number of hydrogen refuelling stations across Europe is progressing unevenly; Germany is leading the way with 86 stations, followed by France and the Netherlands with 27 and 24 stations, respectively. This disparity is closely tied to the number of hydrogen-powered vehicles in each country. Expanding the refuelling infrastructure is crucial for accelerating the widespread adoption of hydrogen-powered vehicles across the continent.

Figure 19: Number of hydrogen refuelling stations in the EU and Norway - 2023



Source: ACER based on data from the European Hydrogen Observatory.

3.3.2. The gas network repurposing challenge

89 The TEN-E Regulation defines 'repurposing' as "*the technical upgrading or modification of existing natural gas infrastructure in order to ensure that it is dedicated for the use of pure hydrogen*". According to the EU hydrogen strategy, repurposing may be more cost-effective than building new hydrogen pipelines because, inter alia, repurposed assets will be largely depreciated. It would also contribute to partly offset the foreseen decommissioning of segments of the current gas network in view of the anticipated natural gas consumption decrease. Moreover, natural gas pipelines are already established, making repurposing a more socially accepted solution compared to building new assets.

90 Currently, the EU gas network consist of more than 200,000 km of transmission pipelines, over 2 million km of distribution network and over 20,000 compressor and pressure reduction stations. Based on the information from the TYNDP-2024, planned hydrogen network projects foresee about 15,500 km of repurposed pipelines, corresponding to 8% of existing gas transmission infrastructure.

91 Repurposing natural gas network elements to supply hydrogen entails a set of challenges that need to be looked at in conjunction, making the decision on whether to repurpose a complex one. These challenges include assessing the technical feasibility and the economic rationale of repurposing, under both the gas and hydrogen system planning perspective, and determining the value of the repurposed assets that will be transferred to the regulated asset base of the hydrogen network operator, including deciding on how to allocate the retrofitting costs. Both the ACER's 2021 white paper on repurposing and the DNV report commissioned in 2022 explore some of these challenges. The relevance of the topic has also been stressed in the conclusions of the 10th Energy Infrastructure Forum in Copenhagen[74].

92 In terms of technical feasibility, most considerations are of the same nature as those of blending (Box 5). For pipelines, exposure to hydrogen can weaken the structural integrity of metals, especially steel, commonly used in transmission pipelines. Hydrogen can cause the material to become brittle, reducing its ability to deform without fracturing, potentially leading to cracking and pipeline failure. Hydrogen accelerated fatigue cracking[75], which related to hydrogen embrittlement, is another significant concern for existing high-pressure natural gas pipelines. For lower pressure pipelines, issues relate primarily to hydrogen leakage and permeation through materials such as polyethylene; while some retrofitting could address these issues, significant concerns remain regarding leakage and safety.

93 Hydrogen has a lower volumetric energy density of hydrogen than natural gas; therefore existing pipelines would need to carry approximately three times more hydrogen to transport the same amount of energy. This would require in general larger compressors and significantly more energy. Many compressors in the natural gas infrastructure are powered by engines or gas turbines that run on natural gas; these would need to be modified or replaced. due to hydrogen's different combustion characteristics and lower volumetric energy content. It is questionable whether it is currently possible to retrofit gas turbo-compressors to handle gas containing more than 40% hydrogen in volumetric terms[76]. Similar to pipelines, hydrogen can embrittle materials, particularly the high-strength steels used in many existing compressors, which can lead to cracking and failure of the compressor components. Seals and other components in existing compressors, typically made from elastomeric or polymeric materials, might also be incompatible with hydrogen. In general, because hydrogen has a wider flammability range and a lower ignition energy than natural gas, retrofitting existing compressors to handle hydrogen safely and efficiently is complex, requiring not only the replacement of seals and other vulnerable components but also potentially the entire compressor unit.

94 Existing metering stations designed for natural gas can sometimes be converted to meter hydrogen, but the feasibility and effectiveness of such a conversion depend on several factors. Certain metering technologies (e.g. ultrasonic meters) can potentially be adapted for hydrogen use with minor adjustments and subsequent recalibration. However, the same issues on material compatibility and safety considerations already outlined for pipelines and compressors would apply; therefore the cost and complexity of upgrading existing meters could be comparable to, or even exceed, the cost of replacement.

95 To mitigate some of the risks or reduce some of the costs of repurposing, existing pipelines may need to operate at lower pressures when transporting hydrogen. When taking into account both the lower energy density per unit volume (one-third that of natural gas) and the potential operation at low-pressure, the amount of energy that can be transmitted by hydrogen could be reduced to as little as one-ninth of that of natural gas[77]. This could give rise to concern over the more general economic rationale of repurposing projects that need to be assessed in the context of the gas and the hydrogen system.

74 The Forum has invited ENNOH, ENTSOG and ACER, in collaboration with the relevant stakeholders, to develop a set of criteria for the repurposing of infrastructure within the context of European infrastructure planning. The Forum has also invited the European Commission to facilitate this activity by moderating the associated meetings, and asked the parties to present the final report at next year's Forum.

75 It refers to the gradual weakening of materials subjected to repeated stress, typically from pressure cycles in pipelines (pressure fluctuations) which can lead to faster crack development, ultimately compromising a pipeline's structural integrity and safety. Technical solutions, such as using coatings, pressure management and adding inhibitors, are necessary to mitigate these risks when repurposing pipelines for hydrogen transport.

76 See also Siemens Energy, Nowega and Gascade Gastransport (2020), Hydrogen infrastructure – The pillar of energy transition - The practical conversion of long-distance gas networks to hydrogen operation, Siemens Energy, Houston, TX.

77 See also Martin, P., Ocko, I. B., Esquivel-Elizondo, S., Kupers, R., Cebon, D., Baxter, T. and Hamburg, S. P. (2024), 'A review of challenges with using the natural gas system for hydrogen', Energy Science and Engineering, pp. 1–15.

96 When assessing the economic rationale, it is important to consider the potential implications for the gas sector. Ideally, an asset can be removed from the gas system when its utilisation rates are expected to be low, and flows can be diverted to other routes with no significant system inefficiencies. This could be assessed both by looking at historical data and by modelling different future demand scenarios to estimate expected network utilisation rates, or capacity bookings. If an asset's utilisation rate is expected to remain significant, the cost of its removal for the gas system should be further investigated and assessed against the benefits of its repurposing. Potential costs for the gas system may be associated not only with weakened security of supply or competition but also with new investments that might be necessary after the removal of the asset (e.g. network reconfiguration). For the hydrogen sector, the assessment of the net benefits of repurposing can rely on indicators similar to the ones used in the context of a cost-benefit analyses[78] for gas infrastructure projects. When evaluating the corresponding costs and benefits of a hydrogen infrastructure, technical parameters such as the change in transmission capacity of a repurposed pipeline compared with natural gas should be duly taken into account.

97 To ensure cross-sectoral consistency and address the potential cross-border implications of repurposing, decisions to remove assets from natural gas networks (either by decommissioning or repurposing) should be made in the context of network planning processes performed at both the national[79] and EU levels[80]. Both national and EU-wide TYNDPs should assess the decommissioning and potential repurposing of natural gas infrastructure. Care should be taken in maintaining consistency between the assumptions used in the national TYNDPs and the assumptions used by gas transmission system operators (and hydrogen network operators in the future) on capacity calculations for the purpose of offering and allocating this capacity to network users. Such integrated planning exercise would also reveal the potential different patterns of network development in the two sectors, with the hydrogen infrastructure likely developing mostly for industrial uses and exploiting supply routes different from the current gas ones.

98 Finally, certain regulatory decisions should be taken on the asset transfer value and the allocation of repurposing costs[81]. The regulatory community tends to agree on employing the residual regulatory asset value, that is, the value of the asset that has not been yet paid for through depreciation allowances[82]. This would mean that the gas transmission system operator would not incur any profit or loss, and the hydrogen network operator would pay for the asset based on the residual economic (and often, consequently, technical) life. Deviations from this principle might arise in the case of past asset revaluations, or in the case of bilateral arrangements between the operators. In such cases, the transfer would entail a profit or loss for the gas system operator and, depending on the methodology to determine the regulatory asset base for the hydrogen operator, it could result in a corresponding loss or profit for the hydrogen operator. This would require a consequent decision on how to allocate the profit/loss among the parties.

99 In addition to the value of the transferred asset, repurposing decisions also entail specific repurposing costs. As a matter of principle, these are borne by, and hence allocated to, hydrogen network operators. However, a gas network element can be built as "hydrogen ready", that is, with a view to a repurposing in the future, comes with additional costs (e.g. different alloys or linings). When transferring the asset, such costs could be entirely passed to the hydrogen network operator, as if they were specific repurposing

78 A draft methodology for the cost-benefit analysis of hydrogen infrastructure has been developed by ENTSOG, pursuant to the TEN-E Regulation. In September 2023, ACER issued an Opinion calling for improvements. The European Commission's decision on approving the methodology is expected this year.

79 The requirements for national TYNDPs are laid out in Articles 55-57 of the hydrogen and decarbonised gas market Directive. TSOs shall submit to the relevant regulatory authority, at least every two years, TYNDPs for both natural gas and hydrogen. Member State can choose to allow a joint TYNDP covering both sectors. The gas TYNDPs shall be based on joint scenarios across natural gas, hydrogen, and electricity, include scenarios on regional distribution of natural gas demand and supply, and report on the future utilisation of individual assets by also highlighting any possible shift of residual utilisation. They shall include comprehensive and detailed information, including the relevant timeframe, on infrastructure that can be or is planned to be decommissioned and on infrastructure that can or is planned to be repurposed. The hydrogen TYNDPs need to consider inter alia the greenhouse gas abatement potential and the energy efficiency and cost-efficiency in relation to other options.

80 At the EU level, the framework for network planning is laid out in the TEN-E Regulation and in the hydrogen and decarbonised gas market Regulation, the latter sets out the EU rules for developing the TYNDP, including specific provisions on decommissioning (Articles 32 and 37). The TEN-E Regulation aims to identify and promote investments in hydrogen (as well as gas and electricity) networks including equipment or installations essential for the hydrogen system, which may be newly constructed or repurposed from natural gas.

81 As per Article 5(1)(b) of the hydrogen and decarbonised gas market Regulation, the value of the transferred asset needs to be properly determined so as to avoid cross-subsidies between the sectors and it needs to be approved by the national regulatory authority. ACER may issue a recommendation on the determination of the asset transfer value (Article 5(6)(c)), and a specific network code on the rules to determine this value may be adopted (Article 71(2)(e)).

82 See for example the key recommendations of the "European Green Deal" Regulatory White Paper series (paper #1).

costs, even in the event they partially have been repaid by the gas users. In such a case there could be a deviation from the principle of residual value, and the amount received by the gas network operator could be paid back to gas users via the gas network tariffs.

3.3.3. The electricity infrastructure challenge

100 To reach the target of 10 Mt of renewable hydrogen production by 2030 set by the Fit-for-55 package, the EU will need between 95 and 140 GW of electrolysers, depending on the operational conditions[83]. These electrolysers will consume some 550 TWh of renewable electricity dedicated to hydrogen production[84]. This amount of electricity corresponds to more than three quarters of the electricity produced by solar and wind in 2023 in the EU[85], requiring the installation of some 180 GW of additional wind and solar capacity[86].

101 Electricity grid development challenges pose an extra risk for the timely development of renewable hydrogen projects that rely on additional renewable electricity. It is necessary not only to build sufficient renewable electricity generation capacity, but also to make the grid reinforcement and expansions in the electricity networks necessary to avoid congestion and curtailments and to connect the newly built renewable power plants and electrolysers to the grid. According to the European Commission's estimates, such investments would constitute a significant part of the EUR 160-210 billion needed for the upgrading of the electricity transmission network this decade. However, the expansion of the electricity transmission networks to achieve the medium-term energy transition goals is moving slower than necessary[87]. Multiyear permitting, social acceptance, and supply chain constraints[88] create bottlenecks that can eventually jeopardise the timeliness of the energy transition. Because of these considerations the European Commission has developed the European grid action plan which proposes actions to accelerate the development of the electricity network.

102 Electrolysers will face competition for renewable electricity from emerging demand, such as electric vehicles and heat pumps. To effectively decarbonise the electricity sector, the growth in electricity demand—including that for renewable hydrogen production—must align with the expansion of renewable electricity generation. The additionality criterion set out in the delegated regulation for RFNBO production rules[89] ensures that renewable hydrogen relies on newly developed renewable capacity. This means that further coordination of investments is essential to connect new renewable capacity, along with any battery storage, that is necessary to meet the rising electricity demand from electrolysers, electric vehicles, and heat pumps. This coordination will help prevent a net deficit in renewable capacity for the overall energy system, ensuring that the resources dedicated to renewable hydrogen production do not compromise the broader renewable generation and decarbonisation needs.

103 Identifying the optimal location of electrolysers is another challenge. Today several industrial sites, expected to become major hydrogen demand centres, are in places with less favourable additional renewable energy potential. This could lead to extensive network expansion either to transport renewable electricity to the electrolyser (if the electrolyser is placed near the hydrogen consumption site) or to transport hydrogen to the industrial area (if the electrolyser is placed near the renewable electricity source). The second alternative allows electrolysers to be located where it is optimal for the configuration and operation of the electricity grid. In this case, proper hydrogen network development may facilitate optimal development of the electricity system including grid expansion, renewable energy utilisation and location of electrolysers and batteries[90]. Such findings reinforce the calls for an integrated and holistic approach to planning and development.

83 Based on estimates from the European Clean Hydrogen Alliance also confirmed by ACER calculations.

84 See also Section 2.1.1. For a summary of the conversion assumptions used in this Report, please refer to Figure 24 in the Annex.

85 Electricity produced from wind and solar in 2023 was 469 TWh and 200 TWh respectively (see ACER's 2024 market monitoring report on key developments in EU electricity markets).

86 Assuming an average capacity factor of renewable energy sources (wind and solar) of 35%. The actual renewable electricity capacity may be even higher considering the temporal correlation constraints. It can be lower if locations with optimum renewable energy potential are chosen.

87 See EMBER's report on grids.

88 For example, see ENTSO-E's recommendations on the European grid action plan, asking for measures to overcome manufacturing capacity and workforce constraints.

89 See Box 1 for more details.

90 For example, see the study by Neuman et.al or the common study by Gasunie, Tennet and Thyssengas for the German energy system

104 The location of electrolysers should also be evaluated in terms of congestion management. A recent study by the Joint Research Centre shows that electrolysers could utilise renewable electricity that would otherwise be curtailed, but at the same time they could also lead to an increase in the cost of remedial actions, and potentially an increase in emissions. While the study is based on certain assumptions regarding the topology and operation of electrolysers, it clearly calls for an integrated planning process, detailed enough to appropriately consider different locational configurations.

105 While optimal configurations could be achieved through an integrated planning approach, locational market signals could also assist project and system developers determine the best placement of electrolysers. Furthermore, these locational signals could enhance the potential of an electrolyser to provide balancing and ancillary services to the electricity system. A recent study commissioned by the European Commission on system integration includes stakeholders' suggestions to provide locational price signals even by reducing the size of bidding zones. This could incentivise investments where most appropriate for the system and increase revenue streams from flexibility services provided by electrolysers. While, technically, electrolysers can provide such services[91], it is expected that their dimensioning and operation will be primarily dictated by hydrogen offtake agreements. For example, providing upward frequency control will depend on the opportunity cost of not producing hydrogen (i.e. not consuming electricity). The availability of hydrogen storage could be important in this respect. Moreover, in providing system services, electrolysers will have to compete with other technologies, such as batteries, that could be more competitive. Project-specific conditions, however, might provide opportunities for the operators of electrolysers to optimise their business case to the benefit of both the electricity system[92] and the hydrogen users.

3.4. Hydrogen costs

106 Renewable hydrogen can contribute to decarbonisation by replacing conventional hydrogen in existing uses and replacing fossil fuels and fossil-based feedstocks in new applications. However, the cost of renewable hydrogen is significantly higher than that of its conventional rivals, which creates uncertainty over the actual level and rate of development of the hydrogen economy. Significant public funding will be necessary to kick-start the market supporting investments in hydrogen supply, demand, and networks. The risks regarding the speed and level of hydrogen uptake stemming from considerations over costs call for caution regarding network development decisions and public financing commitments.

107 The following sections look at the current costs of hydrogen production, identifying the main cost-drivers and discussing future expectations (Section 3.4.1)[93], and it explores the costs of hydrogen transport (Section 3.4.2). The section also includes a discussion about the role and features of PPAs (Box 9), which, it is anticipated, will be used to progressively back more and more electricity procurement for renewable hydrogen production.

3.4.1. Current hydrogen production cost

108 As shown in Section 3.2, at present most hydrogen users produce and consume hydrogen onsite as part of their production process or acquire it from producers via dedicated distribution pathways and bilateral agreements. The fundamentals of such bilateral agreements, in particular those about the supply price, are normally not revealed. Hence, in the absence of liquid markets for hydrogen, policy makers and investors currently rely mostly on estimates of the LCOH based on bottom-up calculations. These calculations use cost-based models considering the various cost-drivers (in terms of investment and operating costs) and, when possible, are verified with information from individual projects or contracts (e.g. hydrogen offtake or PPAs)[94].

91 Not all electrolysers have similar capabilities to provide the services needed by the electricity system. Table 7 in the Annex taken from an ENTSO-E's report on the potential of electrolysers to provide system services shows the mapping of electrolyser technologies with these services.

92 A study by Reiner Lemoine Institute advocates that smaller decentralised electrolysers using local renewable energy surplus and providing flexibility to distribution system operators can be economically viable and system-wise beneficial reducing the need for grid investments.

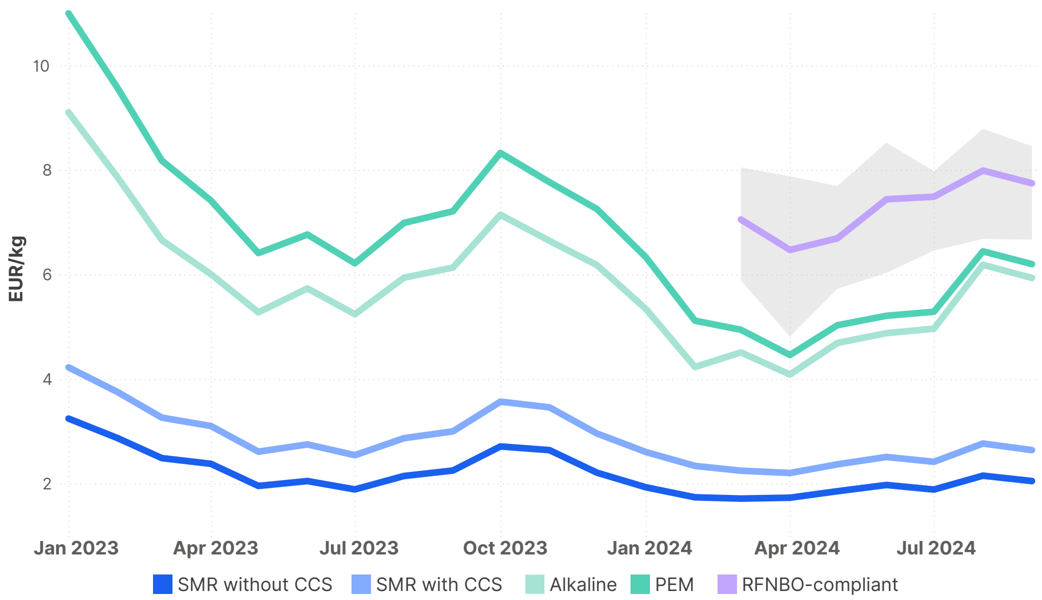
93 The analysis is restricted to the production cost of renewable hydrogen via electrolysis and of low-carbon hydrogen via natural gas reforming using carbon capture as these are considered the most promising technologies to deliver the quantities of hydrogen needed in the short to medium term. By contrast, while the cost of imported hydrogen will be equally important for the EU, it is not analysed further as imports are expected to play a significant role after 2040 (see the impact assessment for the 2040 decarbonisation targets).

94 Other indices are also developed. For example, in May 2024 the European Energy Exchange (EEX) kick-started an effort to increase price transparency by establishing a purely market based weekly price index, called Hydrix. The index refers to renewable hydrogen for Germany and is calculated using information provided voluntarily by the industry. For the period April-July 2024 the index fluctuated around 7 EUR/kg.

109 Figure 20 provides cost estimates of hydrogen produced in the EU from various technologies based on data from S&P Global[95,96]. Since the beginning of 2023, the cost of hydrogen produced via SMR is below 3 EUR/kg with carbon capture adding on average less than 1 EUR/kg to that cost. The production costs of alkaline and proton exchange membrane (PEM) electrolysers (in this graph using electricity from the grid and operating at 95% capacity factor, not necessarily producing renewable hydrogen) depend heavily on electricity prices and are currently (September 2024) around 6 EUR/kg. Notably, RFNBO production rules[97] increase the cost of producing renewable hydrogen bringing it closer to 8 EUR/kg (grey area in the graph). In conclusion, the cost of hydrogen from electrolysis is, on average, two to three times higher than hydrogen produced from natural gas, and the cost of renewable hydrogen three to four times higher.

110 The cost ranges for each technology depend not only on the different cost and technical assumptions, but also on the price volatility of the underlying production factors, namely natural gas and CO_2 emissions allowances in the case of SMR, and electricity in the case of electrolysis. For instance, the recent decrease in natural gas prices since mid-2023 has lowered the cost of producing hydrogen from SMR, thereby increasing its competitiveness against renewable hydrogen. Similarly, the current, relatively low, levels of the CO_2 emission allowances' price (oscillating between 52 and 76 EUR/tonne of CO_2 in 2024) further favour SMR over renewable hydrogen[98]. The following paragraphs provide some further details of the costs elements of the key hydrogen production technologies.

Figure 20: Evolution of cost estimates of hydrogen produced by various technologies – January 2023-September 2024 – (EUR/kg)



Source: ACER based on data from S&P Global.

Note: S&P Global estimates cost based on a methodology that considers, among other parameters, the electricity input costs, and the capital and operational expenditures. Estimates on RFNBO compatible costs are available from April 2024 onward.

95 S&P Global is providing cost valuation for various technology pathways based on detailed cost modelling and using inputs from industry when available. S&P Global is also publishing an energy substitution index for ammonia (AESI) that assesses the price at which energy suppliers would be willing to pay for ammonia as a substitution energy source.

96 Other attempts to provide cost transparency are also available. For example, the HyExchange in the Netherlands publishes the renewable HYCLICX price indicator for the marginal cost of production in the Netherlands, linking the variable price component of hydrogen to the hourly electricity spot market. HYCLIX estimates the cost index for the lowest-priced 50% of hours of electricity each month. These hours largely coincide with a high share of renewable electricity production from wind and solar. This provides some (but not full) alignment with the correlation requirements for RFNBO. The average monthly index for the period January-September 2024 was 2.76 EUR/kg (note this index excludes the capital expenditures and fixed costs of production).

97 See Box 1.

98 In contrast to hydrogen produced via SMR or via electrolysis using electricity bought in the wholesale market, renewable hydrogen will normally rely on long-term PPAs with renewable electricity producers. The price in this case depends on the renewable electricity production cost rather than the wholesale electricity prices, which rely largely on the prices of natural gas, coal and CO_2 emissions allowances. Hence, the higher the cost of these components, the more competitive renewable hydrogen becomes vis-à-vis conventional hydrogen.

3.4.1.1. Renewable hydrogen production costs: overview of relevant cost-drivers

111 The production cost of renewable hydrogen is shaped by two main cost components, the capital cost of the electrolyser and the supply cost of electricity[99]. The first component is technology specific and depends on the maturity of the technology and the economics of the electrolyser manufacturing industry. The cost of electricity, however, is project-specific, and depends heavily on the supply source and contractual arrangements of each project.

112 Both alkaline and PEM and proton exchange membrane (PEM) electrolysis are considered mature technologies and are relatively equally deployed in Europe[100]. Full commercialisation of the anion exchange membrane (AEM) and solid oxide exchange cell (SOEC) electrolysis is still underway[101, 102]. According to the latest IEA's 2024 global hydrogen review, the full capital cost for an alkaline electrolyser is around 1,900 EUR/kW while PEM electrolysers cost around 2,300 EUR/kW[103]. These numbers are some 20% higher than recorded in its previous report. Observations from Bloomberg, based on surveys of producers identify a rise in electrolysers costs in recent years, mainly due to inflationary pressure and lower than expected production scale-up (partly due to delays in freeing up public funding). According to the IEA's 2024 global hydrogen review, the cost of Chinese alkaline electrolysers in 2023 has not changed since 2022 and is around 700 to 1,200 EUR/kW, significantly cheaper than European ones. A report from Hydrogen Europe uses costs for alkaline electrolysers, at 2,250 EUR/kW. It further suggests that cheaper Chinese electrolysers may bring down total capital expenditure by approximately 20%. Despite these considerations, it is important to note that renewable electricity supply is the primary cost driver for renewable hydrogen production. Therefore, alongside the initial investment costs, efficiency, reliability and flexible operation of the electrolyser should also be given equal importance.

113 The production cost of renewable hydrogen depends on the utilisation rate of the electrolyser. At current cost levels, an increase in the utilisation rate of the electrolyser from 4,000 to 5,000 hours per year could lead to a reduction of 8-10% in the production cost of hydrogen, depending on the electricity supply cost. Using electricity directly from intermittent renewable energy sources means the capacity factor will mostly depend on the specific renewable resource deployed. Relying on electricity from the grid (either for the total electricity requirements, or to complement a purchase agreement) increases the utilisation rate but is most unlikely to result in the production of renewable hydrogen according to the RFNBO criteria, at least for most Member States and for the near future[104]. Moreover, simply increasing the capacity factor would not necessarily result in a reduction in the unit production cost since this will also depend on the cost of electricity purchased[105]. Greater capacity factors can also be achieved by investing in batteries, or relying on hydrogen storage options coupled with a downsizing of electrolyser capacity. Several studies indicate that the optimum number of operating hours per year lies

99 Other operating and maintenance costs play a smaller role in the total cost of renewable hydrogen. Grid costs may also represent a significant cost component. These costs can together represent between 6% and 60% of non-household end-user electricity prices (see EUROSTAT). According to a recent report by the UK's Department for energy security and net zero, average electricity network tariffs for large (20-70 GWh/year) consumers in the EU ranged between 6.5 and 20.4 EUR/MWh in 2023, which translate into 0.3-1,0 EUR/kg of hydrogen. At the same time, Member States have different tariff policies and for example, in Germany, there are tariff exemptions for electrolysers.

100 Based on the IEA's database on hydrogen production projects in 2022 both alkaline and PEM electrolysers account for 44 projects in the EU each, with capacities of 66 MW and 88 MW, respectively. Globally, alkaline electrolysis accounts for 71% and PEM for 20% of total electrolysers capacity.

101 In its 2023 Global Hydrogen Review, the IEA rated alkaline and PEM electrolysis technology readiness levels (TRLs) as being at stage 9, that is, the highest deployment readiness level before full maturity. SOECs were at the early market maturity stage, at TRL 8, while AEM was ranked as being at the demonstration phase at TRL 6 (in the 2024 global hydrogen outlook, AEM moved to TRL7).

102 AEM electrolysers are considered a promising technology as they share the flexibility for adjusting to load changes of PEM electrolysers, but do not require critical raw materials, the supply of which might represent a bottleneck for a future large-scale deployment of PEM and alkaline electrolysers. SOECs are also expected to gradually gain market share, as higher operating temperatures increase the efficiency of the process and enable coupling with waste heat sources, while their potential for efficient reverse operation may enhance flexibility and improve the business case.

103 Capital cost figures refer to the complete cost of setting the production unit and include the cost of the electrolyser and the auxiliary systems, and engineering, procurement and construction costs.

104 According to EUROSTAT, the current share of renewable electricity in all Member States is less than the 90% threshold set by the delegated regulation on RFNBOs for hydrogen to qualify as renewable (see Box 1). Based on reporting from the European Environment Agency, the emissions intensity in the electricity sector in Finland, France, Luxembourg and Sweden was already lower than the threshold of 18 gCO_2/MJ (65 gCO_2/kWh) for at least 1 year since 2019, these figures are not necessarily compatible with the methodology set out in the relevant delegated regulation.

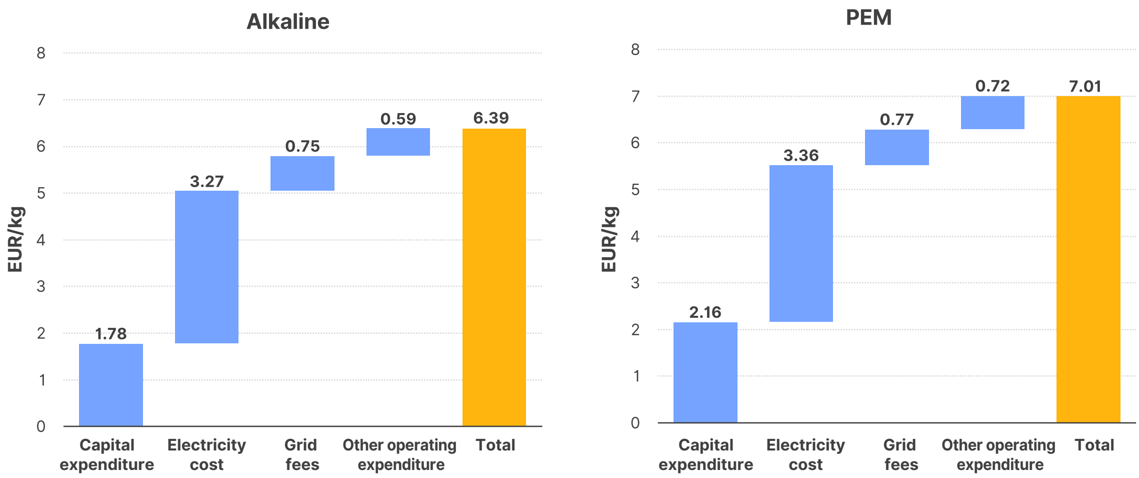
105 Electrolysers may of course limit their purchase of electricity from the grid to hours with lower market prices. However, these normally coincide with hours of high renewable energy output, hence limiting the benefits for electrolysers that would mostly contract their electricity from renewables during those hours via PPAs.

between 4,000 and 6,000[106]. Below 3,000 hours/year, capital costs tend to be predominant in relative terms, and the production cost of renewable hydrogen increases significantly. The structure of the electricity procurement is thus crucial for the viability of hydrogen projects and new types of PPAs starting to emerge to provide greater predictability of production costs and increase the bankability of projects (see Box 8: Power purchase agreements for green hydrogen).

114 Other operational costs of electrolysers include the costs of deionised water circulation[107] and of hydrogen processing and cooling. The stack degradation speed and stack replacement costs are also relevant operational elements[108], though comparatively much lower.

115 The European Commission's analysis of the European Hydrogen Bank's first auction result indicates an average LCOH of between 5.3 and 13.5 EUR/kg (173 and 403 EUR/MWh respectively, see also Box 3). The range is indicative of the projects that werw included in the auction and depicts regional, technological and other project specific choices (e.g. financing arrangements). Figure 21 provides an illustrative example of the cost structure of the LCOH for typical alkaline and PEM electrolysers indicating similarities between the two mature technologies. Under typical assumptions, the largest part of the LCOH is attributed to the cost of electricity, while capital expenditure constitutes the second most important cost component.

Figure 21: Breakdown of hydrogen production costs for alkaline (left) and PEM (right) electrolyser (EUR/kg)



Source: ACER, using the LCOH calculation tool of the European Hydrogen Observatory.

Note: The default cost and the operational assumptions of the tool were used for the calculations apart from operating hours set at 4,000 hours/year; the electricity price set at 60 EUR/MWh and the grid fees set at 14 EUR/MWh. No electricity taxes were considered.

106 See, for example, the KPMG's report *How to evaluate the cost of the green hydrogen business case?*. The report argues that, depending on location and prices, some projects can allow for high utilisation rates, although it is case-specific as in some locations operation of more than 4 000-5 000 hours/year often increases production costs significantly due to the increasing cost of electricity.

107 Access to water resources and the quality of water used in electrolysis can impact costs. Availability of clean water at a reasonable cost is thus essential, and locational aspects are of critical importance as water scarcity (e.g. in drier areas of southern Europe) may be a limiting factor despite the great potential for cheap renewable electricity generation.

108 The degradation rate of the stacks depends on the cumulative current passing through them. The more hours the stack is used, the less efficient it becomes, reducing its economic lifetime. A report by the Oxford Institute for Energy Studies mentions that alkaline electrolysers have a stack lifetime of between 60,000 and 100,000 hours, while PEM electrolysers typically have lifetimes of 50,000–90,000 hours. Conversely, alkaline electrolysers take longer to respond to load changes than PEM electrolysers, which can hinder their suitability for use with variable renewable electricity.

Box 9: Power purchase agreements for green hydrogen

The increasingly volatile electricity prices, coupled with the need for securing financing for renewable energy generation projects, have recently spurred significant interest in PPAs for contracting electricity from renewable sources. This interest is gradually extending to renewable hydrogen projects, with a number of PPAs tied to hydrogen production facilities announced in the past few years in Germany, Sweden, France and Norway (Table 3).

The specific terms and conditions of PPAs are generally defined by the contracting parties to match individual needs, yet there are several general challenges with hydrogen PPAs. While electricity supply profiles of renewable hydrogen must comply with the regulatory criteria for RFNBO qualification (see Box 1), electrolysers need to optimise their utilisation factors. This may result in renewable electricity supply agreements structured over a broader portfolio of renewable electricity production assets, probably over a wider geographical area, and designed to optimise hydrogen production. Safeguarding the temporal correlation criteria while ensuring a sufficiently large capacity factor (e.g. around 60 %) may require a contracting generation capacity that is significantly larger than the nominal capacity of the electrolyser. Achieving larger capacity factors might thus become prohibitively expensive.

Hydrogen demand, on the contrary, is generally characterised by a relatively standard profile with limited flexibility. Renewable hydrogen producers would therefore need to rely on costly options to either secure a steady flow of electricity from renewable sources, or store hydrogen. As the market develops, contractual arrangements similar to those of long-term natural gas contracts (i.e. including take-or-pay or carry-over clauses, and nomination flexibilities) might emerge, to meet inflexible hydrogen demand needs.

Another challenge to securing long term PPAs is the increasing number of hours with negative wholesale electricity prices, which may reduce the incentive to sign long-term contracts while pushing renewable hydrogen producers to leverage lower electricity prices directly from the market. Negative prices would normally be factored into the PPA price settlement, with producers and off-takers employing strategies to hedge their price and volume risk.

Table 3: Example of reported hydrogen PPAs – June 2024

Year	Country	Production target	PPA size (MW)	Renewable source	Term (years)
2024	**Norway**	Green Ammonia	130	Hydro	15
2024	**Germany**	Renewable hydrogen	55	Solar	15
2023	**France**	Renewable hydrogen	15	Onshore Wind	15
2023	**France**	Renewable hydrogen	13	Solar	16
2023	**Norway**	Renewable hydrogen	NA	NA	10
2023	**Norway**	Renewable hydrogen	NA	NA	NA
2022	**Sweden**	Renewable hydrogen	NA	NA	7

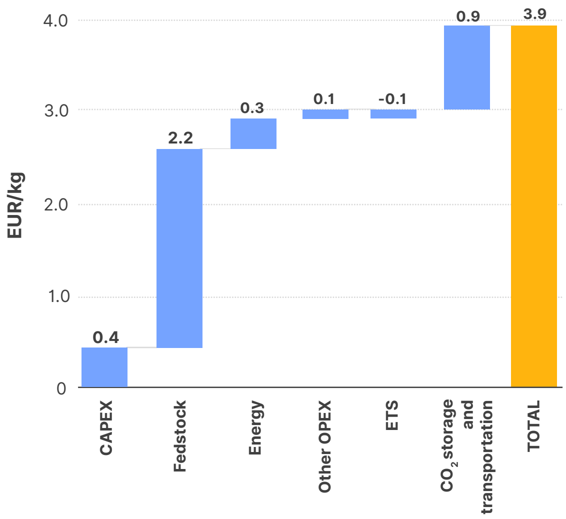
Source: ACER based on data from Pexapark.

3.4.1.2. Production costs of low-carbon hydrogen from steam reforming with carbon capture

116 Low-carbon hydrogen can be produced from SMR coupled with the capturing and appropriate utilisation or storage of the associated CO_2 emissions[109]. In order to qualify as low-carbon, the total greenhouse gas emissions need to be at least 70% lower than of those to the conventional process[110]. The cost of low-carbon hydrogen strongly depends on the price of natural gas and the cost of capturing and storing the CO_2 emissions[111].

117 As discussed in Section 3.4.1, the production cost of hydrogen from SMR in the EU today hovers around 1.5 - 2 EUR/kg. According to S&P Global cost estimates for 2024, the cost of carbon capture and storage (CCS) can add an extra 20 - 50% on the production cost of hydrogen from SMR. Figure 22 illustrates the cost structure of low-carbon hydrogen production via autothermal reforming with carbon capture using natural gas. The cost of natural gas is dominant even in low-price scenarios, and the cost of CO_2 handling (i.e. storage and transport) is the second highest cost component[112].

Figure 22: Breakdown of hydrogen production cost for SMR with carbon capture (EUR/kg)



Source: Hydrogen Europe 2024.

Note: The figure is a reproduction based on the source report. The basic assumptions used in the report are as follows: capital cost of 900 EUR/kW using natural gas at 40 EUR/MWh and average gas network fees at 5 EUR/MWh, electricity costs at 80 EUR/MWh plus average electricity network fees at 29.3 EUR/MWh; other operational expenditures at 3.5% of capital costs; CO_2 capture rate at 94%; CO_2 storage and transport 100 EUR/t; economic lifetime of 20 years; operating hours of 8,000 a year.

118 The cost of hydrogen produced via SMR with carbon capture is lower than that of renewable hydrogen, which has triggered an ongoing debate. Some stakeholders advocate a more relevant role for hydrogen with a reduced carbon footprint (i.e. not necessarily qualifying for low-carbon hydrogen as per EU regulations) as a more viable option to kick-start the market. However, since hydrogen produced from SMR (or other processes based on fossil fuels) is intrinsically tied to fossil fuel utilisation, the expectation is to reduce or completely abandon these methods of hydrogen production in the longer-term when renewable hydrogen will become dominant. Hence, policy makers and investors should also factor into their decision the risk of lock-in effects in carbon emitting technologies. While such technologies might partially address the issue of the high costs of renewable hydrogen, they may also create barriers to achieving the long-term decarbonisation targets.

109 Other low-carbon production routes are possible such as gasification of coal or waste streams with carbon capture, but SMR is the most promising one in Europe and globally.

110 According to a recent technology report by Hydrogen Europe steam reforming with carbon capture technology currently achieves CO_2 captured rates of around 60%, although higher rates, up to 95%, are potentially possible with more extensive and energy demanding retrofitting. Most announced projects intend to use the more advanced autothermal reforming process, which achieves CO_2 capture rates of around 95%, and has high overall efficiency, although no commercial plant has been commissioned yet. According to the latest DNV future outlook for hydrogen, autothermal methane reforming could become the most competitive solution in view of higher efficiency (74-80%) and lower carbon emissions (0.3-1.3 $kgCO_2/kgH_2$).

111 Apart from the natural gas price, hydrogen production cost from SMR depends on project-specific investment costs. Electricity supply costs are also important, although much less relevant than in the case of renewable hydrogen. Oxygen costs also play a role for autothermal reforming and gasification technologies.

112 Due to lack of commercial carbon capture transportation and storage systems, costs are based on assumptions and may vary considerably in practice.

3.4.1.3. Mid-term prospects for renewable and low-carbon hydrogen

119 As illustrated in Section 3.4.1, the capital cost of the electrolyser and the supply cost of electricity together account for the largest part of the production cost of renewable hydrogen. It follows that cost reduction efforts should primarily target these cost components. Various industry associations and market intelligence companies and academia anticipate that renewable hydrogen production costs could fall by up to 50% by the end of the decade, increasing its competitiveness and reducing the need for subsidies.

120 Reductions in the capital costs of electrolysers would be achieved by further optimisation and standardisation of production processes, reductions in the cost of materials, innovation in materials and design, and economies of scale. The IEA's 2024 global hydrogen review envisages a 40-50% drop in average capital costs for alkaline and PEM electrolysers by 2030, assuming that projects announced globally materialise, thereby leading to significant economies of scale. AEM and SOEC electrolyser technologies are also expected to reach commercialisation in the near future, offering new potential solutions for reducing the cost of renewable hydrogen production.

121 As regards electricity, the average levelised cost of renewable electricity can vary by technology and geographical location. According to IRENA, in Germany it is around 55 EUR/MWh for onshore wind, which is similar to the 54 EUR/MWh for offshore wind, while in Spain renewable electricity from photovoltaics is around 43 EUR/MWh. Several studies[113] suggest that there are still substantial potential cost reductions in the future, even for mature technologies such as photovoltaics and onshore wind. To the extent that these expectations materialise[114], the cost of producing renewable hydrogen may reduce substantially. Expectations for a more liquid and mature PPA market may also contribute to alleviating the cost of the electricity produced and facilitate project financing, especially if backed by public schemes providing guarantees[115].

122 Other mid-term developments, such as further reductions in the cost of battery storage, may enable increased utilisation factors for electrolysers thus improving their business case. In the longer-term, highly decarbonised electricity markets will enable full access to grid electricity to produce renewable or low-carbon hydrogen[116]. By-products such as oxygen and, in some cases, heat[117] might also be utilised or sold to the market, potentially increasing the revenues for the electrolyser facility. The same could apply to providing flexibility or ancillary services to the electricity system operators. Additional experience on the flexible operation of electrolysers interacting with heat and electricity systems, and its effect on the stack lifetime and overall performance of the electrolyser, is, however, necessary to avoid efficiency losses when trying to exploit this potential.

123 While future cost reductions can be reasonably expected, other factors can instead push the capital costs of electrolysers upwards. These include macro-economic aspects such as inflation, like in recent years[118], or potential limitations on imported products from China imposed at EU level, including electrolysers[119]. Such developments may put pressure on planned budgets for individual hydrogen projects and public support schemes, which could result in their outreach being substantially reduced. Similarly, they could affect investment costs of renewable electricity production plants, thereby affecting pressure on the cost of renewable electricity and, consequently, that of the cost of renewable hydrogen. The costs of

113 For example the IEA expects further decreases in the cost of renewable electricity, with photocoltaics reaching 30 EUR/MWh, onshore wind 38 EUR/MWh and offshore wind 34 EUR/MWh in 2030, and a further reduction of 11-37% towards 2050 (numbers refer to 2021 euro prices). DNV's energy transition outlook expects reductions of as much as 60% for photovoltaic projects towards 2050, and between 39% and 84% for wind, depending on technology.

114 While cost reductions are generally expected because of continuous growth and innovation, other factors, such as commodity prices, financing, logistics and network availability, may have adverse effects on the cost of renewable power generation investments. For example, the IEA reports an increase of 10% in the cost of wind power generation in the EU and the United States for the first half of 2024 due to manufacturers' pricing practices.

115 So far, Spain, France and Norway have such schemes in place according to Pexapark's 2024 European PPA market outlook. For example, the French guarantee for renewable scheme is designed to compensate the renewable electricity producer for up to 80% of the revenues contracted in the event of a default by the buyer. Notably, the recently published Regulation 2024/1747 aiming to improve the EU's electricity market design enables the introduction of state-backed guarantee schemes for PPAs to reduce the financial risks associated with payment default by the off-taker.

116 In line with the RFNBO production rules. See more in Box 1.

117 For example, SOEC systems operate at temperatures exceeding 500°C, hence waste heat might be valorised.

118 The IEA's 2024 global hydrogen review suggests inflationary increases as high as 50% in Europe, while, according to a recent article capital costs in 2024 have risen world-wide by more than 50% on average, compared to 2023.

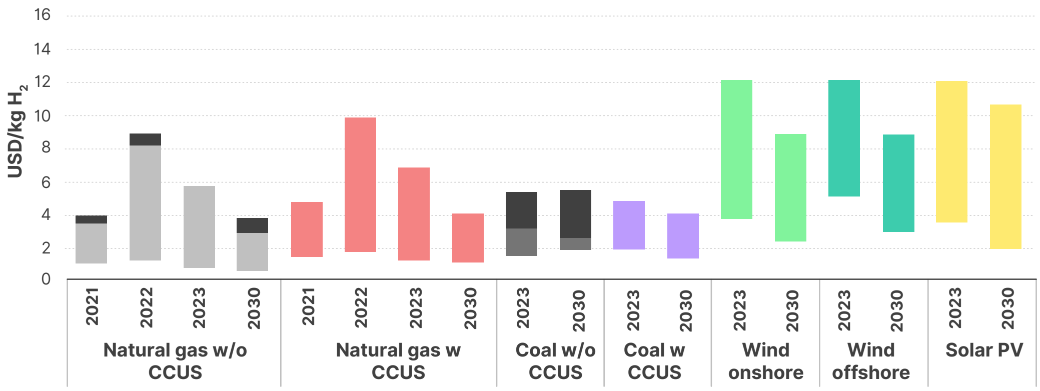
119 For example the terms and conditions for the 2024 auction of the European Hydrogen Bank limit the sourcing of electrolyser stacks (which include surface treatment, cell unit production and stack assembly) from China to a proportion of no more than 25% (in MW).

materials may also be impacted by international trade developments, thereby affecting the expected cost reductions. These types of uncertainties influence investment decisions and might alter the rate of market growth, at least during the early stages of its development.

124 The investment costs for low-carbon hydrogen are also expected to decrease as CCS technology matures because of standardisation, optimisation and upscaling. Recent developments regarding the global liquefied natural gas (LNG) supply capacity indicate that the volatility of natural gas prices for Europe after the second half of the decade is likely to be limited. This might maintain the competitiveness of low-carbon against renewable hydrogen, prompting in turn some interest from industry and selected Member States in kick-starting the market[120]. At the same time, higher prices for CO_2 emissions allowances improve the economics of renewable and low-carbon hydrogen, compared with conventional hydrogen[121].

125 Figure 23 provides the IEA's latest estimates for the prospects of the changes in the cost of producing hydrogen in the short- and mid-terms. The figure indicates that the low to mid end of the range of production costs of renewable hydrogen could compete with conventional hydrogen by 2030[122].

Figure 23: Hydrogen production costs by technology – 2021-2023 and 2030 prospects (USD/kg)



Source: IEA, Global hydrogen review 2024.

Note: The figure is a reproduction from the IEA's 2024 global hydrogen review. CCUS, carbon capture utilisation and storage; PV, photovoltaic. Darker colour areas indicate cost ranges.

126 Eventually, the availability and affordability of the resources used by the different production technologies, together with government policies and incentive schemes, will determine the competitiveness of one production pathway for hydrogen over the others. Charges for accessing electricity and gas networks, and taxation schemes, will also be important elements impacting the economic feasibility of producing renewable and low-carbon hydrogen. The development of the costs of the main production elements of renewable and low-carbon hydrogen is therefore an important key performance indicator during the ramping up phase of the hydrogen market.

3.4.2. Hydrogen transport costs

127 Hydrogen's properties make its transport challenging. While its calorific value is three times higher than that of natural gas, its volumetric energy content is nearly three times lower due to its smaller density. Consequently, to get the same energy content, one needs to transport or store three times the volume of hydrogen, compared with natural gas, and use more energy for compression.

128 Hydrogen can be transported via dedicated hydrogen pipelines or via existing natural gas pipelines that have been properly repurposed to accommodate hydrogen. In addition, hydrogen can be transported

120 It must be noted however that the cost of transportation and storage of the captured CO_2 is quite uncertain and depends on the specific cases (e.g. in terms of distance from storage sites). Furthermore, direct utilisation of natural gas with carbon capture and storage might be more competitive and efficient than producing and further transporting abated hydrogen from natural gas.

121 For example, the IEA predicts that an increase in the carbon price to around 120 EUR/tCO_2 (assuming also significant reductions in the cost of electrolyser and the cost of electricity) could lead to hydrogen from renewables and hydrogen from natural gas with CCS being cheaper than hydrogen from natural gas without CCS.

122 Notably the discovery of underground reservoirs of natural hydrogen could potentially be a disruptive technological breakthrough providing cheap hydrogen. While recent discoveries in France and elsewhere have raised interest there is no definite indication of this stream's prospects.

as compressed or liquid hydrogen, or in the form of chemical carriers such as ammonia, methanol or LOHCs, via special trucks, trains and ships. The choice of transport mode mainly depends on distance and regional characteristics. In general, pipelines are generally a cost-effective solution for distances within the European continent, with trucking being more economical for short distances (up to 500 km). Instead, shipping in liquid form (liquid hydrogen or derivatives) can become a cheaper alternative for distances longer than 3,000 - 5,000 km, making it more suitable for importing hydrogen to Europe[123].

129 The EU policy on hydrogen favours the use of hydrogen in its pure form and thus advocates interconnected markets via dedicated hydrogen networks. The total cost of hydrogen for end users will eventually entail network tariffs covering (at least partly) the network cost, including where relevant terminals, long transmission pipelines, and storage and distribution pipelines. Determining the most appropriate national network investments, considering also cross-border network expansion, is thus important, as it ultimately affects the delivery costs of hydrogen. Hydrogen network development costs may be reduced if existing natural gas infrastructure is repurposed to accommodate hydrogen.

130 In terms of investment costs, according to a report from Siemens Energy, Nowega and Gascade Grastransport, the cost of repurposed gas pipelines may be between 10% and 15% of the cost of new hydrogen pipelines. The Hydrogen Council suggests capital costs for networks, including compressors, of between EUR 0.5 and 1.0 million per km for repurposed pipelines and between EUR 1.9 and 3.8 million per km for new pipelines. In addition, the 2022 study on the European hydrogen backbone from Guidehouse indicates capital costs for medium to large pipelines (excluding compressors) of between EUR 2.0 and 3.4 million per kilometre for new pipelines, and between EUR 0.2 and 0.6 million per kilometre for repurposed ones. This data is consistent with the values inferred from the project information in the 2024 TYNDP (see Section 3.3.1). It must be noted, however, that only a few cases of repurposing projects have been completed so far; hence the estimates provided need to be assessed against concrete cases and further backed by supporting evidence before being considered as fully reliable.

131 The unit cost of transporting hydrogen (in euro per kilogram or euro per megawatt hour) is harder to estimate as it depends not only on the construction cost of the network but also on several other parameters such as volume, load factor, distance, pipe diameter, operating pressure and, operational costs. The operational costs of hydrogen networks are higher than those of natural gas networks, mainly due to the three-times higher flowrates that hydrogen requires to deliver the same amount of energy leading to higher compression costs. Table 3 provides an overview of the main estimates based on a literature review. A recent analysis from Agora Industry suggests that the transmission cost for hydrogen for onshore distances of up to 1,500 km ranges between 10 and 20 EUR/MWh (0.30 - 0.60 EUR/kg). As the distance increases costs also increase, reaching around 45 EUR/MWh (1.35 EUR/kg) for a distance of 3,000 km. A 2019 report by the IEA shows transport costs by pipeline at around 30 EUR/MWh (0.9 EUR/kg) for a distance of 1,500 km, and 60 EUR/MWh (1.8 EUR/kg) for distances of around 3,000 km[124]. The Navigant study prepared for Gas for Climate calculated hydrogen transport costs for a distance of 600 km between 3.7 and 4.6 EUR/MWh for repurposed and new pipelines respectively (corresponding to 0.11 to 0.14 EUR/kg). A study from the Joint Research Centre in 2021 assessing hydrogen delivery options estimates the cost to be 18 - 57 EUR/MWh (0.55 to 1.72 EUR/kg) for a distance of approximately 2,500 km, depending on the utilisation factor of the pipeline. A 2021 report by the Hydrogen Council sets the range between 3 to 28 EUR/MWh (0.08 to 0.85 EUR/kg)[125] for retrofitted (low end of the range) and new pipelines (high end of the range), for distances between 1,000 and 5,000 km. The study on the European hydrogen backbone from Guidehouse, updated in 2022, indicates a LCOH transport costs of 3 - 4 EUR/MWh (0.09 - 0.12 EUR/kg) for repurposed, pipelines and 6 to 12 EUR/MWh (0.19 - 0.35 EUR/kg) for new pipelines, for a distance of 1,000 km.

123 On these aspects, see also the assessment of hydrogen delivery options by the Joint Research Centre. Final use of hydrogen, for example as feedstock in industrial processes, transportation fuel, or fuel for residential heating, may require specific purity levels or delivery methods, influencing the selection of the most cost-effective approach.

124 Using an average exchange rate of 0,8933 EUR/USD in 2019.

125 Using an average exchange rate of 0,8455 EUR/USD in 2021.

Table 4: Costs of hydrogen transport by pipeline based on literature

Study	Cost		Distance
	EUR/MWh	EUR/kg	
IEA (2019)	30	0.9	1,500 km
	60	1.8	3,000 km
Navigant for Gas for Climate (2019) *Retrofitted* *New*	3.7 4.6	0.11 0.14	600 km
Joint Research Centre (2021) *Range depends on utilisation factor*	18 - 57	0.55 - 1.72	2,500 km
Hydrogen Council (2021) *Retrofilled (low range) -* *New (high range)*	3 - 28	0.08 - 0.85	1,000 km to 5,000 km
Guidehouse for European hydrogen backbone initiative (2022) *Retrofitted* *New*	3 - 4 6 - 12	0.08 - 0.85 0.19 - 0.35	1,000 km
Agora Industry (2024)	10 - 20	0.30 - 0.60	1,500 km
	45	1.35	3,000 km

Source: ACER.

132 The ranges in the cost estimates are still very wide, and largely dependent on critical assumptions such as whether they refer to repurposed or newly built pipelines, the implied utilisation factors, and the distance. Moreover, current costs might be different from estimates conducted in the past due to inflation. In case the big number or projects planned in a relatively short period also creates bottlenecks in the value-chain and stress the capacity of equipment supply, this might further increase their costs. Also, the underlying assumptions for the calculation of the levelised cost, such as the economic lifetime of the pipeline, or the discount factor – if any, are not always specified. Therefore, predicting the likely unit transport cost for hydrogen and assessing how the network costs will influence the end user tariffs is not straightforward.

4. Conclusion and recommendations

133 In conclusion, the European hydrogen market starts to evolve, driven by ambitious EU-wide strategies and national policies. Yet, meeting the EU 2030 renewable hydrogen targets remains critical. The current renewable hydrogen consumption remains minimal, and while EU renewable energy and decarbonisation targets could drive the demand, uptake so far has been slow.

134 On the supply side, there is a significant amount of projects for electrolysers, mostly awaiting final investment decisions. However, despite an increase in the funding options and tools, the deployment of these projects faces risks due to uncertainties in demand and future renewable electricity prices. Also, navigating the several funding schemes might be complex, and further clarity would benefit the sector's growth. In addition, national and international certification schemes to enable the intra-European trade of hydrogen and the import of hydrogen derivatives in the EU should be swiftly set up.

135 EU Member States' strategies reflect different levels of ambition, potentially leading to uneven sector development and requiring greater alignment with the broader EU vision. The national regulatory frameworks are still in their early stages. Alignment with the EU regulatory framework and consistency across EU Member States is crucial for cross-border initiatives.

136 The cost of renewable hydrogen produced via electrolysis is still much higher than that produced from natural gas, also as a consequence of EU RFNBO production rules. The first European Hydrogen Bank auction revealed instances of lower costs, but the existing cost gap creates risks for early adopters. Transparency around price dynamics is essential for informed investment decisions. Such higher costs could also impact the competitiveness of sectors like steel, though the effect on the price of final products (for example electric cars) is likely to be moderate, potentially increasing acceptance and viability of renewable hydrogen in the long-term.

137 Capital expenditures and electricity costs are the main drivers of renewable hydrogen costs. Scaling up global electrolyser production and innovation is crucial to reduce capital costs. Maintaining the pace of renewable electricity cost reductions is also key, but it depends on uncertainties like commodity prices and further technological innovations. A highly decarbonised electricity sector could enable cheaper renewable hydrogen production. The benefits that electrolysers can bring to the electricity system in terms of flexibility and ancillary services should also be properly acknowledged.

138 The role of low-carbon hydrogen produced from natural gas with carbon capture is still debated. While it can contribute to lowering hydrogen costs, thus enabling a quicker demand build-up, it may lead to long-term dependence on fossil fuels, potentially hindering decarbonisation efforts. Investors and the hydrogen-consuming industry need more clarity on the role of low-carbon hydrogen in the EU market.

139 Hydrogen infrastructure plays a vital role in sector development, linking low-cost production areas with industrial demand centres. However, current network development plans are based on demand projections and aspirations rather than concrete market needs, which increases the risk of overinvestment. This may result in underutilised networks and may impact the cost recovery of the networks, resulting also in cross-border implications. Accurate demand forecasting and proper monitoring and plan adjustments, are essential to mitigate such risks. Stakeholders' engagement, duly analysis of market trends, and use of market tests with binding commitments could be coupled with enhanced analytical capabilities in demand modelling to improve forecasting. In TYNDPs, the impact of a slower hydrogen demand growth must also be analysed. Finally, an incremental approach to network development based on specific market needs and shorter-term projections should also be considered.

140 Repurposing gas networks for hydrogen could reduce costs compared to building new infrastructure, but uncertainties remain due to limited experience and wide-ranging cost estimates. Repurposing decisions should be carefully evaluated considering the associated technical and economic challenges, including the assessment of cross-sectoral costs and benefits and the potential implications for gas supply security.

141 Planning of gas, hydrogen and electricity networks should be done in an integrated manner, with a focus on the efficient use of infrastructure. Investments in electricity and hydrogen networks should be coordinated to enable decarbonisation in an efficient way and avoid under-utilisation of assets. Integrated planning shall also guide optimal placement of electrolysers; location near renewable electricity production sites could reduce the need for extensive electricity networks, while co-locating hydrogen production and demand may limit the need for new hydrogen infrastructure.

4.1. Recommendations

4.1.1. On completing and clarifying the regulatory framework

142 The European Commission and Member States should provide more clarity on the role of non-RFNBO hydrogen in the market ramp-up phase and beyond.

143 The European Commission and the EU Member States should increase efforts to advance national and international certification schemes to enable the intra-Europe trade of hydrogen and the import of hydrogen derivatives to the EU.

144 EU Member States should quickly transpose the hydrogen and decarbonised gas market Directive into national legislation and appoint hydrogen network operators. Consequently, national regulatory authorities should promptly certify hydrogen network operators, as this is a prerequisite for the establishment of the ENNOH further enabling the implementation of the European regulatory framework.

4.1.2. On enhancing effectiveness of financial support

145 The European Commission should continue its efforts to provide more clarity on EU funding for hydrogen and make it easier for investors to navigate the funding landscape, such as through the Strategic Technologies for Europe Platform. Initiatives such as the hydrogen pilot mechanism can support market development and increase the visibility and coordination of available funding for hydrogen projects in the EU.

146 Similarly, EU Member States should increase their capacities to absorb and effectively allocate EU funds and assist investors in understanding how the EU and national funding environment could jointly deliver.

147 The European Hydrogen Bank's auction is a good example of how competitive and transparent processes can support early hydrogen uptake and enhance market clarity. To increase chances of meeting the mid-term targets and accelerate the hydrogen market development, EU funding to support auctions under the domestic and international legs of the European Hydrogen Bank should increase. Where relevant, EU Member States should make use the auctions-as-a-service mechanism to effectively and quickly allocate national support budgets.

4.1.3. On integrated hydrogen network planning

148 EU Member States, gas and electricity transmission system operators, and hydrogen network operators should plan future energy networks while considering the needs of a demand driven energy transition. As regards hydrogen, they should improve demand forecasting capacity moving beyond aspirational targets, by:

- enhancing analytical capabilities in hydrogen demand modelling and forecasting,
- properly and promptly engaging stakeholders,
- analysing and considering actual market trends and developments,
- including market tests with binding commitments prior to FID.

149 More specifically, and as indicated in ACER's Opinion on the draft TYNDP-2024 scenarios report, hydrogen demand projections in TYNDPs need to align with current trends; the impact of slower hydrogen demand growth should be analysed.

150 Gas and electricity transmission system operators and hydrogen network operators should enhance coordinated and integrated network planning focusing on the efficient use of networks.

151 Repurposing decisions taken by national regulatory authorities, gas transmission system operators and hydrogen network operators should be carefully evaluated in light of the associated technical and economic challenges, including the assessment of cross-sectoral costs and benefits and the potential implications for gas supply security.

152 EU Member States, gas and electricity transmission system operators, and hydrogen network operators should factor in locational considerations—such as congestion, renewable energy availability, and limitations in electricity network expansion—during the planning process. This approach will optimize system integration, enhance the efficient use of networks, reduce electricity network congestion, and maximize the benefits of electrolyser deployment.

153 EU Member States and national regulatory authorities should ensure that an appropriate flexibility-enabling framework is developed so that, where possible, electrolyser performance can be optimised, offering flexibility and ancillary services to the benefit of the whole energy system.

4.1.4. On hydrogen infrastructure financing

154 Where relevant, EU Member States and, where appropriate, national regulatory authorities should clarify the financing regime for cross-border networks and properly allocate costs and risk.

155 National regulatory authorities should request that gas transmission system operators and hydrogen network operators increase transparency on the costs of repurposing over the full lifetime of a repurposed asset.

156 EU Member States and national regulatory authorities should analyse the impact of hydrogen network development on hydrogen (and, where appropriate, gas) network tariffs and timely design financing mechanisms, such as the inter-temporal cost allocation referred to in the hydrogen and decarbonised gas market Regulation, to manage risks from any potentially uncertain evolution of hydrogen demand. ACER will issue a recommendation on the methodologies for setting the inter-temporal cost allocation by 5 August 2025.

157 When future hydrogen demand is highly uncertain, EU Member States, , hydrogen network operators, and, where applicable, gas transmission system operators should consider an incremental hydrogen network development. This should be based on specific market needs and short-term projections, to avoid overbuilding and the risk of stranded assets.

4.1.5. On enhancing market monitoring

158 As the hydrogen market develops, closely monitoring its progress is essential for understanding market dynamics and informing decision-making. The European Commission, EU Member States, and national regulatory authorities should enhance their capacity to oversee the sector, as outlined in the hydrogen and decarbonised gas package and other relevant legislative frameworks. It is imperative to establish clear reporting rules for the production and use of renewable, low-carbon, and unabated hydrogen, and enhance the monitoring of infrastructure developments.

Annex

Figure 24: General assumptions for conversions and calculations

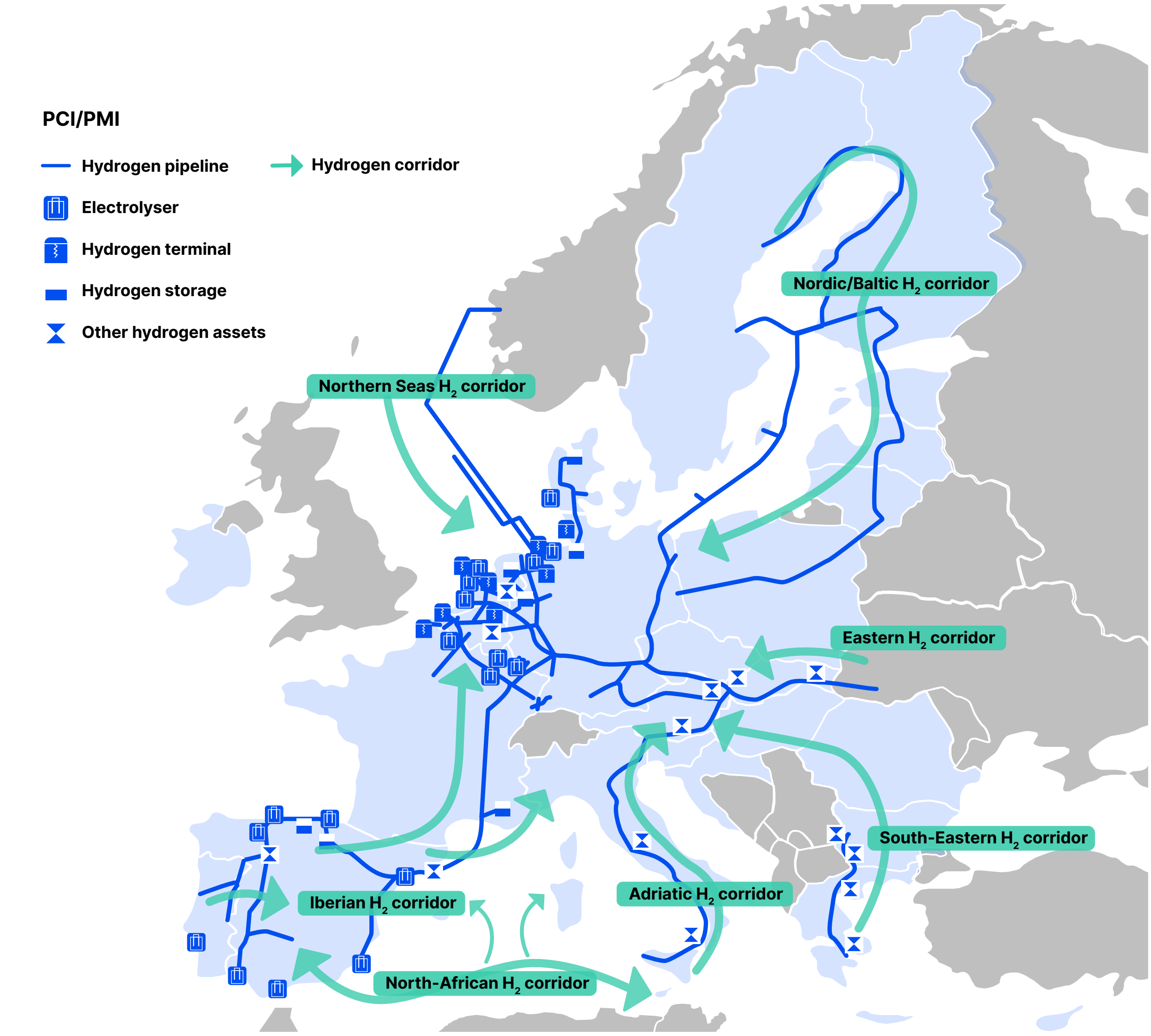
Conversion of measurement units for hydrogen

1 kg	120 MJ/kg	33.3 kWh/kg

Assumptions for electrolysers

CAPACITY	EFFICIENCY	LOAD FACTOR		PRODUCTION		
1 MWe	55 kWh/kg	4,000 hrs/y	46%	72.7 ton/y	2.4 GWh/y	MIN
	61% EFFICIENCY	6,000 hrs/y	68%	109.1 ton/y	3.6 GWh/y	MAX

Figure 25: Map of PCI/PMI and hydrogen import routes according to the European hydrogen Strategy – September 2024



Source: ACER based on the PCI-PMI transparency platform and the RePowerEU plan.

Table 5: Hydrogen relevant national strategic documents – September 2024

Country	Document type	Published	Link
Austria	National Hydrogen Strategy	Jun-22	[EN]
	Austrian integrated network plan (ÖNIP)	Apr-24	[AT]
Belgium	National Hydrogen Strategy	Oct-22	[EN]
Bulgaria	National Hydrogen Strategy (Roadmap)	May-23	[BG]
Croatia	National Hydrogen Strategy	Mar-22	[EN]
	Hydrogen Strategy implementation document	Jun-24	[HR]
Czechia	National Hydrogen Strategy	Jul-24	[CZ]
Denmark	National Hydrogen Strategy	Dec-21	[EN]
Estonia	National Hydrogen Strategy (Roadmap)	Feb-23	[EN]
Finland	National climate and energy Strategy	2022	[EN]
	National Hydrogen Strategy	Feb-23	[EN]
France	National Hydrogen Strategy (1st version)	Sep-20	[FR]
	National Hydrogen Strategy (draft)	Dec-23	[FR]
Germany	National Hydrogen Strategy (1st version)	Jun-20	[EN]
	National Hydrogen Strategy	Jul-23	[EN]
Hungary	National Hydrogen Strategy	May-21	[EN]
Ireland	National Hydrogen Strategy	Jul-23	[EN]
Italy	National Hydrogen Strategy (draft)	Nov-20	[IT]
Lithuania	National Hydrogen Strategy	Jun-24	[LT]
Luxemburg	National Hydrogen Strategy	Sep-21	[EN]
Netherlands	Climate agreement	Jun-19	[NL]
	National Hydrogen Strategy	Apr-20	[EN]
	Hydrogen workplan 2022-2025	Jul-21	[NL]
Poland	National Hydrogen Strategy	Dec-21	[EN]
Portugal	National Hydrogen Strategy	Aug-20	[EN]
Romania	National Hydrogen Strategy	May-23	[EN]
Slovakia	National Hydrogen Strategy	Jun-21	[EN]
Spain	National Hydrogen Strategy (Roadmap)	Oct-20	[ES]
Sweden	National Hydrogen Strategy	Nov-21	[EN]
	National Hydrogen Strategy (supporting document)	May-22	[SW]

Source: ACER.

Note: NECPs can be found at the dedicated website of the European Commission. In Denmark the strategy was followed by a political agreement, which provided with the specific targets. The updated French strategy has been published for consultation in December 2023 but has not been formally approved yet.

Table 6: EU funding programmes with relevance to hydrogen – September 2024

No.	Programme	Scope	Total budget (not specific for H_2)	Support specifics	Tech neutral	EU wide
1	**Horizon Europe** Including the Clean Hydrogen Partnership	Research and innovation projects, testing, demonstration and validation of H_2 technologies, innovation and market deployment, Open Innovation Test Beds for H_2 technologies	EUR 95.5 billion (including EUR 1.2 billion, EUR 1 billion from Horizon Europe and EUR 200 million as a top-up from the European Commission)	Grants	Yes No – renewable and low-carbon H_2	Yes
2	**LIFE (2021-2027)**	Innovative frameworks and capacity building on H_2 technologies	EUR 5.4 billion	Grants	Yes	Yes
3	**Innovation Fund (2020–2030)** including Hydrogen Bank	Breakthrough H_2 technologies, CCUS, electrolyser manufacturing, H_2 use in applications	EUR 40 billion (carbon price of 75 EUR/tCO_2)	Grants Fixed premium	Yes No – renewable H_2	Yes
4	**Breakthrough catalyst (2022–2027)**	Clean hydrogen, SAFs, direct air capture and long-duration storage	EUR 820 million	N/A	N/A	N/A
5	**Connecting Europe Facility – Energy (2021–2017)**	Cross-border H_2 transmission and distribution projects, storage, electrolyser	EUR 5.84 billion	Grants – guarantees, bonds	Yes	Yes
6	**Connecting Europe Facility – Transport (2021–2017)** including AFIF (2021–2023)	HRSs on TEN-T road and railway networks, dedicated to public transport urban nodes and to deployment of H_2 alternative fuels for TEN-T maritime and inland ports and inland waterways	EUR 25.8 billion (including EUR 1.58 billion of AFIF budget)	Grants – guarantees-bonds	Yes	Yes
7	**InvestEU**	H_2 production, HRSs and other H_2-related infrastructure, storage of H_2 technology equipment, supply at commercial scale	EUR 26-million guarantee (backed by EUR 10.46 million of budget through 40 % provisioning rate)	Guarantees	Yes	Yes
8	**European Regional Development Fund**	HRSs, H_2 transmission and distribution projects for territorial integration	EUR 191 billion	Grants	Yes	Yes
9	**Cohesion Fund**	HRSs and other H_2-related infrastructure on TEN-T networks	EUR 43 billion	Grants	Yes	Yes
10	**Modernisation Fund**	Production and use of green H_2 from renewable electricity; assets such as green H_2-fuelled trains/trucks/cars; high-efficiency hydrogen CHP	EUR 48 billion (carbon price of 75 EUR/tCO_2)	NA	Yes	No
11	**IPCEI**	In December 2020, the EU launched a hydrogen IPCEI, with 22 European countries signing a manifesto paving the way for a cleaner hydrogen value chain	N/A	N/A	N/A	N/A
12	**Just Transition Fund**	N/A	N/A	Grants	Yes	Yes

Source: ACER, based on information from the Investors Dialogue on Energy (2024), Discussion on New Pilot Schemes – Green hydrogen, Issue Paper No 14, and the 2024 State of the European Hydrogen Market Report from the Oxford Institute for Energy Studies.

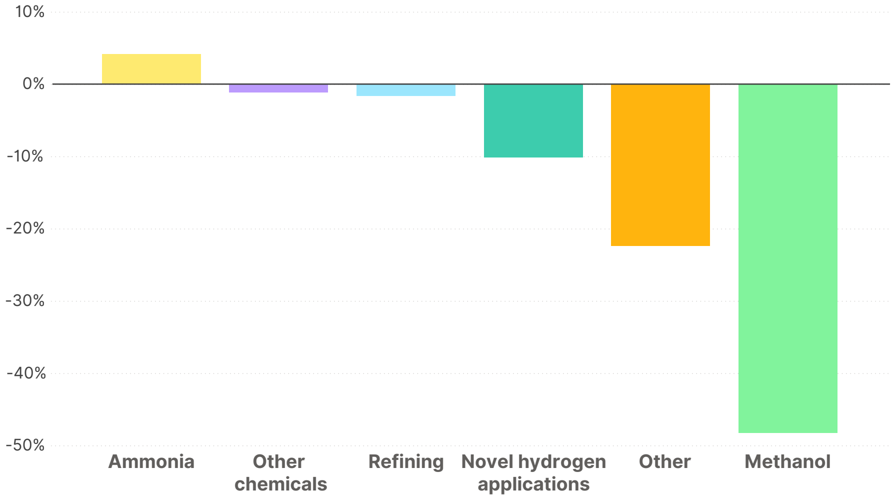
Table 7: Non-exhaustive list of national schemes providing funding for hydrogen projects – September 2024

Case number	Case title	Country	Aid instrument
SA.101308	Aid scheme for the acquisition and modernisation of clean vessels in Italy	Italy	Direct grant
SA.101998	Hydrogen production through electrolysis	Netherlands	Direct grant
SA.102003	RRF Romania - Scheme to support capacity for renewable hydrogen production	Romania	Direct grant
SA.102385	State aid scheme for the decarbonisation of industry from the RRP	Slovakia	Direct grant
SA.102388	State aid scheme for the decarbonisation of industry financed from the Modernisation Fund	Slovakia	Direct grant
SA.103196	Amendment to aid schemes SA.42393 (2016/C) - Reduced CHP surcharge for energy intensive users; and SA.49416 (2017/N) – Reduced offshore surcharge for electro-intensive undertakings	Germany	Other
SA.103346	Germany - Amendment of the Federal aid scheme for the acquisition of light and heavy commercial vehicles with alternative, climate-friendly propulsion systems; ancillary recharging and refuelling facilities and feasibility studies (SA.59352 / SA.63458)	Germany	Direct grant
SA.103648	Production of PtX in Denmark	Denmark	Direct grant
SA.104903	ArcelorMittal France	France	Direct grant
SA.104904	ENER - CEEAG on Hydrogen 2022 - Industry Wave	Spain	Direct grant
SA.105006	RRF-Aid to LOTOS Green H2 Sp. z o.o.	Poland	Direct grant
SA.105338	SA.105338 TCTF-RRF: Support for the development of renewable methane and renewable mathanol production	Finland	Direct grant
SA.106007	TCTF - RRF - Italy: Support for the development of hydrogen valleys	Italy	Direct grant
SA.106299	RRF - Expansion of the LNG Terminal on the island of Krk	Croatia	Direct grant
SA.106534	Rozporządzenie Ministra Funduszy i Polityki Regionalnej z dnia 13 stycznia 2023 r. w sprawie udzielania pomocy finansowej przez Narodowe Centrum Badań i Rozwoju w ramach programu Fundusze Europejskie dla Nowoczesnej Gospodarki 2021-2027	Poland	Guarantee
			Direct grant/ Interest rate subsidy
			Loan/ Repayable advances
SA.107476	RRF - TCTF 2.6 - Aid scheme to support investments for the use of hydrogen in industrial processes in Italy.	Italy	Direct grant
SA.108068	TCTF: aid to support the transition to a net-zero economy	Germany	Other
			Guarantee
			Direct grant
			Tax advantage or tax exemption
SA.108499	TCTF - Germany: Production of green hydrogen in JTF regions	Germany	Direct grant
SA.108653	TCTF - RRF - Reinforcement of the value chain of renewable energy and storage	Spain	Direct grant
SA.108729	2.6 TCTF - DE - Investment aid for industrial decarbonisation through electrification and hydrogen switch	Germany	Direct grant
SA.108953	TCTF - RRF- Investment aid scheme for the production of electrolysers	Italy	Direct grant
SA.109042	TCTF - Portugal: Centralized purchase of renewable hydrogen and biomethane	Portugal	Other
SA.109055	TCTF: Modernisation Fund – Programme ENERG ETS	Czechia	Direct grant
SA.109170	TCTF - Scheme for accelerated investments in sectors strategic for the transition towards a net-zero economy	Austria	Direct grant
SA.109550	German participation in the 'Auctions-as-a-Service' organised under the first EU Innovation Fund Hydrogen	Germany	Direct grant
SA.109663	Measures to facilitate the implementation of the Programmes provided for in sectoral contracts in the fisheries and aquaculture sector	Italy	Direct grant
			Direct grant/ Interest rate subsidy
SA.109761	TCTF - Support for investment in manufacturing towards a climate neutral economy	Netherlands	Direct grant
SA.109766	TCTF - Régime temporaire d'aides à la production de chaleur, de combustibles et de carburants dérivés de la biomasse et de l'hydrogène renouvelable	France	Repayable advances
			Direct grant

Case number	Case title	Country	Aid instrument
SA.109989	TCTF: State aid scheme to provide exceptional investment aid in sectors of strategic for the transition to a climate-neutral economy	Slovakia	Tax allowance
			Other
			Direct grant
SA.110068	NL_Subsidy scheme for large-scale production of fully renewable hydrogen via electrolysis 2024	Netherlands	Direct grant
SA.110254	TCTF - RRF: Agendas for business innovation	Portugal	Direct grant
SA.110511	TCTF: RRF - Italy: Support for the development of hydrogen valleys (prolongation of SA.106007)	Italy	Direct grant
SA.110777	TCTF: Danish investment scheme for green industrial production	Denmark	Direct grant
			Soft loan
			Guarantee
SA.112039	A beruházás ösztönzési célelőirányzat felhasználásáról szóló 210/2014 (VIII.27.) Korm. rendelet alapján nyújtott, 651/2014/EU bizottsági rendelet 14. és 41. cikke szerinti támogatás	Hungary	Direct grant/ Interest rate subsidy
SA.112546	RRF-TCTF: Interventions to support investments in strategic sectors for the transition towards a net zero emissions economy	Italy	Direct grant
SA.113231	TCTF - Investments in strategic sectors for the transition to a net-zero economy (Principality of Asturias)	Spain	Direct grant
SA.113565	Aid for the construction of the Hydrogen Core Network in Germany	Germany	Soft loan
			Guarantee
SA.113739	RRF Romania: State aid scheme to support capacity for the production of renewable hydrogen (reintroduction	Romania	Direct grant
SA.114137	TCTF/RRF - Spain: Support scheme for the production of renewable hydrogen in hydrogen clusters or valleys	Spain	Direct grant
SA.56826	2020 reform of support for cogeneration	Germany	Direct grant
			Other forms of tax advantage
SA.57779	Germany: EEG 2021	Germany	Tax advantage or tax exemption
			Direct grant
SA.58036	Support scheme for alternative fuels infrastructure for commercial transport and the acquisition of low emission commercial vehicles	Denmark	Direct grant
SA.59352	Federal aid scheme for the acquisition of light and heavy commercial vehicles with alternative, climate-friendly propulsion systems and ancillary EV charging facilities	Germany	Direct grant
SA.61890	RRF - Support scheme for the acquisition of alternative fuel buses for passenger transport	Germany	Direct grant
SA.62618	Portugal - Zero Emission Buses and respective supporting infrastructure	Portugal	Direct grant
SA.62619	Germany: H2Global	Germany	Direct grant/ Interest rate subsidy
SA.63278	RRF - Austria - Zero-emission public transport buses and infrastructure (Emissionsfreie Busse und Infrastruktur (EBIN))	Austria	Direct grant
SA.63404	Compensation des coûts des émissions indirectes en France pour la période 2021-2030	France	Direct grant
SA.63458	Germany – Aid for ancillary hydrogen refuelling facilities amending the Federal aid scheme for the acquisition	Germany	Direct grant
SA.63718	SA.63718 - Development of a recharging infrastructure for electric vehicles and hydrogen refuelling stations	Poland	Direct grant
SA.63733	Germany: Aid to ArcelorMittal Hamburg for a decarbonisation project	Germany	Direct grant
SA.64653	Portugal – RRF - Zero Emission Buses and respective supporting infrastructure	Portugal	Direct grant

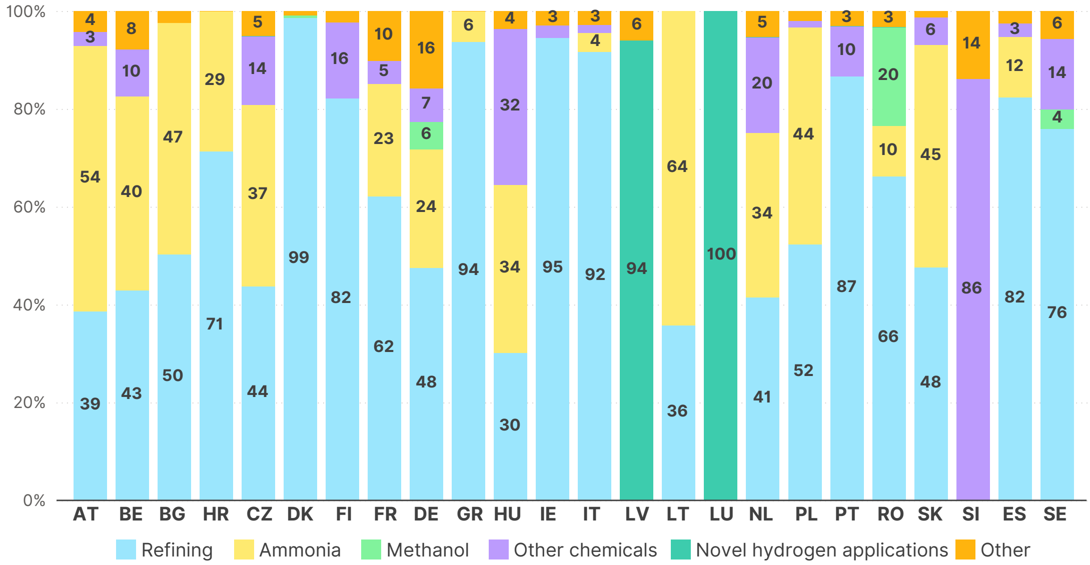
Source: ACER based on information from the European Commission's public database on competition cases.

Figure 26: Year-on-year change of hydrogen consumption in the EU by end-use – 2023 (%)



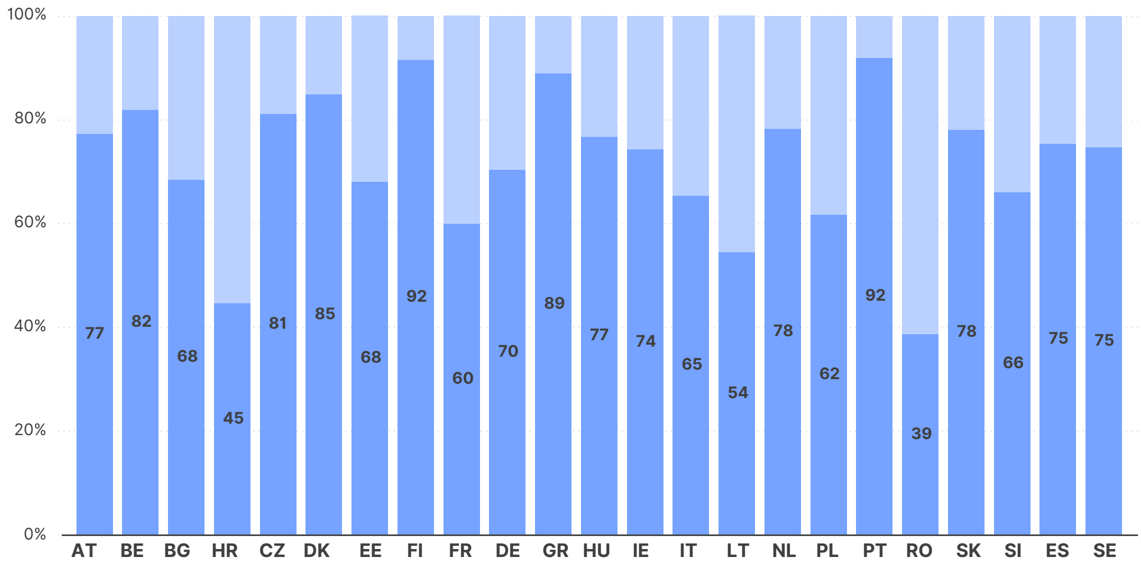
Source: ACER based on data from the European Hydrogen Observatory.

Figure 27: Share of hydrogen consumption by end-use in EU Member States – 2023 (%)



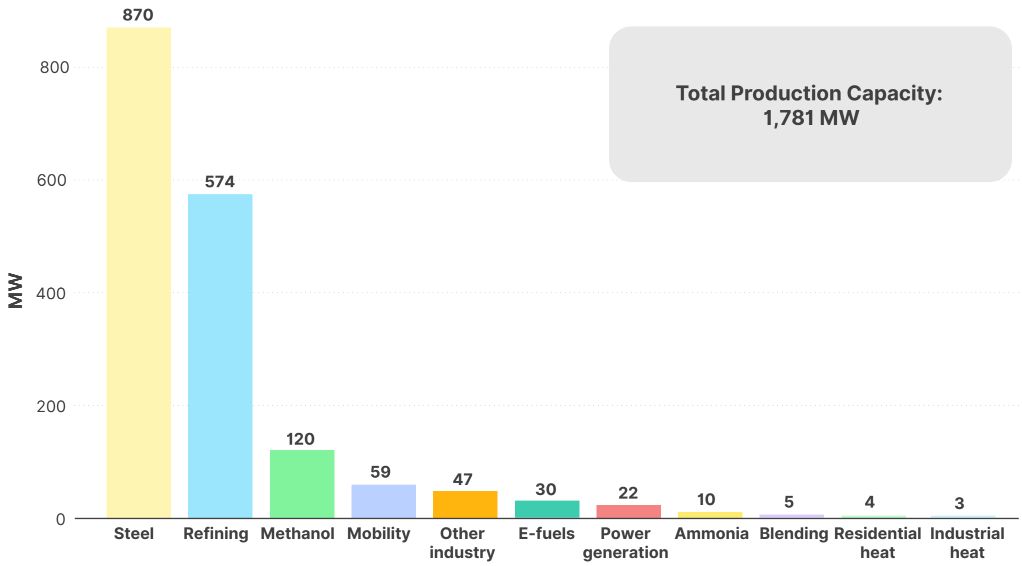
Source: ACER based on data from the European Hydrogen Observatory.

Figure 28: Hydrogen production capacity utilisation rates in EU Member States - 2023 (%)



Source: ACER based on data from the European Hydrogen Observatory.

Figure 29: Electrolysers under construction with expected commissioning by 2026 by end-use – September 2024 (MW)



Source: ACER based on data from the European Hydrogen Observatory.

Note: Data reflects the known electrolysers under construction as of May 2024.

Table 8: Mapping of electrolyser technologies and system services

	Alkaline		PEM		SOEC	
	Today	2030	Today	2030	Today	2030
FCR	Yes with limits	Yes with limits	Yes with limits	Yes with limits	No	Uncertainty about flexibility
aFRR	Yes with limits	Yes with limits	Yes	Yes	No	Uncertainty about flexibility
mFRR	Yes	Yes	Yes	Yes	No	Uncertainty about flexibility
RR	Yes	Yes	Yes	Yes	No	Uncertainty about flexibility
Voltage control	Electrolysers can provide reactive power, if they are equipped with self-commutated rectifiers.					
Congestion management	Yes	Yes	Yes	Yes	No	Uncertainty about flexibility

Source: ENTSO-E, Potential of P2H_2 Technologies to Provide System Services.

Table 9: Planned infrastructure projects per country in the 2024 TYNDP

Country	Pipelines			Terminals			Underground storage		Electrolysers		Total number of projects
	Number of projects	Length (km)	Of which repurposed (km)	Number of projects	Hydrogen import capacity (GWh/day)	Storage capacity (GWh)	Number of projects	Working gas volume (GWh)	Number of projects	Capacity (MW)	
Austria	3	746	520	0	0	0	0	0	0	0	3
Belgium	2	1,185	126	4	215	3,225	0	0	0	0	6
Bulgaria	2	580	0	0	0	0	0	0	0	0	2
Croatia	9	2,006	982	0	0	0	0	0	0	0	9
Cyprus	0	0	0	0	0	0	1	26	1	250	2
Czechia	3	947	947	0	0	0	0	0	0	0	3
Denmark	2	364	93	0	0	0	1	100	1	1000	4
Estonia	1	290	0	0	0	0	0	0	0	0	1
Finland	3	3,000	0	0	0	0	0	0	0	0	3
France	11	3,803	1,329	3	72	1,252	8	1,254	6	2,840	28
Germany	31	8,482	4,954	6	77	3,184	18	12,081	2	1,500	57
Greece	4	1,285	0	1	50	500	2	26	1	250	8
Hungary	4	953	345	0	0	0	0	0	0	0	4
Italy	4	2,509	1,781	1	28	0	1	345	2	1585	8
Latvia	1	288	0	0	0	0	0	0	0	0	1
Lithuania	1	500	0	0	0	0	0	0	0	0	1
Luxemburg	1	80	0	0	0	0	0	0	0	0	1
Netherlands	2	1,786	929	4	233	6,045	1	850	1	1200	8
Norway	1	960	660	0	0	0	0	0	0	0	1
Poland	5	2,982	251	1	18	0	1	0	0	0	7
Portugal	2	553	341	0	0	0	0	0	1	137	3
Romania	2	973	0	0	0	0	0	0	0	0	2
Slovakia	2	519	500	0	0	0	2	29,510	1	1	5
Slovenia	2	358	183	0	0	0	0	0	1	10	3
Spain	7	5,189	1,566	0	0	0	3	4,468	12	7,840	22
Sweden	2	2,086	0	0	0	0	0	0	0	0	2
Other non-EU countries	7	2,339	780	0	0	0	0	0	0	0	8
Total (EU and Norway)	**107**	**42,424**	**15,507**	**20**	**693**	**14,206**	**38**	**48,660**	**29**	**16,613**	**194**
Total (all countries)	**114**	**44,763**	**16,287**	**20**	**693**	**14,206**	**38**	**48,660**	**29**	**16,613**	**202**

Source: ACER based on the TYNDP-2024 project list.

Note: Other non-EU countries include Bosnia and Herzegovina, Tunisia, Ukraine, Switzerland and United Kingdom. The TYNDP-2024 project list includes one additional projects on hydrogen refuelling stations in Spain which is not included in the table.

List of figures

List of tables