Francesco Gabrielli

THE MULTI-PURPOSE NATURE OF HYDROGEN FOR DECARBONISING THE EUROPEAN ENERGY SYSTEM

Integrated Scenarios and Future Challenges

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This book is printed on acid-free paper
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Ai miei genitori,
Francesca e Vigilio

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Introduction

Over 90% of the Sun is composed of hydrogen, which is not only the lightest, but it is also the most abundant element in the universe. A single proton orbited by a single electron constitute the hydrogen atom, that on Earth usually joins another atom to form a hydrogen molecule (H_2). Largely due to its simple structure, H_2 is mostly found in compounds with other molecules, such as water (H_2O), being thus difficult to isolate from other elements. But why should we try to isolate hydrogen from the compounds it can be found in? This question is key to contextualise our work, as hydrogen can be a critical enabler of the energy transition paradigm.

While economies and societies keep evolving and energy demand at the global level continues to grow, the need to enhance the decoupling of economic growth from (mostly fossil) energy use is increasingly pressing. Given higher energy prices, supply disruptions and fear of repeated supply shortages in the last three years after the pandemics and the resurgence of different regional armed conflicts, global energy intensity improvements - defined as the percentage decrease in the ratio of total energy supply per unit of gross domestic product (GDP) - have slowed down. At the same time, however, energy and climate policies, particularly those of the European Union (EU), have been relaunched with new and highly ambitious decarbonisation targets, aiming to make Europe the first climate neutral continent by mid-century[1].

[1] Becoming «climate neutral» means reducing greenhouse gas emissions as much as possible, but it also means compensating for any remaining emissions. This is how a net-zero emissions balance can be achieved (Council of the European Union, 2019).

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Although the EU currently represents only about 6 % of global GHG emissions (European Commission 2024), the proposal of the European Commission presented in early 2024 to set an emission reduction target of 90% by 2040 compared to the 1990 levels (European Commission, 2024), is only the latest example of an enhanced ambition to decarbonise all sectors. Decarbonisation strategies must however be integrated in the well-known «energy trilemma», which involves trade-offs and opportunity costs between security of energy supply, competitiveness and sustainability issues. Along with the implementation of energy efficiency measures, the installation of new renewable capacity is currently the main driver of decarbonisation efforts, which remain nonetheless subject to renewables' intermittency (if we exclude hydropower and geothermal energy) and seasonality in their production profiles. Therefore, realising the ambitious energy and climate agenda requires both stability and predictability. While the latter can be guaranteed by a comprehensive and future-proof regulatory framework that is able to simplify bureaucratic procedures and attract private capital investments, stability requires different technological solutions capable of enabling the phase-out of fossil fuels.

While EU energy policies in the previous decade were almost exclusively concentrated on developing and deploying renewable power technologies like solar and wind and encouraging massive electrification of end-use applications and production processes, the policy framework introduced with the Fit-for-55 - and the subsequent adoption of the REPowerEU plan in 2022 - has been carving out an important role for clean molecules in enabling decarbonisation where the penetration of electricity is not possible, thus avoiding reliance on traditional fossil fuels. Clean molecules include low-emission gases (e.g. biogas and biomethane), abated fossil gases (thanks to carbon capture and storage), renewable and emission-negative gases, that are likely to both directly substitute unabated gas in some cases and to gain a market share in new applications previously served by other non-gaseous energy vectors, like diesel or electric cars. One of such molecules is hydrogen, the development of which has not only become a critical pillar of the EU's decarbonisation strategy, but it also represents an important component of Europe's industrial policy. Indeed, several Member States within the Union are home to world-class industrial players along the hydrogen and fuel-cell value chains, thus potentially making the EU one of the most advanced global hubs in the manufacturing of H_2 technologies. From an energy point of view, hydrogen can support decarbonisation as it produces zero carbon emissions at the point of its use (either as a feedstock or as a fuel) and it can also be combined with other molecules, such as CO_2 to produce so-called «synthetic fuels», that help reduce emissions by displacing fossil fuels both in industry and transportation.

Given the technological, economic, regulatory and political implications of hydrogen development and deployment at the EU level, this thesis attempts to analyse the integration of H_2 into the European energy system from an economic policy perspective along four different chapters. While the analysis on how and why hydrogen can prove crucial for decarbonisation will be addressed repeatedly based on the specific context of each chapter, the question of whether hydrogen integration would be actually feasible and economically viable will be the backbone of our discussion.

The effective decarbonisation of the energy system is only possible if both final uses and the entire energy supply chain are low- or zero-emission. That is why Chapter 1 will address and compare the different hydrogen production methods that currently exist, from the most to the least polluting, and assess their cost-effectiveness. While being relatively easy to produce, hydrogen can be difficult to transport, as it is extremely light and flammable, and it has a low energy density in terms of volume compared to natural gas, for example, thus requiring greater transport capacity for the same amount of energy. Therefore, finding the most efficient transport mode for H_2 and evaluating its storage needs is critical to assess its potential market development. Lastly, we will briefly mention the potential hydrogen end-uses, so as to prepare the ground for the different concrete cases addressed in the following chapters.

Chapter 2 will thus examine the policy and regulatory landscape at the EU level that can support the development of an integrated hydrogen market, while estimating the investment needs to enable the creation of H_2 production hubs, transmission networks and regional demand centres. Despite the early adoption of an EU Hydrogen Strategy (in 2020) that has provided a roadmap for new policy and investment measures, not all EU Member States have been keeping the pace of the EU's agenda, both because of their different political and economic priorities, and because of the structure of their national energy systems, which varies significantly from one EU country to the other.

Out of the EU's top three economies, Italy is the last one to have adopted a national hydrogen strategy, while countries like France and Germany (and also Spain) have already consolidated their national roadmaps with a view to upscaling hydrogen in their energy mixes and potentially importing it from neighbouring countries. Indeed, import proves essential to achieve the H_2 targets set at the EU level, as these significantly outpace the means available to the EU countries to produce hydrogen at present. Therefore, in Chapter 3 we will analyse the potential creation of several «hydrogen supply corridors» that would be needed to meet the expected renewable and low-carbon hydrogen demand in the EU, with Germany as the main demand driver, up to 2040-50. In this context, Italy could potentially become one of the major hydrogen producers and importers in the EU, mainly thanks to its extensive gas network and interconnections, and its geographic location, which is naturally projected into the southern Mediterranean, thus giving access to both ample renewable resources and potential low-cost hydrogen imports from North African countries.

As the development of the currently small hydrogen market requires the simultaneous transition of both supply (including import) and demand, in Chapter 4 we will examine a concrete use case related to hydrogen use in hard-to-abate industries in Italy. These sectors are indeed characterised by their technical inability to electrify their production processes and energy uses, thus currently continuing to consume large amounts of fossil fuels, mostly natural gas. Here, hydrogen can prove to be a game-changer, by enabling the replacement of those high-emitting energy inputs, and complementing the energy uses that are already electrified. The significance of H_2 for decarbonising hard-to-abate sectors is underlined by the newly adopted EU rules on hydrogen, by several Member States' national H_2 strategies as well as by the industry itself, with a view to supporting the energy transition and develop a European (and Italian) value chain for cutting-edge hydrogen technologies.

The work that will be carried out in the next four chapters is inspired both to the courses taken during the master's degree, in particular the «Energy, Environment and European Security» course, to the specialised trainings on natural gas and hydrogen completed at the Florence School of Regulation within the European University Institute, as well as to the traineeship experiences at the European Energy Forum and at the Delegation of Confindustria to the European Union. This dissertation benefited from the scientific support of the Istituto Affari Internazionali (IAI) in the context of the "Eni Sustainable Energy Scholarship" part of the IAI-ENI Strategic Partnership[2].

[2] https://www.iai.it/en/ricerche/iai-eni-strategic-partnership

CHAPTER 1

The fundamental toolbox for analysing the development of a hydrogen economy

Introduction

Hydrogen has long held promise as a clean energy carrier, but its potential remained largely unfulfilled, mostly owing to two fundamental problems: its low density, which makes it hard to handle, and the fact that – contrary to fossil fuels – hydrogen is extremely difficult to isolate from other elements (Alverà 2021). However, due to the ever-growing concerns about the anthropogenic nature of climate change, H_2 has been increasingly regarded as the missing piece of a decarbonised energy system, because of numerous reasons including the following: hydrogen production can be carried out using diverse energy resources and methods (see the next paragraph); H_2 does not emit CO_2 at the point of use and upon combustion it produces water (H_2O); it can be used as energy carrier and can also be employed as a fuel for combined heating and power (CHP) production systems; finally, due to the intermittent and non-dispatchable nature of solar and wind (renewable) energy sources, hydrogen can be regarded as a key candidate that can be used as a storage medium, especially for long-term renewable energy storage (Ishaq et al. 2022).

A true decarbonisation of national energy systems is however possible only if both final uses and the entire energy supply chain are emission-free. Therefore, in this case, a comprehensive life-cycle assessment of hydrogen delivery is necessary. That is why the first section of this chapter will be devoted to evalu-

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ating and comparing the different hydrogen production methods, both from a technical and a cost-effectiveness point of view. Before deepening the technological aspects related to H_2 generation, it is important to mention the so-called «hydrogen colour spectrum» (National Grid 2022) that has been progressively established in the literature as the primary methodology to classify the renewability of the sources from which H_2 is produced. The colours used to identify fossil-based hydrogen generation are four: black (or brown), grey, blue, and turquoise. The first colour represents H_2 production from coal (or lignite), resulting in high levels of CO_2 and carbon monoxide that are released in the atmosphere. Grey hydrogen is usually produced from natural gas via steam methane reforming (SMR), which will be thoroughly explained in the next section, since it is currently the most exploited technology, but also one that generates around 11 tonnes of CO_2 for every tonne of hydrogen produced (Alverà 2021). Blue hydrogen instead, despite being sourced from fossil fuels (mainly methane), is coupled with a system that captures the emitted CO_2, which is then often stored (Carbon Capture and Storage, CCS) or sold and used in other industries (Carbon Capture and Utilisation, CCU). The fourth colour identifies a method that is still in an experimental stage and involves the breakup of methane molecules (CH_4) in their constituent parts, namely hydrogen and solid carbon, following the heating up of methane in the absence of oxygen. Methane cracking therefore does not result in CO_2 emissions, but temperatures between 800 and 1200°C (and thus a lot of energy) are needed to split CH_4 due to its high stability (Alverà 2021). The remaining colours of the spectrum that identify the way in which hydrogen is produced are pink (or red/purple) and green. While the former uses nuclear power (either in form of heat or electricity produced by the power plant) to produce H_2, green hydrogen is generated through the water electrolysis process by employing renewable electricity, thus avoiding CO_2 emissions during production[1].

After the techno-economic assessment of hydrogen production methods in the first section, the second section of this chapter will deepen a critical component of the hydrogen economy, namely transmission and storage systems. The main routes of hydrogen transport that are currently under development and that will be analysed are: repurposed gas networks, newly built H_2 pipelines, and more flexible (road, rail, river and maritime) transportation networks. The choice of the most effective delivery method depends on the chosen means of storage, as changes in the state of hydrogen increase energy losses, delivery distance, and throughput (Reuß et al. 2017; Yang and Odgen 2007). Finally, the third section of this chapter will address hydrogen final uses, that cover a broad range of applications, from the heavy industry sector to residential heating and

[1] A 2023 IEA report has put forward a proposal to abandon the hydrogen «colour codes» and to adopt a new methodology to define the different hydrogen production processes based on their emission intensity, because the agency argues that the use of colours or terms such as «clean» and «low-carbon» can obscure many different levels of potential emissions and deter potential investors from hydrogen projects (IEA 2023).

CHP units, which are increasing in importance in decentralized energy systems (Weidner et al. 2019). In many of the «hard-to-abate» industries (chemical, steel, cement), hydrogen (mostly in its "grey" form) is mainly used not as an energy carrier but as a feedstock.

Two final aspects should be considered before examining the different components of the hydrogen economy. The first concerns the safety of using H_2, since most hydrogen hazards relate to the fact that, like methane, hydrogen gas cannot be spotted with human senses (Rigas and Amyote 2013), even though leaks can be detected thanks to the addition of odorants to the gas. On the other hand, unlike gasoline, hydrogen is neither toxic nor carcinogenic (Linde AG 2018). The second aspect is related to H_2 utilisation and particularly to the willingness to pay of consumers for using hydrogen-based technologies (such as in transport or heating). According to economic theory, a customer purchases a product or service if two main conditions are met: 1) the utility provided by the good exceeds the so-called total cost of ownership (TCO), that is, its net utility is positive, and 2) if the product's net utility is the highest among all available alternatives (Hafner and Luciani 2022). In this case, the reduction of CO_2 emissions incurred in using hydrogen-based technologies may raise the perceived utility of the product, while the TCO depends on the dimension of fixed and variable costs (such as for example the cost of hydrogen fuel for cars).

1.1 Hydrogen generation

The first essential step lies in the selection of the primary energy source for producing hydrogen. The former must first and foremost be reliable and affordable. The current main hydrogen production method is through fossil fuels (around 95-96% globally) and more specifically natural gas reforming (also called steam-methane reforming, SMR), methane partial oxidation and coal gasification (Ishaq et al. 2022). Only the remainder 4-5% is produced from water electrolysis, meaning that associated to hydrogen production there are still significant CO_2 emissions. Although such a ratio between electrolytic and fossil-based H_2 has tended to hold steady in recent years, the importance of avoiding carbon-based (and thus polluting) technologies to produce hydrogen has emerged, together with significant concerns regarding the efficiency of carbon removal methods, such as carbon capture, utilisation and storage (CCUS). To this end, we will outline the salient features of the different hydrogen generation methods, whose cost-effectiveness and economic aspects will be addressed thereafter. Finally, we will focus more specifically on the growing attention towards the production of renewable (green) hydrogen.

1.1.1 Hydrogen production processes

A broad range of methods is available for H_2 generation which can be categorized into two primary groups: renewable technologies and non-renewable technologies (Nikolaidis and Poullikkas 2017). The latter category includes hydrocarbon pyrolysis and hydrocarbon reforming, which encompasses the three fossil-based methods mentioned above. On the other hand, hydrogen production via renewable energy has two main branches, namely biomass-based and water-splitting technologies. Processes that use biomass as the raw material fall into two further sub-categories: thermochemical technologies such as gasification, pyrolysis, combustion, and liquefaction; and biological processes comprising fermentation and bio-photolysis stages (Nikolaidis and Poullikkas 2017). Water-splitting processes instead include electrolysis, photo-electrolysis, and thermolysis where water is the feedstock. A technical overview of those technologies is provided in the next paragraphs, mainly building on Ahmed et al. (2022).

Fossil-fuel processing technologies

The basic operating principle of such technologies is the extraction of the high hydrogen content of fossil fuels by breaking down the hydrocarbons in different ways. As stated above, these H_2 extractions can occur either by reforming the molecular structure of the compounds or by imposing the thermal decomposition of hydrocarbons at extremely high temperatures (Kumar and Himabindu 2019). Despite the significant amount of emissions, these technologies offer low-cost and easily adaptable alternatives to non-conventional hydrogen extraction mechanisms and above all lead to a significantly higher yield of hydrogen (Ahmed et al. 2022). Hydrocarbon pyrolysis can indeed have a 78% H_2 yield and up to 91% conversion efficiency (Pérez et al., 2021). This process produces hydrogen by thermal decomposition (with temperatures up to 1175°C), where the light liquid hydrocarbons (i.e., methane, ethane, etc.) are decomposed through a thermo-catalytic process that produces elemental carbon and hydrogen.

The partial oxidation technology is instead a conversion process that is used to extract hydrogen and CO_2 as the by-products of steam, oxygen (O_2) and hydrocarbons. If any sulphur is present in the latter element, it is removed initially and then the feedstock (methane) comes into contact with O_2 so that the hydrocarbon becomes partially oxidized. When using coal as a feedstock, this process is also known as coal gasification, whereby pressure and heat break down coal into its chemical constituents, resulting in a synthetic gas mixture, composed mainly of CO and H_2. The produced syngas ($CO+H_2$) is then treated using steam reformation techniques. The process is very similar to steam reformation technology (see the next paragraph), and the only major difference is the initial oxidization step, while the conversion efficiency can be up to 99% (Fakeeha et al., 2020).

Finally, the steam methane reforming (SMR) process is a well-established technology that includes several stages, such as synthesized gas production, water-gas shift (WGS), and gas purification. Light hydrocarbons and heavy naphtha are used as feedstock, with no requirement for an oxygen source. After the first step involving the de-sulphurisation of natural gas, the actual steam methane reforming takes place, whereby natural gas reacts with steam at high temperatures and forms carbon monoxide and hydrogen gases, according to the following conversion: $CH_4 + H_2O \rightarrow CO + 3H_2$. The produced CO can further be reacted with steam using the water gas shift reactor to convert carbon monoxide into CO_2 and additional hydrogen can be produced: $CO + H_2O \rightarrow CO_2 + H_2$ (Ishaq et al. 2022). Since the products of this conversion are mostly H_2 and CO_2, they are purified using CO_2 removal mechanisms (Nikolaidis and Poullikkas 2017). If carbon capture technologies are not integrated as a final stage in this process, SMR results in large quantities of GHG emissions due to the carbon dioxide produced while extracting hydrogen, thus representing one major drawback of this technique. This notwithstanding, as will be discussed in the economic analysis of H_2 production methods, SMR has drawn the attention of many researchers and policymakers due to its high efficiency in hydrogen production (70 to 85%) with low operational, feedstock (0.3 \$/kgH_2) and production (1.25 to 3.50 \$/kgH_2) cost (Kannah et al. 2021).

Renewable hydrogen production technologies

Renewable techniques have gathered pace, mostly relying on water electrolysis. The latter is indeed used to split water into its components of oxygen and hydrogen using electricity generated from solar, wind, geothermal, hydro, and biomass energy sources, according to the following reaction: $2H_2O \rightarrow 2H_2 + O_2$. The relative simplicity of this process leads to focus more on the type of instrument used to perform the water splitting, namely the electrolyser.

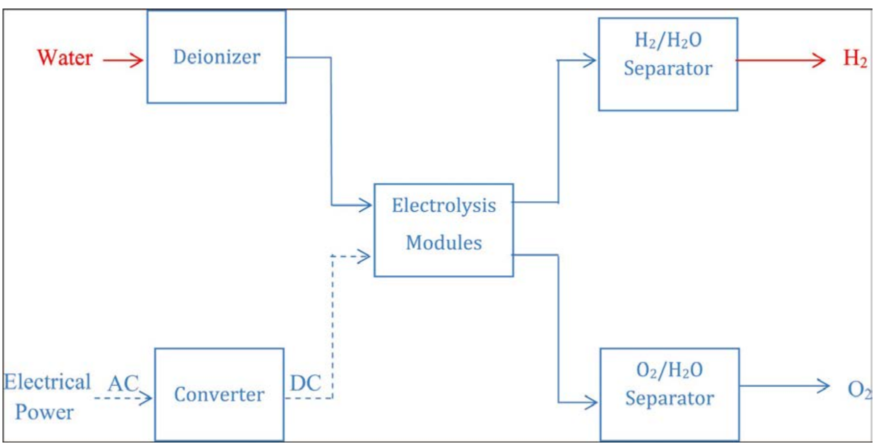

Figure 1 – Flow diagram of the water electrolysis process. Source: Nikolaidis and Poullikkas (2017).

Solar energy can play a significant role in clean and sustainable hydrogen production, not only through photovoltaic generation, but also with solar thermal and photo-electrochemical technologies (Calls et al. 2019). The concentrated solar thermal energy source can be used to produce hydrogen using multiple routes namely, solar thermolysis, solar thermo-chemical cycle, mechanical energy to electrical energy, solar gasification, solar cracking, and electrolysis (Ishaq et al. 2022). The electrical power produced from the photovoltaic source is instead directly employed to the electrolysis for hydrogen production. As to photo-electrolysis, sunlight in a photo-electrochemical cell is used to produce H_2 from water (Scott 2019).

Wind energy (power produced from the conversion of kinetic energy into mechanical energy through a turbine and finally electrical energy by a generator) is another critical source of green hydrogen. The electrical energy extracted from the wind energy source is alternating current (AC), thus an alternating-direct current (DC) converter is employed to feed the DC electrical power to the electrolyser for hydrogen production (Ishaq et al. 2022). It is important to address the difference between onshore and offshore wind turbines, since their location has significant implications for the generation costs of green H_2. There are more wind resources on the offshore sites globally in comparison with onshore (approximately twice as medium onshore wind farms), and when sited offshore, the acoustic and visual impact is very trivial, therefore much larger areas can be used (Wang et al. 2019)[2].

Geothermal energy is transmitted to the earth's surface using steam or hot water and it can be utilized for multiple purposes, such as cooling, heating, or producing electricity (Ishaq et al. 2022). Using this source of energy to produce hydrogen mainly refers to electrical power generated that feeds the electrolyser to split water. But geothermal energy can also be used to heat the water which makes electrolysis more efficient (Soltani et al. 2019) and geothermal heat can be employed for thermochemical hydrogen production (Balta et al. 2010). A geothermal source with a high temperature is required for lower cost hydrogen production and liquidating processes (Ishaq et al. 2022). Another technology that can be exploited to produce green hydrogen is hydropower, which is considered renewable due to the fact that the cycle of water is continuously renewed. However, excluding a few countries that are abundant in this source (such as Norway), hydropower is generally used as a backup to meet the peak-load demand as it can be voluntarily started and stopped, and the energy flows can be concentrated and controlled (Peng et al. 2021).

One final technology that allows to produce hydrogen avoiding net-GHG emissions is biomass gasification. The latter can be defined as a process that converts biomass – such as crop residues, forest residues and solid waste – into syngas ($CO+H_2$) by means of oxygen and/or steam at temperature greater than 700°C (Capurso et al. 2022), thus transforming an organic material into carbon monoxide, carbon dioxide and hydrogen. Gasification is a considerably cleaner process of conversion as compared with combustion, because gasification produces fuel

2 A recent DNV study has found that offshore hydrogen production connected by pipeline could be cheaper than onshore hydrogen production. Given the expected EU demand for climate-neutral hydrogen at around 2,000 terawatt hours (TWh) by 2050, DNV sees the potential to produce 300 TWh of hydrogen using electricity from offshore wind farms in the North Sea by 2050 (Bernert 2023).

in the form of syngas rather than burning it which prevents many pollutants to be emitted such as nitrogen oxides (NO_x) and sulphur oxides (SO_x) that occur at higher temperatures (Ishaq et al. 2022). The latter elements are combustion products that are emitted in the form of smoke when the temperature is higher than that of gasification, and they have indeed adverse effects on the ozone layer in the troposphere, thus worsening the global warming process. Biomass gasification's efficiency is around 46% (Staffell et al. 2019). Because plants consume carbon dioxide from the atmosphere as part of their natural growth process as they make biomass, they contribute to off-setting the carbon dioxide released from producing hydrogen through biomass gasification, resulting in low net greenhouse gas emissions (US Department of Energy 2019). If combined with a Carbon Capture and Storage (CCS) technology, hydrogen production from biomass gasification could be even carbon negative (Capurso et al. 2022).

1.1.2 Economic assessment of hydrogen production methods

Since hydrogen is not widely accessible in nature, the energy conversion routes highly influence the overall cost of hydrogen production (Ahmed et al. 2022). An analysis of the main cost components involved in the upstream stage of the H_2 value chain is therefore important in order to have a sharper picture of the hydrogen economy. Firstly, cost parameters for H_2 production can be divided into two major categories, which will be also mentioned in the subsequent sections, namely operational (OPEX) and capital (CAPEX) costs. The latter have been sub-divided, by Kannah et al. (2021), into two groups: the direct capital costs, that include instrumentation, control system and site-specific costs, and indirect capital costs, that include engineering and supervision, construction costs, legal and contractor expenses and contingency. Instead, operating costs are represented by the raw material (the feedstock), by labour and maintenance costs. In the next paragraphs, first a definition of «Levelised Cost of Hydrogen» is provided, secondly, the costs of the main hydrogen production methods will be outlined and compared to one another, drawing from the existing techno-economic literature. Thirdly, some important cost parameters of the hydrogen upstream component – such as the Net Present Value (NPV), the Return on Investment (ROI) and the Pay-Back Period (PBP) – will be discussed.

The methodology used to establish the capital and operating costs of hydrogen production is indeed defined as «Levelised Cost of Hydrogen» (LCOH), which enables different production routes to be compared on a similar basis. The LCOH indicates how much it costs to produce 1kg of hydrogen, taking into account all the relevant variables that affect production, namely CAPEX, OPEX and – if renewable electricity is used – the annual hourly production curve of the renewable resource (Vector Renewables 2022). For the purpose of this chapter, it is therefore essential to briefly examine how the LCOH is calculated. Since it is used for evaluating the economic performance of hydrogen production, the LCOH is defined as discounted cash flows divided by the discount hydrogen output, according to the following formula (Tang et al. 2022):

$$\mathrm{LCOH} = \frac{\sum_i \frac{I_i+M_i+O_i-R_i}{(1+r)^i}}{\sum_i \frac{E_i}{(1+r)^i}} \tag{1}$$

where I_i is the investment in year i, M_i the maintenance and service cost in year i, O_i the operational cost in year i, E_i the energy (hydrogen) output in year i, [kg], R_i the revenue income in year i, and finally r is the cost of capital, [%]. If the investment, the other costs and the revenue are taken in euros [€], the LCOH is thus expressed in € per kg of hydrogen [€/kg_{H2}]. As defined in economic and financial theory, the discounted cash flows are used to find the present value of the expected future cash flows using a given discount rate, so that investors can determine whether future cash flows of a project (in this case related to hydrogen production) are larger than the value of the initial investment. This is the concept of the net present value (NPV). Drawing from the formula described above, since the aim is to investigate the cost components, the cash flows and the hydrogen output are simplified as constants along with the years, thus resulting in the following equation (Tang et al. 2022):c

$$\mathrm{LCOH} = \frac{(I+M+O-R)\sum_i \frac{1}{(1+r)^i}}{E\sum_i \frac{1}{(1+r)^i}} = \frac{(I+M+O-R)}{E} \tag{2}$$

To have a first practical outlook of the evolution of the LCOH on a global level, the IEA has provided a chart (Figure 2) that reports the actual LCOH in 2021 and 2022, versus the expected LCOH for 2030, based on the path to climate neutrality by 2050, for different production sources.

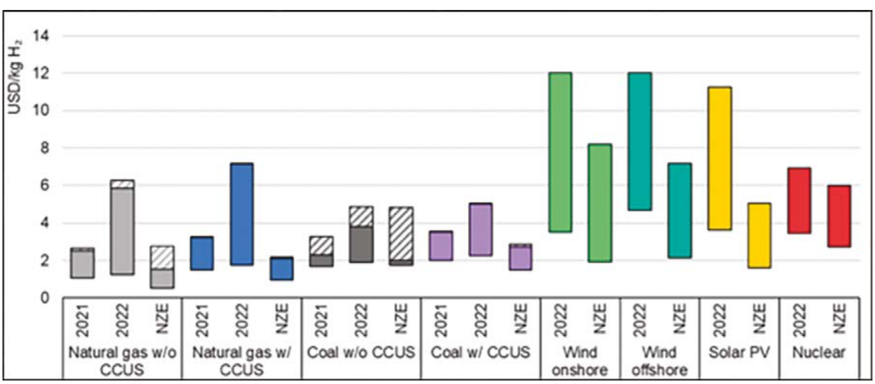

Figure 2 – Levelised cost of hydrogen production by technology in 2021, 2022 and the Net Zero Emissions by 2050 Scenario [\$/kg_{H2}]. Source: IEA (2023c). Notes: CCUS = carbon capture, utilisation and storage; PV = photovoltaic; NZE= Net Zero Emissions by 2050 Scenario in 2030. Solar PV, wind and nuclear refer to the electricity supply to power the electrolysis process. NZE values refer to 2030. The dashed area represents the CO_2 price impact.

The LCOH shows a high variability depending on the hydrogen production source. When using natural gas, it can be seen that costs are comparatively lower than when using renewable technologies. The spikes in the 2022 LCOH for natural gas (both with and without CCUS) are mainly due to the gas price crisis sparked by Russia's war against Ukraine in early 2022 and the already present tightness in gas markets from late 2021. All costs are projected to be declining by 2030 compared to 2022, but wind- and solar PV-based H_2 production will remain costlier than the fossil-based one also in the medium term, even though prices will be lower overall compared to today.

Since in the following we will review the literature assessing H_2 generation costs according to each technology, one last element should be mentioned in this first part, because it will also be useful to better understand the next chapters, which will be dealing with the integration of electricity and hydrogen molecules. The LCOH's calculation methodology can indeed be compared to the technique used to compute the so-called «Levelised Cost of Electricity» (LCOE), which – being always linked to the concept of the present value of the investment – is calculated by the net present value (NPV) of the total cost of building and operating a power generating asset, and dividing this number by the total electricity generation over the lifetime of the plant (US Department of Energy 2013). The LCOE is therefore the measure of lifetime costs of the power plant divided by its energy production, thus allowing for comparisons of different technologies (solar, wind, natural gas…) with unequal life spans, different CAPEX, different risks and returns. As will be mentioned later in this chapter, one of the current most significant challenges in increasing the size of the hydrogen economy and scaling-up green hydrogen production lies in reducing the cost of the electrolyser, since the H_2 production cost is greatly influenced by the electrolyser capital cost, and the maximum electrolyser utilisation (load hours) results in lower H_2 production costs, which accounts about 3000-6000 operating hours (Kannah et al. 2021).

The latter element is one of the main reasons why steam-methane reforming (SMR) is still the most widely used technology for H_2 production, since its high efficiency leads to larger hydrogen yield per unit of feedstock, resulting in a production cost that lies between \$1.25 and \$3.50 (or €, given today's quasi-parity of the two currencies) per kg of H_2. As SMR leads to significant CO_2 emissions, carbon capture and storage (CCS) technologies are used and therefore the cost of H_2 production can increase, being no less than 2.27 $\$/kg_{H2}$ (Nikolaidis and Poullikkas 2017). Coal gasification lies between 1.30 and 1.60 $\$/kg_{H2}$ (Ahmed et al. 2022). Such methods of thermo-chemical conversion are thus extensively exploited due to the energy density and huge availability of carbon-based fuels. Indeed, on a global level, approximately 48% of H_2 is produced from natural gas, 30% using oil and 18% using coal.

Renewable hydrogen produced through water electrolysis shows, instead, higher costs per kg. For instance, Kuckshinrichs et al. (2017) documented the economic analysis of mature H_2 production technology (Alkaline water electrolysis, AWE) at three different site locations in Europe – Germany, Austria, and Spain. They reported that the LCOH was around 3.64 $€/kg_{H2}$ at the German site, whereas in Austria and Spain sites, the levelised cost of H_2 was slightly higher (15 to 18%), mainly owing to the higher electricity cost. Matute et al. (2019) have estimated the cost of H_2 production for AWE around 6 €/kg_{H2} and Proton-exchange membrane (PEM) based water electrolyser as 7 €/kg_{H2}. According to Ahmed et al., (2022), photo-electrolysis with a solar energy source can have a production cost as high as 10.36 \$/kg_{H2}, and a similar pattern is also followed by the H_2 production technologies using biomass (lignocellulose in this case), whose cost lies around 12 €/kg_{H2}. Table 1 gives a schematic overview of the above-mentioned data.

Table 1 – Costs of hydrogen production using available technologies. Source: own elaboration based on selected studies.

Technology	LOHC [\$ & €/kg_{H2}]	Study
Steam-methane reforming	1.25-3.50	Ahmed *et al.* (2022)
SMR with Carbon Capture and Storage (CCS)	2.27	Nikolaidis and Poullikkas (2017)
Coal gasification	1.30-1.60	Ahmed *et al.* (2022)
Renewable hydrogen (water electrolysis using ALK and PEM electrolysers)	3.64 (Germany ALK), ~5 (Austria, Spain ALK), ~6 (ALK), 7 (PEM)	Kuckshinrichs *et al.* (2017) Matute *et al.* (2019)
Renewable hydrogen (photo-electrolysis)	10.36	Ahmed *et al.* (2022)
Biomass technologies	12	Ahmed *et al.* (2022)

Because green hydrogen is mostly produced via electrolysis, it is interesting to briefly focus on the way in which production (fixed and operating) costs for water electrolysis are formed, so as to have the necessary theoretical instruments to analyse the next section covering renewable hydrogen in particular. The factors that determine the CAPEX, the OPEX and the mass of hydrogen produced (M_{H2}) can be specified as follows (Kannah et al. 2021):

$$CAPEX=CCA+(OMC+IC).CCA.A \tag{3}$$

$$OPEX = COE \cdot \frac{r_{H_2} \cdot HHV}{\eta} \cdot LT \cdot CF \tag{4}$$

$$MH_2=rH_2.LT.CF \tag{5}$$

where CC_A = capital cost of electrolyser, A = net area of the electrode (used to split water), COE = cost of electricity, rH_2 = rate of H_2 production, HHV = higher heating value of hydrogen[3], η = efficiency of the electrolyser system, LT = lifetime

[3] The heating value (or energy value or calorific value) of a substance is the amount of heat released during the combustion of a specified amount of it. The calorific value is thus the total energy released as heat when a substance undergoes complete combustion with oxygen un-

of the electrolyser, CF = capacity factor[4], OMC = operation and maintenance costs, IC = installation costs, and CC_A times A = total capital cost. The cost of electricity is one of the most critical elements for establishing the convenience of the whole electrolysis system, and also the water supply must be considered. Electricity cost is strictly connected to the concept of power purchase agreements (PPAs). These are increasingly used contracts signed between a producer and a consumer of electricity that fix a certain price, thus insulating the counterparts from market price volatility. For instance, Fragiacomo and Genovese (2020) include PPAs to calculate the electricity cost in their economic analysis of renewable hydrogen production in southern Italy[5].

Before moving to the analysis of renewable hydrogen replacing fossil-based H_2, one last point should be made with regard to the methods used to establish the cost-effectiveness of a hydrogen production technology. Return on investment (ROI) and the pay-back period (PBP) will be briefly addressed. While the latter can be defined as the time, in years, that the expected benefits of the investment equal the fixed assets, namely when the NPV is equal to zero, the ROI index represents the potential economic returns compared to the initial investment (Fragiacomo and Genovese, 2020). Therefore, ROI can allow to identify the total growth of the production plant from the start to the end of its life. Kannah et al. (2021) present the following formula to calculate ROI: ROI = (AF/FCI)*100%, where AF is the annual profit (difference between annual revenue and annual production cost) and FCI is fixed capital investment (cost required for purchase of land, equipment and installation). Typically, a value of ROI above 20% is considered as profitable for the scaling up process.

1.1.3 Renewable hydrogen substituting polluting hydrogen production methods

Renewable hydrogen, as outlined by the EU Hydrogen Strategy (2020) is defined as «hydrogen produced through the electrolysis of water (in an electrolyser, powered by electricity), and with the electricity stemming from renewable sources», adding that «the full life-cycle greenhouse gas emissions of the production of renewable hydrogen are close to zero» (European Commission

der standard conditions. The higher heating value (HHV) - or gross energy, upper heating value, gross calorific value GCV, or higher calorific value - indicates the upper limit of the available thermal energy produced by a complete combustion of fuel. It is measured as a unit of energy per unit mass or volume of a substance. The HHV is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. See: Wikipedia Contributors (2019). *Heat of combustion*. [online] Wikipedia. Available at: https://en.wikipedia.org/wiki/Heat_of_combustion.

[4] The capacity factor can be defined as the ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period (U.S. NRC 2021)

[5] The role of PPAs is currently also being enforced in the context of the reform of the electricity market design at the European Union level (see the next chapters).

2020)[6]. The newly adopted EU Delegated Acts on Renewable Hydrogen further specify that unless the electricity system is already largely decarbonised, it is crucial to match the electricity demand for hydrogen production with additional renewable electricity generation, otherwise electrolysers' additional electricity demand could risk leading to increased fossil-based power generation (European Commission 2023).

Therefore, using «clean hydrogen» as a synonym for renewable H_2, it is important to introduce the concept of «well-to-gate» when accounting for emissions in hydrogen production. This is an assessment methodology that calculates the lifecycle emissions associated with upstream feedstock production, upstream transportation, and onsite hydrogen production, thus excluding downstream storage and transport emissions, service and end-of-life emissions, and it can be measured in grams or kilos of CO_2 equivalent per kg of produced hydrogen (Connell 2022). For instance, the well-to-gate GHG emissions of steam reforming of natural gas are about 9 kg of CO_{2eq}/kgH_2, while those of SMR with carbon capture and storage (CCS) with 90% capture are equal to 1 kg of CO_{2eq}/kgH_2, and 4 $kgCO_{2eq}/kgH_2$ with a capture rate of 56% (IEA 2019).

Several obstacles must be considered when assessing the increasingly wider employment of renewable hydrogen and the flexibility that the latter can provide to decarbonise polluting sectors of the economy. The first key component is renewable electricity, which when produced through solar PV or wind can also be referred to as variable renewable energy (VRE). Hydrogen produced from renewable electricity (through an electrolyser) could indeed facilitate the integration of high levels of VRE into the energy system, because the electricity consumption of electrolysers can be adjusted to follow wind and solar power generation, where hydrogen becomes a source of (long-term) storage for renewable electricity (IRENA 2018). Moreover, hydrogen from renewable electricity could create a new downstream market for renewable power, because it has the potential to reduce renewable electricity generators' exposure to power price volatility risk, in instances where part or all generation is sold to electrolyser operators through long-term contracts (e.g. PPAs). The second key element is thus the electrolyser, analysed hereafter.

Scaling-up electrolysers to reduce the cost of green hydrogen

The measures taken by several governments and by the EU to set manufacturing capacity targets for electrolysers are increasingly coupled with financial incentives to expand production, but electrolysers deployment – and thus the supply of

[6] Hydrogen produced from biomass (through biogas) is also considered renewable by the Renewable Energy Directive (2018), but it is not included in the definition of «Renewable fuels of non-biological origin» (RFNBOs) as included by the European Commission in the «Additionality Delegated Act», formally adopted in June 2023, because biomass is defined as «the biodegradable fraction of products, waste and residues from biological origin from agriculture, including vegetal and animal substances, from forestry and related industries, including fisheries and aquaculture, as well as the biodegradable fraction of waste, including industrial and municipal waste of biological origin» (Renewable Energy Directive 2018).

renewable H_2 – will be eventually determined by the demand for green hydrogen. According to the International Renewable Energy Agency (2021), cost declines in electrolyser manufacturing are greatest during the current, early stage of deployment, when the cumulative capacity deployed is still small and the market is relatively concentrated in a few companies. On the other side, however, current costs suffer from lack of transparency, due to the nascent stage of the industry, which will likely be resolved as large-scale manufacturing facilities come online and large projects get commissioned (IRENA 2021). By considering figure 3, which reports the planned investments (in GW/year) in electrolyser manufacturing capacity between 2021 and 2030, it is clearly visible that Europe and China have got the largest share in planned capacity, thus aiming to exploit economies of scale.

Before focusing on the specific cost reduction strategies, it is important to illustrate the main features of the existing electrolyser technologies, drawing from a detailed report published by IRENA (2020). Electrolysers can be distinguished in four categories, two of which are fully mature or rapidly emerging (ALK and PEM), and the other two can be promising technologies in the medium term (SOEC and AEM). ALK (which stands for alkaline) electrolysers have a simple system design and are relatively easy to manufacture, having electrode areas up to 3 m^2. There are indeed two electrodes (anode and cathode) in an electrolyser, which are contained in a cell, that is the core of the machine. This type of electrolyser has been used since the 1920s for non-energy purposes mainly in the chemical industry. On the contrary, the rapidly growing PEM (proton exchange membrane) electrolyser technology uses electrodes with advanced architecture that allows them to achieve higher efficiencies, thus operating more flexibly and reactively than current ALK technology and have a shorter response time (NREL 2016a; NREL 2016b). SOEC (solid oxide) electrolysers hold the promise of greater efficiencies compared to ALK and PEM, being however a less mature technology, SOEC can potentially be a game-changer in the medium term. Finally, AEM (anion exchange membrane) electrolysers are the latest model, with limited deployment but a potential that lies in the combination of a simpler environment, from alkaline electrolysers, with the efficiency of a PEM electrolyser. Alongside efficiency, the CAPEX of the electrolyser is another important parameter to take account of. For the purpose of this chapter, two main capital cost estimations are outlined, for the two most developed technologies, ALK and PEM.

According to Proost (2019), capital costs by 2020 lied between 800 and 1300 €/kW for alkaline, and between 1000 and 1950 €/kW for PEM systems, and by 2030, these costs are estimated to be only slightly lower than in 2020, being in the range 700-1000 €/kW and 850-1650 €/kW for alkaline and PEM, respectively, as summarised in Table 2. It is important to keep in mind that the global installed capacity of water electrolysis for H_2 production has remained in the megawatt-scale. Only at the end of 2022 the total electrolyser capacity reached around 1.4 GW, which nonetheless represents an almost threefold increase compared to the 513 MW of installed capacity in 2021, that in turn represented a nearly 70% increase compared with 2020 (304 MW), according to the IEA (2022).

Table 2 – Capital costs of ALK and PEM electrolysers in 2020 and 2030 (€/kW). Source: own elaboration from Proost (2019).

Electrolyser technology	Cost in 2020	Cost in 2030
Alkaline (ALK)	800-1300	700-1000
Proton exchange membrane (PEM)	1000-1950	850-1650

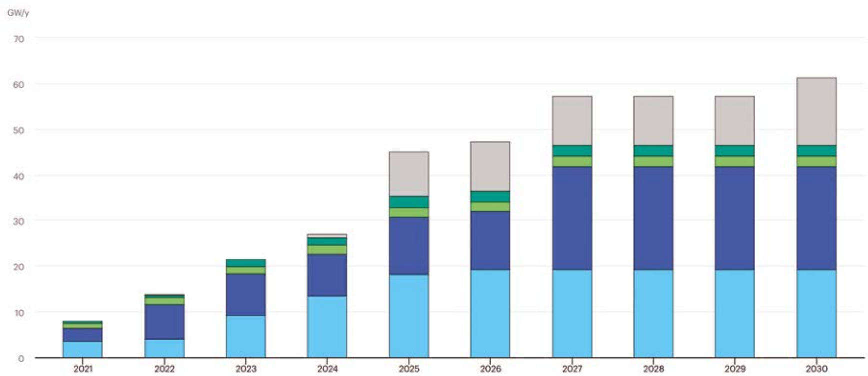

Figure 3 – Planned electrolyser manufacturing capacity by region, 2021-2030 [GW/year][7]. Source: IEA (2022).

Depending on the country or area where water electrolysis must be carried out, there can be a barrier to the large-scale deployment of electrolysers determined by the supply of critical materials used in this technology. For instance, solid oxide electrolysers, which have the potential for much higher efficiencies and market development, depend almost exclusively on China for around 95% of their critical materials, such as zirconium (Zr), gadolinium (Gd), lanthanum (La), yttrium (Y) and many others (IRENA 2020). Van Berkel et al. (2020) outline three strategies to reduce this dependence on critical materials: 1) prevention or reduction of use implies the substitution of materials, reducing their amount per unit of installed capacity, or varying the technology mix to achieve a lower use overall; 2) extension of the use of equipment includes achieving a higher productivity with less material per kilogram of hydrogen, or extending the lifetime of the electrolyser (i.e. the same amount of material allocated over greater production); and 3) recycling.

Strategies for electrolyser cost reduction

As a final item, the main cost reduction strategies for widening the deployment of electrolysers should be outlined. The largest benefits for economies of

7 From the bottom up in each column: Europe, China, North America, India, Unspecified.

scale for electrolyser manufacturing seem to be reached around the 1 GW/year level (IRENA 2020). Between 2022 and the first part of 2023, several important players in the energy transition announced the construction of so-called «giga factories» to produce electrolysers, such as the project announced in Italy by the electrode manufacturer company De Nora and the national gas transmission system operator SNAM, which formed a joined venture to build a 2GW electrolyser factory (Collins 2023), or the new plant in Spain announced by energy company Iberdrola and US company Cummins at the end of 2022 (Trendafilova 2022).

Two main strategies can be identified to reduce the cost of producing such a technology. Increasing the manufacturing scale of the electrolyser can have a positive impact on its specific cost, while decreasing the cost contribution of buildings, improving the utilisation of equipment (more volume produced from each unit), and reducing losses (IRENA 2020). The second strategy is defined by IRENA (2020) as «learning-by-doing», and it is related to the learning curve (or learning rate), that indicates the percentage decrease in production costs as installed capacity for a given technology doubles[8]. This decline in costs is driven by competition between firms in the market and is complemented by innovation powered by research. Larger deployment leads both to more experience (learning) from multiple projects and to lower risk perception by financial institutions, which results in lower cost of debt and lower investment costs (IRENA 2020).

1.2 Hydrogen transportation and storage

A critical component of the decarbonisation effort is constituted by the establishment of a cost-effective hydrogen transportation and storage system, in order to take full advantage of hydrogen as a clean energy carrier. This section aims at outlining the H_2 delivery and storage options currently under development and which have been subject to in-depth analysis both by industry and policymakers. The technical and economic assessments carried out in the next paragraphs will mainly refer to EU-commissioned studies and evaluations. Therefore, estimations on investment and cost parameters of the concerned infrastructures will reflect the EU's energy system configuration[9].

We will first analyse the different forms in which hydrogen is made suitable for transportation, and an overview of the main techno-economic aspects of the relevant transport infrastructures will follow. Before moving to this discussion, it is

[8] The learning rate is an important indicator of the competitiveness of renewable energy technologies, such as solar and wind, which according to Statista (2023) have a learning rate of 23% and 12% respectively, while IRENA (2020) estimated that the electrolyser learning rates will be around 13% for PEM and 9% for ALK between 2020 and 2030.

[9] The EU Hydrogen Strategy recognises the important role that the transport of hydrogen will play in enabling the penetration of renewable hydrogen in Europe, and especially after 2025 there will be a need to deploy an EU-wide infrastructure to supply hydrogen, therefore a pan-European hydrogen grid will need to be planned (Cebolla et al. 2022). This aspect will be addressed specifically in the second chapter of this work.

worth mentioning that the literature provides for several different classifications of the hydrogen transmission component. For instance, Ishaq et al. (2022) group the hydrogen transportation supply chain for potential future ramp-up into four categories: on-site, semi-centralized, centralized, and intercontinental modes of hydrogen transportation. In a JRC research paper, the hydrogen delivery chain is instead divided into three main segments: the «packing», where hydrogen is prepared for its transport; the transport itself; and the «unpacking», where hydrogen is prepared for its final use (Ortiz Cebolla et al. 2022). Similarly, a study commissioned by the Directorate-General for Energy of the European Commission differentiates between a conversion component (compression, liquefaction, etc.), transmission and distribution components (long-distance transport infrastructure and local distribution network) and inter-seasonal and intra-day storage capacity (European Commission 2021). It is therefore essential to underline that – due also to the uncertainty of future hydrogen demand (and thus of transport needs) in each country – the technical architecture of the hydrogen transport infrastructure is highly context-dependent (Palovic and Poudineh 2022)[10].

1.2.1 Making hydrogen suitable for its transportation

As regards the issue of transportation, five forms of H_2 are considered: compressed hydrogen (CGH_2), liquefied hydrogen (LH_2), ammonia (NH_3), methanol (MeOH), and Liquid Organic Hydrogen Carriers (LOHC). While the first two forms involve only the presence of hydrogen, the last three can be defined as «chemical carriers», since H_2 is mixed with other elements, making it suitable for being transported. Given that these technologies not only allow for the transport of hydrogen, but also for its storage (ENTSO-G et al. 2021), the same classification is used for discussing H_2 storage.

Compressed hydrogen (CGH_2)

Since hydrogen has a low volumetric density, it can be compressed so as to increase its density, thus reducing the volume necessary for its storage and transport. Therefore, the higher the pressure the higher the density of the hydrogen, but also the more is the energy required for its compression up to the chosen final pressure (Cebolla et al. 2022). Hydrogen compression costs depend both on the technology and the pressure, but also on the flow-rate, which is defined as the quantity of fluid (hydrogen in this case) that is passing through a cross-section of a pipe in a specific period of time[11]. According to the U.S. Depart-

[10] Hydrogen infrastructure - like electricity and natural gas infrastructure - is colour-blind, in the sense that hydrogen compressors (used to efficiently transport and store hydrogen from its point of production to end-use), for instance, do not «see» the H_2 production method colour, as every process produces the same low molecular weight hydrogen gas.

[11] The flow rate, or the amount of fluid that flows in a given time, is usually measured in [Sm^3/day] for natural gas, but for hydrogen it can be measured in [kgH_2/h] (Ghadban 2021).

ment of Energy[12], the capital costs of compressors delivering hydrogen with a pressure of around 10 MPa (megapascal) and a flow-rate of 8300 kgH_2/h are about $6 million.

Liquefied hydrogen (LH_2)

Liquefaction plants are used to liquefy hydrogen, whose liquid state requires a temperature of -253ºC, involving severe technical challenges to carry out such operation. In its liquid state, nonetheless, hydrogen's density is 2.3 times higher than that of compressed H_2, thus allowing more molecules to be transported using less space (Cebolla et al. 2022). While the capital investment for a liquefaction plant is around $2.5 to 5 million per tonne of H_2 per day (Connelly et al. 2019), the overall cost is mostly driven by OPEX (high energy cost of liquefaction), but prices could be brought down to 50% by scaling up capacity, which today ranges between 4 and 10 $tonnes_{H2}$/day for a conventional liquefaction plant in Europe (Cebolla et al., 2022).

Ammonia

Besides being an essential component in fertilizer production, ammonia (NH_3) is a chemical commodity traded on a global scale, whose production capacity has been steadily growing. European ammonia production is in the order of 20 Mt/yr (Dolci 2018). This chemical carrier is usually produced by reacting hydrogen (ideally supplied by electrolysers) and nitrogen at high temperatures (400-550ºC), and when hydrogen is needed at the arrival site, ammonia is cracked, involving subsequent hydrogen purification steps (Cebolla et al. 2022). NH_3 is regarded as one of the key elements for the creation of a wider hydrogen transport market, since it can be liquefied and kept at around -30ºC, thus requiring less energy and being easier to ship. Indeed, ammonia currently accounts for about 40% of global hydrogen demand with around 31 Mt of H_2, of which 80% is used for fertilisers (Breitschopf et al. 2022).

Methanol

Like ammonia, methanol can be used both as an industrial feedstock and as a chemical carrier. Almost the whole European production of methanol is located in Germany (Boulamanti and Moya 2017), and it is conventionally based on syngas ($CO+H_2$) followed by methanol synthesis (Cebolla et al. 2022). Another solution consists of CO_2 hydrogenation: the latter is a chemical reaction between molecular hydrogen and another compound or element (CO_2 in this case), using a catalyst.

[12] Available at: https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery.

Liquid Organic Hydrogen Carriers (LOHC)

The last chemical carrier to be analysed is constituted by a series of molecules able to release or accept hydrogen, being easy to handle at room temperature and atmospheric pressure, and having physical properties similar to fossil fuels, therefore allowing for the use of existing infrastructure for transport (Cebolla, et al. 2022). According to the European Union Agency for the Cooperation of Energy Regulators (2021), every unsaturated compound (that can be found in crude oil and refined petroleum products) can take up hydrogen during hydrogenation (see above). Together with ammonia, LOHC can have lower costs by 2030 (around \$2-2.5 \$/kgH_2) compared to liquefied hydrogen (2 to 3.7\$/kgH_2), according to the IEA (2023).

1.2.2 Critical infrastructures for building a hydrogen economy

Repurposed gas networks

A brief analysis of the economics of gas transportation by pipeline is necessary to understand the challenges of hydrogen delivery using existing infrastructure. The essential components of such a transportation system are pipes and compressors, since gas moves through pipelines as a result of a pressure differential (from high to lower pressure points), which is created by compressor stations that are generally built every 100 to 500 km along the length of the pipeline (Natgas 2013). It is also important to consider the different types of pipelines based on where they are used: gathering pipelines collect raw natural gas from production fields and connect it to the mainline transmission grid; transmission pipelines (up to about 120 cm in diameter) move gas through long distances (thus at high pressures); distribution pipelines (up to around 25 cm in diameter) deliver natural gas to small industrial plants and customers at lower pressure (2-10 bar or 0,2-1 Mpa); finally, service lines (up to 5 cm in diameter) deliver gas to residential customers at a pressure of 1 bar (Natgas 2013).

From an economic point of view, the most cost-efficient pipeline system design (both CAPEX and OPEX) must consider that length and terrain are external and thus fixed factors. The endogenous components that must be taken into account are linked to several dimensions: the quantities (of gas) to be transported, based on actual or expected demand; the diameter of the pipe (which is inversely correlated with the need for compressors along the line); the maximum allowable operational pressure (MAOP), that is in a trade-off with the thickness of the pipeline's walls; the velocity of the flow, usually up to 72 km/h to prevent pipe erosion; and finally the capacity of compressor stations, that influence OPEX (Hafner and Luciani 2022).

Repurposing natural gas pipelines for hydrogen transportation entails several challenges and technical issues. According to the European Union Agency for the Cooperation of Energy Regulators (ACER 2021), the latter can include embrittlement (and subsequent degradation) of the steel which pipelines are made of, since H_2 molecules can infiltrate and cause cracks resulting in pipeline failure[13]. Therefore, not only further costs must be added for adapting the pipes with a layer of internal coating (to chemically protect the steel layer) to allow pure hydrogen to flow, but this gas also needs greater compression (approximately 3 times more compared to methane) in order to achieve a similar energy flow (ACER 2021). Finally, maintenance and monitoring of the pipelines' quality would need to be enhanced to inhibit hydrogen embrittlement (Cerniauskas 2020).

Newly built hydrogen pipelines

Besides the purely technical challenges involved in repurposing natural gas pipelines, during such an activity the supply of methane to customers would nonetheless need to be ensured continuously. Therefore, instead of converting all existing lines, completely new hydrogen pipes can represent an alternative to repurposing, while natural gas ones remain operational to ensure security of gas supply. The design, construction, and operation of H_2 pipelines are however more challenging than most other fluids, also due to safety risks associated with hydrogen's large flammability range in air and invisibility of the flame (Khan et al. 2021). It is important to underline that there can be a significant difference between hydrogen transportation in transmission and distribution pipelines, because high-strength steels that are more often used in natural gas transmission pipelines are more susceptible to H_2 embrittlement (Khan et al. 2021). This in turn means that the lower-strength steel of distribution pipelines (which have a lower pressure) is more suitable for hydrogen pipelines. GRTGaz – the main transmission system operator in France – noted indeed that French regional networks with smaller diameters of steel pipes and with lower yield strength are less sensitive to hydrogen embrittlement compared to larger transmission pipelines, which are more likely to be made of technologically more advanced types of steel (GRTGaz 2019). On the other side, the use of lower grade steel means only lower operating pressures are possible or that the wall thickness will need to be increased to accommodate the high operating pressures of future hydrogen transmission pipelines (Khan et al. 2021).

Road, rail, river, and maritime transportation networks

At present, compressed hydrogen gas is mostly transported by road, using systems known as multiple-element gas containers (MEGCs), consisting of bundles of gas cylinders, that are either metallic or made of a combination of internal liner (metallic or plastic) wrapped with a carbon fibre-based composite material (Cebolla et al. 2022). These containers are usually mounted on trucks, enabling the transport of smaller quantities of hydrogen gas (or liquid H_2 by means of in-

[13] Hydrogen embrittlement can be technically understood as a metal's loss of ductility and reduction of load-bearing capability due to the absorption of hydrogen atoms or molecules by the metal (ENTSO-G et al. 2021).

sulated tanks) in the range of 1 to 4 tonnes of H_2 per truck, according to the same JRC report. The latter as well suggests that there are currently no commercial solutions for railway hydrogen transport. However, in late 2022, the German national railway operator Deutsche Bahn suggested transporting large amounts of green hydrogen on trains in order to offer an alternative to still-non-existent hydrogen pipelines, planning to use ammonia as a carrier and cracking it into its components to extract and use the hydrogen (Amelang 2022).

All the above discussed options do not allow for the transport of large amounts of hydrogen comparable to those of natural gas that nowadays cross the globe in form of LNG. The typical size of an LNG tanker (ship) is in the range of 125 000-175 000 m^3, but when methane is regasified it acquires around 600 times more volume than LNG. Currently, a prototype for a liquid hydrogen carrier developed by Kawasaki Heavy Industries, the «Suiso Frontier», has been under trial transporting liquefied hydrogen from Australia to Japan with a capacity of 1250 m^3 or around 85 tonnes of liquid hydrogen (Kawasaki Heavy Industries Ltd 2019). However, hydrogen is mostly carried through ammonia, which is currently performed on a regular basis and requires partial or full refrigeration (ammonia liquefies at -33°C) in order to keep the ammonia cargo in liquid form around atmospheric pressure (Cebolla et al. 2022). Maritime transport of hydrogen implies also an upgrading of LNG terminals. The latter infrastructures can indeed become entry gates of hydrogen into the EU, since they provide industrial-scale access to maritime logistics, have tanks with large storage capacities ready to work in cryogenic conditions, and direct connection to the gas grid (ENSTO-G et al. 2021). Given the lower temperature (-253ºC) required for hydrogen liquefaction compared to natural gas (-160ºC), LNG terminals' components need to be replaced, even though the technology itself is not new. In different parts of the world, LH_2 production, handling, and distribution have been performed for over 50 years, and the experience of the LNG industry will be invaluable to build on that existing knowledge (ENTSO-G et al. 2021).

1.2.3 Cost-effectiveness comparison of H_2 transport methods

The economic analysis of hydrogen transportation via new or refurbished pipelines needs to take the levelised cost of transmission (LCOT) into account. The latter – which is reported for the European scenario – can be defined as the discounted cost per MWh of hydrogen transported by the pipeline (European Commission 2021). As summarised in Table 3, while the investment cost for completely new hydrogen pipelines – based on estimations for the German network – would amount to no less than €2.48 million (in 2019 prices) per km of pipeline length and those for a repurposed gas pipeline would be around €0.37 million/km (in 2019 prices), the LCOT for refurbished and newly built pipelines is estimated at around 3.7€/MWh per 600 km and 4.6-45€/MWh/600 km respectively (European Commission 2021). Thus, it can be said that the investment cost of repurposing the existing lines is around 15% of the cost of building new hydrogen pipes, even though there are other studies that report a CAPEX per km of refurbished hydrogen pipelines equal to around 33% of the cost of newly built lines (ACER 2021). These figures suggest that converting the gas network to carry pure hydrogen can be cheaper that building new infrastructures. However, as mentioned in the previous sub-section, the process of conversion can involve issues with gas supply and should therefore be done gradually, and it should especially consider the developments in hydrogen demand across long distances.

Table 3 – Investment costs [M€$_{2019}$/km] and Levelised Cost of Transmission (LCOT) [€$_{2019}$/MWh/600 km] for new and refurbished hydrogen pipelines. Source: own elaboration from European Commission (2021).

Type of pipeline	Investment costs	LCOT
New	2.48	4.6-45
Refurbished	0.37	3.7

The identification of the different «tipping points» – here understood as the points where one particular method of hydrogen transportation becomes more cost-effective than the one previously used – is useful to put the technologies into perspective and contextualise them in the next chapters. If trucks are seen as the most cost-effective option for H_2 transport in small volumes (less than 10 tonnes per day) over short distances (up to 200 km) (ACER 2021), the cost of MEGC systems is around 790-1100\$/kg$_{H2}$ using compressed hydrogen, while beyond a distance of 300/400 km it is more cost-effective to transport liquid H_2[14]. In terms of shipping routes, while transporting ammonia appears much cheaper than pure hydrogen transport, for distances below 1500 km, transporting hydrogen gas by pipeline is likely to be the cheapest delivery option, and above 1500 km ammonia or LOHC become more cost-effective (IEA 2019). Conversion costs can significantly impact business cases since as much 28% (11kWh/kg) of the transported energy can be consumed during LOHC dehydration and hydrogen separation (ENTSO-G et al. 2021).

Before analysing the current technologies for storing hydrogen, it is interesting to combine the different H_2 transportation methods and assess their cost-efficiency, drawing from Cebolla et al. (2022), who also provide some of the most updated figures in terms of costs. Hydrogen delivery costs (in €/kg$_{H2}$) are plotted against distance for 1 Mt of H_2 per year in a two-fold scenario: 1) high electricity prices (Figure 4), with a production site electricity price of 50 €/MWh and a consumption site price of 130 €/MWh, and 2) low electricity prices (Figure 5), with a production site electricity price of 10 €/MWh and a consumption site electricity price of 50 €/MWh. While the first price scenario is based on current and 2022-23 electricity prices, the low-price scenario includes future (2030+) estimated renewable electricity price trends. It is important to note that the colour of the background (blue and red for Figure 4, blue, red and green in Figure 5) reflects the cheapest hydrogen transport method for each distance.

[14] Available at: https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery.

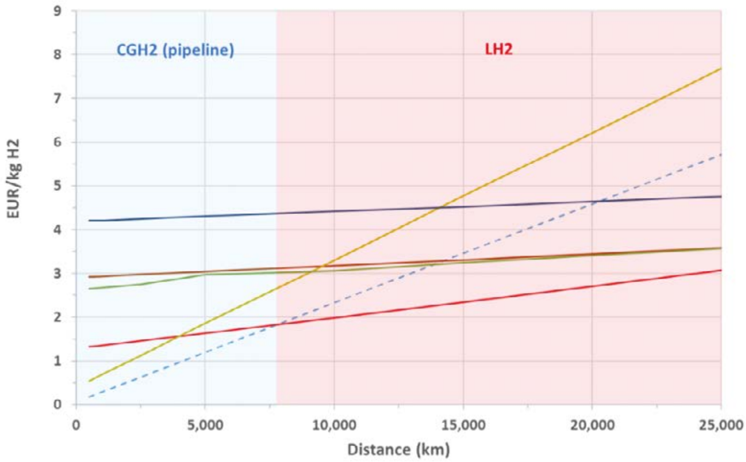

Figure 4 – Hydrogen delivery cost vs. distance (High electricity price)[15]. Source: Cebolla et al. (2022).

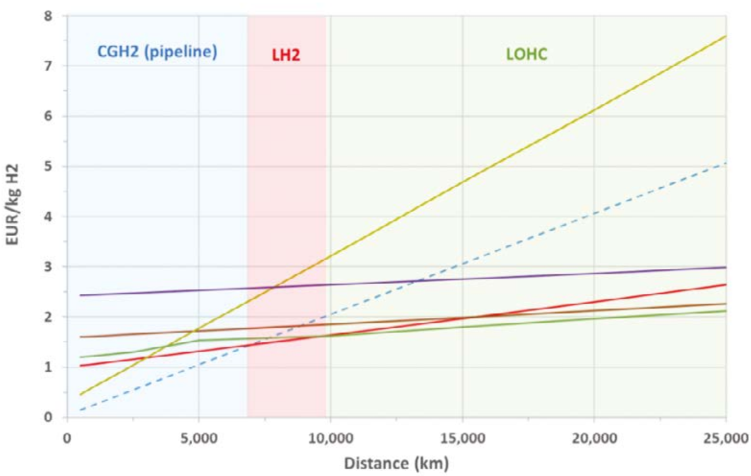

Figure 5 – Hydrogen delivery cost vs. distance (Low electricity price)[16]. Source: Cebolla et al. (2022).

For high electricity prices (Figure 4), compressed hydrogen transported in pipelines is the cheapest option up to around 7500 km, whereas for distance be-

[15] On the left-side, from the bottom up, the curves correspond respectively to: Compressed hydrogen in pipelines, Compressed hydrogen in ships, Liquefied hydrogen, LOHC, Ammonia, Methanol.

[16] On the left-side, from the bottom up, the curves correspond respectively to: Compressed hydrogen in pipelines, Compressed hydrogen in ships, Liquefied hydrogen, LOHC, Ammonia, Methanol.

yond 7500 km liquefied hydrogen remains the most cost-effective method, due to the additional costs involved in combining H_2 with the other chemical carriers. In the low electricity price scenario (Figure 5), hydrogen pipelines are the cheapest option up to around 6500 km, after which LH_2 becomes the more economic option. From around 10000 km, LOHC becomes the most cost-effective option, while for very long distances (above 15000 km), ammonia and LOHC (brown and green lines) perform better than LH_2 (red line), mainly due to the issue of boil-off (which imply hydrogen losses during transportation when H_2 is liquefied).

1.2.4 Hydrogen storage technologies

Storage has been insufficiently explored up to this point, and no viable business model for hydrogen – as an internationally or even locally traded commodity – could possibly omit the fact that this substance in most cases will have to be stored at least right after its production and before its delivery to the end user (Patonia and Poudineh 2023). This is especially true with renewable (solar and wind-generated) H_2, since its generation is intermittent, but its current and projected demand (mainly from industrial customers) is stable. Therefore, while the availability of renewable energy for hydrogen production is subject to strong fluctuations, the operation of pure H_2 networks serving significant hydrogen demand would require the services of highly flexible hydrogen storage (ACER 2021). According to Usman (2022), the practical hydrogen storage is perhaps the biggest hurdle in the success of the hydrogen economy on a large scale.

Given the need to decarbonise the economy, hydrogen storage not only serves final H_2 demand, which will gradually increase in the next decades, but it has become increasingly important to provide for long-term electricity storage when non-dispatchable power sources (such as solar and wind) are used to produce renewable electricity. While batteries, for instance, can absorb short-term renewable electricity fluctuations, hydrogen can allow for larger-scale and longer-term storage mainly through Power-to-Gas (P2G) technologies. Hydrogen contribution will be critical to manage seasonal peaks in the RES electricity demand and supply, due to the projected increase in electrification and overall use of renewables. It will also optimise investments in energy systems by reducing over-investments in electricity grids.

There is however an issue related to the actual efficiency of using electricity to produce hydrogen (by electrolysis), storing the hydrogen, and then converting it back to electricity by using a gas turbine and a power generator, or a fuel cell. Hydrogen re-electrification with these two methods can have efficiencies as high as 50%[17], which means that at least 50% of the energy is lost. Nonetheless, it should not be neglected that the alternative to hydrogen production, storage and re-electrification could be that renewable electricity must be curtailed because

[17] Retrieved from: Energy Storage Association. (n.d.). *Hydrogen Energy Storage*. [online] Available at: https://energystorage.org/why-energy-storage/technologies/hydrogen-energy-storage/#:~:text=Hydrogen%20Re%2DElectrification

of the lack of electrolyser capacity to transform the surplus renewable electricity into renewable hydrogen. The efficiency of such a situation would be equal to zero.

It is essential to analyse hydrogen storage technologies along two dimensions: 1) the physical forms or chemical compounds in which hydrogen can be stored, and 2) the sites where H_2 can be placed when needed. The five forms of hydrogen previously addressed will be analysed here to account for their use as storage options. Large- (country-) scale storage of hydrogen is still technologically limited to H_2 compression and injection underground (Patonia and Poudineh 2023). The second form of pure hydrogen (liquefied H_2) presents significant challenges when it is stored, owing to the evaporation of part of this hydrogen – known as «boil-off» – which is a consequence of the heat transfer from the (warmer) storage tank surroundings, to the stored hydrogen (Cebolla et al. 2022). This in turn will imply a pressure increase inside the tank, but not necessarily a loss of hydrogen, since the evaporated H_2 may be redirected back to the liquefaction plant, or to an intermediate gas storage buffer, or directly to a final user (Cebolla et al. 2022). According to the same JRC report, however, these measures require additional equipment and integrated refrigeration and storage (IRAS), thus implying higher costs. The last three options are hydrogen compounds: ammonia (NH_3), which can be stored at cryogenic temperatures at atmospheric pressure; methanol (MeOH), whose storage is usually performed in stainless steel tanks; and LOHC, which can be stored in large quantities at ambient conditions in double-walled containers, as used for crude oil or diesel (Cebolla et al. 2022).

The second dimension of the present analysis concerns hydrogen storage sites, about which there is currently substantial debate in Europe. All the available options can be divided into above ground and underground storage. The former is almost exclusively represented by superficial tanks, containing either compressed or liquefied hydrogen. Compressed hydrogen, however, even at very high pressure (700 bars or 70 Mpa), has only 15% of the energy density of gasoline, so storing the equivalent amount of energy as hydrogen at a vehicle refuelling station, for instance, would require nearly seven times the space (IEA 2019). On the other hand, ammonia has a greater energy density, but it will also lead to greater energy losses due to the required conversion process (IEA 2019). Finally, the costs for large tanks (200-300 tonnes) of liquefied H_2 can range between 150-300 €/kgH_2 (Derking et al. 2019).

Underground hydrogen storage (UHS) can be subdivided into three main types of formations, that provide large-scale seasonal storage: salt caverns, aquifers and depleted fields (ENTSO-G et al. 2021). Other types of underground storage include conventionally mined rock caverns, abandoned mines and also pipe storage, which is located a few meters below ground level and it is not classifiable as geological storage (Kruck et al. 2013)[18]. Geological and reservoir constraints, technical and safety limitations, legal barriers, conflicts of interest, and

[18] Gas that is stored within the pipes of a gas transmission or distribution system is known as «line pack», and it is used by gas system operators as a means of balancing the system or meeting

social acceptance are amongst the most significant barriers to the implementation of UHS (Tarkowski and Uliasz-Misiak 2022).

Salt caverns

These sites are suitable for storing pure hydrogen due to their low cushion gas requirement[19], the large sealing capacity of rock salt and the inert nature of salt structures, limiting the contamination of the hydrogen stored (ENTSO-G et al. 2021). Besides, salt caverns offer very flexible H_2 storage (injection) and retrieval but, as can be seen in Figure 6, opportunities for storing hydrogen in salt caverns are geographically limited to a few areas in several EU Member States (ACER 2021). The largest potential is indeed located in the southern part of the North Sea and in its bordering countries. The potential for hydrogen storage in European salt caverns (onshore and offshore) has been estimated at 2.5 billion tonnes of hydrogen, with the largest potential in Germany (42%) (Caglayan et al. 2020)[20].

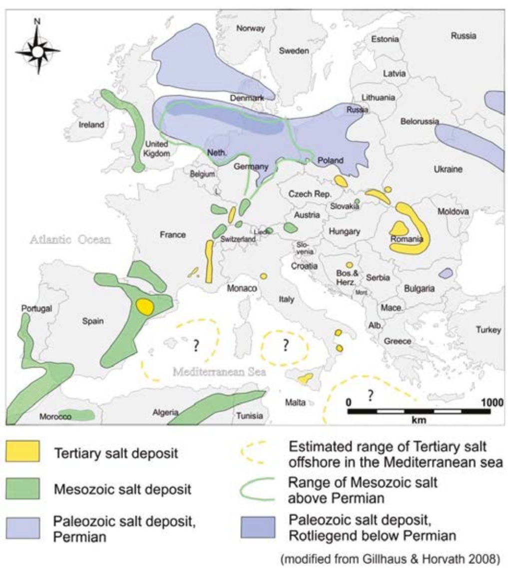

Figure 6 – Salt deposits in Europe. Source: Kruck et al. (2013).

customer demand even when supply delivered to the system on a given day does not match consumption. Retrieved from: https://www.energyknowledgebase.com/topics/line-pack.asp

19 Cushion gas (or base gas) is the volume of natural gas (or hydrogen gas in the case of H_2 storage) intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season (Energy Information Administration 2015).

20 Salt caverns can also be employed as fast-cycle storages, meaning that hydrogen can be injected and withdrawn quite rapidly, which can turn out to be a significant asset when hydrogen demand (especially for the industrial sector) will be rather flat compared to seasonal demand of natural gas today.

Aquifers

Such formations are made of porous and permeable rock containing fresh water or brine, and if they are overlain by a layer of impermeable cap rock (e.g. tight shale) they can be used to store gas, but they are rather inflexible to operate (Kruck et al. 2013). In addition, saline water in combination with hydrogen attacks rock, steel, and cement (ACER 2021). This storage option involves higher uncertainties concerning its costs compared to salt caverns, and in most cases the costs are expected to be higher than for the latter and for depleted hydrocarbon fields (Kruck et al. 2013).

Depleted fields

These share the porous rock characteristic with aquifers, except that they were filled with hydrocarbons in the past which have been withdrawn (Kruck et al. 2013). Notwithstanding possible contamination of hydrogen with the hydrocarbons and other gases in the reservoir (ACER 2021), the advantage of depleted fields is that these structures are well known from the time when the reservoir had been explored and tested, and the remaining gas can be used as cushion gas (Kruck et al. 2013). In late April 2023, Austria's gas storage operator RAG launched the world's first underground hydrogen storage pilot at a former natural gas reservoir in Rubensdorf, aiming at demonstrating the role that hydrogen can play in seasonal energy storage (Dokso 2023). The pilot project will store 1.2 million m^3 of hydrogen (produced by a PEM electrolyser), equivalent to 4.2 GWh of power, thus being used to store excess renewable electricity on the grid. Figure 7 provides the equivalent in TWh of hydrogen storage needs and potential according to the targets of 20 EU countries plus the UK.

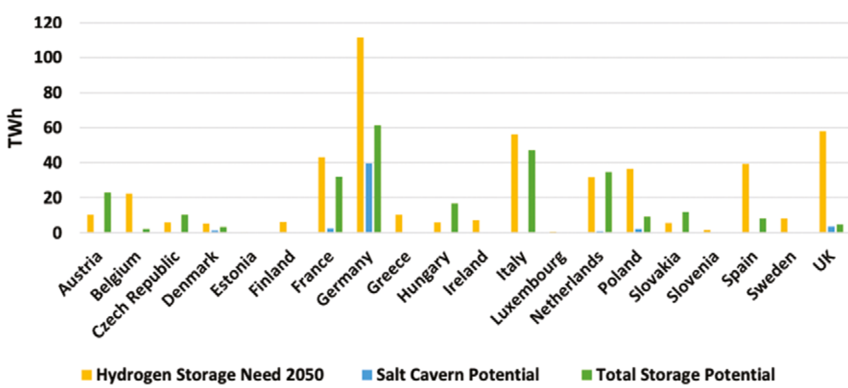

Figure 7 – Estimates of hydrogen storage need by 2050 vs. potential. Source: Cihlar et al. (2021).

The existence of several hydrogen storage technologies implies significant differences in the so called «Levelised cost of storage» (LCOS or LCHS). The latter is defined as the discounted cost per MWh of H_2 discharged[21] (European Commission 2021). Hence, when hydrogen is specifically used to store electricity[22], the LCOS divides the total cost of this electricity storage technology across its lifetime by its cumulative delivered electricity, describing the minimum revenue required for each unit of discharged energy for the storage project to achieve a net present value (NPV) of zero[23]. Following the analysis of the LCOH and LCOT, table 4 outlines the LCOS estimations for the three main underground storage options examined above.

Table 4 – Levelised Cost of Hydrogen Storage for different underground storage options [€/MWh_{H2}]. Source: own elaboration based on European Commission (2021).

Type of underground storage	LCOS
Salt cavern	17
Depleted gas field (monthly cycle)[24]	51-76
Porous rock cavern (bi-annual cycle)	104

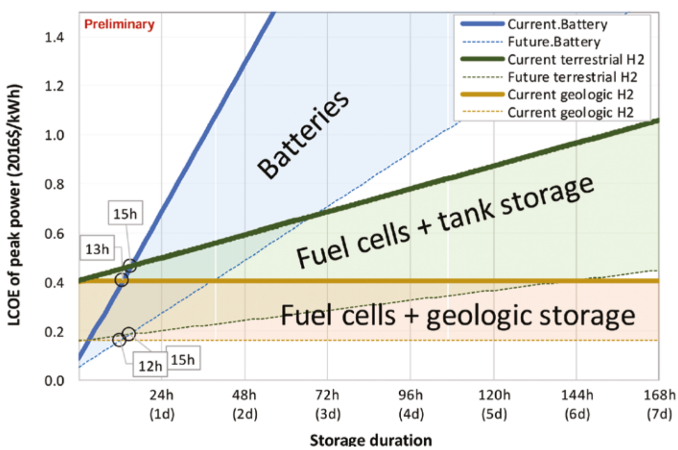

Figure 8 – Economic performance benchmarks for current & future hydrogen and batteries. Source: Penev et al. (2019).

[21] Energy storage devices (such as hydrogen) are «charged» when they absorb energy, either directly from renewable generation devices or indirectly from the electricity grid, and they "discharge" when they deliver the stored energy back into the grid (EASE 2023).

[22] 1 tonne of hydrogen delivers around 33 MWh of electrical energy.

[23] See: Schmidt, O. (n.d.). *Projecting the future lifetime cost of electricity storage technologies*. [online] Storage Lab. Available at: https://www.storage-lab.com/levelized-cost-of-storage.

[24] The number of times a storage can be fully filled and emptied during a defined period of time is known as «storage cycling rate» (KYOS, 2023).

One last key aspect to consider when dealing with hydrogen as electricity storage is the LCOE (Levelised cost of electricity), which can explain why this molecule can be stored for extended periods of time at very low marginal cost relative to electricity. Figure 8 gives an illustration of the price competitiveness of storing electricity in batteries versus hydrogen storage coupled with fuel cells (to convert H_2 back to electricity). The LCOE (given in \$/kWh) indicates that hydrogen technologies could be more economical than batteries for storage duration beyond 15 hours.

1.3 Hydrogen utilisation

This section aims at completing the analysis on the hydrogen value chain, by outlining the sectors that are and will progressively be most impacted by the use of hydrogen, either after its re-electrification or as a fuel. We deepen the relevant aspects of present and future H_2 demand in the EU countries in the following sectors: industry, transport, buildings, and power generation. While China is the largest hydrogen consumer globally (around 30 million tonnes or 29% of global consumption), the EU accounted for around 8% (7.4 Mt) in 2022, and within the EU the largest H_2 consumer is also its biggest producer, Germany (1.7 Mt) (IEA 2023c). According to Tarvydas (2022), hydrogen usage in end-use sectors will remain negligible in the next decade, but by 2040 and 2050 the EU's H_2 demand could provide between 10 and 20% of final energy demand[25].

1.3.1 Industry

Hydrogen will compete with bioenergy and fossils with carbon capture and storage (CCS) in decarbonising hard-to-abate industrial sectors (Tarvydas 2022). One key application where green hydrogen can be introduced is steelmaking. The latter industry accounts for 4% of all the CO_2 emissions in Europe and 22% of industrial carbon emissions (Bellona Europa 2021), since the primary steelmaking method involves two fundamentally high-emission steps: first, the iron ore is melted in a blast furnace (at about 2000°C) usually using natural gas or coke (made from coal), thus obtaining so called «pig iron» in a process known as «direct reduction of iron» (DRI); second, the pig iron is made into steel, via a process that can generate up to 1.85 tonnes of CO_2 for every tonne of steel produced (Alverà 2021). When green hydrogen – instead of fossil fuels – is used to reduce the iron ore, the latter is heated between 800-1200°C, obtaining pig iron, which can be then fed into an Electric Arc Furnace (EAF), where electrodes generate a current to melt the pig iron to produce steel (Bellona Europa 2021) with no emissions[26]. Such a technique has been around at a

[25] The implications of the Fit-for-55 ambitions and the REPowerEU Plan's acceleration will be examined in the next chapter.

[26] As of November 2022, approximately 24 DRI projects (40 to 50 Mt of DRI capacity) had been announced, being located primarily in Western and Northern Europe (Durinck et al. 2022).

commercial scale since the late 1960s, but not with pure (or green) hydrogen, thus generating emissions.

Although hydrogen (and especially green H_2) costs more than fossil fuels, the existence of a carbon price, such as the EU ETS, can make cleaner alternatives more competitive, not to mention the spike in fossil gas prices, that started in late 2021 and worsened after the beginning of Russia's large-scale invasion of Ukraine in early 2022. According to the European Commission (2021), the investment cost of new hydrogen DRI-EAF based manufacturing capacity is between 400-752 €/tonne of annual steel production capacity, while the steel production costs using the same technology are between 386-685 €/tonne of crude steel.

Besides steelmaking, which is projected to cover most H_2 demand amongst the hard-to-abate sectors by 2050, there are other industries which can potentially scale up their use of this clean molecule. One example is provided by the cement sector, that can use hydrogen either as a fuel in the cement production process (replacing coal and natural gas), or as a means to capture CO_2 and use it as feedstock (carbon capture and utilisation) for the production of other products such as building materials and fuels (Commodity Inside 2023). The same can be done in the ceramics industry, as demonstrated by the agreement between the Italian company Iris Ceramica and the national gas TSO SNAM in late 2021, that aims to fully decarbonise the company's production process through a 100% hydrogen-fuelled plant (Iris Ceramica 2021)[27].

1.3.2 Transport

According to Tarvydas (2022), 4% of fuel demand in transport will be met by hydrogen by 2030, rising to 17% and around 27% in 2040 and 2050 respectively. It is however important to distinguish between the different categories of transport, since some of them will see a quicker scale-up of hydrogen-fuelled vehicles while in other types of transport the molecule will remain rather cost-inefficient compared to electricity-powered or alternatively fuelled vehicles. Hydrogen can become the key to decarbonising heavy-duty and long-haul transport, as there are hardly any other zero-emission alternatives available (Ruf 2018). Those categories include maritime and aviation applications, which however remain at a prototyping stage. In the shipping sector, hydrogen fuel cells are used, but only in a few cases are they employed as propulsion. Fuel cells can be used as auxiliary power units for on-board energy needs, while for airplanes, fuel cell-powered flights are not regarded as feasible (Ruf 2018). Hydrogen can rather play a more significant role in the production of e-kerosene (used as a fuel in aviation), which is generated by combining H_2 and CO_2, and is included in the category of the so called «e-fuels» or «power-to-liquid». Two conditions are essential for e-kerosene to have zero greenhouse gas emissions. First, hydrogen needs to be

[27] This case will be examined more in detail in Chapter 4 of this work on the Italian hard-to-abate sectors.

produced using renewable electricity, and second, carbon dioxide needs to be captured from the atmosphere (Transport & Environment 2021).

Light and medium-duty transport deserves a separate discussion, as there is currently much debate on the actual cost-effectiveness and maturity levels of fuel-cell cars and hydrogen buses. The former have been introduced in the market but their commercial availability is still limited, and their original equipment manufacturers (OEMs) are almost exclusively located in East Asia (Ruf 2018). Fuel-cell buses are instead a more mature application, mainly for urban areas, even though their technology readiness level (TRL) must take into account the relevant infrastructure needs, such as hydrogen filling stations. These can create bottlenecks and obstacles towards scaling-up hydrogen-powered vehicles[28]. Hydrogen-fuelled trains also present some criticalities, even though they have been gathering pace to replace conventional diesel trains, as happened in Germany at the Elbe-Weser Railroad Company, which has become the first in the world to operate a fleet of hydrogen trains in regular operation (Weyerer 2022).

1.3.3 Buildings

One of the sectors where the introduction of hydrogen is more discussed – and perhaps most controversial – is the residential sector. The latter is the second largest consumer (behind the transport sector) of final energy in the EU (around 33%) (European Environment Agency 2025) and it is responsible for around 6% of GHG emissions from energy, emitting more than the power sector (Hydrogen Europe 2022). It is important to point out that households use energy for various purposes: mainly space and water heating (around 79% combined), space cooling, cooking, lighting and electrical appliances and other end-uses also outside the dwelling themselves (European Environment Agency 2025). Given that studies investigating the residential applications of hydrogen are still scarce, the use of hydrogen in buildings should be assessed as part of a complete energy system (Rongé and François 2021), not only on the level of a single house, taking into account also the efficiency improvements and renovation of buildings.

Focusing on the main uses of energy in households (heat and power), hydrogen can be used via three main technologies: hydrogen gas boilers, combined heat and power (CHP) units and hybrid heat pumps. The first appliance functions in the same way as a natural gas boiler, even though hydrogen burns with a much higher flame speed, which can generate nitrogen oxides (NO_x, with high global warming potential) during combustion, thus needing a burner re-design (Rongé and François 2021). Controlling these factors while excluding hydrogen for open-flame cooking for which it is not an option, may come at a higher cost and lower fuel efficiency (Korberg et al. 2022). The second technology, CHP,

[28] At the end of 2022, the German city of Wiesbaden was forced to retire its ten hydrogen-powered fuel-cell buses - a year after they were delivered - after its publicly owned transport company's €2.3m filling station broke down (Collins 2022).

can be based on either combustion of hydrogen or on fuel cells. The latter system is currently offered by several suppliers in form of «micro-CHP» (in the order of 10s of kW) and they are mostly connected to the natural gas grid and extract the hydrogen from the natural gas (cracking) before feeding it into the fuel cell (Rongé and François 2021). This is only possible where hydrogen-ready infrastructure is already in place, thus recalling the potential issues in repurposing the distribution grid mentioned in the previous section. Finally, hybrid heat pumps are a combination of an air-source heat pump (absorbing heat from outside and releasing it inside) and a gas boiler, with a single control operating the whole system. Hydrogen can be used in the boiler instead of natural gas. Such a technology can help to decarbonise only if hydrogen comes from renewables, which is where most of the sceptical views are concentrated[29]. In the short term, hydrogen in buildings will remain expensive, mainly due to the lack of infrastructure for distribution and the high investment costs, but after 2030, upscaling of hydrogen supply for the industry will lead to the availability of low cost H_2 for other applications (Rongé and François 2021).

1.3.4 Power Generation and back-up

As reported by the JRC paper on the role of hydrogen in decarbonisation scenarios (Tarvydas, 2022), different studies claim that power generation from hydrogen increases tenfold (compared to 2030), reaching 162 TWh, while the same analyses see around 4-5% of the electricity demand met by hydrogen by 2050. The main issue concerns the RES installed capacity needed to produce the (green) hydrogen that can be reconverted into electricity (a process that currently involves substantial energy losses). For a sustainable power plant, the access to the fuel will be crucial, while the mode of fuel (H_2) transport and distance have a strong impact on costs and distribution emissions. Likewise, the storage volumes and capabilities need viable solutions[30]. Finally, besides the role hydrogen can play in mitigating seasonal variations in RES production through long-term storage of electricity, fuel cells and hydrogen can also provide for a low-emission alternative as back-up power for critical infrastructures (e.g. data centres, hospitals…) and can provide off-grid power supply for remote areas (Ruf et al. 2018).

1.3.5 The «clean hydrogen ladder»

Finally, we briefly discuss the competition clean hydrogen will have to face to win its way into the economy, as in almost all use cases there can be cheaper, simpler, and safer solutions towards full decarbonisation. The following concepts will take into account the techno-economic aspects of hydrogen use cases,

[29] In early 2022, the first smart hydrogen hybrid heating system in the world was demonstrated in the UK, bringing together an H_2 boiler with an electric air-source heat pump (Campbell 2022).

[30] See: https://www.wartsila.com/energy/sustainable-fuels/hydrogen-in-power-generation.

without considering the push-factor represented by policy support schemes and incentives, that will instead be discussed – at an EU level – in the next chapter. Figure 9 shows the so called «clean hydrogen ladder», which summaries in a simple graphic – based on peer-reviewed research – where clean hydrogen is sure to be part of a net-zero future («unavoidable») and where there are other solutions available («uncompetitive»), along a series of steps on the ladder (red to green). The combination of thermodynamics, micro-, macro-economic, and geopolitical factors within a simple figure can be a double-edged weapon, but it is useful to put all the pieces together. Indeed, the H_2 uses mentioned above, such as steelmaking, long-term electricity storage, long-haul aviation, and shipping, are also in the upper part (future scale-up) of the ladder. Some other uses, such as domestic heating, urban and short-range transport are in the bottom part of the ladder mainly because of the current lack of proper infrastructure (like distribution lines or hydrogen refuelling stations) and thus higher overall costs.

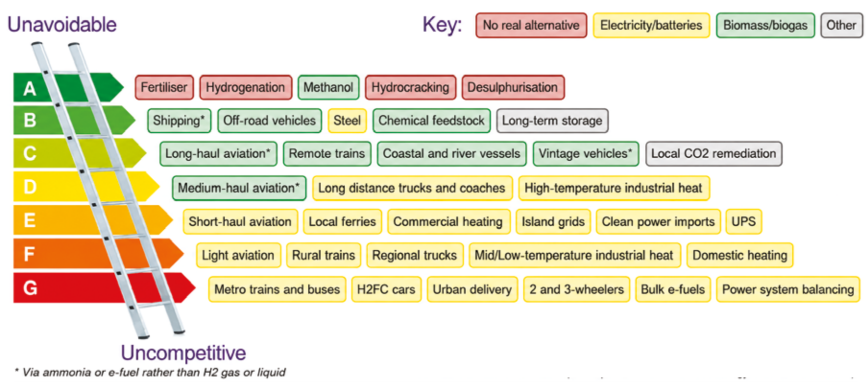

Figure 9 – Clean hydrogen ladder 5.0. Source: Liebreich, M. (2023).

Conclusions

The analysis carried out to identify and discuss the key components of a hydrogen economy (production, transmission, storage systems and end-uses) is a preliminary step to more precisely assess the EU and Italy's policies aimed at integrating hydrogen into the energy system. As emerged from the examination of H_2 production methods, major political and financial efforts are needed to decarbonise the still largely fossil-based hydrogen generation, while the competitiveness of clean (renewable) hydrogen production depends to a large extent on renewable electricity and electrolyser costs. The focus on the H_2 transmission component has instead exposed the increasingly pressing investment and regulatory challenges related to the creation of a hydrogen infrastructure network, which is currently on the political agenda of both EU institutions and the largest Member States. In addition, the need for greater integration between the gas and power sectors has been made clear by addressing hydrogen storage technologies, whereby this clean molecule can allow for large-scale and long-term storage mainly through Power-to-Gas (P2G) systems. Finally, one further discussion point concerns hydrogen demand, and thus the still uncertain potential for hydrogen-based end uses.

Two fundamental issues have emerged from the above analysis. The first is strictly related to the cost component, namely the investment irreversibility and the capital indivisibility of grid-based infrastructures and therefore the challenges in planning the transport infrastructure for hydrogen. Investment will have to be increasingly coordinated not only with future H_2 demand, but also with infrastructure development in other sectors. The second issue concerns the effectiveness of producing hydrogen where clean energy sources are cheap and transporting it to the customer, and producing clean electricity to generate hydrogen close to the demand sites.

CHAPTER 2

Hydrogen integration into the European energy system

Introduction

The thrust of this chapter is to evaluate the current and planned European Union (EU) measures aimed at enhancing the role of clean hydrogen in achieving the long-term socio-economic viability of a climate-neutral energy system. Given the enduring challenges and the subsequent responses that have been characterising the energy landscape at the European level, the following discussion will adopt a bi-dimensional logic: on the one hand, the existing EU energy governance system will be examined against the most recent steps made by the EU institutions to bolster resiliency and provide flexibility to the system; on the other hand, more specific EU actions targeted at preparing the ground for a hydrogen economy will be analysed in light of the regulatory, infrastructural and cost-effectiveness needs.

The EU and its Member States have realised the importance of translating their vision towards 2040-50 into a roadmap, based on no-regret[1] options consistent with the strategy for 2030 (Fit-for-55), and on all the major decarbonised technologies, such as renewables coupled with energy efficiency, as well as green

[1] No-regret in this context can be understood as taking climate-related decisions or actions that make economic good sense, whether or not a specific climate threat actually materializes in the future.

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hydrogen, biomethane, and synthetic fuels. The current system reflects, to a large extent, not only the concern for the supply of imported fossil fuels, but also the traditional distinction in different energy vectors (e.g., electricity, natural gas, etc.) and in different national systems. In the coming years, the European governance of energy will have to evolve towards multi-vector coordination and integration, and multi-level (EU, regional, national, and local) decision-making and governance (Tubiana et al. 2022). The future will imply a more decentralised energy system and, hence, a distributed decision process that must be incorporated into the policy framework to decarbonise Europe by 2050.

Still, the existing framework dates back to the adoption of the Clean Energy Package (published in 2016 and fully adopted in 2019), while the Fit-for-55 package (presented in July 2021), was followed by REPowerEU (published in May 2022), which further increased the Fit-for-55 climate ambitions. These last two frameworks rest on the European Green Deal (outlined in 2019 by the Von der Leyen I Commission), which sets the ultimate target of climate neutrality by 2050. Hydrogen fits into this scenario as a critical enabler of the energy transition, as clearly outlined in the EU Hydrogen Strategy, presented in 2020. The deployment of H_2 in Europe faces important challenges that neither the private sector nor Member States can address alone (European Commission 2020a). The key issue lies in driving (green) hydrogen development past the tipping point, for which a critical mass in investment, an enabling regulatory framework, new lead markets, and sustained research and innovation are needed. These elements - including a large-scale infrastructure network - can only be offered by an EU-wide market and by cooperation with third country partners (European Commission 2020a). If such cooperative approach between policymakers, industry and investors does not emerge and current policies remain in place (business-as-usual approach) hydrogen will see much lower deployment levels, and decarbonisation targets may remain unmet (Fuel Cells and Hydrogen Joint Undertaking 2019).

According to the FCH JU 2019 report, the EU has got several assets that make it particularly well-suited to lead in hydrogen and fuel cell technology. First, it has world-class players along the hydrogen and fuel cell value chains that can drive the development and deployment of hydrogen solutions. Second, it has strong research institutions in hydrogen and well-developed programmes to support research, development, and deployment (RD&D) at the EU, national, and regional levels. Third, the EU is committed to achieving environmental targets, such as increasing renewables, decreasing carbon emissions, and cutting local emissions, and environmental consciousness and awareness is high among its citizens. Fourth, it has an extensive natural gas network, which it can rely on to decarbonise industries and transports.

In view of these challenges, the following discussion is organised along three sections. First, an analysis of the EU regulatory context will be provided, with a focus on the role accorded in the Green Deal to clean molecules and hydrogen in particular. The second section will follow with an in-depth examination of the most recent EU initiatives to address the upscaling of both hydrogen demand

and supply. Finally, the missing piece of the puzzle, i.e. hydrogen infrastructure, will be considered from a regulatory, cost-efficiency and geo-economic perspective in the last section.

2.1 Updating the EU's regulatory context to meet the needs of the low-carbon transition

2.1.1 The «Clean Energy for all Europeans» Package

The Clean Energy Package (CEP) still represents one of the main legal frameworks on which the existing energy and climate legislation at the EU level is based, while it has been revised through the Fit-for-55 and REPowerEU initiatives. The CEP is only the fourth of the so-called «packages» that have shaped and steadily updated the European energy (mainly electricity and gas) markets. After the «First Energy Package», which consisted of an Electricity Directive (1996/92) and a Gas Directive (1998/30), the energy market liberalisation efforts were coupled with further market integration steps. The «Second Energy Package», adopted in 2003, contained two Directives (for gas and electricity) and one Regulation (on access to the network for cross-border exchanges in electricity), while mandating the creation of independent national regulatory authorities (NRAs). Thanks to this package, households and industrial consumers were free to choose their gas and electricity suppliers, thus fostering competition in the market. Finally, two Directives and three Regulations constituted the «Third Energy Package», adopted in 2009. The updated gas and electricity Directives were accompanied by the Regulation (713/2009) establishing the Agency for the Cooperation of Energy Regulators (ACER), the Regulation (714/2009) on conditions for access to the network for cross-border exchanges, and the Regulation (715/2009) on conditions for access to the natural gas transmission networks (Florence School of Regulation 2020a). An example of the increasing importance accorded to market integration and cross-border cooperation was the creation of the European Networks for Transmission System Operators for electricity and gas (ENTSO-E and ENTSO-G). The CEP contains four Directives and four Regulations, mostly concerning electricity and energy efficiency. Table 5 summarises the eight pieces of legislation contained in the CEP.

The objective of the CEP was thus to make the EU energy market suitable for the low-carbon transition, even though - unlike the previous packages - it did not include specific legislation for the gas sector, focusing instead on electricity. A separate new gas package was indeed foreseen to be put forward by the Commission in 2020, but also due to the emergency spurred by the COVID-19 pandemic and the subsequent policy initiatives (e.g., Next Generation EU), the new gas framework was proposed in conjunction with the Fit-for-55 package, in late 2021, and has been referred to as the «Hydrogen and Decarbonised Gas Market Package». The latter piece of legislation thus provides a sort of complement to the CEP, since it is crucial to create a consolidated framework and provide regulatory certainty to facilitate the integration of low-carbon and renewable gases into the market.

Table 5 – Acts adopted under the Clean Energy Package. Source: own elaboration based on European Commission (2019) and Florence School of Regulation (2020a and 2020b).

Subject of the act	Type of act	Publication on the OJEU	Content of the act
Energy Performance of Buildings	Directive 2018/844	19 June 2018	Member States are obliged to establish a long-term renovation strategy to support the renovation of the national stock of residential and non-residential buildings into a highly energy efficient and decarbonised building stock by 2050;[2]
Energy Efficiency	Directive 2018/2002	21 December 2018	EU-level target of 32.5% for energy efficiency for 2030, compared to a baseline scenario established in 2007, with a possible upward revision in 2023; «Energy efficiency first» principle;
Renewable Energy	Directive 2018/2001	21 December 2018	Binding target of 32% for renewable energy sources in the EU's energy mix by 2030, with a possible review for an increase in 2023;
Electricity	Directive 2019/944	14 June 2019	Rules for the generation, transmission, distribution, supply and storage of electricity (market design); consumer empowerment and protection aspects;
Electricity	Regulation 2019/943	14 June 2019	Principles for the internal EU electricity (wholesale) market and network operation; New bidding zone review process and establishment of regional coordination centres, replacing the regional security coordinators, and complementing the transmission system operators' roles on a regional scope;
Governance of the Energy Union and Climate Action	Regulation 2018/1999	21 December 2018	New governance system for the Energy Union; Each Member State is to establish an integrated 10-year National Energy and Climate Plan (NECP) for 2021 to 2030, with a longer-term view towards 2050; The plan is to outline how the Member State will achieve its respective targets;
Risk Preparedness in the electricity sector	Regulation 2019/941	14 June 2019	Requirement for Member States to prepare plans on how to deal with potential future electricity crises;
ACER	Regulation 2019/942	14 June 2019	Update of the role and functioning of the European Union Agency for the Cooperation of Energy Regulators (ACER); increase in the competence of the ACER in cross-border cooperation;

[2] Buildings are responsible for around 40% of energy consumption and around 30% of CO_2 emissions in the EU, making them the single largest energy consumer in Europe (European Commission 2019).

2.1.2 The EU Hydrogen Strategy: A Roadmap for the EU

The Communication[3] presented in July 2020 to the European Parliament and Council by the European Commission referred to as the «EU Hydrogen Strategy» has got at its core the goal of the Commission to significantly reduce the production costs of «green» hydrogen, so as to make it competitive with fossil-based H_2. The strategy includes however also a long-term geopolitical and industrial ambition: Europe is a highly competitive player in clean H_2 production technologies, and it could reap significant benefits from the development of a global hydrogen market (Grossi 2020)[4]. The difference between the past peaks of interest in hydrogen and today's situation is mainly due to the rapid developments in renewable energy technologies and the subsequent cost decline of renewables, which open new possibilities for hydrogen. The 2020 EU Hydrogen Strategy estimated that cumulative investments in renewable hydrogen in Europe could be up to €180-470 billion by 2050, and in the range of €3-18 billion for low-carbon and fossil-based H_2, while employing more than 1 million people in the hydrogen value chain (European Commission 2020a). Table 6 summarises the stages into which the Commission decided to divide the H_2 strategy[5]. While the H_2 market is likely to develop through a gradual trajectory and at different speeds across sectors, the policy focus must be initially on laying down the regulatory framework for a liquid and well-functioning market and on incentivising both supply and demand in lead markets (mainly industrial applications and mobility), including through bridging the cost gap between conventional solutions and renewable and low-carbon hydrogen and through appropriate State aid rules (European Commission 2020a).

Table 6 – Phases of the EU Hydrogen Strategy. Source: own elaboration based on European Commission (2020a) and Tarvydas (2022).

	Phase 1: 2020-2024	Phase 2: 2025-2030	Phase 3: 2030-2050
H_2 technology and market maturity	Renewable H_2 use is limited to sectors already employing hydrogen (chemicals)	Gradual integration of H_2 into the energy system and into new applications (steelmaking, trucks, rail, maritime applications)	Technological maturity of renewable H_2, application in all hard-to-abate sectors and balancing role for renewable-based electricity systems

3 COM 2020/301 final

4 As stated by European Commission's President Ursula von der Leyen in her 2023 State of the Union speech, on 13th September 2023, the modernisation of Europe's industry goes hand in hand with decarbonisation, and the EU's ambition to promote clean technologies aligns with the hydrogen industry's vision for a sustainable future and supports the «Made in the EU» concept. See: https://ec.europa.eu/commission/presscorner/detail/en/speech_23_4426.

5 The electrolyser and production targets set out in the strategy are not legally binding.

	Phase 1: 2020-2024	Phase 2: 2025-2030	Phase 3: 2030-2050
Electrolyser installed capacity	6 GW	40 GW	500-550 GW (max scenario)[6]
Production of renewable H_2	Up to 1 million tonnes (Mt)[7]	Up to 10 Mt	Up to 70 Mt
Infrastructure	Infrastructure needs for transporting hydrogen will remain limited	The need for an EU-wide logistical infrastructure will emerge	Fully developed EU hydrogen network in place (with connections to non-EU countries)

The rules designed and proposed so far by the EU institutions are targeted at an emerging market that should first establish itself. In 2025, market growth has remained insufficient to meet EU and national targets, as electrolyser capacity only reached 308 MW in 2024, hence way behind the 6 GW target for 2024 and 40 GW for 2030 (European Union Agency for the Cooperation of Energy Regulators 2025).

It is interesting to address the progresses made by the EU from the publication of the H_2 strategy in 2020 up to the time of writing. This can be done by assessing the 20 «key actions» outlined in the document of the EU Hydrogen Strategy, and reported in Table 7, together with the follow-up information about their implementation. These actions are sub-divided into five dimensions: 1) an EU investment agenda, 2) actions to boost hydrogen demand and production, 3) a supportive framework for infrastructure and market rules, 4) promotion of research and innovation in H_2 technologies, and 5) the international dimension.

Table 7 – Key Actions of the EU Hydrogen Strategy. Source: own elaboration based on European Commission (2020a) and European Commission: https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen/key-actions-eu-hydrogen-strategy_en.

Dimension	Key Actions	Follow-up information
An EU investment agenda	Develop an investment agenda to stimulate the roll out of production and use of hydrogen and build a concrete pipeline of projects, through the European Clean Hydrogen Alliance.	Over **840 projects** have been collected under the Clean Hydrogen Alliance

6 The same amount of intermittent renewable capacity should be added to provide electricity. The required capacity could be reduced by installing short-term energy storage (batteries). In order to meet electricity demand for green hydrogen production in the EU, installed wind capacity will need to grow by 50% between 2020 and 2030 in the average hydrogen demand scenario (around 40 Mt). In the maximum scenario (around 68 Mt), both solar and wind installed capacity would have to almost triple (Tarvydas 2022).

7 A kilogramme of hydrogen has an energy value of about 33.3 kWh, so a tonne of hydrogen delivers about 33 MWh and a million tonnes about 33 terawatt hours (TWh).

Dimension	Key Actions	Follow-up information
An EU investment agenda	Support strategic investments in clean hydrogen in the context of the Commission's recovery plan, in particular through the Strategic European Investment Window of InvestEU.	At the end of 2021, 15 EU countries had included **hydrogen in their Recovery and Resilience Plans**
actions to boost hydrogen demand and production	Propose measures to facilitate the use of hydrogen and its derivatives in the transport sector in the Commission's Sustainable and Smart Mobility Strategy, and in related policy initiatives.	The **Sustainable and Smart Mobility Strategy** was published in December 2020
actions to boost hydrogen demand and production	Explore additional support measures, including demand-side policies in end-use sectors, for renewable hydrogen building on the existing provisions of the Renewable Energy Directive.	The revision of the RED includes **sector-specific targets for renewable H_2** in industry and transport
actions to boost hydrogen demand and production	Work to introduce a common low-carbon threshold/standard for the promotion of hydrogen production installations based on their full life cycle GHG performance.	The Hydrogen and Gas package requires the European Commission to adopt a **common definition for low-carbon hydrogen** (see section 1.4.1)
actions to boost hydrogen demand and production	Work to introduce a comprehensive terminology and European-wide criteria for the certification of renewable and low-carbon hydrogen.	The RED and the revised Gas Directive include **certification schemes for renewable and low-carbon hydrogen**
actions to boost hydrogen demand and production	Develop a pilot scheme for a Carbon Contracts for Difference programme, in particular to support the production of low carbon and circular steel, and basic chemicals.	The **revised EU ETS** includes the option to introduce CCfDs[8]
a supportive framework for infrastructure and market rules	Start the planning of hydrogen infrastructure, including in the Trans-European Networks for Energy and Transport and the Ten-Year Network Development Plans (TYNDPs).	The Hydrogen and Gas Package includes **coordinated planning for hydrogen infrastructure**

[8] CCfDs are contracts between a public administration and a company that set a fixed carbon price over a given period, which reduces the investment risk for companies that want to adopt GHG-neutral technologies, and shares the CO_2 costs between public and private entities. If the market price for emission allowances (EU ETS) is lower than the carbon avoidance costs for the company, the public administration pays the difference to the company. If the carbon price is higher, the company must pay the difference to the public administration. See: https://cefic.org/media-corner/newsroom/whats-next-for-carbon-contracts-for-difference-and-can-they-really-boost-innovation-in-europe/.

Dimension	Key Actions	Follow-up information
a supportive framework for infrastructure and market rules	Accelerate the deployment of different refuelling infrastructure in the revision of the Alternative Fuels Infrastructure Directive and the revision of the Regulation on the Trans-European Transport Network.	The **Alternative Fuels Infrastructure Regulation** (AFIR) and Trans-European Transport Network revision include support for hydrogen refuelling stations
a supportive framework for infrastructure and market rules	Design enabling market rules to the deployment of hydrogen through the review of the gas legislation for competitive decarbonised gas markets.	The Hydrogen and Decarbonised Gas Markets Package includes an **enabling framework for H_2 infrastructure and markets**
promotion of research and innovation in H_2 technologies	Launch a 100 MW electrolyser and a Green Airports and Ports call for proposals as part of the European Green Deal call under Horizon2020[9].	The Horizon2020 call resulted in the financing of three **100 MW renewable H_2 electrolysers** in Germany, the Netherlands and Portugal.
promotion of research and innovation in H_2 technologies	Establish the proposed Clean Hydrogen Partnership, focusing on renewable hydrogen production, storage, transport, distribution and key components for priority end-uses.	The **Clean Hydrogen Partnership** was established in November 2021
promotion of research and innovation in H_2 technologies	Steer the development of key pilot projects that support hydrogen value chains, in coordination with the SET Plan[10].	Hydrogen has been integrated into **implementation Working Group on Renewable Fuels** under the SET Plan activities
promotion of research and innovation in H_2 technologies	Facilitate the demonstration of innovative hydrogen-based technologies through the launch of calls for proposals under the ETS Innovation Fund.	The first round of the **Innovation Fund** included 3 large-scale and 5 small-scale hydrogen projects
promotion of research and innovation in H_2 technologies	Launch a call for pilot action on interregional innovation under Cohesion Policy on Hydrogen Technologies in carbon-intensive regions.	The interregional innovation action supported the «**European Hydrogen Valley partnerships**»
The international dimension	Strengthen EU leadership in international fora for technical standards, regulations and definitions on hydrogen.	The **International Partnership for a Hydrogen Economy** (IPHE) published a report on GHG emissions associated with H_2 production

9 Horizon2020 was the EU's research and innovation funding programme from 2014 to 2020 and has been replaced by Horizon Europe (EU programming cycle 2021-2027).

10 The Strategic Energy Technology Plan (SET Plan) is an instrument (established in 2007) with the goal to improve new and low-carbon technologies and bring down their costs, by promoting cooperation among EU countries, companies, and research institutions.

Dimension	Key Actions	Follow-up information
The international dimension	Develop the hydrogen mission within the next mandate of Mission Innovation[11].	A «**Clean Hydrogen Mission**» was launched in 2021 under Mission Innovation
The international dimension	Promote cooperation with Southern and Eastern Neighbourhood partners and Energy Community countries on renewable electricity and hydrogen.	The EU's joint communication on the **Southern Neighbourhood** has established hydrogen as a new strategic priority, and a hydrogen workshop has been established with the **Eastern Partnership**
The international dimension	Set out a cooperation process on renewable hydrogen with the African Union.	The «**Africa-EU Green Energy Initiative**» was launched in 2022
The international dimension	Develop a benchmark for euro denominated transactions by 2021.	Hydrogen was included in a **communication to the European Central Bank** in 2021

2.1.3 The EU Energy System Integration Strategy

The EU strategy on hydrogen is complemented by the Strategy for Energy System Integration (ESI), which was released at the same time, in July 2020. Without adopting a systemic perspective, it is indeed more difficult - if not impossible - to exploit the transformations occurring in one sector to foster advancements in other sectors of the energy system. The latter today is still built on several parallel, vertical energy value chains, which rigidly link specific energy resources with specific end-use sectors (European Commission 2020b). For instance, petroleum products are predominant in the transport sector and as feedstock for industry. Coal and natural gas are mainly used to produce electricity and heating. Electricity and gas networks are planned and managed independently from each other. Market rules are also largely specific to different sectors. According to the ESI strategy, such a model of separate silos is technically and economically inefficient and leads to substantial losses in the form of waste heat and low energy efficiency. This is why emerging technologies, such as renewable hydrogen, can not only contribute to decarbonisation, but can transform the same structure of the energy system, by integrating different energy carriers flexibly and fostering decentralisation.

Energy system integration can be defined as «the coordinated planning and operation of the energy system as a whole, across multiple energy carriers, infrastructures, and consumption sectors» (European Commission 2020b). The main idea behind integrated energy systems, which are also known as «multi-energy systems» or «hybrid energy systems», is to move from a single energy carrier to multiple energy carriers to exploit the synergies from their interplay,

[11] Mission Innovation is a global initiative on clean energy launched at the COP21, which the EU joined in 2016.

thereby increasing the efficiency in the energy resources used (Graditi and Di Somma 2022). In their book *Technologies for Integrated Energy Systems and Networks*, Graditi and Di Somma (2022) define this concept as an integrated infrastructure for all energy carriers with the electrical system as a backbone, characterised by a high level of integration between all networks of energy carriers, coupling of electrical and gas networks, heating and cooling, supported by energy storage and conversion processes. Figure 10 shows such a concept, which links the various energy carriers with each other and with the end-use sectors (households, tertiary sectors, industry and transport).

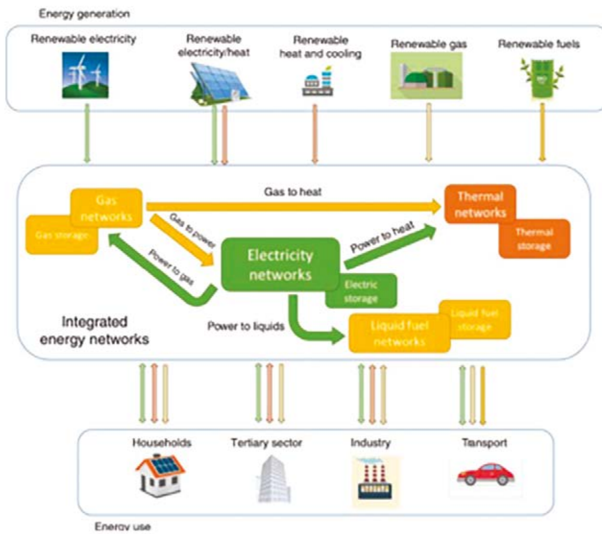

Figure 10 – Scheme of an integrated energy system. Source: Graditi and Di Somma (2022).

Therefore, energy system integration relies on «sector coupling» to achieve full integration. Sector coupling can be defined as «the process of progressively interlinking the electricity and gas sectors - by optimising the existing synergies in the generation, transport, and distribution of electricity and gas - with the ultimate scope to build a decarbonised and hybrid EU energy system» (Florence School of Regulation 2020c). Therefore, despite being limited to electricity and gas, sector coupling is the key to integrate more sectors in the future, given the projected increase in electrification of end-uses, and the enhanced role of clean molecules (mainly biomethane and hydrogen). Power-to-Gas (P2G) technologies, already mentioned in this work, are a typical - and rather new - instrument to foster sector coupling, because they can serve the double purpose of converting curtailed electricity into renewable (or low-carbon) hydrogen (depending on the type of electricity used) for storage or direct use, and even into natural gas (after methanisation) (Florence School of Regulation 2020c). As reported in Van Nuffel (2018), sector coupling leads to a lower overall cost, mainly because of reduced investment costs, since the lower peaks in electricity demand and supply allow for less reinforcement investments in the electricity transmission and distribution grids and require less gas-based power generation capacity. Hence, also efficiency can be higher in a system with sector coupling, which uses assets in a more economical way. This is why the EU ESI Strategy aims at gradually shaping a new integrated energy system, by putting forward concrete policy measures that have been divided into six main pillars: 1) a circular energy system based on efficiency, 2) increased electrification based on renewable energy sources, 3) renewable and low-carbon fuels in hard-to-abate sectors, 4) empowering consumers' choice, 5) infrastructure integration, and 6) digitalisation for a smarter interconnection.

The pillars of the ESI Strategy have been confronted with numerous challenges. Firstly, the application of the «energy efficiency first» principle must materialise, while the Primary Energy Factor (PEF) [12] can be used as a tool to facilitate comparisons of savings across energy carriers. Secondly, electrification has shown a slower pace, increasing only by 5% in the last thirty years (European Commission 2020b). For this reason, and according to the provisions of the new RED III (see section 2.1.4.2. below), it is crucial to accelerate permitting for installing renewable power capacity and further electrify the energy mix. Part of such newly installed renewable capacity must be used to ramp-up clean hydrogen production, as this molecule is a critical enabler of system integration, and methane-based H_2 with CCS has been facing a too slow growth. This is also because a proper CCS system needs an integrated infrastructure to manage and transport CO_2. It is important to keep in mind that infrastructure investments typically have an economic life of 20 to 60 years, so there can also be a serious risk of lock-in effects and stranded assets.

2.1.4 «Fit for 55» Package and «REPowerEU» Plan

The Fit-for-55 Package

The European Commission presented the «Fit-for-55» Package in July 2021 to implement and achieve the aims of the European Climate Law, which took effect on 29th July 2021. The package consisted of thirteen interlinked strategic and legislative proposals to revise existing EU energy and climate laws and six proposals to adopt new legislation. After setting ambitious targets such as climate neutrality by 2050 and a 55% reduction of net GHG emission by 2030, the European Commission also designed an equally ambitious and strict timeline to reach those objectives, which however must consider the possible frictions

[12] The primary energy factor (PEF) indicates the amount of primary energy used to generate a unit of final energy (electrical or thermal), allowing a comparison of the primary energy consumption of products with the same functionality using different energy carriers (European Commission 2020b).

and obstacles enshrined in the EU ordinary and special legislative procedures. As is being demonstrated at the time of writing, final decisions on some of the proposed legal acts have yet to be made, while other acts have been recently adopted or politically agreed upon[13].

Some of the changes proposed through the «Fit-for-55» Package are not limited to one specific sector or sub-sector, but are intended as cross-sectoral regulatory acts, that contribute to integrating the energy system to other sectors. Figure 11 provides an explanatory overview of those linkages between sectors and shows the legislation proposed to realise the objectives of the EU Climate Law. The key areas of action of Fit-for-55 are the energy, buildings, and transport sectors. Some links between the key proposals imply, for instance, that the revised Gas and Hydrogen Regulation and Gas and Hydrogen Directive (both part of the «Hydrogen and Decarbonised Gas Market Package») refer to the revised Renewable Energy Directive (RED) for the definition of renewable gas. In turn, both the RED and the Energy Performance of Buildings Directive (EPBD) refer to definitions included in the revised Energy Efficiency Directive (EED)[14]. The latter and the proposal for a Social Climate Fund (SCF) refer to each other with respect to the use of the fund[15]. Finally, the Energy Taxation Directive (ETD)[16] refers to the definitions in the revised RED and in the new Alternative Fuels Infrastructure Regulation (Erbach and Jensen 2022).

[13] Among the key proposals for new and updated legislation, the European Parliament and the Council of the EU formally adopted the revised Renewable Energy Directive in October 2023; the new Energy Efficiency Directive was formally adopted in July 2023, as well as the Fuel EU Maritime Regulation and the ReFuelEU Aviation to decarbonise maritime and air transport applications; the new Alternative Fuel Infrastructure Regulation (AFIR) was also adopted in July 2023, which is also relevant for hydrogen integration in the transport sector; the new ETS was adopted after two years of negotiations in line with the objectives of the EU Climate Law; finally, the Hydrogen and Decarbonised Gas Markets Package, which is one of the cornerstones of the EU hydrogen policy, was formally adopted in April 2024.

[14] The Fit-for-55 proposal to amend the EED provided for an increase of the Union's binding energy efficiency target for final and primary consumption of at least 9% in 2030 compared with the projections of the 2020 reference scenario, thus expressing the target in a different manner in comparison to the EED adopted under the Clean Energy Package (32.5% compared to 2007 scenario), and representing raised ambitions. The energy efficiency target has been further increased by the REPowerEU Plan (see next paragraph).

[15] As part of Fit-for-55, the European Commission proposed to create a Social Climate Fund to address the social impacts that might arise from the revised Emission Trading System, that has been extended to the buildings and road transport sectors.

[16] The initial ETD (Directive 2003/96/EC) was aimed at providing a harmonised framework for imposing taxation on energy products and electricity in the EU Member States. Its proposed revision focuses on the structure of the tax rates (based on the real energy content and environmental performance of fuels and electricity, rather than on volume) and on broadening the taxable base (by including more products and abolishing some of the current tax exemptions) (Schlacke *et al*. 2022).

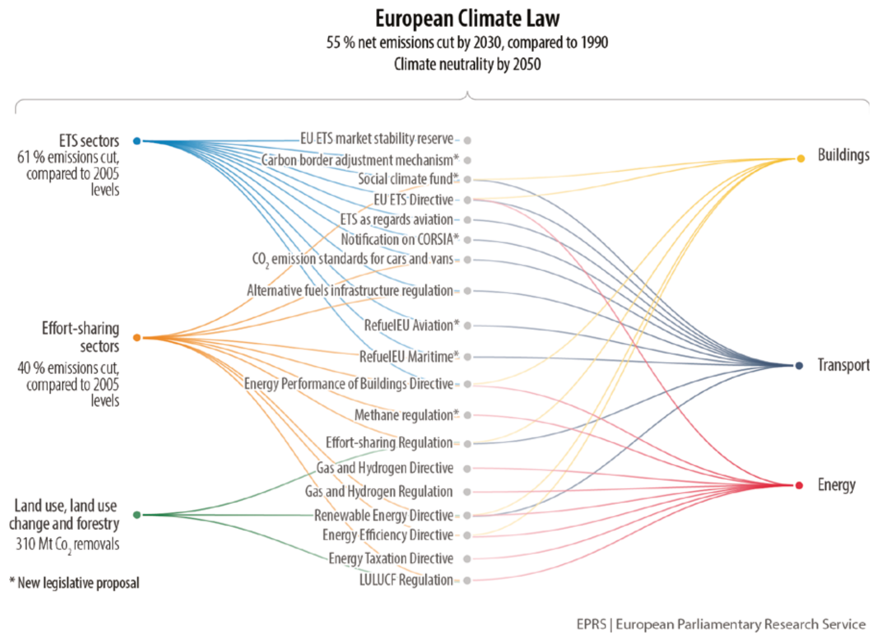

Figure 11 – The «Fit-for-55» Package. Source: Erbach and Jensen (2022).

The REPowerEU Plan

While the legislative proposals introduced with the «Fit-for-55» Package were being negotiated by the EU institutions, the European Commission published the REPowerEU Plan on 18th May 2022, to respond to the energy market disruptions sparked by Russia's war against Ukraine[17]. This initiative included actions in four key areas, which had been also affected by the tightening of energy supply chains and increased gas prices since late 2021. The plan includes efforts targeted at diversifying and securing the EU's energy supplies, as well as saving energy and boosting renewables. The updates that REPowerEU has brought to Fit-for-55 are aimed at preserving and strengthening the EU's climate policy trajectory, including enhanced targets for green and low-carbon gases, such as biomethane and hydrogen. Table 8 gives an overview of the main amendments put forward with REPowerEU concerning the Fit-for-55 legislative proposals. Besides the short-term measures taken to fill gas storages and diversify the energy supply away from Russian fossil fuels, the REPowerEU Plan has focused on a series of targeted amendments to the RED, the EED, and the EPBD. Since all three directives were already in the process of being revised as part of Fit-for-55, the amendments are meant to feed into this ongoing process of legislative revision.

[17] COM 2022/230.

Table 8 – Main legislative updates of REPowerEU. Source: own elaboration based on European Parliament (2023a).

Legislative act	Fit-for-55 Package	REPowerEU Plan
Renewable Energy Directive[18]	RES in final energy consumption: **40%**	RES in final energy consumption: **45%**
Energy Efficiency Directive[19]	Energy Efficiency target: **9%** reduction in primary energy consumption by 2030 compared to 2020	Energy Efficiency target: **13%** reduction in primary energy consumption by 2030 compared to 2020
Energy Performance of Buildings Directive	All new buildings must be zero-emission buildings by 2030; existing buildings must be transformed into **zero-emission buildings by 2050**	Additional obligation for Member States to ensure new buildings are **solar-ready** and to install solar energy installations on buildings, covering all new residential buildings from 2030

Given the scope of this thesis, the REPowerEU Plan will be mentioned in the light of the initiatives targeted at developing hydrogen, even though some other major changes have been rolled out by the European Commission to strengthen the EU energy system. One critical measure is represented by the mandate to add a «REPowerEU chapter» in the National Recovery and Resilience Plans (NRRPs), thus also increasing the financial resources to bring about decarbonisation[20]. Furthermore, boosting the industrial low-carbon transition and the use of renewables are two key areas of action, as well as investments in energy infrastructures and interconnections.

2.1.4.1 Hydrogen and Decarbonised Gas Market Package

The revision of the Gas Directive (2009/73/EC) and the Gas Regulation (2009/715/EC) is part of the «Hydrogen and Decarbonised Gas Market Package» (HDGMP), proposed by the European Commission in December 2021. Two years after, in December 2023, the EU's legislative institutions managed to agree on a final version of both the Directive and Regulation, both of which were formally adopted in early 2024, with the aim to create a favourable regulatory environment for the uptake of the so-called «clean molecules». In 2021, power and heating generation represented the largest share of natural gas use in the EU at roughly 31% of overall consumption, while around 24% of gas was used by households, and a further 23% by the industry sector (European Council 2023). The EU's total natural gas consumption was around 343 billion cubic

[18] The revised Renewable Energy Directive (RED III) was formally adopted by both Council and Parliament in Autumn 2023 (see section 2.1.4.2).

[19] After the EU Parliament and the Council of the EU had adopted the new rules to reduce final energy consumption at EU level by 11.7% in 2030, the new EED entered into force in late 2023.

[20] This aspect will be discussed in Chapter 3 when analysing Italy's hydrogen policies.

metres in 2022 (Statista 2023)[21]. A significant amount of this demand is likely to be electrified in the future as it is typically more efficient in the context of a renewable-dominated energy mix. Within this context, projections for the gas sector broadly envisage a diminished overall role for molecules (Olczak and Piebalgs 2019). However, there is likely to still be a requirement for significant volumes of molecular energy. This is due in part to the physical properties of energy in such a form. According to the TYNDP 2022 Scenario Report[22], current national policies show a large role for methane with very limited evolution of the demand until 2030, when the methane demand will decrease with the implementation of the strategy of some Member States which see the uptake of their hydrogen demand (ENTSO-E and ENTSO-G 2022). Figure 12 clearly shows that the current share of fossil gas consumption will have to be almost completely replaced by clean molecules (biogas, hydrogen, and e-gases) by 2050.

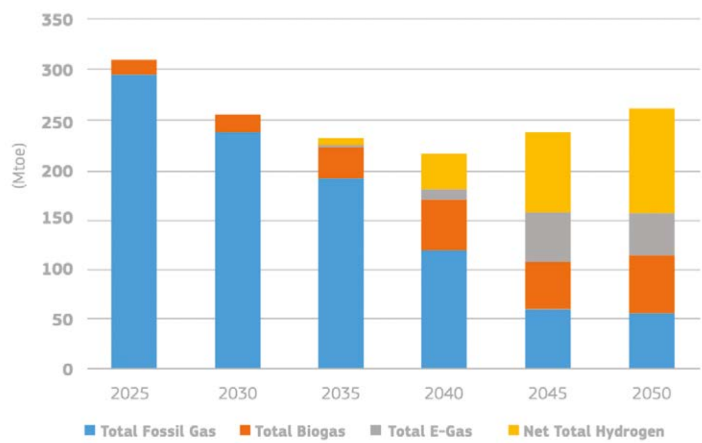

Figure 12 – Total consumption of gaseous fuels in 2050 [Mtoe][23]. Source: European Commission (2021a).

The Commission's initial proposal set two main goals. On the one hand, the package had to establish the legislative base for the decarbonisation of gas markets, and on the other hand, it was aimed at creating a hydrogen market (Tanase and Anchustegui 2022). These objectives will contribute to putting Europe at the forefront in terms of regulatory innovation in an area that is expected to be a vital component of the energy transition. The latter goal includes the crea-

21 Currently, some 300 Mtoe (350-400 bcm) of gaseous fuels are consumed in the EU per year, of which 95% is natural gas.

22 TYNDP refers to the Ten-Year Network Development Plan, prepared jointly by European Network of Transmission System Operators for electricity (ENTSO-E) and gas (ENTSO-G) every two years.

23 1 Mtoe = 1.11 billion cubic metres (bcm) of natural gas.

tion of regulatory incentives towards a fit-for-purpose infrastructure where hydrogen can be cost-effectively transported from production to consumption (Tanase and Anchustegui 2022). Table 9 summarises the key areas of revision of the rules within the HDGMP, as proposed by the European Commission at the end of 2021.

Table 9 – Key areas of revision in the European Commission's HDGMP proposal. Source: own elaboration based on Tanase and Anchustegui (2022).

Area of revision	Proposal of the European Commission
Infrastructure	Adaptation of the Gas Directive and Gas Regulation to accommodate renewable and low-carbon gases (including hydrogen and biomethane) and to **enable the repurposing of the existing gas infrastructure** for their transport, storage and import.
Market design	Design of a **hydrogen and market framework** (third party access, tariffs, unbundling, ban of long-term gas supply contracts after 2049).
Inter-TSO cooperation	Creation of the **European Network of Network Operators for Hydrogen** (ENNOH) to promote a dedicated hydrogen infrastructure, cross-border coordination, interconnector network construction, and elaborate specific technical rules.
Cross-border cooperation	**5% cap for hydrogen blend** at cross-border interconnection points from 1st October 2025.
Consumers' protection	Consumer protection rules modelled on the ones applicable to electricity markets, **facilitating supplier switching, price comparisons**, and getting accurate data on consumption.
Renewable certificates	A **certification system for renewable and low-carbon gases** in line with the rules of the Renewable Energy Directive applicable to renewable gases.
Security of energy supply and gas storage	Measures to cover renewable and low-carbon gases, as well as introducing additional provisions on critical areas, namely **cybersecurity and supply disruptions**; Development of a **strategic approach to gas storage** by incorporating storage considerations into energy risk assessments.

One critical aim of the HDGMP is to ensure a more integrated network planning between electricity, gas and hydrogen networks, as emphasised in the EU Strategy for Energy System Integration. According to the Commission, at the national level, there may continue to be two separate network plans for gas and electricity, but both will need to be developed on the basis of a joint scenario covering electricity, gas and hydrogen, as this helps to ensure that there is a common vision between different energy vectors in the future (European Commission, 2021a)[24]. The initial HDGMP proposal introduced an additional

[24] The network plans should also provide transparency on network parts that will not be needed anymore or could be used for transporting hydrogen in the future, as well as providing indications for the optimal size and location of power-to-gas facilities such as electrolysers.

national network planning for hydrogen and an EU-wide ten-year network development plan, which would include the modelling of an integrated network, build on national hydrogen network plans, national investment plans, cross-border interconnectors, and identify gaps in investments. The revised Gas Directive, as agreed by the EU legislators, requires gas TSOs and hydrogen network operators to prepare every two years a ten-year network development plan for methane and H_2, while hydrogen distribution network operators must cooperate with electricity and natural gas distributors to develop a network plan every four years (Council of the European Union 2023c).

Infrastructure is thus the keystone of the future development of an integrated hydrogen market. The European Commission assumes that there will be two gaseous networks: a methane-based infrastructure, which will evolve from the current natural gas-based system to one which uses more biomethane and synthetic methane; and a hydrogen-based infrastructure, which will complement and partly replace the current natural gas one (Barnes 2023). This is why also a separate organisation for hydrogen operators (ENNOH) was included in the initial proposal, and it has been kept in the final agreement between the Council and Parliament (Council of the European Union 2023d), even though the latter institution had insisted on expanding the role of the already existing ENTSO-G to also cover hydrogen network operators, thus becoming an "ENTSO-G&H" and avoiding the creation of the ENNOH (European Parliament 2023b). Although we could claim that integrating those operators into the already existing ENTSO-G would have been faster and could have provided benefits from common expertise, the revised legislation requires ENTSO-G to also prepare the hydrogen network plans for a transition period (until 2027) until the ENNOH is established (Council of the European Union 2023d). The creation of a new separate entity to coordinate future hydrogen operators could be also justified by the fear (mostly felt by the Council) that having one single ENTSO-G&H might give an incentive to incumbent (natural gas) operators to exclude potential new entrants, thus distorting the market to their advantage.

Regarding hydrogen networks, the Commission initially proposed to abolish tariffs at interconnection points between different Member States from 2031 (Barnes 2023). Given that tariffs would have been equal to zero, the national regulatory authorities (NRAs) should have agreed a system of financial compensation for cross-border H_2 infrastructure, because tariffs are usually the essential means through which network operators recover their revenue and thus enable the physical flow of gas in the system. Cross-border tariffs reflect the cost of moving gas from one network in one country to another. The proposal to remove such tariffs on hydrogen networks was based on the Commission's idea that cross-border transport tariffs hinder trade[25]. However, as we pointed out,

[25] This element is known as «pancaking issue», which refers to the accumulated effect of cross-border tariffs on the delivered price of natural gas or hydrogen that crosses several borders from point of entry into the EU grid to point of delivery. For example, depending

removing those tariffs will require several network operators to agree revenue-sharing mechanisms which would be complex.

As a result, the EU's co-legislators agreed that for the hydrogen market every national regulatory authority must consult the neighbouring NRAs on the draft tariff methodology and submit it to the Agency for the Cooperation of Energy Regulators (ACER), while each Member State, and thus every NRA, will maintain the right to set its own tariff (Council of the European Union 2023d). The revised Gas Regulation adds the possibility for EU countries to merge adjacent entry-exit systems - i.e. the different zones of the gas network - to achieve regional integration where tariffs can (but do not have to) be abolished at the interconnection points. When choosing such option, the regulatory authorities may approve a common tariff and an effective compensation mechanism between TSOs for the redistribution of costs on account of the abolished interconnection points (Council of the European Union 2023d). The legislators also agreed on a series of discounts on tariffs for renewable and low-carbon gases accessing the natural gas system, concerning:

1. the injection from production facilities, with a discount of 100% for renewable and 75% for low-carbon gas;

2. the injection to and withdrawal from storage facilities, with a 100% discount in the Member State where the renewable and low-carbon gases were first injected into the system;

3. the interconnection points between Member States, with a discount of 100% on the capacity-based tariffs[26] for all network users, after one year from the entry into force of the revised Gas Regulation, and only after providing the respective TSO with a proof of sustainability, based on a valid sustainability certificate in accordance with the Renewable Energy Directive II.

Regarding hydrogen blending at interconnection points in the gas grid, the Parliament and Council agreed on a 2% instead of a 5% H_2 share, as had been initially proposed by the Commission. Some experts have argued that the supply of renewable hydrogen will be so limited in the early years that it is better to focus its use on hard-to-electrify sectors such as heavy industry, rather than «waste» it by blending it into natural gas flows (Barnes 2023). Moreover, at present, the permitted proportion of hydrogen in gas transmission networks varies significantly from one EU Member State to another. For instance, only 0.5% is allowed in Sweden, 4% in Austria, 5% to 10% in Germany and up to 12% in the Dutch gas grid (Zemite et al. 2023).

on the contractual path chosen, LNG delivered and regasified at Rotterdam could be sold to a customer in the Slovak Republic. Such gas would pay an entry tariff into the Dutch grid, then exit and entry tariffs as it went from the Dutch to the German grid, and so on from the German to Czech grid, and from the Czech grid to the Slovak grid. The Commission sees pancaking as a barrier to trade (Barnes 2023).

[26] Those tariffs are charges based on the transport capacity of the gas infrastructure rather than solely on the volume of gas consumed by users.

The revised Gas Directive includes a reference to «low-carbon hydrogen», thus potentially opening the way to the so-called blue H_2. The 9th recital states that «In line with the EU Hydrogen Strategy, the priority for the Union is to develop renewable hydrogen produced using mainly wind and solar energy». It nonetheless continues stating that «Low- carbon fuels (LCFs) such as low-carbon hydrogen (LCH) may play a role in the energy transition, [...] particularly in the short and medium term to rapidly reduce emissions of existing fuels, and support transition of the Union's customers in hard-to-decarbonise sectors in which more energy or cost-efficient options are not available». A more precise - even though incomplete - definition of «low-carbon hydrogen» is provided by Article 2 of the revised Gas Directive, where such type of H_2 is included in the concept of «low-carbon gas» which meets a «greenhouse gas emission reduction threshold of 70%» (Council of the European Union 2023c)[27].

As a final item in the revision of the gas package, the issue of unbundling - the separation of energy supply generation from the operation of the transmission network - should be mentioned. In its initial proposal, the Commission suggested a horizontal unbundling model, i.e. when a hydrogen network operator is part of a company active in transmission or distribution of natural gas (or electricity), it must be independent at least in terms of its legal form and must ensure that accounts are kept separate between the two activities (Tanase and Anchustegui 2022). After 2030, however, the Commission proposed the Ownership Unbundling (OU) model, i.e. the highest degree of unbundling, which prevents a company that owns and operates a network from being active in the other (competitive) segments of the hydrogen or gas supply chain. Such a proposal would nonetheless prevent transmission system operators (TSOs) in several Member States from owning and operating a hydrogen network after 2030, with the effect of disincentivising investments into hydrogen and its supporting infrastructure. This is also why the Council of the EU and the European Parliament decided to allow other, less restrictive, unbundling models to apply to hydrogen networks, and they agreed to allow Member States not to apply the OU model under certain conditions (Council of the European Union 2023c)[28].

The integration of clean molecules in the EU's energy mix still faces limitations and bottlenecks. First, replacing fossil gas with biomethane or hydrogen does not completely solve the issue of lifecycle GHG emissions. Clean molecules can also be climate forcers, characterised, for instance, by fugitive emissions. Secondly, the aspect of lifecycle emissions involves an opportunity cost, con-

[27] On 8 July 2025, the European Commission published a delegated act (EU 2025/2359) on low-carbon hydrogen, which operationalises the formal definition of low-carbon H_2 and explains how to calculate the required 70 % GHG emissions savings compared to the use of unabated fossil fuels (European Parliament 2025).

[28] One possible unbundling model is the Independent Transmission Operator (ITO), which allows the vertically integrated company to maintain the ownership of the transmission network, but it requires the company to comply with some rules aimed at ensuring the independence of its other businesses in the supply chain (e.g. a type of legal unbundling).

cerning the allocation of scarce resources (e.g. renewable electricity) to different uses, such as electrolysis to produce green hydrogen, or the electrification of transport applications. That is why different EU initiatives aimed at decarbonisation may end up competing for the same renewable electricity. Thirdly, the cost-effectiveness of clean molecules and the speed at which they can be scaled largely depend on the cost and availability of renewable electricity, as well as the support schemes introduced by governments. Unsubsidised, renewable hydrogen typically remains uncompetitive with fossil H_2 in most of the circumstances.

2.1.4.2 Renewable Energy Directive III

The Hydrogen and Decarbonised Gas Markets Package is strongly linked with the proposals set out in the revised Renewable Energy Directive (RED). After the adoption of RED II (Directive 2018/2001), the European Commission expanded its scope with the proposals included first in Fit-for-55, and then in REPowerEU. The latter plan indeed raised the required share of renewable energy sources (RES) in the EU's final energy consumption to 45% by 2030, and the Commission included measures to accelerate permitting procedures for new RES power plants, whereas Member States would be required to designate «renewables go-to areas» suitable for RES installations (European Parliament 2023a). The proposal also included a series of higher EU and national targets for different sectors (transport, industry and buildings) and the promotion of (renewable) hydrogen consumption in transport and industry (European Parliament 2023d). The European Parliament adopted the more ambitious RES targets (including sector-specific targets) proposed by the Commission, reaching a provisional agreement with the Council on 30th March 2023. The two co-legislators formally adopted the RED III (Directive 2023/2413) in September (Parliament) and October 2023 (Council)[29]. Table 10 outlines the content of the main items agreed upon by the co-legislators regarding the RED.

Table 10 – Key elements of the Renewable Energy Directive III. Source: own elaboration based on Council of the European Union (2023b).

Items	Measure
RES target in EU final energy consumption	Agreement to raise the share to **42.5% by 2030 with an additional 2.5% indicative top up that would allow to reach 45%.**
Transport sector target	Possibility for member states to choose between: a binding target of **14.5%** reduction of **greenhouse gas intensity** in transport from the use of renewables by 2030 or a binding share of at least **29%** of **renewables** within the final consumption of energy in the transport sector by 2030

[29] After the entry into force of the Directive, Member States have got 18 months of time to transpose it into national law.

Items	Measure
Transport sector sub-targets	**5.5%** for **advanced biofuels** and **renewable fuels of non-biological origin** (mostly renewable hydrogen and hydrogen-based synthetic fuels). Within this target, there is a minimum requirement of **1%** of **renewable fuels of non-biological origin (RFNBOs) in 2030.**
Industry sector target	Increase in the use of renewable energy annually by **1.6%**. **42%** of the **hydrogen** used in industry should come from RFNBOs by 2030 and **60%** by 2035.
Buildings sector target	Indicative target of at least a **49%** renewable energy share in 2030.
Heating and cooling	Binding increase of **0.8%** in RES per year at national level until 2026 and **1.1%** from 2026 to 2030.
Permitting	Member states will design **renewables acceleration areas** where renewable energy projects will undergo simplified and fast permit-granting processes. Renewable energy deployment will also be presumed to be of «**overriding public interest**», which will limit the grounds of legal objections to new installations

Most importantly, for the purpose of our discussion, the revised Renewable Energy Directive contains the definition of renewable gas, including renewable fuels of non-biological origin (RFNBOs). The rules to comply with in order for an RFNBO to count towards the EU's policy targets have been defined in two critical Delegated Acts to the Renewable Energy Directive, published by the European Commission in February 2023, and formally adopted in June 2023[30]. As the number of implemented production projects increased and improvements were made in the generation of RFNBOs, an issue emerged on the end-uses of those fuels and energy carriers, concerning the availability of sufficient renewable electricity to produce them.

– First Delegated Act[31]

RFNBOs are the subject of the first Delegated Act (DA), which defines when hydrogen, hydrogen-based fuels and other energy carriers can be considered RFNBOs. These were first defined in the 2018 Renewable Energy Directive (RED II) as «liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the content of which is derived from renewable sources other than biomass»[32]. However, the Commission proposed to count RFNBOs towards the EU's renewable energy targets regardless of the end-use sector in which they are used, thus expanding the scope for hydrogen develop-

[30] The final texts are unchanged from the draft acts adopted by the Commission on 13th February 2023. The rules formally enter into force 20 days following their publication in the Official Journal.

[31] Commission Delegated Regulation 2023/1184

[32] Article 2.36 of the Renewable Energy Directive II (Directive 2018/2001).

ment. Article 1 of the new RED III amends the previous definition, describing RFNBOs as «liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass». Gaseous renewable H_2 produced by feeding renewables-based electricity into an electrolyser is therefore considered an RFNBO, whereas liquid fuels, such as ammonia (NH_3), methanol, or e-fuels, are considered RFNBOs when produced from renewable hydrogen (European Commission 2023a).

The first DA is also known as «Additionality Delegated Act» because the rules that it sets out aim to ensure that RFNBOs are only produced from «additional» renewable electricity, which is generated at the same time and in the same area as the production of RFNBOs[33]. Unless the electricity system is already largely decarbonised, it is indeed crucial to match the electricity demand for hydrogen production with additional renewable electricity generation (European Commission 2023a). If H_2 production were not matched by additional RES electricity, the additional electricity demand of electrolysers (used to produce H_2) could lead to increased fossil-based power generation, thereby increasing - rather than decreasing - emissions. According to the RED II, as of 1st January 2021, RFNBOs are indeed counted towards the EU's renewable energy targets if they deliver GHG emissions savings of at least 70% compared to fossil fuels (Erbach and Svensson 2023)[34].

Because the Renewable Energy Directive provides for a default rule on grid electricity used to produce RFNBOs, the «Additionality DA» acts as a sort of «derogation», providing two scenarios in which the RFNBOs can be considered fully renewable (i.e., produced with renewable electricity). These two scenarios have been introduced by the Commission mainly because currently (and in the near future), given the 70% GHG emissions reduction requirement, the GHG intensity of the electricity grids in most EU Member States is too high, i.e. not fulfilling the emissions saving requirement of the RED[35]. The default rule included in the RED states that the share of RFNBOs corresponds to the average share of renewable electricity on the electricity network of the country in which the RFNBO production is located. Table 11 outlines the two scenarios under which the first DA allows the hydrogen (RFNBO) produced to be counted as fully renewable.

[33] To improve the readability of this section, we may use «hydrogen» to mean «renewable fuels of non-biological origin», and «electrolyser» instead of «installation producing renewable liquid and gaseous fuel of non-biological origin», as used in both delegated acts.

[34] This corresponds to around 3.38 kg of CO_2 per kg of hydrogen. Besides setting the 70% threshold for RFNBOs, Article 25.2 of the RED II also requires the Commission to adopt a delegated act on GHG savings and calculation of lifecycle emissions by 1st January 2021, which it did with a two-year delay, when it published the second DA in February 2023 (see below).

[35] This situation might change by 2030, when in 10 EU Member States it will be possible to produce hydrogen from grid electricity with an emission factor below the 70% GHG reduction threshold (Hydrogen Europe 2023).

Table 11 – Scenarios under the Additionality Delegated Act to count hydrogen produced as fully renewable. Source: own elaboration based on Directive 2018/2001 (RED II) and Baker McKenzie (2023).

References in the legal acts	Provisions
Default rule - RED II (Art. 27 par. 3)	«Where electricity is used for the production of renewable liquid and gaseous transport fuels of non-biological origin, [...], **the average share of electricity from renewable sources** in the country of production, [...], shall be used to determine the share of renewable energy» No further requirements needed
«Direct line» setup - First DA (Art. 3)	The RFNBO (H_2) production facility is **connected directly to a new renewable electricity installation** and does not use grid electricity. The renewable electricity installation must be **connected via a direct line to the RFNBO production plant** (electrolyser) and have come into operation at most **36 months** before the RFNBO production facility.
«Grid connection» setup - First DA (Art. 4)	The RFNBO production facility (electrolyser) is connected to the grid, but the **electricity used is «demonstrably» renewable**.

While the off-grid option is the simplest approach to ensuring that the electricity used to produce hydrogen is 100% renewable[36], it becomes more difficult to ensure that the electricity taken from the grid comes from renewable sources, because it is usually generated by a mix of renewable, nuclear and fossil sources (Erbach and Svensson 2023). Therefore, the first DA outlines four alternative options under which it can be demonstrated that grid electricity used in the electrolyser is renewable (Baker McKenzie 2023):

1. Where the electrolyser is located in a bidding zone[37] containing a 90%+ level of renewables, and the number of its production hours is capped at the same percentage of the year (the maximum number of operating hours for the electrolyser operation is determined by multiplying the renewable energy share in the electricity mix by the number of hours in a year);
2. Where the RFNBO production plant is located in a bidding zone in which the emission intensity of electricity generation is lower than 18 gCO_2eq/MJ (i.e., a low-carbon bidding zone), it relies on electricity produced under a renewable power purchase agreement (PPA) and it complies with «temporal» and «spatial» correlation requirements set out in the Delegated Act (see below);

[36] Despite being simpler, this off-grid approach limits electrolyser operation to the periods when renewable electricity can be produced (i.e., intermittency), or requires additional investment into electricity storage (Erbach and Svensson 2023).

[37] i.e., a region in which the same electricity price is applied. In the EU, bidding zones are usually entire Member States, except for Sweden, Denmark, and Italy, which are divided into several bidding zones (Erbach and Svensson 2023).

3. Where the RFNBO is produced with electricity consumed during an imbalance settlement (i.e., the electricity is consumed during a period of curtailment of RES electricity);
4. All other grid situations (default option) in which the renewable electricity is procured via a renewable PPA, and «additionality», «temporal» and «spatial» correlation requirements are met.

Taking the current European electricity system into account, options 2 and 4 (both involving the conclusion of a PPA with a renewable producer) will be the most common. It is important to explain the three requirements (additionality, temporal and spatial correlation) that are present in those two scenarios, as well as in the off-grid option with the electrolyser directly connected to the renewable power plant. Table 12 reports the three criteria as set out in the first DA, showing for each criterion to which scenario they apply. As a general rule, and to facilitate the early ramp-up of hydrogen infrastructure, the Commission's DA introduces a transitional phase with relaxed rules, i.e. the rules on additionality will not apply until 1st January 2038 for the renewable power plants that came into operation before 1st January 2028. This is mainly because the planning, permitting processes and installation of new additional renewable power takes time and could result in delays in the deployment of electrolysers, limiting the potential to create economies of scale (European Commission 2023a).

Table 12 – Criteria of additionality, temporal correlation and spatial (geographical) correlation. Source: own elaboration based on Baker McKenzie (2023) and Erbach and Svensson (2023).

References in the first Delegated Act	Provisions	Scenario of application
Article 5 - Additionality	Hydrogen producers have to make sure that the electricity used for the production of hydrogen is matched by the production of renewable electricity: showing that the producers generate **RES electricity corresponding to the amount of hydrogen** they claim as renewable or through a **renewable PPA**	· **Off-grid** (direct line) option · On-grid option number **4** (default option)
Article 6 - Geographical correlation	Hydrogen producers have to ensure that the **additional renewables are located in the area where hydrogen is produced.** The renewable power plant must be located either: **in the same bidding zone** as the electrolyser; or in an **interconnected bidding zone** with electricity prices equal or higher than the electrolyser's bidding zone; or in an **offshore zone interconnected** with the electrolyser's bidding zone.	· On grid option number **2** · On-grid option number **4** (default option)

References in the first Delegated Act	Provisions	Scenario of application
Article 7 - Temporal correlation	Hydrogen producers must make sure that **renewable electricity generation and hydrogen production coincide temporally**: Until 31st December 2029, hydrogen has to be produced in the same **calendar month** as the RES electricity under a PPA; From 1st January 2030, hydrogen has to be produced during the same **one-hour period** as the RES electricity when the electricity price is below 20 €/MWh[38].	· On-grid option number **2** · On-grid option number **4** (default option)

– Second Delegated Act[39]

This Delegated Regulation (the «Methodology Delegated Act») establishes a methodology for calculating the lifecycle GHG emissions savings achieved from using RFNBOs and recycled carbon fuels (RCFs), given the 70% emission reduction criterion foreseen by the RED II[40]. For the purpose of our discussion, we will focus the following analysis on RFNBOs only, and hydrogen in particular. The methodology established by the second DA defines the total lifecycle emissions from the use of RFNBOs as the sum of emissions from the supply of inputs (including electricity, processing, transport and distribution, and combustion of the fuel in its end use) minus any emissions savings from carbon capture and storage (Erbach and Svensson 2023). More precisely the formula used to calculate GHG emissions from production and use of RFNBOs is the following[41]:

$$E = e_i + e_p + e_{td} + e_u - e_{CCS} \tag{6}$$

where E are the total emissions from the use of the fuel (gCO_2eq/MJ of the fuel)[42], e_i the emissions from supply of inputs[43], e_p the emissions from processing, e_{td} the emissions from transport and distribution, e_u the emissions from

38 Member States may also start applying the hourly rule from July 2027, after notifying the Commission.

39 Commission Delegated Regulation 2023/1185

40 Recycled carbon fuels are defined under the 2018 Renewable Energy Directive as «liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin, [...] 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.

41 Retrieved from Annex to the Commission Delegated Regulation (EU) 2023/1185.

42 1 MJ (Megajoule) corresponds to around 0.2 kWh, or 1 kWh is about 3.6 MJ.

43 Within the supply of inputs, there are «rigid» inputs and «elastic» inputs. Rigid means that the supply of those inputs does not increase with increasing demand, while elastic means that the supply expands with increasing demand (e.g. crude oil, crops...).

combusting the fuel in its end use, and e_{CCS} the emission savings from carbon capture and storage (CCS). Emissions from the manufacture of machinery and equipment are not considered by the Annex to the Methodology Delegated Act (Official Journal of the European Union 2023). Instead, to calculate emission savings from production and use of RFNBOs, the Annex specifies that they shall be calculated as follows:

$$Savings = (E_F - E)/E_F \tag{7}$$

where E represents the total GHG emissions from the use of RFNBOs, and E_F the total emissions from the fossil comparator. The latter has been established by the European Commission at a value of 94 gCO_2eq/MJ for RFNBOs. Therefore, the reference point set by the second DA means that the total lifecycle GHG emissions from the production and use of RFNBOs (or RCFs) must not exceed 28.2 gCO_2eq/MJ (which is equal to the fossil fuel comparator minus the 70% saving, as established by the RED II).

There are several ways to reduce CO_2 emissions in the life cycle of RFNBOs. According to Jones et al. (2023) the two main ways of reducing the lifecycle GHG emissions are (i) to use inputs that are associated with avoided emissions (such as captured CO_2) and (ii) use carbon capture and storage during the process for making the fuel. It is important to note however that CCS after the fuel's combustion is not considered in the methodology. For renewable fuels incorporating carbon (notably e-fuels, sustainable aviation and maritime fuels), ensuring that the source of carbon used as part of the production process is associated with avoided emissions is absolutely critical for them to meet the 70% savings requirement (Jones et al. 2023). This is because, chemically speaking, the combustion of these fuels at the point of use produces the same GHG emissions as if they were derived from fossil fuels (Jones et al. 2023).

Given that RFNBOs are produced both via a direct connection to a renewable power plant and via grid electricity, it is important to analyse the methods to assess the emission intensity of the electricity grid, as provided by the second DA. Recital n. 11 of the act states that if the electricity used to produce RFNBOs is taken from the electricity grid, it is therefore not considered as fully renewable, and the average carbon intensity of the electricity consumed in the Member State where the RFNBO is produced should be applied. The delegated act requires the operators to use one of the three alternative methods - set out by the Regulation and outlined in Table 13 - to calculate the carbon intensity of the electricity grid[44].

[44] The emission intensity is expressed either in gCO_2eq/MJ or in gCO_2eq/kWh of electricity generated. The emission intensity of the grid of the major EU countries (as of 2020) is (in gCO_2eq/MJ): Germany = 99.3, France = 19.6, Italy = 92.3, Spain = 54.1, Poland = 196.5 (Official Journal of the European Union 2023).

Table 13 – Methods to attribute greenhouse gas emissions values to the electricity taken from the grid not qualifying as fully renewable. Source: own elaboration based on Annex to the Commission Delegated Regulation (EU) 2023/1185.

1. Calculation based on bidding zones	The GHG emission intensity is determined at the level of countries or bidding zones - if the required data are publicly available.
2. Calculation based on full load hours	The GHG emissions values are attributed depending on the number of full load hours (FLH) that the electrolyser is operating: - Where the number of FLH is equal or lower than the number of hours in which the marginal price of electricity was set by renewable or nuclear power plants, grid electricity used for RFNBOs is given a GHG value of **zero gCO_2eq/MJ**. - Where this number of FLH is exceeded, grid electricity is attributed a GHG emissions value of **183 gCO2eq/MJ**.
3. Calculation based on the marginal unit producing electricity	The GHG emissions value of the marginal unit generating electricity at the time of RFNBO production in the bidding zone may be used.

2.2 The EU's most recent initiatives to upscale renewable and low-carbon hydrogen

2.2.1 REPowerEU: The Hydrogen Accelerator

Among the other aspects included in the REPowerEU Plan the European Commission launched the so-called «Hydrogen Accelerator», aimed at complementing the EU Hydrogen Strategy, and increasing the EU's ambitions on renewable hydrogen, envisaging a total investment range of €335-471 billion only by 2030. A new target of 10 million tonnes (Mt) of renewable hydrogen imports into the EU by 2030 has been established, together with the target of 10 Mt of domestic renewable H_2 production (European Commission 2022b). Of this domestically generated hydrogen, about 6.6 Mt was already considered in the Fit-for-55 scenario, therefore REPowerEU has increased the internal production by 3.4 Mt. At the external level, the 10 Mt of H_2 import are subdivided into 6 Mt of renewable hydrogen and 4 Mt of ammonia.

Since 1 Mt of hydrogen has an energy value of around 33 TWh, this means that at least 350 TWh of additional renewable electricity generation will be required to produce 10 Mt of H_2 per year by 2030. To have an estimate, this compares to 541 TWh of solar and wind generation in the EU27 in 2020, while the total EU27 gross electricity generation (including hydro, fossil fuels, and nuclear) was of 2781 TWh (Barnes 2023). On the demand side, the REPowerEU Plan rests on some critical assumptions regarding hydrogen usage within the EU. Figure 13 compares the projected hydrogen use by sector in 2030, as estimated by the Fit-for-55 Package first, and then by REPowerEU.

The Commission assumes a reduction in natural gas demand by industry of 35 bcm between 2021 and 2030, based on increased energy efficiency and a switch to alternatives such as electrification and hydrogen. Out of the 35 bcm reduction in natural gas demand, 27 bcm is expected to be replaced by 8 Mt/y of hydrogen, with 2 Mt/y replacing oil and coal use (Barnes 2023). **The use of hydrogen in industrial heat, for example, is planned to increase 4.5-fold compared to the Fit-for-55 targets**. A more than **2.5-fold increase is envisaged in the transport sector.**

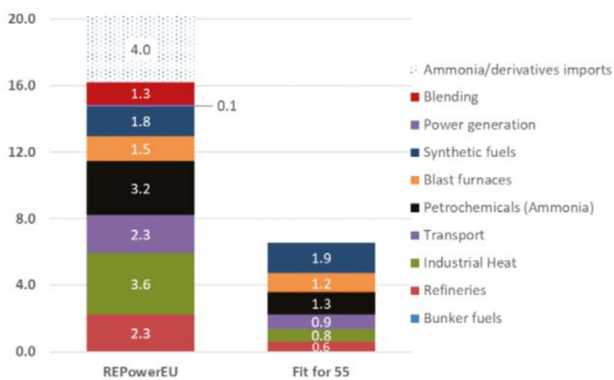

Figure 13 – Hydrogen use by sector in 2030 [Mt of H_2]. Source: European Commission (2022b).

The expected drop in natural gas use can raise the potential for repurposing existing gas pipelines for hydrogen transportation. Although cross-border hydrogen infrastructure is still in its infancy, the basis for planning and development has already been set by the inclusion of hydrogen infrastructure in the revised Trans-European Networks for Energy (TEN-E) (European Commission 2022c). Given the 10 Mt import target, several «hydrogen corridors» have been identified and partnerships with third countries have been established. Studies indicate that until 2030 the imports of hydrogen into the EU are most cost-efficient via pipelines from the neighbourhood and in the form of ammonia through ships over long distances (European Commission 2022b)[45].

The REPowerEU Hydrogen Accelerator also includes several policy initiatives and legislative proposals that have been integrated into the current revision process of key energy legislation (e.g. the Hydrogen and Decarbonised Gas Markets Package and the Renewable Energy Directive). Besides the already mentioned sub-targets for RFNBOs under the RED for industry and transport, and the adoption of the two hydrogen Delegated Acts, the REPowerEU Action Plan also includes the regular reporting on the uptake of renewable hydrogen

[45] The aspect of hydrogen import routes will be analysed in detail in Chapter 3.

in key sectors (starting in 2025), the proposal to double the number of the so-called Hydrogen Valleys[46], the scale-up of electrolyser manufacturing, whose details are outlined in the «Electrolyser Declaration», and the mapping of the hydrogen infrastructure needs[47] (Conti and Kneebone 2022). In addition, as was reported in the section covering the progresses of the EU Hydrogen Strategy, the 840 investment projects collected under the European Clean Hydrogen Alliance, include the production of H_2 (the installation of over 50 GW of electrolysers), transportation and usage of hydrogen by industry, mobility applications, energy systems and buildings (European Commission 2022b). The discussion on the Important Projects of Common European Interest (IPCEI) on hydrogen, and the need to fast-track them, will be addressed in the section 2.5 on H_2 funding flows.

2.2.2 The European Hydrogen Bank

After the announcement made by Commission's President Ursula Von der Leyen in her State of the Union speech in September 2022, the European Commission presented the European Hydrogen Bank (EHB) through a Communication in March 2023[48]. The EHB is an instrument, implemented by the European Commission, consisting of two financing mechanisms to support renewable hydrogen production within the EU and internationally, while providing data on hydrogen demand, supply, flows and prices and playing a coordination role to facilitate the blending with the existing financing instruments (such as the EU funds) to support hydrogen projects (European Commission 2023b). This initiative has been spurred mainly by the need to close the current investment gap - estimated at around €90-115 billion - and connect future renewable hydrogen supply with the EU's demand objective, including imports of H_2 from international producers.

Today, Europe hosts over 30% of proposed hydrogen investments globally, but while the first final investment decisions (FIDs)[49] took place in 2022, a vast

[46] Hydrogen Valleys bring together - in a limited geographical area - all the elements of renewable hydrogen production, storage and end-use into an integrated ecosystem. Hydrogen valleys can vary in size and scope thus proving to be very flexible in adapting to local energy needs (European Commission 2022b).

[47] The European Commission in the 36th European Gas Regulatory Forum (in May 2022) mandated several associations of energy sector operators (ENTSOG, EUROGAS, GIE, GEODE, GD4S and CEDEC) to visualize all hydrogen infrastructure projects collected under different existing processes in the form of a map. The latter, which can be consulted here (https://www.h2inframap.eu), is continuously updated with the latest information on new investment projects.

[48] COM 2023/156

[49] FID is the point in the capital project planning process when the decision to make major financial commitments is taken. At the FID point, major equipment orders are placed, and contracts are signed for Engineering, Procurement and Construction (EPC). See: https://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/fid/.

majority of hydrogen investments in Europe are still at the planning stage (European Commission 2023b). This can be traced back to two main reasons: on the one hand, investors need regulatory certainty and therefore the regulatory framework mentioned in the previous sections should be quickly finalised, and on the other hand, more demand visibility is needed. This is part of the so-called chicken-or-egg dilemma, whereby the demand from customers will not materialise until there are no appropriate infrastructures that supply hydrogen, but without that demand, investors will not finance hydrogen infrastructures, which in turn means zero demand. Table 14 reports the European Commission's estimated investments needed to achieve the target of 10 Mt of domestic (EU) hydrogen production and to enable the imports of an additional 10 Mt from third countries.

Table 14 – Estimated investments needed to achieve the target of 20 Mt/y of green hydrogen and derivatives (billion €). Source: European Commission (2023b).

Type of investment	Amount needed (billion €)
Electrolysers	50-75
Internal (EU) pipelines	28-38
H_2 storage	6-11
Additional renewable electricity[50]	200-300
International H_2 value chains	500

Given the H_2 investment challenges mentioned so far - electrolyser manufacturing capacity, hydrogen production capabilities, expansion of H_2 demand in new sectors, and development of dedicated infrastructure - there currently remains a «green premium» in terms of higher costs for those choosing hydrogen over fossil fuels. The green premium is the additional cost of choosing a clean technology over one that emits more GHG (i.e. the difference between the costs of the two technologies), and therefore it helps to see which barriers still need to be overcome (Breakthrough Energy 2022). According to the European Commission, the targeted use of public resources to finance the green premium can leverage private sector investments and reduce the risk of investing in renewable hydrogen production. Around €1 billion is estimated to be required to enable 0.04-0.06 million tonnes of renewable hydrogen production capacity per year, and after 2025, the market premium is expected to decline due to decreasing production costs and increased demand for green products produced with renewable hydrogen (European Commission 2023b).

50 The target of 10 Mt of renewable hydrogen production will require around 150-210 GW of additional renewable installed capacity generating electricity at low cost (European Commission 2023b).

The structure of the European Hydrogen Bank

The EHB's structure consists of a «domestic» and an «international» pillar. Regarding the first dimension, the domestic pillar supports the scale-up of hydrogen production within the EU, with supply-side auctions allocating fixed premium payments to hydrogen producers (see in detail below). The goal of the international pillar is instead to secure diversified imports of renewable hydrogen (and derivatives) from outside the EU, both with fixed premium payments to international producers and with other funding options that are currently being explored by the European Commission. Given that several Member States have been developing strategies to support the import of hydrogen from third countries[51], the Commission is studying how best to design the international leg of the European Hydrogen Bank, considering that imports of H_2 will fall within the scope of the Carbon Border Adjustment Mechanism (CBAM) from 2026[52].

As regards the proposed activities under the EHB, there are four pillars that can be summarised as follows. First, the creation of a domestic market will be initially supported by the EU Innovation Fund (see next paragraph). Second, H_2 imports into the EU will be supported by green premium auctions. Third, transparency and coordination activities will include assessments on demand, H_2 flows, infrastructure needs and cost data. The fourth pillar of activities is divided into two subjects: the use of existing EU financing instruments, and the existing international financing instruments (concessional loans, guarantees).

The first pilot auction and the «Auctions-as-a-Service» mechanism

The Innovation Fund allocates funds through a pilot auction directed at the production of renewable hydrogen, as defined in the Commission's Delegated Acts on RFNBOs. Through such market-based tools, the European Commission transfers the funds after interested projects have submitted a bid, in order to receive support, in form of a fixed premium per kg of hydrogen produced, for up to 10 years of operation. The Commission has indeed decided to allocate funds using auctions for three main reasons: 1) because of the successful use of auctions to support renewable power projects in several EU Member States, which have helped lower the price of renewable energy, 2) the efficient allocation of

[51] In 2021-2022, EU Member States and companies have signed hydrogen cooperation Memoranda of Understanding (MoUs) with at least 30 countries around the world. On behalf of the EU, the European Commission has signed MoUs and/or Partnerships with Egypt, Japan, Kazakhstan, Morocco, Namibia and Ukraine (European Commission 2023b).

[52] The mechanism has a 3-year transitional period starting from 1st October 2023, with emission monitoring, and actual surrendering of CBAM certificates (payments) will start in 2026/27 (Hydrogen Europe 2022). Although not part of the initial European Commission proposal, the CBAM will also apply to hydrogen, together with cement, iron and steel, aluminium, fertilisers, and electricity. The inclusion of hydrogen in the EU CBAM was a result of the interinstitutional negotiations between the European Commission, the European Parliament, and the Council (Marcu *et al*. 2023).

support, which creates competition between producers and provides payments based only on certified and verified H_2 production, and 3) the reduced costs for the public and the lower risks, that can attract more private capital (European Commission 2023c). The auction funded by the Innovation Fund under the umbrella of the EU Hydrogen Bank was launched on 23rd November 2023, awarding up to €800 million to renewable H_2 producers in the European Economic Area (European Commission 2023c)[53].

One significant novelty of this initiative is the so-called «Auctions-as-a-Service» (AaaS) mechanism, put in place by the Commission to enhance the scope of the support to H_2 production. Although the RFNBO Delegated Acts provide a uniform basis for the certification of renewable hydrogen across Europe, support schemes can vary considerably between Member States (European Commission 2023b). That is why the Commission has proposed to extend the Innovation Fund auctions as a platform to Member States, enabling them to use their own resources for projects on their territory, by relying on an EU-wide auction mechanism and select the most competitive projects (European Commission 2023b). Hence, through «Auctions-as-a-Service», the Commission would run a single auction, which would first clear the Innovation Fund budget, and then the remainder of the financial support can be supported by Member States themselves.

Connecting «H2Global» and the European Hydrogen Bank

The EU also decided to link the EHB with «H2Global», Germany's support scheme for renewable hydrogen. The latter, which is an auction-based instrument, has been financed by the German Government with €900 million for the first «funding window», and its implementation is managed by the H2Global Foundation (*H2Global Stiftung*), whose subsidiary, HINT.CO (*Hydrogen Intermediary Network Company*) uses the funding provided to compensate for the difference between supply and demand prices (European Commission 2023d). European Commissioner for Energy Kadri Simson (2019-2024) and German Federal Minister for Economic Affairs Robert Habeck (2021-2025) agreed to link the EHB with H2Global during a bilateral meeting on 31st May 2023 with the aim to expand this approach to other Member States and to jointly develop a European auction targeting international hydrogen imports (Habibic 2023). Thus, it can be argued that the international pillar of the European Hydrogen Bank has been taking shape. As emphasised by the CEO of Hydrogen Europe (a major EU hydrogen industry association), such a step was needed to remain credible with the implementation of the EU Hydrogen Strategy, since the EU will need more hydrogen than it can domestically produce in the required timeframe (Collins 2023).

[53] Bids had to be submitted until 8th February 2024, after which the applicants were informed about evaluation results as early as April 2024 and signed the Grant Agreements within nine months after the call closure.

2.2.3 An overview of hydrogen funding in the EU

The last part of this section dedicated to hydrogen-specific policy initiatives looks at the spectrum of the funding sources that support the scale-up of clean hydrogen in the EU. The adoption of the two Delegated Acts on RFNBOs has contributed to better channelling EU funds towards renewable hydrogen and to guiding the approval of national state aid schemes for hydrogen projects. Significant investments for the production of renewable hydrogen are also being channelled through the National Recovery and Resilience Plans, as more than €10 billion have been assigned so far under the Recovery and Resilience Facility, and several Member States have been able to provide public funding to hydrogen projects via the Important Projects of Common European Interest (IPCEI). The EU Innovation Fund has been providing resources both for renewable H_2 (through fixed-premium auctions) and electrification in industry. The Commission has also allocated an additional €200 million for Hydrogen Valleys, as part of REPowerEU, and has been supporting the work of the Clean Hydrogen Partnership[54] to which it provided €1 billion under Horizon Europe (European Commission 2023a).

The funding sources for clean hydrogen also come from the European Investment Bank (EIB) and the InvestEU fund, which aims at mobilising private investment. The latter fund as well as Cohesion Policy funding (mainly through the European Regional Development Fund) and the Just Transition Fund (JTF), mentioned in the European Hydrogen Bank Communication, will provide support to Member States and regions for investments in the whole hydrogen value chain. In addition, the EIB has committed to exceed 50% of its overall lending, by 2025, for climate action and environmental sustainability, and it is also one of the «implementing partners» of the InvestEU fund, together with the European Bank for Reconstruction and Development and the Nordic Investment Bank. In the past decade, the EIB provided over €1 billion in financing directly linked to hydrogen projects, and this was recently complemented by the EIB's REPowerEU €30 billion package which aims to mobilise up to €115 billion by 2027 of investments leading to decarbonisation of the EU industry (European Commission 2023b).

Mapping hydrogen funding flows in the EU

For the purpose of this work and given the articulated nature of the different sources of EU funding for hydrogen projects, it is essential to mention the

[54] The Clean Hydrogen Partnership (legally known as the «Clean Hydrogen Joint Undertaking») is the successor of the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), which it has replaced since 2021. The members of this public-private partnership are the EU (represented by the European Commission), the fuel cell and hydrogen industries (represented by Hydrogen Europe) and the research community (represented by Hydrogen Europe Research). Retrieved from: https://www.clean-hydrogen.europa.eu/about-us/who-we-are_en

different channels and sources, in order to establish a general framework, without specifying the functioning and implementing stages of each single funding programme. Figure 14 shows the revenue flows from the origin of the funds (at the top) or the revenue-generation mechanisms (e.g. the EU ETS), down towards different major funds and programmes, i.e. massive budgets with significant but cross-sectoral ambitions (e.g. the Cohesion Fund or Next Generation EU), and from there, the financial resources flow down into smaller and more specific «secondary» funds and mechanisms more closely related to energy sector decarbonisation (Kneebone 2023).

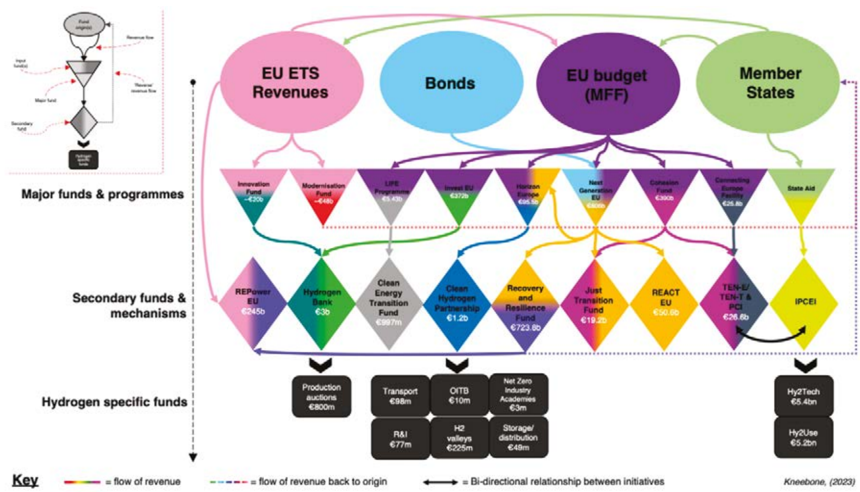

Figure 14 – Hydrogen funding instruments and flows in the EU (billion €). Source: Kneebone (2023).

As can be seen in the figure, the main funding sources are represented by the EU long-term budget (the Multi-Annual Financial Framework 2021-2027), the EU ETS revenues, the bonds through which the EU borrows on financial markets, and the resources of single Member States. The latter follow an essentially straight path since the EU countries' own resources can be directed towards the IPCEI projects in form of state aid (after the approval of the European Commission). It is of course important to consider that a large part of the EU budget is also financed by the Member States. The EU MFF feeds six main programmes (LIFE, InvestEU, Horizon Europe, Next Generation EU, the Cohesion Fund and the Connecting Europe Facility), some of which are directly managed by the European Commission, then providing resources for more targeted funds, such as the Just Transition Fund, REACT EU, the TEN-E and TEN-T, as well as the European Hydrogen Bank and REPowerEU. These last two funding sources are also supported by other mechanisms. Revenues from the ETS then flow partly into REPowerEU, but they also flow into InvestEU and the EU Innovation Fund, which in turn feed the EU Hydrogen Bank, a critical tool to enable better coordination between funding programmes and to provide clarity to potential project developers.

The Important Projects of Common European Interest in the hydrogen sector

Launched by a declaration signed by 22 EU Member States and Norway in December 2020, IPCEI are State aid schemes for supporting projects in infrastructure or research, development and innovation (R&D&I), which are carried out by the private sector and are supported by the funds of the Member States. According to the European Commission (2021b), IPCEI are meant to make a very important contribution to sustainable economic growth, jobs, competitiveness and resilience, as well as to overcome market or systemic failures or societal challenges that prevent a project from being carried out in the absence of the aid. It is important to consider that IPCEI do not have budgets in of themselves but are rather vehicles for accessing finance (Kneebone 2023). Therefore, the European Commission plays a key role in this regard since it is tasked with approving the State Aid funding for IPCEI.

As of 2024, the IPCEI on hydrogen include two sets of projects approved in 2022 (*Hy2Tech* and *Hy2Use*), one adopted in February 2024 (*Hy2Infra*) and one in May 2024 (*Hy2Move*)[55]. *Hy2Tech*, approved in July 2022, involves 35 companies from fifteen Member States. The latter will provide up to €5.4 billion in public funding, while expecting to unlock an additional €9 billion in private investment and the creation of approximately 20000 direct jobs (European Commission 2022d). *Hy2Use*, approved by the Commission in September 2022, includes 35 companies from thirteen Member States, which will provide up to €5.2 billion in public funding in the coming years, thus expecting to unlock around €7 billion in private investments (European Commission 2022e). Whereas *Hy2Tech* covers mainly H_2 generation, fuel cells, storage and end-use applications, *Hy-2Use* supports research and innovation and first industrial deployment of hydrogen technologies. The third and IPCEI, *Hy2Infra*, complements the first two by supporting the gradual emergence of an EU-wide hydrogen transmission infrastructure starting from different regional clusters. While expecting to unlock €5.4 billion in private investments, public funding for this IPCEI totals €6.9 billion, which will be provided by the seven Member States (including France, Italy and Germany) that notified the project to the EU (European Commission 2024). The last IPCEI (*Hy2Move*) will provide up to €1.4 billion in public funding, unlocking an additional €3.3 billion in private investments, and it will cover mainly hydrogen integration into road, maritime, and air transport, as well as high-performance fuel cells and advanced refuelling stations.

[55] Among the IPCEI approved in other sectors there are projects related to microelectronics and communication technology sectors, and also batteries.

2.3 A pan-European hydrogen network as a key component of the decarbonised European energy system

This section is aimed at analysing how the future hydrogen transmission network - the key enabler of a hydrogen market in Europe - can be most effectively developed, also considering the need to connect integrated network planning to reasonable assumptions and existing EU laws. H_2 infrastructure planning indeed presents a number of challenges, which are mostly linked to a technological and institutional misalignment, both of which must be addressed. The first misalignment is given by the complexity in planning a network where hydrogen transport will include parts of the gas and power networks. The tendency to centralise the architecture and planning process of power and gas networks (because of their natural monopoly characteristics) determines instead the institutional misalignment. To overcome the technological misalignment the existing sector-specific energy infrastructure planning processes will need to be enhanced with cross-sectoral mechanisms, that allow coordination of hydrogen-driven energy infrastructure expansion with the development of hydrogen infrastructure in other sectors (Palovic and Poudineh 2022). On the other hand, given that several hydrogen delivery options (mainly in the transportation sector) have a decentralised nature, there will be the need for new mechanisms to account for hydrogen investments outside the natural monopoly setting, thus overcoming the institutional misalignment (Palovic and Poudineh 2022). Table 15 outlines three approaches on how to integrate hydrogen into the energy transport infrastructure planning in Europe, avoiding the two misalignments. Whereas the first two approaches are one the opposite of the other, the third one (regulatory) represents a compromise between the other two.

Regulators play a critical role in guiding policymakers on the future development of gas and hydrogen networks. Despite having a different scope, the regulators' sphere of action is complementary to policymaking. The analysis on the most recent EU legislative initiatives and policy proposals, especially concerning the Hydrogen and Decarbonised Gas Markets Package, has shown that regulators must ensure that basic principles of network management and operation (e.g. network access, cost-reflectivity, efficiency, monitoring) are upheld. However, while the transition to renewable and low-carbon gases (e.g. biomethane) can largely be based on the existing gas market, the hydrogen market model does not have prior patterns nor predecessors. Therefore, adaptation and flexibility are even more crucial, particularly given the lumpiness of such infrastructural investments[56]. The emergence of a new hydrogen network will mainly depend on the location of renewable power plants that provide clean electricity to electrolysers and the emergence of demand centres, but it will also be driven by the potential H_2 import routes from the neighbourhood and from repurposed LNG

[56] Lumpiness refers to the fact that this type of investments (especially gas transmission lines) entails chunky expenditures of equipment that cannot be installed piecewise, due to its highly integrated structure or technology (Jiao and Zhang 2022).

terminals. There are many infrastructure trade-offs regarding how and from where energy is transported across Europe, provided that planning and operation can be tightly coordinated, as the more energy transport capacity, the more costs can be reduced (Neumann et al. 2023).

Therefore, we will attempt to both examine a concrete example of the abovementioned approaches to network infrastructure planning at the European level and address the potential development of a hydrogen network in Europe. First, an in-depth examination of the ENTSO-G Ten-Year Network Development Plan (TYNDP) for gas and hydrogen will be carried out. Secondly, the recent «European Hydrogen Backbone» initiative will be analysed as a complementary, bottom-up effort to the centrally developed TYNDP.

Table 15 – Approaches for hydrogen transport infrastructure planning. Source: own elaboration retrieved from Palovic and Poudineh (2022).

Type of approach	Centrally Coordinated Approach	Market-Based Approach	Regulatory Approach
Characteristics	- Central planner who coordinates infrastructure expansion across different sectors - New, neutral institution or common information platform that promotes exchange among stakeholders - Integrated scenario planning for transmission networks[57] - Example in the EU: ENTSO-G and ENTSO-E network development plans	- Market-driven energy infrastructure development - Cross-sectoral coordination is decentralised - Coordination is optimised by individual stakeholders responding to price signals at energy markets - Possibility for merchant transmission investments (MTIs)[58] - Most infrastructure projects are backed by long-term contracts between investors and gas or electricity shippers[59]	- Classical network governance mode - Hydrogen-driven investments are based on the social benefit to the entire system - Coordination with providers of alternative mode of transport if those are socially more preferable - Regulated operators of network infrastructures are driven towards the socially optimal behaviour when the consequences of their decisions are priced

57 Given the locations of the expected energy production and demand, future energy transportation needs are identified and allocated to different sectors by the central planner.

58 Merchant Transmission Investments are profit-motivated investments in transmission (cross-border) infrastructure undertaken by non-regulated market players. They are often thought to be the second-best option when regulated investment fails to develop at a suitable pace, but they can also lead to partial un-regulated monopolization of the network, which increases the risk of anti-competitive effects (De Hauteclocque and Rious 2011).

59 In the energy domain, a shipper can be defined as person (entity) that buys an energy commodity from producers or importers, transports this commodity through the network, and sells it to its customers. Retrieved from: https://www.edfenergy.com/large-business/glossary.

Type of approach	Centrally Coordinated Approach	Market-Based Approach	Regulatory Approach
Main advantages	- Better addresses investment risks - Better addresses network externality effects	- Possibility for cross-sectoral infrastructure competition - Better deals with technological uncertainty	- Incentive to cost minimisation - Regulated operators are free to cooperate with other hydrogen infrastructure investors

2.3.1 ENTSO-G Ten-Year Network development plan

The Ten-Year Network Development Plan (TYNDP) provides an overview of the European gas infrastructure and its future development, by mapping the integrated gas network according to a range of development scenarios (ENTSOG 2023a)[60]. For the first time, in the TYNDP 2022, ENTSOG developed a dual gas system modelling approach considering both methane and hydrogen networks simultaneously, thus adjusting the TYNDP to include REPowerEU ambitions with respect to hydrogen infrastructure development. The parallel policy-based infrastructure assessment was developed by ENTSOG together with the TSOs to incorporate additional infrastructure needs required to comply with the relevant policy objectives, such as the 2030 hydrogen imports targets defined by the REPowerEU Plan (ENTSOG 2023a). The approach developed by ENTSOG in the TYNDP 2022 refers to both the existing natural gas infrastructure and the planned natural gas and hydrogen infrastructure. Both types are interconnected, allowing to capture interactions between the two gases and assess the role of the transmission system of both fuels in satisfying demand under different conditions.

For the purpose of this work, it is essential to outline the planned and ongoing hydrogen projects, also considering the potential repurposing of gas transmission lines. Today in the EU and the UK around 205 000 km of gas pipelines exist (ENTSOG 2023b), as shown in Figure 15. Given that, unlike methane, hydrogen infrastructure levels can only be defined with the consideration of planned projects, the TYNDP 2022 defines two contrasted hydrogen infrastructure levels (ENTSOG 2023c):

– Level 1 is a project-based infrastructure level, composed of all hydrogen projects submitted by project promoters to the TYNDP 2022 (including infrastructure submitted as «hydrogen-ready») as well as H_2 projects submitted to the first Projects of Common Interest (PCI) selection process under the revised TEN-E Regulation[61];

[60] The EU Gas Regulation 715/2009 (revised under the Hydrogen and Decarbonised Gas Markets Package) requires ENTSOG to develop the TYNDP every two years.

[61] The Projects of Common Interest are energy infrastructure projects, such as electricity or gas interconnectors, that link the energy systems of the different EU countries and can

– Level 2 is defined as a policy-based infrastructure, composed of hydrogen infrastructure level 1 and additional infrastructure assumptions needed to enable the EU policy objectives for hydrogen.

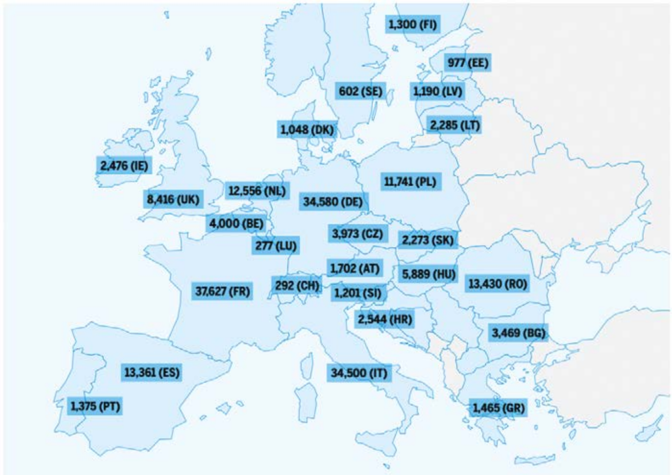

Figure 15 – Transmission length in the EU and UK in 2022 [km]. Source: ENTSOG (2023b).

Hydrogen infrastructure projects included in the TYNDP 2022

After introducing a new infrastructure project category in the TYNDP 2020 for «Energy Transition Projects», ENTSOG decided to develop this category into four different new single project categories, thus allowing for sector-specific insights and displaying development trends (ENTSOG 2023a). The 2022 TYNDP includes 216 investments (in 26 countries) relevant for these four categories, which are: 1) new or repurposed infrastructure to carry hydrogen (HYD), 2) projects for retrofitting infrastructure to integrate hydrogen (RET), 3) biomethane development projects (BIO), and 4) other infrastructure-related projects (OTH). Hydrogen infrastructure projects can be further sub-divided into three groups, namely on-shore and off-shore H_2 transmission pipelines, newly constructed or repurposed liquefied hydrogen terminals (including for hydrogen derivatives, such as ammonia), and hydrogen storages. Overall, 359 investments are covered by the TYNDP 2022 out of which 143 are natural gas projects, 153 are HYD, 13 RET, 11 BIO and 39 OTH (ENTSOG 2023a). Table 16 outlines the 153 HYD investments for each of the three groups (pipelines, liquefied H_2 terminals, and storages).

therefore benefit from accelerated permitting procedures and funding.

Table 16 – Investments in the HYD (hydrogen) infrastructure category in the TYNDP 2022. Source: own elaboration based on ENTSOG (2023b).

Number of investments	Type of investment	Description of the investments
45	Pipelines	investments related to the repurposing of existing pipelines for hydrogen use
45	Pipelines	investments related to the construction of on- or offshore pipelines to enable the transport of pure hydrogen
3	Storage	investments related to the repurposing of existing storages to enable the storage of pure hydrogen
12	Storage	investments related to the construction of storages to enable the storage of pure hydrogen
12	Liquefied H_2 terminals	investments related to new liquefied hydrogen terminal including hydrogen embedded in other chemical substances with the objective of injecting the hydrogen into the grid
7		investments related to equipment or installation essential for the hydrogen system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations
23		investments related to hydrogen production with network related function
2		investment that enables the production, reception, injection, transportation, or end-use supply of hydrogen
4		other hydrogen related investments
153	Total	

As can be derived from the above table, the highest share of H_2 investments falls into the category of construction and conversion of existing infrastructure to transport and store 100% hydrogen. From the TYNDP 2020 to that of 2022, investments in the four energy transition categories (HYD, RET, BIO, OTH) have increased, thus showing the willingness of project promoters to commit to the EU's decarbonisation targets. According to ENTSOG (2023b), the increase in investments over the last two years stems from the need of industries and societies in the EU to reduce their GHG emission in the near-to mid-term future, and from the provisions set out in the recently adopted acts and initiatives at the EU level, aiming at enhancing the deployment of renewable gases along with renewable electricity. Figure 16 shows the number of investments per country and the type of infrastructure of the four new categories, and Figure 17 illustrates the status of those projects, included in the TYNDP 2022. Such investments are mostly in the «less-advanced» stage, whereas the other two stages are the «advanced» and the «final investment decision» (FID) stage.

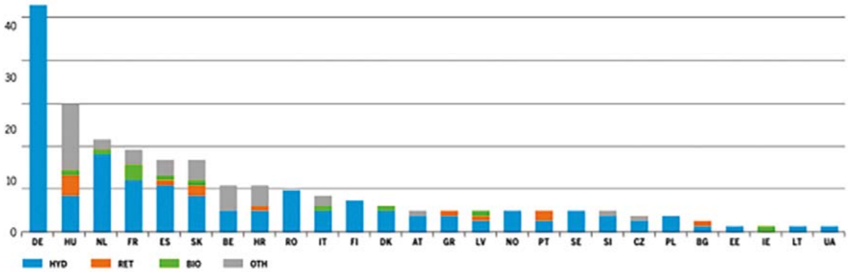

Figure 16 – Number of investments per country and type of infrastructure. Source: ENTSOG (2023b).

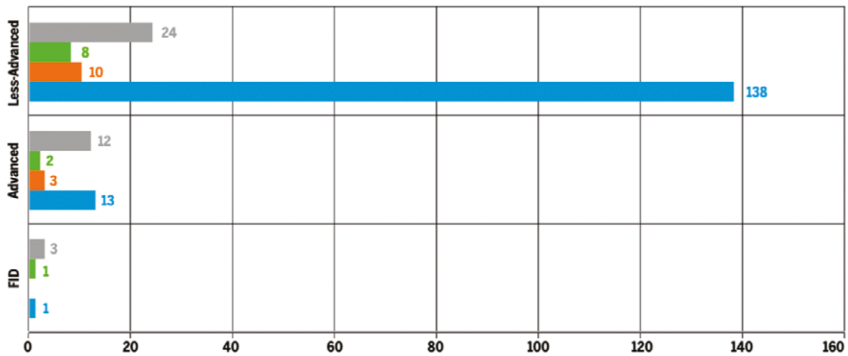

Figure 17 – HYD, RET, BIO and OTH investments by maturity status[62]. Source: ENTSOG (2023b).

The TYNDP 2024

The latest TYNDP foresees capital investments exceeding €210 billion, approximately 80% of which are dedicated to hydrogen, and the remaining 20% is mainly allocated to natural gas (ENTSOG 2025). Out of the 326 projects included in ENTSOG's TYNDP 2024, more than 200 focus on hydrogen (in the TYNDP 2022 they were 153). Nearly 80% of the 110 new projects introduced in the 2024 cycle are hydrogen-related, representing a twofold increase compared to TYNDP 2022 (ENTSOG 2025). This development highlights the EU's strategic commitment to establishing a hydrogen backbone and prioritising regional interconnections and renewable energy integration.

[62] HYD (blue), RET (orange), BIO (green), OTH (grey).

2.3.2 The European Hydrogen Backbone Initiative

With the current 33 member companies participating[63], the European Hydrogen Backbone Initiative (from now on «the Initiative») aims at defining the critical role of hydrogen infrastructure in the EU's decarbonisation effort and in the creation of a liquid and competitive renewable and low-carbon hydrogen market. The Initiative was conceived in 2020 and it has been developing transmission scenarios, connecting hydrogen supply and demand in Europe, towards 2030 and 2040. By examining its regular reports, it is possible to understand the importance of having a new regulatory framework able to ensure hydrogen integration, and to connect the dots with the previously outlined elements, such as the emergence of two parallel gas transport networks, one dedicated to hydrogen, and the other to (bio)methane. The Initiative estimates that around 30 000 km of hydrogen pipelines will be commissioned by 2030, and around 57 600 km by 2040 (European Hydrogen Backbone 2023). Table 17 summarises the envisioned length of the future hydrogen network, as projected by the Initiative.

Table 17 – Envisioned length of the EHB network [km]. Source: own elaboration based on European Hydrogen Backbone (2023).

Year	Overall length	Length of repurposed pipelines	% repurposed pipelines
2030	32616	16864	51.7
2040	57662	34290	59.5

While ongoing multiple studies are investigating to which extent it is technically feasible and economically efficient to use the existing natural gas infrastructure for the transport of hydrogen, according to Grote et al. (2022), about 70% of the total onshore pipeline length in Europe could possibly be reused or repurposed for the transport of hydrogen. Although repurposed pipelines will represent a clear majority of the overall network, the increase in total pipeline length for the 2040 network is mainly due to the newly built pipelines (European Hydrogen Backbone 2023).

Previous analyses of the Initiative have shown that a hydrogen pipeline can transport some 65 TWh of hydrogen per year (Van Rossum et al. 2022). This result is based on two assumptions: 1) a pipeline can transport around 13 GW of hydrogen (capacity), and 2) a load factor of 5000 hours in a year is considered. By multiplying the capacity (13 GW) by the time (5000 hours), we obtain 65000 GWh, that correspond to 65 TWh. This means that transporting 10 Mt (or 330 TWh) of hydrogen, as set by the REPowerEU import target, would require approximately five (65 TWh multiplied by 5) large-scale pipeline corridors towards Europe.

[63] As of 2023, the participating companies (mainly TSOs) are: Amber Grid, Bulgartransgaz, Conexus, CREOS, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, FlusSwiss, Fluxys Belgium, Gas Connect Austria, Gasgrid Finland, Gassco, Gasunie, GASCADE, Gas Networks Ireland, GRTgaz, National Gas Transmission, NET4GAS, Nordion Energi, OGE, ONTRAS, Plinacro, Plinovodi, REN, Snam, TAG, Teréga, Transgaz, Transitgas AG and the TSO of UA. See: ehb.eu.

Costs of an expanded H_2 network

Since the publication of its first infrastructure report, the European Hydrogen Backbone has steadily revised its cost estimations on the development of a dedicated H_2 network within the span of 15-20 years up to 2040. The two fundamental cost components are CAPEX and OPEX. Given that here the cost estimations and the economic analysis are limited to the transmission part of the hydrogen market, it is interesting to outline the evolution of both the CAPEX and OPEX values, and the so-called levelized cost of hydrogen transport (LCOT).

While a cubic meter of hydrogen contains only one third of the energy of a cubic meter of methane at the same pressure (lower «energy density» of H_2), this does not mean that three times as many pipelines are required to transport the same amount of energy, because the maximum energy capacity of an H_2 pipeline can be increased up to 80% of the energy capacity it has when transporting natural gas (Wang et al. 2020). There can be variations across regional gas networks concerning operating pressures, pipeline diameters and compression system designs, which would impact cost estimates. However, the European Hydrogen Backbone has taken an infrastructure-driven view (as opposed to designing parameters for a specific system demand) and has selected a generic network design, thus obtaining cost ranges that are deemed representative of the EU-average (Wang et al. 2020). Table 18 reports the evolution of the CAPEX and OPEX estimations of the Initiative up to 2040. Initially, operational costs were lower than expected, and they remained quite stable in subsequent estimations. Instead, capital expenditure, which is split into the pipeline costs and the compression cost component, progressively increased (also due to the rising inflation and market disruptions).

Table 18 – Evolution of CAPEX and OPEX values according to the network cost estimations by 2040 (in billion €). Source: own elaboration based on Wang et al. (2020), Jens et al. (2021), and Van Rossum et al. (2022).

Year of the EHB report	CAPEX	OPEX[64]
2020	27-64	1.6-3.5
2021	43-81	1.7-3.8
2022	80-143	1.6-3.2

The investment costs and the levelised cost of transmission (LCOT), as estimated in the EHB reports, largely reflect the cost assessments carried out in the first chapter of this work, concerning both new and repurposed H_2 pipelines. If we consider first the unit capital cost figures (in million € per km of pipeline length), we can indeed see that the cost estimations outlined in Table 3 (Chapter 1) correspond to the data reported by the EHB. The EHB estimates

[64] A load factor of 5000 hours per year is assumed.

a CAPEX of around 2.8 M€/km for new pipelines, and 0.3-0.6 M€/km for repurposed pipes (Van Rossum et al. 2022), while the economic analysis in Chapter 1 included costs of 2.48 M€/km for new pipelines, and around 0.37 M€/km for repurposed lines. This category of costs mostly depends on variables such as the electricity price and the compressor size. The levelised cost of hydrogen transmission is also like that hypothesised in the first chapter, as it is estimated at around 3.3-6.3 €/MWh in the EHB report, and it is around 3.7-4.6 €/MWh in the first chapter of this thesis.

Conclusions

The analysis presented in this chapter has shown the extent to which the EU's approach, and that of the European Commission in particular, has been influenced by its own experience in the previous efforts to liberalise natural gas markets. This includes not only the discussion regarding the new Hydrogen and Decarbonised Gas Markets Package, thus linking the role of hydrogen and biomethane with the need to replace fossil-based molecules, but it also regards the critical issue of the network structure (unbundling issues, market access and infrastructure planning). After examining the key proposals made by the Commission and negotiated by the EU legislative institutions, a question arises as to whether these regulatory measures will allow enough flexibility and time for the still emerging hydrogen market and infrastructure to reach maturity. Scenarios developed by the EU institutions and research bodies, as well as those drawn up by private entities and energy sector associations must consider the possibility that the H_2 market will develop at a slower or even faster pace in the next decades, and thus the proposals may bolster or slow down the establishment of a mature market.

The importance of timely investments has been stressed also because there is the possibility to repurpose and retrofit part of the existing infrastructure for hydrogen. This perspective is currently characterised by a so-called «chicken or egg problem», whereby H_2 producers, consumers, infrastructure operators and regulatory actors are all waiting for the other one to take the first step. Several top-down funding mechanisms have been put in place to create a favourable environment for private investments, but the most critical element that must be considered is the identification of potential hydrogen off-takers, who can drive demand in different sectors. Industry and long-haul or public transport applications can serve as frontrunners in the uptake of hydrogen, as various projects around the EU currently demonstrate, also thanks to the nascent hydrogen valleys.

This situation partly reflects the status of the emerging hydrogen economy in Italy, which will indeed be the subject of the next chapters, together with the examination of how to ensure that enough renewable and low-carbon hydrogen is imported in Europe, through a fit-for-purpose infrastructure, a part of which will be located on Italy's territory. Finally, the need to integrate the electricity and gas sector to unlock the potential of a clean energy system, as was analysed in this chapter, is one of the main items that we will attempt to deepen, with respect to the Italian power and gas systems, which are among the largest in the EU.

CHAPTER 3

Italy in the European energy transition: the role of hydrogen

Introduction

The development of a European (green) hydrogen economy within a long-term energy transition path involves an essential role for those Member States that combine two main elements: the industrial readiness to develop clean energy technologies and a large potential for exploiting renewable energy sources, on the one hand, and the presence of hydrogen off-takers that can drive demand, on the other. However, the adoption of hydrogen is dependent on both the maturity of its production technologies and the cost-efficiency of its end-use applications. Therefore, only a simultaneous transition both in supply (through construction of new H_2 generation plants and infrastructures) and in consumption (through the substitution of transport means and/or industrial processes) can limit the «chicken-or-egg» problem that affects the H_2 value chain.

The path towards increased H_2 deployment has been made clearer by the EU Hydrogen Strategy, published in 2020. Its adoption has been followed by the rollout of national H_2 strategies in more than 19 EU Member States so far, including the major EU economies - Germany, France, Italy Spain and Poland. However, among these countries - which also represent the top energy-consuming and the largest GHG emitting EU Member States - Italy has been the last one to adopt a more comprehensive, long-term vision for the development of a hydrogen economy within its borders. Until late 2024, when the natural gas and hydrogen sector had already started forming private initiatives to give

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Book References DOI 10.36253/979-12-215-1013-3.references

shape to the future H2 economy, Italy's "Hydrogen Strategy Preliminary Guidelines" were the only official policy document specifically addressed to the development of a national H_2 value chain. Later in 2021 Italy's hydrogen policy was almost entirely based on the different H_2 targets and investments included in its National Recovery and Resilience Plan (NRRP), whose implementation continues to this day.

Analysing the Italian case can prove to be interesting because, while it remained without a defined H_2 strategy during the decisive years of the energy crisis in which the EU decided to dramatically reduce its energy dependence on its historically largest gas supplier (Russia), the interest in developing hydrogen steadily increased in recent years, leading to improved investments in R&D for H_2 deployment and to participation in several international projects, including Important Projects of Common European Interest (IPCEI) and Mission Innovation (IEA, 2023a). At the same time, Italian decision-makers, especially after the start of Russia's war against Ukraine, have been increasingly advocating for Italy's potential role as an «energy bridge» between Europe and North Africa, focusing on natural gas imports in the short term and on clean hydrogen in the longer term, whereby the molecule can be produced from renewables at lower costs and imported into Europe, by taking advantage of Italy's geographic location and extensive gas network and interconnections.

Italy's relevance for the development of a hydrogen economy is given also by its territorial configuration. For instance, lower costs of electricity production through solar PV in the southern part of the country can raise the attractiveness of creating H_2 production hubs in southern Europe (together with Spain and Greece), which would then determine a different structure of the future hydrogen network. This would involve the creation of pipeline routes to import renewable hydrogen that cannot be produced domestically and achieve the EU's targets.

Given the recently approved EU Delegated Regulations on the criteria defining hydrogen as renewable (RFNBO) or low-carbon, and the adoption of the Hydrogen and Decarbonised Gas Package, it is essential for a country like Italy to develop its gas and power systems by considering the need for new cross-sector infrastructures. To this end, cooperation between the national gas and electricity transmission system operators (TSOs) must be enhanced, also because - especially after 2030, the development of new and repurposed hydrogen pipelines will unlock new possibilities for locating electrolysers, i.e. outside the areas where H_2 is consumed, thus reducing the need to reinforce the electricity grid in those areas where electrons will be used to both meet the conventional demand and feed the electrolysers. The potential cost savings resulting from the reduced need for further reinforcements of the electricity system will be compensated by increased investments in the hydrogen transport network.

Another critical part of the hydrogen infrastructure consists of H_2 storages (mainly salt caverns), which must be considered when deciding where to locate electrolysers. These can indeed adapt their electricity consumption for producing hydrogen based on their proximity to an H_2 storage site, resulting in a truly flexible use of the electricity system. In the presence of large storage capacities, the production of renewable hydrogen can be concentrated during the periods when the electricity system presents renewable production margins, avoiding the simultaneous operation of electrolysers and thermal power plants. The flexible operation of electrolysers has several advantages for system stability and the cost-effective integration of wind and solar generation, leading to low curtailment rates of renewables and a lower requirement for firm capacity[1] (Neumann et al. 2023).

Given the above-mentioned aspects, this chapter is divided into two sections. Drawing from the discussion on the EU's hydrogen production and import targets, the first section analyses the European hydrogen supply corridors, based on the figures produced by the European Hydrogen Backbone Initiative (EHBI) and the national targets set by the countries that have already released a national hydrogen strategy or that have been planning to do it. This will allow a comparison between a private sector initiative (the EHBI) and an institutional perspective. Given Italy's status as a potential import corridor that only recently started developing a long-term hydrogen roadmap, the second section will evaluate Italy's domestic policy initiatives towards H_2 development, thus preparing the ground for an in-depth discussion on hydrogen use in the hard-to-abate sectors in the final chapter of this thesis.

3.1 The European Hydrogen Supply Corridors

Higher costs, limited space for installing renewable power plants and the slow pace of new hydrogen capacity projects in Europe contribute to making H_2 imports (also in form of its chemical derivatives) more attractive. The establishment of several hydrogen import routes into the EU is necessary to achieve the H_2 supply targets set by REPowerEU (10 Mt of green H_2 production and 10 Mt imported). The key question is related to where such imports should come from and what the potential export or transit countries are doing to expand their hydrogen production capacities. Three main hydrogen import routes have been identified in REPowerEU, which states that the European Commission «could facilitate coordinated EU action in cooperation with industry to develop by 2030 three major hydrogen import corridors to North Africa, to the North Sea area and as soon as conditions allow to Ukraine» (European Commission 2022).

Therefore, based on several analyses of supply and demand potentials, as well as the TSOs' technical assessments of the ability to repurpose their natural gas pipelines and build new hydrogen pipelines, the European Hydrogen Backbone Initiative (EHBI) identified up to six supply corridors (North Sea, Baltic, Southeast and East, Southwest, North Africa-Italy). Those import routes were also integrated in a document of the European Clean Hydrogen Alliance (ECHA) in 2023, with the aim to accelerate their establishment. Nonetheless, it is important

[1] Firm capacity can be understood as a guarantee of a level of supplied power, which a supplier has committed to always make available during the period of commitment.

to define and justify the spatial dimension in which EU H_2 imports will occur, as several countries across the globe have pledged to start exporting hydrogen from their shores either via ship or via pipeline[2].

As was seen in the first chapter, while transporting ammonia appears much cheaper than pure hydrogen transport, for distances below 2000 km transporting hydrogen gas by pipeline is likely to be the cheapest delivery option, and above 1500 km ammonia (NH_3) or liquid organic hydrogen carriers (LOHC) delivered via ship become cost-effective[3]. Therefore, the identification of the EU's H_2 supply corridors has also been determined by the distance of supplier countries from the EU Member States, as well as by the already existing infrastructural links between potential hydrogen suppliers and EU importers. Depending on the carrier and the transport distance, costs can shift the competitiveness in favour of domestic production, which however in the case of the EU will not be enough to achieve the hydrogen targets for 2030 and beyond. Figure 18 shows the estimated significant differences in hydrogen import costs between geographical supply regions and between transport means and forms of hydrogen (liquid, compressed, or chemical carriers). Northwest Europe (Germany in particular) is considered as an example of a potential demand centre.

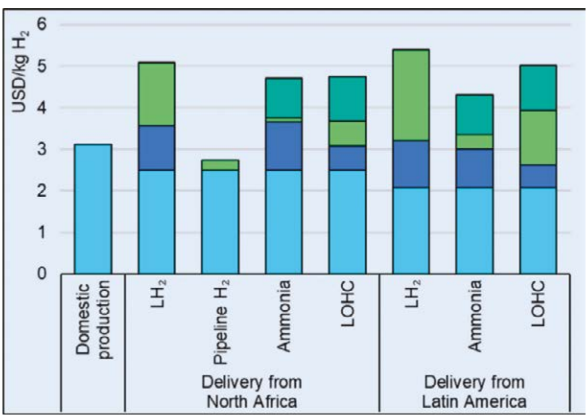

Figure 18 – Supply costs of hydrogen and ammonia in North-west Europe compared to imports ($\$/kg_{H2}$). Source: IEA (2023b). Notes: each colour represents the cost of one stage of H2 delivery: light blue = production, dark blue = conversion, light green = transport, dark green = re-conversion (e.g. ammonia cracking).

[2] Potential hydrogen-exporting countries based on announcements made so far include Chile, Brazil, Canada, the US, Egypt, Saudi Arabia, the UAE, Namibia, Oman, Australia, and regions such as MENA and Latin America (IEA 2023b).

[3] Around 10% of global ammonia demand was met through international trade (import-export) in 2021, and for methanol the trade share was 20%. However, existing trade is linked to use in the chemical industry, and international trade in ammonia and methanol for fuel purposes has only been tested in some first pilot projects (IEA, 2023b).

As shown in the figure, export from North African countries appears as the cheapest option among those present, mainly because hydrogen delivery via pipeline does not involve conversion and re-conversion costs. Although hydrogen levelised production costs (LCOH) in Latin America are cheaper than European domestic production, the transport costs (only possible via ship in form of ammonia or other chemical carriers) do not make Latin America optimal for supplying the EU countries with clean hydrogen. According to the International Energy Agency's «Global Hydrogen Review 2023», transporting compressed hydrogen via pipeline can indeed be the most competitive option in terms of cost, adding only about 0.4-0.5 $\$/kg_{H2}$ for a 3000 km distance, and potentially lowering this transport cost further if repurposed pipelines will become available[4].

However, there are several obstacles that must be addressed before new hydrogen trade routes can be opened. One important issue concerns the lack of a common internationally agreed methodology to determine the emission intensity of hydrogen (while it exists for EU domestic production), potentially leading to a fragmented market. Guaranteeing compliance of imported hydrogen with the EU's certification standards is necessary to develop import-export value chains. For this reason, strategic dialogue and partnerships are needed between the EU and exporters to create a framework for future H_2 trade (Directorate-General for Energy 2022)[5].

It is also important to define the most useful tools to ensure investment certainty in hydrogen trade. Bilateral trade agreements, often between companies, but in some cases involving government institutions, currently account for the majority of announced import-export projects (IEA 2023b). These provide clear pricing mechanisms that encourage investments in capital-intensive hydrogen projects. Auctions are another instrument for awarding trade contracts, by creating a bidding competition and helping move the demand- and supply-side price levels closer (IEA 2023b). The result of those not yet defined issues can be seen in the discrepancy between the EU policy targets for hydrogen import, and the announced hydrogen export projects to Europe. While the former set a 10 million tonnes of (clean) H_2 import target by 2030, the latter amount to around 5 Mt of hydrogen (IEA 2023b). This numbers are also due to the difficulty of exporters to identify potential hydrogen off-takers for their projects.

An analysis of the EHBI, conducted at the onset of Russia's war against Ukraine in 2022, has also shown that potential clean H_2 imports into Europe

[4] It should be considered that currently, the repurposing of existing methane pipelines faces potential availability constraints due to long-term natural gas commitments and capacity contracts which have been signed for the years to come. This signals that some pipelines might be unavailable for eventual repurposing to hydrogen transport, depending on the demand quantities after 2030. But as natural gas demand decreases in line with decarbonisation efforts, import capacities are likely to free up for hydrogen transport (Directorate-General for Energy 2022).

[5] On 5th December 2023, during the 28th Conference of the Parties to the U.N. Framework Convention on Climate Change, 39 countries (including Germany, Italy, the US, India and Brazil) endorsed the COP28 «Declaration of Intent on the Mutual Recognition of Certification Schemes for Renewable and Low-Carbon Hydrogen and Hydrogen Derivatives», thus signalling an increased but still slow pace in the international clean hydrogen trade.

could amount to around 5.4 million tonnes, while the study identified 12 Mt of domestic hydrogen supply potential by 2030 (European Hydrogen Backbone 2022). Such an amount of H_2 supply and import will be driven mainly by the German economy, which - according to its updated national H_2 strategy - expects demand of around 3 Mt (95-130 TWh) of H_2 across all sectors in 2030, including the need to decarbonise its current fossil-based unabated H_2 demand of 55 TWh (European Clean Hydrogen Alliance 2023). Having the largest gas storage capacity in the EU and the fourth in the world (after the USA, Russia and Ukraine), Germany can also gradually repurpose its gas storage sites to provide much-needed hydrogen storage capacity (including new salt caverns that are available adjacent to existing storage sites). The development of the German domestic hydrogen market has therefore significant effects on the overall realisation and speed of the EU hydrogen supply corridors (European Clean Hydrogen Alliance 2023). That is also why Germany has been included in each of the corridors identified in the EHBI study in 2022, and the German gas transmission operator Open Grid Europe (OGE) is involved in the establishment of all six corridors[6]. Those supply routes consider the same H_2 demand for Germany, and then add the projected demand of the countries concerned in each region.

3.1.1 North Sea Corridor

The potentially interconnected hydrogen supply corridor (Figure 19) in the North Sea area involves nine (both EU and non-EU) countries: Belgium, the Netherlands, Denmark, Germany, the UK, France, Luxembourg, Norway, and Ireland. By developing mainly offshore wind, large-scale integrated hydrogen projects and ramping up ship imports of H_2 derivatives (ammonia, methanol and LOHC), the corridor could help meet the demand of the energy-intensive industrial clusters in and around Rotterdam, Zeebrugge, Antwerp, Wilhelmshaven, le Havre, and the Ruhr area, to name a few.

Nonetheless, in the near term the corridor offers access to abundant low-cost blue hydrogen supply, thanks to the combination of existing natural gas reserves in the North Sea and the higher number of existing and planned CCS facilities compared to other parts of the continent (IOGP 2023). According to North Sea Energy (2022), green hydrogen production will steadily grow and be at par with blue H_2 by 2040, mainly thanks to wind energy produced offshore[7]. Indeed, the

[6] On 15th November 2023, the German government unveiled the details of the country's future hydrogen pipeline network, which is set to span 9,700 km by 2032, requiring a total investment of around €20 billion (which will be covered by private funding), and comprising 60% of existing natural gas pipelines. Construction of the hydrogen network is expected to commence next year, and the German government will provide financial support in the first 20 years to ensure commercially viable tariffs and promote the growth of a hydrogen economy, given the initially limited number of users of the network (HydroNews 2023).

[7] On 24th April 2023, the nine countries involved in shaping the North Sea hydrogen supply corridor signed the «Ostend Declaration» aiming to jointly build at least 120 GW of offshore wind energy capacity by 2030 and at least 300 GW by 2050 in the North Sea (Taylor 2023).

United Kingdom in its national H_2 strategy has foreseen to develop large-scale blue hydrogen projects to kick-start the H_2 economy from the mid-2020s, whereas renewable electrolysis will be developed through small-scale projects (HM Government 2021). While the exact hydrogen production mix by 2030 will be influenced by a range of factors such as the CO_2 and electricity prices, the UK's targets are expected to generate up to 42 TWh of «low-carbon hydrogen» by 2030 (HM Government 2021). Blue hydrogen supply will play an important role also for Norway, which since the start of Russia's war against Ukraine has become the EU's largest single natural gas supplier. The Norwegian Government's hydrogen strategy (published in 2020) explicitly promotes the production of methane-based hydrogen coupled with CCS, claiming that Norwegian authorities will work to ensure that natural gas reforming combined with CCS can compete on equal terms with hydrogen from water electrolysis in the European energy market (Norwegian Ministry of Petroleum and Energy 2020). Given the EU's current policy framework, it is essential to better coordinate the EU's import targets with the exporters' intentions regarding the nature of hydrogen. In its updated National Hydrogen Strategy, Germany claims to support «a limited amount of low-carbon blue hydrogen» (Bundesministerium für Wirtschaft und Klimaschutz 2023), thereby adopting a more flexible stance compared to its previous intention to invest only in green H_2.

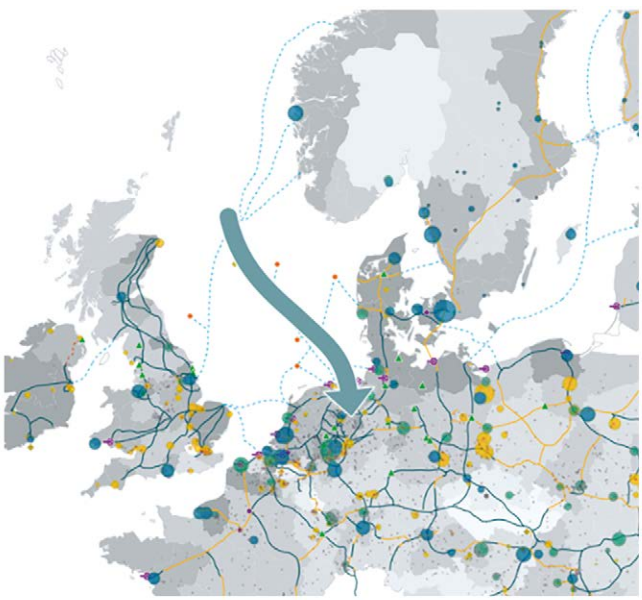

Figure 19 – The North Sea H_2 Supply Corridor. Source: European Hydrogen Backbone (2022).

Due to an already highly integrated offshore and onshore gas infrastructure and the national hydrogen backbones in the Netherlands, Belgium and Germany currently under construction, this North Sea import corridor is arguably the most advanced in terms of development stages. Up to 2030, industrial clusters in the UK and north-western Europe will drive hydrogen demand, whose estimates (including H_2 supply) are reported in Table 19. The transport and power sectors will contribute to increasing H_2 demand from 2040 onwards. On the other side, the corridor enables access to a hydrogen supply potential of around 250 TWh by 2030, increasing to roughly 850 TWh by 2040, with a significant increase of green H_2, which will represent around 70% of all hydrogen supply by 2040. The remaining supply will be made of blue (20%) and grid-based hydrogen (10%)[8]. As can be seen in the table, these last two hydrogen categories will increase less than the green supply between 2030 and 2040.

Table 19 – Demand and Supply of H_2 in the North Sea Corridor [TWh/year]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Total demand[9]	~260	~900
Total supply (green H_2)	106	181
Total supply (blue H_2)	69	568
Total supply (grid-based H_2)	74	103

The demand centres in the North Sea area will be able to access hydrogen, whose production costs will progressively decrease. These will range between 1.6 and 3.5 €/kg_{H2} by 2030, and they will further diminish to around 1.5-2.6 €/kg_{H2} by 2040, due to increased supply options and decreased technology costs (European Hydrogen Backbone 2022). If we compare the costs of hydrogen supply with those of methane (CH_4), reported in Table 20, we can clearly note that hydrogen will more likely start replacing methane in the hard-to-abate industrial sectors from 2040 onwards, since its costs per MWh will still largely exceed those of natural gas by 2030[10].

With regard to the North Sea, central Europe and Germany in particular, a recent study from Aurora Energy Research (Tracey 2023) has shown that renewable hydrogen imports could compete with EU production by 2030, as the levelised cost of hydrogen in Germany will range between 3.9 and 5 €/kg_{H2} in 2030 compared to 3.1 €/kg_{H2} in Australia and Chile, 3.2 €/kg_{H2} in Morocco

8 Grid-based hydrogen is produced from water electrolysis with a grid-connected electrolyser, which therefore does not guarantee the renewable nature of that hydrogen.

9 The demand for 2030 is mostly concentrated in Germany (90-100 TWh per year), the Netherlands (46), Denmark (27), the UK (27) and Belgium (25 TWh). By 2040, the UK and the Netherlands increase their demand above 100 TWh.

10 In order to compare methane with hydrogen, the costs of hydrogen have been converted from «per kg» to «per MWh»: 1 €/kg = 30 €/MWh (knowing that 1 kg of hydrogen has an energy value of about 33 kWh).

and 3.6 €/kg$_{H2}$ in the UAE. Despite additional transport and conversion costs, Aurora claims that imports remain competitive, and that pipelines would provide the cheapest transport option for renewable hydrogen imports to Germany (Tracey 2023). According to the study, imports from Morocco via pipeline would cost 3.72 €/kg$_{H2}$ in 2030, but currently the EU is not on track to have an operational hydrogen pipeline network that could deliver supplies from Morocco to Germany by 2030. Action to accelerate pipeline development could reduce import costs by at least 20% compared to transporting renewable hydrogen by ship (Tracey 2023).

Table 20 – Cost-competitiveness of hydrogen with natural gas in the North Sea Corridor [€/MWh]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Hydrogen[11]	48-105	45-78
Methane	59-73	62-69

3.1.2 Nordic and Baltic Corridor

The development of offshore wind power supply is one of the main drivers also for the corridor (Figure 20) that can bring H_2 towards industrial clusters in the Baltic region, in Poland and eastern Germany. It is estimated that the Baltic Sea area holds a potential of 93 GW of offshore wind energy (Jordaens 2023). This corridor involves nine countries, which are all part of the EU: Finland, Sweden, Denmark, Estonia, Latvia, Lithuania, Poland, Czechia and Germany. One of the earliest, greenfield hydrogen infrastructure projects in Europe is indeed located in the Bothnian Bay (between Finland and Sweden) and has been identified as the «Nordic Hydrogen Route». Finland already has an onshore wind capacity of 5.7 GW, but the 42 MW «Tahkoluoto wind farm» in the Gulf of Bothnia is the only operational offshore wind farm it has so far (Jordaens 2023). The first sections of the Nordic Hydrogen Route project are expected to be operational by 2030, while the on- and off-shore wind capacity could reach 28 GW by 2030 and 48 GW by 2040, thus exceeding the growth of the regional electricity demand[12]. The Nordic Hydrogen Route investment is estimated at €3.5 billion, offering a hydrogen transportation cost (which adds to the production cost) of 0.1-0.2 €/kg$_{H2}$ (European Hydrogen Backbone 2022). In early 2024, the «Nordic-Baltic Hydrogen Corridor» pipeline project, first presented

11 The cost range for hydrogen includes green (wind and solar PV), blue and grid-based hydrogen. The lowest cost both for 2030 and 2040 is represented by the production cost of Norway's blue hydrogen, and the upper limit is given by Germany's grid-based and green H_2.

12 Retrieved from the website of the «Nordic Hydrogen Route»: https://nordichydrogenroute.com/project/

in 2022, took a decisive step forward, as the concerned TSOs signed the contract assigning the specialised company AFRY Management Consulting Oy to carry out the pre-feasibility study for this future Northern European H_2 corridor (Hydronews 2024).

Figure 20 – The Nordic and Baltic H_2 Supply Corridor. Source: European Hydrogen Backbone (2022).

The demand and supply potentials of this corridor are mostly driven by the steel sector in Germany and in the Nordic countries, together with H_2 adoption in some transport applications. In this case, after Germany, Sweden is the leading driver of H_2 demand by 2030 (50 TWh), followed by Denmark (27 TWh), Finland (25 TWh) and Poland (22 TWh). By 2040, the hydrogen demand of all these countries is expected to increase, doubling in the case of Finland and Sweden, and rising six-fold for Poland (European Hydrogen Backbone 2022). On the side of hydrogen supply, both Sweden and Finland will contribute to a larger extent to ramping up green H_2. As shown in Table 21, renewable (mostly wind-based) hydrogen will dominate H_2 supply, leaving a smaller fraction to grid-based H_2. No blue hydrogen is instead envisaged in this corridor, except for Poland, whose national H_2 strategy points to a role for «low-carbon» (and thus also blue) hydrogen in partially decarbonising the country's economy (Ministerstwo Klimatu i Środowiska 2021).

In the envisioned hydrogen corridor, the evolution of production costs points to a region that is actively pursuing cost-effective production methods, while expanding renewable capacity. The levelised costs of hydrogen range from 2.1

to 3.8 €/kg$_{H2}$ in 2030, and they are projected to decrease significantly reaching 1.5-2.7 €/kg$_{H2}$ in 2040 (European Hydrogen Backbone 2022). The cost comparison between hydrogen and methane confirms the pattern identified in the North Sea corridor. While methane has an economic advantage over hydrogen in 2030 (Table 22), the cost dynamics begin to shift by 2040, as the cost of H_2 drops and becomes more competitive, whereas methane shows a much narrower range, which incorporates CO_2 costs.

Table 21 – Demand and Supply of H_2 in the Nordic and Baltic Corridor [TWh/year]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Total demand	~220	~725
Total supply (green H_2)	130	423
Total supply (blue H_2)	-	-
Total supply (grid-based H_2)	54	48

Table 22 – Cost-competitiveness of hydrogen with natural gas in the Nordic and Baltic Corridor [€/MWh]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Hydrogen[13]	63-114	45-81
Methane	59-73	63-69

Finland and Estonia published their hydrogen roadmaps in 2023. While the latter is focused on the first H_2 deployment steps until 2030, Finland's strategy explicitly states that the Nordic country aims to become «the leading high-value hydrogen economy in Europe by 2035» (Hydrogen Cluster Finland 2023), both by developing domestic clean H_2 production and by increasing its export of hydrogen-related technologies and services. According to Finland's strategic document, the country could produce 12 to 98 TWh/y of hydrogen by 2035 and between 80 and 212 TWh/y by 2024 (Hydrogen Cluster Finland 2023). Sweden has been focusing its efforts on upscaling hydrogen in industry and heavy-duty vehicles, as well as by setting electrolyser capacity targets (European Hydrogen Backbone 2022). However, as of late 2023, Sweden's hydrogen strategy is still in the draft stage.

13 The lowest cost of hydrogen for both 2030 and 2040 is represented by the production cost of Denmark offshore wind-based hydrogen, and the upper limit is given by Poland's grid-based and green H_2.

Given the high dependency that green hydrogen production in this corridor will have on the installation of new wind farms, it is important to mention the current crisis that is affecting the wind power industry, and especially offshore wind. The global supply chain disruption caused by the Covid-19 pandemic pushed up the costs also for wind energy technologies, but while most companies could offset the cost increases by raising prices, several wind developers have been locked in contracts to sell power at rates set years ago (Paulsson et al. 2023). Therefore, the owners cannot adjust the price of the power they will sell when the projects come into operation. Companies have faced cost increases of 40% in the space of 12 to 18 months, according to the Swedish utility Vattenfall AB, and higher interest rates make it more expensive for wind developers to borrow from investors (Paulsson et al. 2023).

3.1.3 Eastern Corridor

The hydrogen supply route involving the EU's eastern Member States and neighbouring Ukraine features several short- and long-term uncertainties. For the purposes of this thesis, it is essential to highlight the potential contribution of Ukraine to the EU's hydrogen targets, while considering the existing bottlenecks and obstacles resulting from the ongoing war with Russia. Besides the current difficulties in kick-starting the development of hydrogen supply chains within its borders, Ukraine's situation has sparked concerns regarding the speed of its economic recovery and the operational state of its natural gas infrastructure. Ukraine would boast ideal conditions for the development of large-scale, renewable hydrogen production, thanks to its high renewable energy capacity potential, estimated at around 500-800 GW, with an H_2 supply potential of approximately 1000-1500 TWh (European Clean Hydrogen Alliance 2023). However, some of the best (sunnier and windier) locations for renewables are in the south and east of the country, where much of the Russian invasion has concentrated. Ukraine's well-established ammonia and steel production industries would be suitable candidates to consume (offtake) the green hydrogen produced, to create a first national hydrogen market. Additionally, the country features a substantial number of large-scale underground gas storage facilities, that could be retrofitted for storing H_2 (European Clean Hydrogen Alliance 2023)[14].

Notwithstanding the status quo, and given the existing large gas pipeline connections between Ukraine and the EU countries, different initiatives have taken shape with the goal to prepare the ground for clean hydrogen imports from Ukraine. The «Central European Hydrogen Corridor» is an initiative launched in 2021 by four gas infrastructure companies of the four countries involved in creating the corridor (Figure 21): OGE (Germany), NET4GAS (Czech Republic), Eustream (Slovakia), and Gas TSO of Ukraine (Ukraine) (CEHC 2023). This initiative ex-

[14] Moreover, at the end of 2021, Ukraine's national oil and gas company Naftogaz joined the European Clean Hydrogen Alliance, with the ambition to become a national leader in hydrogen production for export to EU countries.

plores the feasibility of creating a hydrogen «highway» through Central Europe, mainly relying on repurposed natural gas pipelines, combined with targeted investments in new H_2 lines and compressor stations. The project is currently in the pre-feasibility study, while the first results indicate that it is technically feasible to transport up to 52 TWh (or 1.5 Mt) of hydrogen per year by 2030. Total investment for the 1225-km hydrogen corridor, from the Ukraine/Slovakia border to large hydrogen demand centres in southern Germany, is estimated in €1-1.5 billion (CEHC 2023), which is relatively low. This is mainly because of the repurposing of already existing transport infrastructures. On the other hand, the investment costs of the Ukrainian part of the corridor will depend on the exact location of the hydrogen production sites in the country. Finally, the total expected levelised cost of hydrogen transmission (which adds to the production cost) is estimated to be in the range of 0.1-0.15 €/kg_{H2} per 1000 km, which is in the lower range of the cost estimated by the EHBI (0.11-0.21 €/kg_{H2})[15].

Figure 21 – The Central European Hydrogen Corridor. Source: https://www.cehc.eu/cehc-project/.

Before its invasion of Ukraine, Russia had also drafted a plan to ramp up low-carbon hydrogen exports to Europe (up to 2 Mt by 2035) to meet the demand from its former gas customers' growing commitments to decarbonisation (Martin 2023). But while there are currently no potential European buyers of Russian hydrogen (mainly due to the ongoing war and the effects of Western's sanctions), there are also no known incentives for Russian industries to switch from fossil-based hydrogen and fossil fuels to low-carbon hydrogen in the near term.

3.1.4 South-eastern Corridor

Another attractive route along which hydrogen can be produced and cost-effectively transported stretches over south-eastern Europe, involving Greece,

[15] Retrieved from: https://www.cehc.eu/cehc-project/

Bulgaria, Romania, Hungary, Slovenia, Croatia, Slovakia, Czechia, Austria as well as Germany. The opportunities offered by this corridor (Figure 22) are mainly due to the abundant renewable potential and the vast land availability coupled with high-capacity factors for solar PV and onshore wind especially in Romania, Ukraine and Bulgaria (European Hydrogen Backbone 2022).

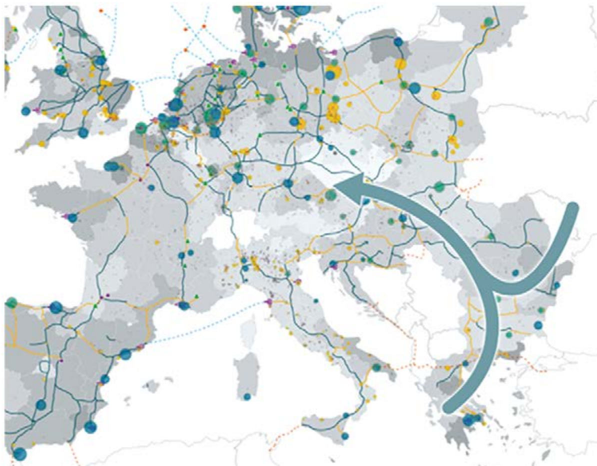

Figure 22 – The South-eastern H_2 Supply Corridor. Source: European Hydrogen Backbone (2022).

Table 23 reports the total hydrogen demand and supply potentials along the south-eastern corridor, where the major driver of H_2 adoption is the industrial sector, that uses hydrogen mainly as a feedstock. Besides Germany, the countries driving the demand in this area up to 2030 are Romania (14 TWh) and Austria, while they (together with Greece, Slovakia and Hungary) will increase their H_2 consumption more significantly by 2040, when e-fuels will be playing a greater role (European Hydrogen Backbone 2022). The corridor enables access to a hydrogen supply potential of around 50 TWh by 2030, of which 65% is made of grid-based hydrogen, increasing to roughly 350 TWh by 2040, with an 85% share of green hydrogen and a 15% grid-based H_2.

Table 23 – Demand and Supply of H_2 in the South-eastern Corridor [TWh/year]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Total demand	~165	~660
Total supply (green H_2)	14	292
Total supply (blue H_2)	-	-
Total supply (grid-based H_2)	38	54

Compared to the other corridors analysed so far, the south-eastern supply route presents a much wider gap between demand and supply potentials, as demand is almost twice as the hydrogen supply in 2040. Such a scenario can be also due to the fact that some countries along this corridor have not yet adopted their hydrogen strategy and have not identified specific demand centres, that could help direct investments and provide for the creation of regional hydrogen markets. Austria, which adopted its H_2 strategy in 2022, emphasises the role of «climate-neutral hydrogen», thus including also blue H_2, as a necessary means to decarbonise up to 80% of its current industrial hydrogen use by 2030 (Bundesministerium, Klimaschutz, Umwelt, Energie, Mobilität, Innovation un Technologie 2022). Hungary, which adopted a strategy for H_2 in 2021, also highlights the need to develop blue hydrogen in the near term (up to 2030) for cost-efficiency reasons and, only after, start developing what the strategy calls «carbon-free hydrogen», produced via electrolysis. In particular, the strategic document sets a target of 20 000 tonnes per year of low-carbon H_2 and 16 000 tonnes of green H_2 by 2030, together with 240 MW of electrolyser capacity (Innovációs és Technológiai Minisztérium 2021). Slovakia also adopted its national H_2 strategy in 2021, planning to consume - mainly in industry, transportation and, only later, energy sectors - around 0.2 Mt/year of hydrogen domestically by 2030, while reaching around 0.4-0.6 Mt by 2050, 90% of which will be covered by low-carbon sources (Sinay 2021). The document further argues that the main goal will be to cover as much of the hydrogen needs as possible from domestic sources only, but in the long-term, it will be necessary to cover some of the consumption by import from abroad.

This is also why the role of (current or potential) transit countries such as Greece and Bulgaria proves important to enable hydrogen imports along this corridor from outside the EU. These two countries have indeed expressed their interest to enhance cooperation on hydrogen production and infrastructure planning. Greece's national natural gas system operator (DESFA) and Bulgaria's Bulgartransgaz signed a letter of intent for cooperation in the field of hydrogen, while the Bulgarian company is developing a project for retrofitting the national gas transmission system for transporting H_2[16].

In the south-eastern corridor, the ranges of the levelised cost of hydrogen generation are slightly above those examined in the previous corridors. By 2030, the south-eastern supply route features costs from 2.5 to 4.5 €/kg_{H2}, while these production costs decrease to 1.7-3.1 €/kg_{H2} as supply options increase, technology costs decrease and imports from Ukraine (ideally) scale up (European Hydrogen Backbone 2022). When comparing hydrogen and methane supply costs in this area, the data reported in Table 24 indicate a competitive edge for CH_4 around 2030, even when CO_2 costs are included. By 2040, however, the cost range for hydrogen decreases significantly, while methane costs remain rela-

[16] Retrieved from: https://www.desfa.gr/en/press-center/press-releases/desfa-and-bulgartransgaz-will-cooperate-in-the-field-of-hydrogen

tively high, thus suggesting that hydrogen will likely become more competitive as economies of scale are realised and investments in new natural gas supplies start decreasing.

Table 24 – Cost-competitiveness of hydrogen with natural gas in the South-eastern Corridor [€/MWh]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Hydrogen[17]	75-135	51-93
Methane	59-73	62-69

3.1.5 South-western Corridor

The south-western hydrogen supply route can become a fundamental building block for hydrogen supply to north-western Europe. This corridor (Figure 23) includes Portugal, Spain, France, Belgium, Luxembourg and it terminates in Germany. While potentially exploiting green hydrogen production in the Iberian Peninsula in the short term, such corridor could also benefit from the existing interconnection between Spain and Morocco, thus providing access to hydrogen imports from the Maghreb country in the longer term[18].

Despite hosting around one third of the EU's LNG regasification capacity which can be repurposed for receiving hydrogen and a wide renewable potential that can be used to generate green H_2, the Iberian Peninsula currently suffers from a lack of energy interconnections with the rest of Europe, thus making the establishment of a south-western H_2 corridor more challenging. While being defined as an «energy island», Spain has been insisting on the need to urgently increase gas and electricity interconnections across the Pyrenees, but France steadily opposed such calls for several years and has only recently changed its position (Escribano 2022)[19]. Spain had claimed that France's continued opposition was due to its intention to safeguard its nuclear energy sector (which generates around three quarters of the nation's electricity) from the competitive influence of Spain and Portugal's ample renewable resources. Paris has further argued that technical difficulties for its predominantly nuclear-based grid could emerge if more Iberian renewable energy streams across France's borders are allowed.

17 The lowest cost of hydrogen for 2030 is represented by grid-based H_2 in Austria, and the lowest cost for 2040 is given by the import cost from Ukraine, while the upper limit is represented by Romania's wind-based green H_2.

18 Spain has two gas pipeline connections with Algeria: the first (Medgaz) is operating at full capacity; and the second (Maghreb Europe) transits through Morocco, but it was discontinued by Algeria in October 2021.

19 Resistance from Spain's northern neighbour has kept Spain far below the EU target for electricity interconnection, which is under 5%, compared with the targets of 10% for 2020 and 15% for 2030 (Escribano 2022).

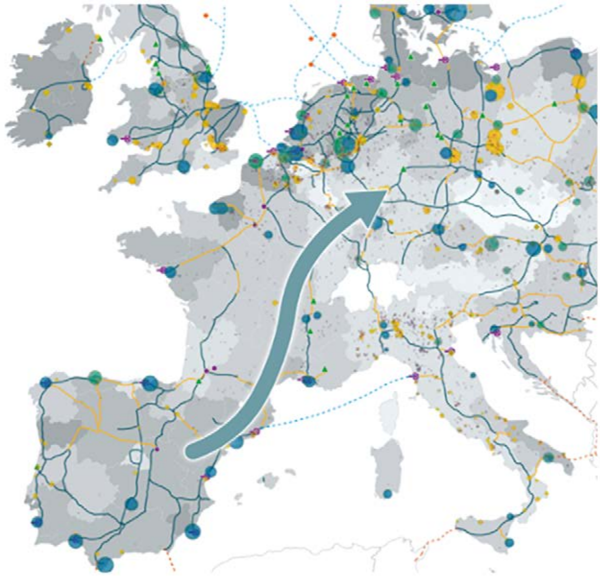

Figure 23 – The South-western H_2 Supply Corridor. Source: European Hydrogen Backbone (2022).

None of the interconnection summits held by successive French presidents with Spain led to tangible results, but now the newly re-launched «H2-Med» project could signal an improved effort towards the creation of a dedicated supply route. «H2-Med» indeed represents the third version of a suggested pipeline linkage between eastern Spain and France, which had been initially conceptualised as the «Midi-Catalonia» project, but this was put on hold and rejuvenated in 2021 as a hydrogen-ready natural gas interconnection linking Barcelona and Marseille (known as the «Bar-Mar»). However, the fact that this pipeline would have not been operational until 2030, led Spain to dump the project in favour of directly transporting hydrogen through the «H2-Med» subsea pipeline, thus also benefitting from facilitated EU financing (Onyango 2022). The planned interconnection has been included in the list of the «Projects of Common Interest» (PCI)[20] at the EU level, which was published by the European Commission (2023a) on 28th November 2023. One month earlier, Open Grid Europe (OGE), one of Germany's major gas grid operators which is also involved

[20] As was mentioned in the second chapter, PCI are energy infrastructure projects that link the energy systems of the different EU countries and can therefore benefit from accelerated permitting procedures and funding. The selection of those projects is made by the European Commission through a list that has been published every 2 years since 2013, and it gives preference to projects in corridors identified in the TEN-E Regulation.

in the development of the other corridors, had officially joined the «H2-Med» pipeline project (Kyllmann 2023).[21]

On the southern side of Spain, one long-term opportunity for this corridor would be the potential repurposing of the Maghreb-Europe pipeline, to enable low-cost hydrogen supply from Morocco in particular. The African country has been implementing its national hydrogen strategy (adopted in 2021), which is divided into three main phases. Up to 2030, Morocco plans to upscale the hydrogen market by producing green ammonia for domestic industrial use, and by exporting hydrogen products. Up to 2040, green hydrogen projects will become economically viable thanks to the decline in the cost of the technology and the export of e-fuels will increase, while by 2050 hydrogen use will expand beyond industry and heavy transport (Ministère de l'Énergie des Mines et de l'Environnement 2021). Nonetheless, the first step for fulfilling ambitious plans to export green hydrogen is to install more renewable energy capacity in Morocco, where, according to Franza (2021), political support is strong. The country set the target to reach 52% RES capacity in the power sector by 2030 and has had a good track record in RES deployment (Franza 2021).

The gap between potential hydrogen demand and supply in the south-western corridor is relatively narrow, even though significant. According to the EHBI projections, which are reported in Table 25, total H_2 demand is set to increase more than three-fold between 2030 and 2040, mainly due to the wider adoption of e-fuel solutions and the balancing role of hydrogen in an increasingly renewable-based power sector. Green (renewable) hydrogen will likely constitute around 85% of total H_2 supply by 2040, up from roughly 65% in 2030. On the other hand, by analysing the national H_2 strategy already adopted by the countries along this route, it can be argued that blue hydrogen will hardly play a considerable role. Both Spain and France do not mention this type of H_2 in their roadmaps for 2030 and 2050. The French strategy instead mentions the role of renewable H_2 and «decarbonised hydrogen», produced via electrolysis (Gouvernement 2020), which clearly points to nuclear-based electricity, since neither the production nor the use of such hydrogen emits CO_2. Moreover, given the already low CO_2-intensity of France's electricity grid, this country could even be able to meet the criteria outlined by the EU Delegated Acts to recognise grid-based hydrogen as renewable H_2 in the not-too-distant future.

The French and Spanish H_2 strategies emphasise the need to first and foremost decarbonise the current hydrogen use in industry, and then develop clean H_2 solutions also in transport. A significant difference between the various strategic documents is that Spain only mentions renewable hydrogen (Ministerio para la Transición Ecológica y el Reto Demográfico 2020), which signals the willingness to strongly enhance the renewable installed capacity in the country. It is important to point out that no H_2 imports are reported for Morocco up to

[21] Open Grid Europe signed a memorandum of understanding with the existing consortium partners Enagás (Spain), REN (Portugal), GRTgaz and Teréga (both from France).

2030, as hydrogen flow through the existing interconnection with that country would likely not be possible until after 2030, but both the Moroccan H_2 strategy and the EHBI projections show that Morocco could be able to export around 10 TWh after 2030 and 46 TWh per year from 2040 (Ministère de l'Énergie des Mines et de l'Environnement 2021).

Table 25 – Demand and Supply of H_2 in the South-western Corridor [TWh/year]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Total demand[22]	~200	~720
Total supply (green H_2)	107	488
Total supply (blue H_2)	23	28
Total supply (grid-based H_2)	34	53

The levelised cost of hydrogen production in the south-western corridor appears much more competitive than the south-eastern supply route, and substantially in line with the Nordic-Baltic and North Sea corridors. By 2030, the south-west corridor provides access to hydrogen costs ranging from 2 to 3.8 €/kg_{H2}, decreasing to 1.4-2.7 €/kg_{H2} by 2040, especially thanks to imports from Morocco and the wider deployment of solar PV in Spain and Portugal (European Hydrogen Backbone 2022). When comparing methane and hydrogen costs, (Table 26), hydrogen becomes materially more competitive with fossil CH_4 only from 2040 onwards.

Table 26 – Cost-competitiveness of hydrogen with natural gas in the South-western Corridor [€/MWh]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Hydrogen	60-114	42-66
Methane	59-73	62-69

3.1.6 North Africa-Italy Corridor

As the other two major hydrogen corridors identified in REPowerEU, the North Africa-Italy supply route could prove to be critical for low-cost hydrogen supply to industrial clusters in Europe. Such long-term perspective entails a pivotal role for the Italian energy (mainly gas) transmission infrastructure, whose

[22] The demand for 2030 is mostly concentrated in Spain (46 TWh/y), France (33), Belgium (25), and - as already mentioned several times - Germany (90). All these countries' H_2 demand will triple by 2040.

abundance, coupled with Italy's geo-economic position, could significantly enhance the country's role in the international H_2 value chains. Figure 24 shows the corridor - primarily involving Italy, Austria, Slovakia, Czechia, and Germany - which currently includes two major infrastructural projects aimed at creating an H_2 backbone. This will consist mainly of repurposed pipelines, which could potentially allow to reduce upfront investment costs.

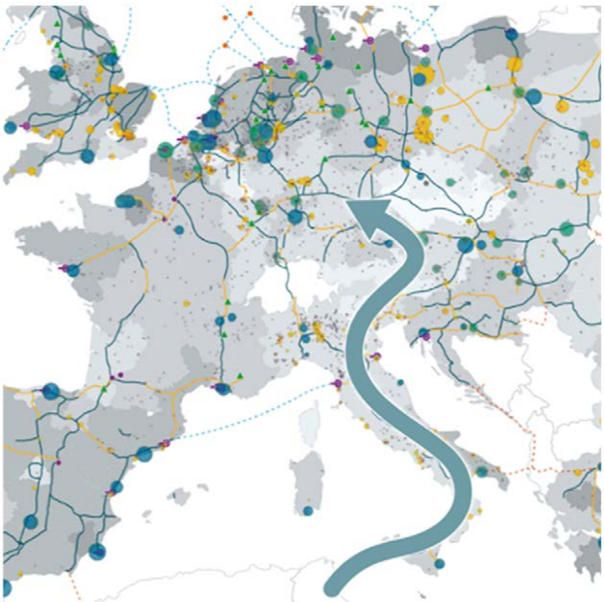

Figure 24 – The North Africa-Italy H_2 Supply Corridor. Source: European Hydrogen Backbone (2022).

It is however crucial to identify the specific North-African countries that could potentially supply the corridor with clean hydrogen. According to the European Hydrogen Backbone (2022), potential producer countries, which are also directly connected via a single pipeline to Italy (Sicily), are Tunisia and Algeria, but other suppliers can be included as well, Egypt being one of them[23]. Although direct pipelines links between this country and EU countries do not exist now, Egypt's potential role in contributing to the EU's 20 Mt of green H_2 target by 2030 could be enhanced. At COP27 in November 2022, the European Commission signed a Memorandum of Understanding (containing non-binding measures) with the Egyptian Ministry for Petroleum, Electricity and Renewable Energy, aimed at establishing a strategic partnership on renewable hydro-

[23] Italy is connected to North Africa both via the «Enrico Mattei-Transmed» pipeline (Algeria-Tunisia-Sicily) and also via the «Greenstream» pipeline (Libya-Sicily).

gen and providing funds for Egypt's domestic transition away from fossil fuels (European Commission 2022b)[24]. However, this country needs to cope with recurrent sovereign debt issues, high inflation rates and severe environmental degradation, which also include water scarcity, potentially affecting green hydrogen production, as well as the need for a more robust domestic regulatory framework (Dargin 2023).

A similar scenario also characterises Tunisia, the North African country geographically closest to Italy. As was seen in the south-western H_2 supply corridor with Morocco, Tunisia is also poor in indigenous fossil fuel resources, and it is dependent on foreign energy exports. Therefore, this country could benefit from the development of a renewable hydrogen export infrastructure. As Morocco for Spain, so is Tunisia a transit country for Algerian natural gas to Italy, thus already providing for a first constraint, as Tunisian operators would need to coordinate with Algeria to make use of existing pipelines to transport hydrogen. In addition, despite having a regulatory framework governing renewable energy that could be adapted to the green hydrogen sector (Bouafif 2023), Tunisia currently does not have a defined roadmap to produce and export clean H_2. A November 2023 World Bank report confirms that Tunisia's H_2 strategy has yet to be adopted, but it claims that this country could supply, through Italy, markets in Germany and Austria with a strong green hydrogen demand (World Bank Group 2023). The report further argues that several studies see the export market for green H_2 in Tunisia expanding rapidly after an initial market catalyst through the local market in replacement for grey hydrogen, mostly used in the fertiliser sector (World Bank Group 2023). If we look back at the time when most national H_2 strategies started to be adopted following the publication of the EU Hydrogen Strategy (2020), Tunisia was listed in the same category as Morocco in terms of attractiveness as a future hydrogen supplier, with lower potential volumes but comparable costs of delivery Franza (2021).

We can measure such attractiveness by looking at the investment conditions and the hydrogen production costs in those specific countries. If we consider the first criterion, we can see that Tunisia, Egypt and Morocco perform much better than the other countries in the Middle East and North Africa (MENA) region, according to the World Bank's Regulatory Indicators for Sustainable Energy (RISE). Those can be used to understand whether a country presents good or bad investment conditions in the categories of energy access, energy efficiency and renewable energy, thus allowing to calculate the potential capital costs for major infrastructural projects (Braun et al. 2023)[25]. Countries with good in-

[24] The European Commission has contributed with around €35 million to Egypt's Energy Wealth Initiative, and the European Bank for Reconstruction and Development (EBRD) has been lending Egypt $80 million for its nascent green hydrogen industry (Dargin 2023).

[25] According to Braun *et al.* (2023), low-carbon energy (planned and committed) investments in the MENA region are dominated by solar PV (50%), followed by clean hydrogen (21%), nuclear (14%) and wind (10%).

vestment conditions will have lower capital costs[26]. The other useful indicator for determining the countries with the highest H_2 supply and export potential in the region is the hydrogen production cost. Figure 25 clearly shows that H_2 costs for 2030 (in green) and mean production costs for 2050 (in red) are lower for Morocco, Tunisia and Egypt. Using the conversion formula mentioned above ($1\ €/kg_{H2} = 30\ €/MWh$), we can compare the costs in the figure with those estimated by the European Hydrogen Backbone Initiative. Table 27 reports the cost ranges for hydrogen supply for the MENA region as a whole, in order to have a realistic estimate. It is important to consider that the cost range of the EHBI also includes H_2 production in the other countries of the North Africa-Italy import corridor, thus contributing to lowering the overall cost. While in 2030 natural gas will still be much more affordable than hydrogen, in 2040 it has a cost range of 62-69 €/MWh along this corridor, against a range of 42-84 for hydrogen (European Hydrogen Backbone 2022). This can have wider impacts on the adoption of H_2 in hard-to-abate sectors.

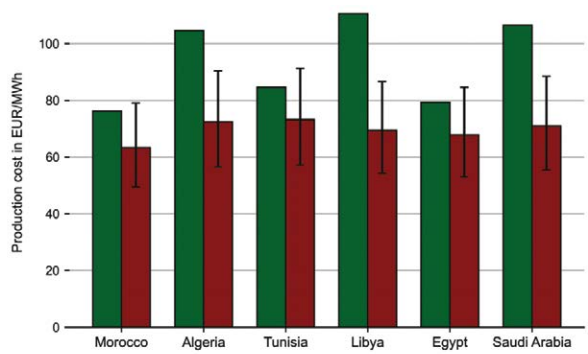

Figure 25 – Hydrogen production costs for 2030 and mean production costs for 2050 in the MENA region [€/MWh]. Source: Braun et al. (2023).

According to the EHBI, the German and Italian industrial sectors will drive H_2 demand, which is projected to increase fourfold between 2030 and 2040 in this corridor and will consist mostly of green hydrogen, as reported in Table 28 (European Hydrogen Backbone 2022)[27]. It is interesting to note that the 70 TWh of green H_2 in the EHBI projection for 2030 are entirely supplied by North African imports (mainly from Tunisia and Algeria via pipeline). However, given

[26] The cost of capital for an investment can be expressed as the weighted average cost of capital (WACC), which includes all the sources of capital (debt and equity) that a company pays to finance its assets.

[27] Italy's hydrogen demand is projected to increase from 23 TWh/year in 2030 to 89 TWh in 2040 and more than 187 by 2050 (European Hydrogen Backbone 2022). For the current demand scenario, see the next section.

the untapped potential and the slow pace of H_2 development in North African countries, such a scenario will be hardly feasible.

Table 27 – Comparison of hydrogen production costs in the MENA region. Source: own elaboration based on European Hydrogen Backbone (2022) and Braun et al. (2023).

	2030	2040	2050
European Hydrogen Backbone (2022)	2.1-3.8	1.4-2-8	-
Braun et al. (2023)	2.5-3.7	-	2.1-2.4

Table 28 – Demand and Supply of H_2 in the North Africa-Italy Corridor [TWh/year]. Source: own elaboration based on European Hydrogen Backbone (2022).

	2030	2040
Total demand	~140	~550
Total supply (green H_2)	70	303
Total supply (blue H_2)	-	-
Total supply (grid-based H_2)	26	37

At the same time, several European TSOs involved in the corridor are planning to invest in building a hydrogen transport network and facilitate market ramp-up. So far, two significant infrastructural projects have been developed to enable H_2 imports through the North Africa-Italy corridor, both via Austria and also Switzerland. The «SoutH2 Corridor» and the «SunsHyne Corridor» involve several TSOs, and both projects foresee a total hydrogen pipeline length of 3000-3400 km, largely consisting of repurposed lines. Table 29 summarises the main elements of the two projects, which aim to connect each country's H_2 pipeline systems operated by the national TSOs into one large supply route. Some national governments of the countries concerned have already endorsed the projects, in particular those of Austria, Germany and Italy, whose Energy Ministries, on 9th April 2023, signed a joint letter of support for a «Southern Hydrogen Corridor», thus supporting the projects in obtaining the status of Projects of Common Interest (Gas Connect Austria 2023). Like the previously mentioned «H2-Med» pipeline, all the projects that constitute the southern hydrogen corridor have obtained the PCI status[28].

Notwithstanding the ongoing planning and development process of the H_2 infrastructure along this corridor, many challenges are likely to remain unmet in the near term. The limited renewable energy infrastructure and the low re-

[28] Out of the 166 selected PCI, over half (85) are electricity, offshore and smart grid projects, and for the first time 65 hydrogen and electrolyser projects are included, together with 14 CO_2 network projects that will help create a market for carbon capture and storage.

newable penetration in the energy systems of the North African countries is an obstacle to the production of clean hydrogen. Although countries like Tunisia and Algeria have been taking part in some renewable and hydrogen development projects and they are already interconnected to Italy, the flow of hydrogen towards Europe largely depends on the repurposing of pipelines connecting Algeria and Tunisia and on their respective financing. Moreover, the North African region is currently affected by severe political instability. Algeria, which is one of the main natural gas suppliers for Italy, has been experiencing a protracted domestic tension between the political-military complex and societal pressures for reform, as well as the willingness of the country's leaders to weaponise energy in inter-state controversies (Giuli 2022), as happened with neighbouring Morocco.

Table 29 – The «SoutH_2 Corridor» and the «SunsHyne Corridor» projects. Source: own elaboration based on the projects' official websites: https://www.south2corridor.net, https://www.sunshynecorridor.eu.

	SoutH2 Corridor	SunsHyne Corridor
Project partners	**SNAM** (Italy), **TAG** (Austria), **GCA** (Austria), **Bayernets** (Germany)	**SNAM** (Italy), **TAG** (Austria), Eustream (Slovakia), **NET4GAS** (Czechia), **OGE** (Germany)
Planned national infrastructures	· **Italy**: Italian H2 Backbone (SNAM) · **Austria**: H2 Readiness of the TAG Pipeline System (TAG), H2 Backbone WAG + Penta-West (GCA) · **Germany**: HyPipe Bavaria – The Hydrogen Hub (Bayernets)	· **Italy**: Italian H2 Backbone (SNAM) · **Austria**: H2 Readiness of the TAG Pipeline System (TAG) · **Slovakia**: H2 repurposing project (Eustream) · **Czechia**: H2 repurposing project (Czechia) · **Germany**: H2ercules (OGE)
Length [km]	· **Italy**: 2300 · **Austria**: 380 · **Germany**: 300	· **Italy**: 2300 · **Austria**: 380 · **Slovakia**: no data available · **Czechia**: ~400 · **Germany**: 1500 (whole H2ercules project)
Estimated import capacity [TWh/y]	· **Italy**: 165 (62 export) · **Austria**: 61 (TAG) + 54 (GCA) · **Germany**: 52 (From Austria)	· **Italy**: 165 · **Austria**: 61 · **Slovakia**: no data available · **Czechia**: 52 · **Germany**: 52

3.2 The development of a hydrogen economy in Italy

An analysis of Italy's potentially strategic role in connecting hydrogen supply in North Africa to the demand centres in Europe cannot however disregard the Italian domestic policy efforts to give shape to a low-carbon and clean hydrogen value chain. Such initiatives include the Italian integrated National Energy and Climate Plan (NECP), whose development is mandated by EU Regulation

2018/1999 on Governance of the Energy Union, to detail national objectives for each of the five dimensions of the Energy Union[29]. While the European Commission closely monitors and regularly reports on the progress made in these plans, the current ones (submitted by 31 December 2019) cover the period 2021 to 2030, but Member States were due to submit their draft updated NECPs, in line with article 14 of Regulation 2018/1999, by 30th June 2023[30]. Therefore, by looking at Italy's 2019 and 2023 versions of the NECP, it can be possible to determine the importance accorded to hydrogen development in the Italian plan. Following the adoption of the NECP's first version in 2019, the Italian Ministry of Economic Development (MISE) published a document containing «Preliminary Guidelines for a National Hydrogen Strategy», with the aim of setting electrolyser and renewable hydrogen targets which however have not so far been clearly linked to a specific demand.

In 2022 hydrogen (mainly fossil-based grey H_2) consumption in Italy was approximately 0,6 Mt/year (European Hydrogen Observatory 2023), which roughly correspond to 19 TWh, equal to slightly more than 1% of overall national energy consumption (1300 TWh in 2022)[31]. It is important to assess whether the electrolyser (GW) and hydrogen (Mt) targets set by the H_2 Strategy Preliminary Guidelines can both decarbonise the current unabated hydrogen consumption and increase the hydrogen contribution to the national energy mix from 1% to 2% by 2030. The interest in accelerated (clean) hydrogen development is also emphasised in the National Recovery and Resilience Plan (NRRP), approved in 2021 and where around €3.7 billion in funds are allocated to measures explicitly dedicated to hydrogen-related projects. The financing of the NRRP (through the Recovery and Resilience Facility) is based on the performance of the single country in attaining specific «milestones» (qualitative indicators) and «targets» (quantitative indicators), which have been included in the plan and are subject to regular assessments by the European Commission every 2 months[32]. Hydrogen funding in this instrument is assigned mainly through grants, managed either by the national Ministry of Environment and Energy Security (MASE) or by

[29] The five dimensions are: 1) security, solidarity, and trust; 2) a fully integrated internal energy market; 3) energy efficiency; 4) climate action and decarbonisation; 5) research, innovation, and competitiveness. Retrieved from: https://energy.ec.europa.eu/topics/energy-strategy/energy-union_en.

[30] Art. 14 states that «by 30 June 2023, and subsequently by 1 January 2033 and every 10 years thereafter, each Member State shall submit to the Commission a draft update of the latest notified integrated national energy and climate plan or shall provide the Commission with reasons justifying why the plan does not require updating».

[31] As shown in the previous chapter, if we consider that 1 million tonnes of hydrogen have an energy value of around 33 TWh, then it is correct to consider the above-mentioned numbers.

[32] To benefit from support under the Recovery and Resilience Facility, EU governments have submitted national recovery and resilience plans, outlining the reforms and investments they will implement by end-2026, with clear milestones and targets. The plans had to allocate at least 37% of their budget to green measures and 20% to digital measures.

local (regional) authorities. Against this background, the final adoption of the updated NECP and the adoption of a dedicated National Hydrogen Strategy, both completed at the end of 2024, represent the two most recent and significant steps undertaken by the Italian government in defining its medium- and long-term objectives for hydrogen development.

3.2.1 Hydrogen in the 2019 National Energy and Climate Plan[33]

The Italian NECP sets national targets for 2030 concerning energy efficiency, renewable sources, and reduction of CO_2 emissions, as well as goals related to energy security, interconnections, the single energy market, competitiveness, and sustainable mobility. However, the first version of the NECP does not include a specific chapter or section dedicated to hydrogen development and integration into the Italian energy system. Instead, the 2019 NECP only mentions hydrogen when outlining the 2030 scenarios in the transport sector, as well as potential energy storage options, but without setting overall targets. According to the plan, a contribution of around 1% of the renewable transport target was expected for hydrogen (Ministero dello Sviluppo Economico 2019). This would involve direct use in hydrogen-powered cars, buses, heavy transport, and trains (especially on some non-electrified routes), and also potential applications in maritime transport or through integration into the methane network for transportation purposes[34]. The plan then claims that, in the context of hydrogen development in the mobility sector, integrated solutions for multi-fuel distribution through fuel cells could play a significant role, as the Renewable Energy Directive II (adopted in 2018 and then revised under Fit-for-55) set a specific target for hydrogen in the transport sector of 14% by 2030. It was indeed the RED II that provided the definition of renewable fuels of non-biological origin (RFNBOs), whose deployment, as was seen in Chapter 2, was foreseen only in the transport sector. The scope of RFNBOs has been extended to industry and heating with the new RED III adopted in October 2023, and it is thus not covered by the 2019 Italian NECP.

The 2019 plan only makes a general mention to the need to attract private investments for developing the clean hydrogen value chain in Italy and stresses the importance of developing storage and power-to-gas facilities, particularly aimed at storing excess production from non-programmable renewables «through safe and reliable storage of hydrogen in liquid and gaseous energy carriers» (Ministero dello Sviluppo Economico 2019). This could indeed address the so-called «electricity overgeneration», a phenomenon that can derive from two situations. Overgeneration from congestion occurs when there is a high renewable energy

[33] Italy's NECP is officially known as «Piano Nazionale Integrato per l'Energia e il Clima (PNIEC)».

[34] The plan continued stating that, within that 1% for renewable transport, a differentiated usage approach could include 0.8% H_2 injection into the network in a mixture with natural gas and/or H_2 conversion into methane, and 0.2% for direct use in cars, buses, and trains.

generation, but the transport capacity of the electrical grid is insufficient, and thus the demand-supply balance (which needs to be maintained in every moment) prevents the full exploitation of renewable electricity. Overgeneration from lack of demand, instead, can occur when, even with sufficient transport capacity, the intensity of production from non-programmable renewables cannot be entirely absorbed by the system, due to a lack of demand.

It is important to recall that renewable energy sources and green hydrogen are mutually dependent. While the production of energy from renewable sources enables the production of green hydrogen, H_2 enables the levelling out of peaks in energy production from renewables through H_2 storage. Although Italy's 2019 NECP outlines the growth trajectories of renewable energy sources up to 2030, it does not identify a specific portion of the RES generation that could be entirely dedicated to producing green H_2. Regardless of the possibility of importing hydrogen and/or renewable electricity produced in North Africa, questions remain about the gap between the renewable electricity produced and not consumed, and the potential foreseeable demand for hydrogen in 2030, which could be met using that renewable electricity. This aspect has been only partially clarified by the 2023 version of the NECP, which outlines more precise H_2 targets and raises the RES installed capacity trajectory (see section 3.2.4.).

3.2.2 The Italian Hydrogen Strategy: Preliminary Guidelines

The ambition outlined in Italy's Preliminary Guidelines to the National Hydrogen Strategy lies in doubling hydrogen's contribution to the national final energy demand, and increase the electrolyser installed capacity. H_2 penetration in the Italian energy mix should increase to 2% from the current 1%, while electrolysis would see 5 GW of new capacity by 2030 (Ministero dello Sviluppo Economico 2020). The guidelines further state that around €10 billion in investments would be needed for achieving such targets, but it does not identify the amount of resources that should be earmarked for renewables, which would provide the electricity to feed the electrolysers. Within those €10 billion, the guidelines claim that around €5-7 billion would be destined to H_2 production, and around €3 billion to distribution and consumption infrastructures (such as hydrogen refuelling stations, H_2 trucks etc.), but without mentioning potential necessary investments in the construction of new hydrogen pipelines or in the repurposing of existing gas lines to transfer the molecule.

Three main hydrogen use categories can be identified by analysing the strategy's preliminary guidelines. While in the long-term up to 2050, hydrogen is expected to be largely used in the hard-to-abate sectors involving energy intensive production processes (Ministero dello Sviluppo Economico 2020), H_2 will need to become more competitive up to 2030 in order to enable the development of a national hydrogen ecosystem. As we explained in Chapter 1, in the steel industry, for instance, green hydrogen represents the only emission-free alternative for the direct reduction of iron (DRI), which currently uses natural gas as the preferred feedstock. The second use-case for this molecule is envisaged in the transport sector, especially in heavy-duty vehicles such as long-haul trucks and in railways (Ministero dello Sviluppo Economico 2020)[35]. More than for other applications, consumer (users') choices in this sector are driven both by the total cost of ownership (TCO) and by other parameters such as the refuelling time and the range (km) of the vehicle. The TCO for fuel cell trucks will hardly become competitive in the near future. According to the Government's guidelines, instead, fuel cell-powered trains could become cost-competitive with diesel-fuelled ones in the next decade (Ministero dello Sviluppo Economico, 2020)[36]. The third way in which hydrogen can be employed, as mentioned in the preliminary guidelines, is in a blend with natural gas in the national gas transport network. The ministerial document mentions blending for both «low-carbon» and green H_2. While no specific target for either of the two types is envisaged, the guidelines state that overgeneration from renewables can be leveraged to produce green H_2 «for blending at lower cost» (Ministero dello Sviluppo Economico 2020).

In Chapter 2 we mentioned the issue of hydrogen blending in the gas grid, since there is currently no common framework but there are only national rules in each EU country that regulate blending at different percentages, thus hampering cross-border hydrogen flows. Furthermore, blending should be given a precise scope, but Italy's preliminary guidelines to the H_2 strategy claim that «blending low-carbon hydrogen into the network can be an effective method to contribute to decarbonisation goals» (Ministero dello Sviluppo Economico 2020), without linking it to potential national demand clusters. Although some recent studies conducted on the Italian gas distribution network show that hydrogen blending can help decarbonise the energy sector by supporting the penetration of renewables (Guzzo et al. 2022), the design of a clear strategy moving towards a growing percentage of hydrogen injection into the gas network is essential. Moreover, since power-to-hydrogen plants will be needed to blend green hydrogen into the Italian gas network, the planning of new P2H facilities cannot be realised without taking into consideration the current location of renewable power plants as well as the setting up of new ones (Pellegrini et al. 2020).

As shown by another study (Kanellopoulos et al. 2022), Italy currently presents a discrepancy between the potential technical capacity for hydrogen blending and the electrolyser (P2H) target set by the preliminary guidelines, and also included in Italy's National Recovery and Resilience Plan (see section 3.2.3). The study has indeed calculated that a 5% of hydrogen blending in the European gas network would need around 18 GW of electrolyser capacity, while around 40-70 GW would be needed to reach a 20% blending level. Italy, which

[35] According to the Preliminary Guidelines, the long-haul truck segment is among the sectors with a significant responsibility for emissions, accounting for 5-10% of all transportation emissions. A penetration of at least 2% of long-haul fuel cell trucks can be anticipated by 2030, within a total national fleet of approximately 200,000 vehicles (Ministero dello Sviluppo Economico 2020).

[36] Currently, about one third of the railways in Italy are dedicated to diesel trains.

has a 5 GW electrolyser target by 2030, would need around 14 GW to be able to inject a 20% hydrogen blend into the gas grid (Kanellopoulos et al. 2022). This means that the electrolyser capacity should be further boosted, if Italy plans to increase its H_2 blending targets.

Regarding where best to locate H_2 production, the preliminary guidelines point out that both decentralised and centralised hydrogen production could have different benefits. The major advantage of fully on-site production is the absence of transport for both hydrogen and electricity; however, producing enough hydrogen through on-site renewables may not be technically possible due to space constraints, requiring on-site balancing of supply and demand (Ministero dello Sviluppo Economico 2020). On the other hand, centralised production could allow economies of scale on electrolysers and benefit from higher load factors of renewables located in sunny or windy areas such as southern Italy. This option would however imply the accurate planning of a hydrogen (or hydrogen-ready) transmission infrastructure and/or new investments in the reinforcement of power lines.

3.2.3 Hydrogen in the National Recovery and Resilience Plan

Around €23.7 billion have been allocated to the second «Component» of Mission 2 (Green revolution and ecological transition) of the Italian National Recovery and Resilience Plan (NRRP), including around €3.6 billion for investments in H_2 technology (Presidenza del Consiglio dei Ministri 2021). Component 2, labelled «Renewable energy, hydrogen, grid and sustainable mobility», foresees reforms and investments aimed at enhancing renewables penetration via decentralised and utility-scale solutions, and strengthening the grid to accommodate and synchronise the new renewable sources and decarbonise end uses. Table 30 outlines the different investments and reforms related to the development of a hydrogen value chain and their current status, together with the funding that has been issued for those measures and the target that must be met by end-2026, as mandated by the Recovery and Resilience Facility Regulation.

By examining the measures and the relevant amount of funding provided, a focus on medium-to-large scale investments in the industrial sector can be observed. €500 million (Investment 3.1) are allocated for the production of hydrogen in disused industrial areas, which are known as «Hydrogen Valleys». Those are regional integrated hydrogen ecosystems, which can be distinguished into three archetypes: 1) local, small-scale and mobility-focused (green) hydrogen production projects serving mobility applications, usually involving dozens of local stakeholders and being led by public-private partnerships or regional public authorities; 2) locally integrated, medium-scale producers and consumers of hydrogen with a focus on industrial feedstock and 3) large-scale hydrogen production and international export focus (Weichenhain et al. 2022). Hard-to-abate sectors (such as steel, glass, ceramics, paper etc.) constitute the primary destination for boosting hydrogen use and decarbonise production, according to investment 3.2 (€2 billion) of the Italian plan.

Table 30 – Investments and Reforms in the Italian NRRP related to hydrogen technology. Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2023a) and Ministero delle Infrastrutture e dei Trasporti (2023). Notes: letter M refers to the Mission, letter C refers to the Component, letter I to the Investment and letter R to the Reform included in the Plan.

Measure	**Status**[37]	Total funding [€]	Target by 2026
M2, C2, I3.1: **Hydrogen production in disused industrial areas**	The Government adopted two Decrees in late 2022 for the allocation of resources and the definition of tenders for the Regions. All Regions have published the public notices and are finalising the **adoption of Decrees to allocate the grants**.	€500 million	· Completion of **at least 10 hydrogen production projects** with an average capacity of at least 1-5 MW each
M2, C2, I3.2: **Hydrogen use in hard-to-abate sectors**	After the adoption of a Decree in late 2022, the Government has started the **selection procedure for hydrogen projects** in mid-2023.	€2 billion	· **Decarbonisation of at least one industrial facility** in a hard-to-abate sector
M2, C2, I3.3: **Testing hydrogen for road transport**	In mid-2023 the Ministry of Transports and Infrastructures published the final **public notice to allocate the funds**	€230 million	· Construction of **40 hydrogen refuelling stations**
M2, C2, I3.4: **Testing hydrogen for rail transport**	An **Executive Decree adopted in March 2023** allocated the financial resources to the applicant Regions	€300 million	· Construction of **at least 10 renewable hydrogen refuelling facilities** on at least 6 railway lines
M2, C2, I3.5: **Hydrogen R&D**	**R&D contracts** have been awarded between mid-2022 and 2023	€160 million	· **At least 4 R&D projects** completed
M2, C2, I5.2: **Hydrogen (electrolysers)**	**IPCEI agreements** between the Italian Government and relevant industries have enabled the subsidised production of electrolysers	€450 million	· Commissioning of **one industrial facility for the production of electrolysers** with a 1GW capacity per year

[37] at the time of editing (January 2026).

Measure	**Status**[37]	Total funding [€]	Target by 2026
M2, C2, R3.1: **Administrative simplification and reduction of regulatory barriers to hydrogen deployment**	Several Decrees adopted to introduce **simplifications for the manufacturing of electrolysers** and **guarantees of origin** for renewable hydrogen		
M2, C2, R3.2: **Measures to promote the competitiveness of hydrogen**	**Tax incentives** entered into force with Law 2022/79 and Ministerial Decree 2022/347		

It is nonetheless important to point out that since mid-2023 the NRRP has been partially revised, because of the adoption of the REPowerEU Plan at the EU level, which provides additional funding for energy transition measures, but requires Member States to update their national recovery plans to integrate those funds. The revised Italian NRRP, which was approved by the European Commission in November 2023, will allocate an additional €2.76 billion from REPowerEU, through ETS revenues[38]. However, due to the de-financing and reshaping of some chapters of the NRRP, around €1 billion (out of the initial €2 billion) have been eliminated from the funds allocated to hydrogen use in hard-to-abate sectors (Dipartimento per le Politiche Europee 2023). Instead, Hydrogen Valley projects have received further support (around €90 million) from their initial €500 million. Such investments can serve the purpose of enabling the creation of local hydrogen markets thus fostering the development of a H_2 value chain. It can be further argued that one of the core aims of creating H_2 Valleys is to focus the production and consumption of green hydrogen on strategic areas already connected to the electricity grid, especially where the renewable potential is higher[39]. Indeed, southern Italy is the area that hosts most H_2 Valley projects, with 26 of the 54 projects covering 50% of the total available funds, while, in the North, 18 projects will come to life (covering 36% of the budget) and in the Centre 7 (18% of the total funds) (Energia&Mercato 2023).

Another major target to be accomplished by 2026 is the construction of an industrial plant to produce 1 GW-capacity electrolysers, known as «Gigafactory». This project was declared eligible by the European Commission to receive funding under the IPCEI *Hy2Tech* project, which we mentioned in Chapter 2 as one of the major State aid instruments to foster the growth of

38 The funds allocated by the revised NRRP increase from the initial €191.5 to €194.4 billion, mainly due to €2.7 billion from ETS quotas and €146 millions in GDP adjustments. The total reprogramming carried out amounts to €21.4 billion, of which €2.8 billion in additional resources (Il Sole 24Ore 2023).

39 The claim that the RES electricity potential is higher in southern Italy will be demonstrated and discussed in Chapter 4 of this thesis.

hydrogen supply chains. The Gigafactory project includes six major Italian companies (Ansaldo, Fincantieri, Iveco Italia, Alstom Ferroviaria, Enel and De Nora in partnership with SNAM) and two research organisations (ENEA and Fondazione Bruno Kessler) (Hydronews 2023a). From a total of around €1 billion destined to Italy for this first IPCEI on hydrogen, the electrolyser «Gigafactory» project will receive around €63 million in public funding[40]. Such initiative can be seen as complementary to the second project aimed at producing GW-scale electrolysers, namely the new Gigafactory that Ansaldo Green Tech - a subsidiary of Ansaldo Energia - will build in Genoa. This plant, expected to reach a 600 MW/year capacity by 2026, will focus on the most innovative electrolysis technologies, i.e. SOEC (Solid Oxide Electrolysis Cells) and AEM (Anion Exchange Membrane) and will not produce alkaline or PEM electrolysers (Hydronews 2023c)[41].

3.2.4 Hydrogen in the new National Energy and Climate Plan

The 2024 National Energy and Climate Plan (NECP) is currently the most updated version of the renewable and low-carbon energy targets set by the Italian Government to contribute to the EU's climate goals. The Ministry of Environment and Energy Security formally submitted to the European Commission the proposal to update the NECP on 30th June 2023 and the plan was finally adopted in the second half of 2024. Unlike the previous one, the updated NECP includes a chapter dedicated to the deployment of renewable hydrogen in the transport and industry sectors by 2030, thus already signalling an increased interest in developing this molecule. This can be mainly explained by the fact that the new Renewable Energy Directive (RED III) sets mandatory overall targets for the uptake of renewable hydrogen in transport, industry and heating in the form of RFNBO by 2030, as discussed in Chapter 2. Together with such type of renewable H_2, the Italian plan includes an unquantified contribution of renewable biomass-based hydrogen to the national targets up to 2030[42]. However such form of H_2 is not included in the definition of renewable hydrogen provided by the RED II Delegated Acts, which have been designed to provide regulatory clarity for hydrogen generation and deployment. A brief mention in the NECP is made for blue hydrogen as well, but without setting specific

[40] The first phase of the work involves the demolition of the old facility on an area of 25,000 m^2. The new centre is estimated to have a production capacity of 2 GW (Hydrogen-News 2023).

[41] At the end of November 2023, the Italian Ministry of Environment and Energy Security launched a €100 million incentive, in form of non-repayable grants financed through the NRRP (under investment 5.2), to support the development of the components of the renewable hydrogen value chain, thus including those for manufacturing electrolysers. Around 40% of the resources are allocated to the southern Regions and to the islands (Invitalia 2023).

[42] As was seen in Chapter 1, this type of hydrogen is produced from the gasification of biomass in the form of crop residues, forest residues and solid waste.

targets[43]. Therefore, uncertainty remains about the exact amount of blue and biomass-based H_2 that should be deployed to achieve the NECP's targets. The second type, in particular, has a renewable nature but cannot count in reaching the RED III targets. The Italian NECP clearly states that «this type of fuel will play an increasing role in achieving decarbonisation, but the extent of its contribution is difficult to quantify at present» (Ministero dell'Ambiente e della Sicurezza Energetica 2023b).

In December 2023 the European Commission released its opinion on the draft updated NECP, recommending Italy to include more detailed and quantified policies in a way that enables a timely and cost-effective achievement of its national contribution to the EU's binding renewable energy target of at least 42.5% in 2030, as well as to describe in particular how it plans to further facilitate permitting with faster and simpler procedures, and how the design of the obligation on fuel suppliers in the transport sector will be covered and include measures for promoting hydrogen in industry and prepare the EU for renewable hydrogen trade (European Commission 2023b).

Therefore, we should look at the real contribution of sector-specific targets for renewable hydrogen set by the new version of the NECP to assess their real weight in the current and estimated final energy consumption by 2030. Table 31 outlines the new NECP targets for renewable hydrogen demand by 2030, together with the total final energy demand of all sectors by 2030 - which we have converted into TWh for comparability reasons. Projections of hydrogen use in industry indicate that about 0.115 Mt (3.8 TWh) of renewable H_2, both bio and non-bio (RFNBO), will be needed to reach the industry target in 2030. For transport, a total consumption of about 0.136 Mt (4.5 TWh) of renewable H_2 is estimated. No targets have been set for the residential, tertiary and agricultural sectors, as the NECP stresses the importance to foster hydrogen use in the hard-to-abate industrial and transport sectors, while considering H_2 blending into the gas grid (Ministero dell'Ambiente e della Sicurezza Energetica 2023b), which is in line with the H_2 Strategy Preliminary Guidelines (see section 3.2.2). Overall, the targets for renewable hydrogen by 2030 would lead to a consumption of about 0.25 Mt/year (8.2 TWh), 80% of which is estimated to be produced domestically, and the remainder will be imported according to the NECP[44].

[43] The final version of the Italian NECP of 2024 states that blue hydrogen production, which is complementary to renewable hydrogen and features lower production costs compared to it, could facilitate a faster decarbonisation of industrial sectors, particularly those that currently rely on grey hydrogen (Ministero dell'Ambiente e della Sicurezza Energetica 2024a).

[44] The final version of the NECP of 2024 includes roughly the same quantities of H2 for the same sectors (industry and transport). The latest version of the NECP also states that the largest contribution to the growth of renewable energy will come from the electricity sector itself: generation from renewable energy sources is expected to reach around 237 TWh by 2030, including approximately 10 TWh allocated to the production of green hydrogen (Ministero dell'Ambiente e della Sicurezza Energetica 2024a).

Table 31 – Estimated renewable hydrogen consumption targets over final energy demand by sector by 2030. Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2023b, 2024a).

Sector	H_2 amount [Mt]	H_2 energy value [TWh]	Final energy demand [TWh]
Industry	0.115	3.8	282
Transport	0.136	4.5	379
Residential	-	-	308
Tertiary	-	-	168
Agriculture	-	-	29
Total	0.251	8.2	~1160

Nevertheless, a question remains on the actual contribution of renewable hydrogen to the final energy demand by 2030. As can be seen from the table, final energy consumption across all sectors is projected to be around 1160 TWh in 2030, which is slightly less than the current 1300 TWh (Ministero dell'Ambiente e della Sicurezza Energetica 2023c). With such data in mind, we can calculate the approximate share of H_2 in the final energy demand, which according to the H_2 Strategy Preliminary Guidelines and the new NECP could rise to 2% from the current 1%. If we consider the (mostly unabated) H_2 demand of around 19 TWh in 2022, we can see that it is equal to roughly 1.4% of the 2022 final energy demand (1300 TWh). But then if we take only the projected renewable hydrogen demand (8 TWh) and compare it to the final energy demand across all sectors in 2030 (1160 TWh), renewable H_2 contribution is barely 0.7%. In order to reach the 2% of H_2 in final energy demand as mandated by the NECP and the preliminary guidelines, we have considered the current unabated grey hydrogen demand (19 TWh) and added the projected renewable H_2 demand, thus obtaining around 27 TWh of hydrogen, which correspond to around 2.3% of the final energy demand across all sectors in 2030. These estimates on hydrogen contribution to the Italian energy mix are summarised in Table 32.

Table 32 – Hydrogen contribution to the final energy demand in 2022 and 2030 [%]. Source: own elaboration. Notes: P.G. stands for Preliminary Guidelines.

Hydrogen targets	% of final energy demand in 2022	% of final energy demand in 2030
NECP and H_2 Strategy P.G.	1%	2%
Actual projection Renewable H_2	~0%	0.7%
Actual projection All types of H_2	1.4%	2.3%

3.2.5 "Strategia Nazionale Idrogeno": The Italian Hydrogen Strategy[45]

In November 2024, the Italian Ministry of Environment and Energy Security (Ministero dell'Ambiente e della Sicurezza Energetica 2024b) presented the Italian National Hydrogen Strategy ("the Strategy"), outlining a more comprehensive policy framework for the deployment of renewable and low-carbon hydrogen over the short (today-2030), medium (2030-2040) and long (2040-2050) term. While positioning H_2 as a key pillar of Italy's decarbonisation pathway, the Strategy is fully aligned with the objectives of Italy's 2024 NECP and the EU target of climate neutrality by mid-century. It therefore does not introduce brand new hydrogen targets at national level for 2030, but it goes beyond the NECP's time horizon, and it identifies the potential H_2 demand and supply by 2050. By adopting a scenario-based approach on three levels ("base", "intermediate", "high-diffusion"), the Strategy acknowledges that the future role of hydrogen will depend on multiple cross-cutting factors, including technological maturity, market development and system integration.

As reported in Table 33, the Strategy estimates a potential national hydrogen demand between 2 and 4.16 Mt H_2 by 2050 across the three scenarios (Ministero dell'Ambiente e della Sicurezza Energetica 2024b)[46]. While the document discusses the potential costs of different hydrogen production methods (electrolysis, SMR, pyrolisis etc.), we cannot find any direct quantitative target for renewable (green) hydrogen compared to what is outlined in the 2024 NECP. The Strategy mentions instead electrolyser capacity targets (from 3 GW by 2030 to 15-30 GW by 2050), which can be considered only a proxy measure of the potential renewable H_2 production.

Table 33 – Total Hydrogen Demand in Italy by 2050 (Three Scenarios). Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2024b).

Scenario	Total Hydrogen Demand [Mt H_2]	Total Energy Demand [TWh]
Base	~2.23	~74.3
Intermediate	~3.17	~105,7
High diffusion	~4.16	~138.7

Decarbonisation is envisaged as the result of a portfolio of solutions, combining increased renewable electricity generation (of which up to 90 GW of new

[45] The final document on the Italian hydrogen strategy was published after the conclusion and the defence of this thesis. For this reason, the updated data and information that are present in this publication were added afterwards.

[46] The Strategy reports all the values in million tons of oil equivalent (Mtoe). For the sake of consistency with the rest of this publication, all the values in Mtoe have been converted to million tons (Mt) of H_2 and in TWh, based on the lower heating value (LHV) of hydrogen, assumed at approximately 120 MJ/kg, and on the equivalence 1 Mtoe = 41.868 PJ.

renewable capacity to feed the above-mentioned electrolyser capacity), carbon capture and storage (CCS), biofuels, biomethane and hydrogen, with the possible contribution of next-generation nuclear power. Within this mix, H_2 is primarily targeted at the transport (2.34 Mt out of the 4.16 Mt of the high diffusion scenario) and hard-to-abate sectors (1.29 Mt). H_2 in the civil sector has instead almost no penetration (Ministero dell'Ambiente e della Sicurezza Energetica 2024b). Although the share of hydrogen projected to be used in the transport sector is almost double of that foreseen for the industrial HTA sector, we can argue that H_2 will not be used directly to fuel transport means like airplanes or ships but it will be rather used to produce the synthetic fuels that will be actually employed in those applications (see also Section 1.3.2.).

Beyond climate objectives, the Strategy emphasises broader policy goals, including energy security, the development of a competitive national hydrogen value chain, and the ambition for Italy to act as a Mediterranean energy hub, supported by international cooperation and dedicated infrastructure. In this context, the Strategy identifies projects like the Southern Hydrogen Corridor as strategic enablers for positioning Italy as a key entry point for hydrogen imports into the European market. The document indeed projects that around 70% of the total H_2 supply by 2050 will be produced domestically, and it points to a significant share in imports, at around 30% (Ministero dell'Ambiente e della Sicurezza Energetica 2024b).

Conclusions

The analysis carried out in this chapter has evaluated the plans to create several import routes for clean hydrogen into the EU from a cost-effectiveness and geoeconomic points of view, emphasising the need to accurately combine the construction of new H_2 transport infrastructures with potential demand clusters in Europe. At a domestic level, new areas where to locate renewable power plants must be identified considering the construction of new electrolysers directly connected to a renewable facility or the need to strengthen the electricity grid to bring green electrons to the P2H plants. However, the production of hydrogen from grid-based electrolysis can eventually limit the supply of green H_2, because in the 90% of EU countries the national electricity grid is not decarbonised enough to be considered renewable according to the EU's rules (see Chapter 4). In the above discussion we have also mentioned the need to simplify and shorten planning and permitting procedures for the full value chain of renewable and hydrogen projects, which is critical for the establishment of all corridors.

At the external level, several obstacles must be addressed before new hydrogen trade routes can be opened. One important issue concerns the lack of a common internationally agreed methodology to determine the emission intensity of hydrogen (while it exists for EU domestic production), potentially leading to a fragmented market. Guaranteeing compliance of imported hydrogen with the EU's certification standards is necessary to develop import-export value chains.

For this reason, strategic dialogue and partnerships are needed between the EU and exporting countries.

A country that could facilitate such partnerships especially with potential green hydrogen suppliers on the southern shores of the Mediterranean is Italy. The overview of the infrastructural projects related to the H_2 corridors highlights the pivotal role played by Italy's transmission infrastructure. The Italian hydrogen «backbone» promoted by SNAM is not only the longest of those in the North Africa-EU corridor, but it could also enable the EU to access the cheapest alternative among all other import options to achieve the H_2 targets and meet growing industrial (mainly German) H_2 demand. For this reason, SNAM's technical document on the «Italian H2 Backbone» will be analysed in Chapter 4, along with the discussion of the current status and planning of the Italian gas and electricity transmission systems.

Nonetheless, the analysis of Italy's policy initiatives towards clean H_2 development has highlighted that initial efforts should be on decarbonising the current unabated fossil-based hydrogen consumption, by setting more ambitious targets. Italy must compete with its international peers, aiming to assume an enabling role in the entire European strategy, but playing this role means defining a long-term and ambitious vision, and leading to useful actions to create a competitive advantage for national industrial supply chains. Although the Italian National Hydrogen Strategy argues that renewable H_2 should have priority over other types of hydrogen[47], it does not define binding quantitative targets for renewable H_2 production. Instead, it adopts a scenario-based approach, providing indicative ranges for hydrogen demand, electrolyser capacity and domestic production, while referring to renewable and low-carbon hydrogen jointly. More specific quantitative references to green hydrogen emerge indirectly through the NECP, notably via electricity generation targets allocated to electrolysis, rather than through explicit hydrogen output targets.

[47] Italy's national strategy prioritizes the development of hydrogen produced from renewable sources as a key pillar of the energy transition, while not excluding other production pathways. In particular, it acknowledges the potential role of blue hydrogen - especially in connection with advances in carbon capture and storage (CCS) - as well as hydrogen generated from nuclear energy, consistent with ongoing sustainable nuclear programs (Ministero dell'Ambiente e della Sicurezza Energetica 2024b).

CHAPTER 4

The Italian hard-to-abate sectors: a case study on potential hydrogen use

Introduction

Due to the net-zero and low-carbon objectives enshrined in the policy frameworks which we analysed both for Italy and the EU, governments and industries have been examining the potential solutions to decarbonise those parts of the economy which are labelled hard to abate (HTA). Despite being poorly defined, this concept can be used to include sectors such as steel, iron, non-metallic minerals (glass, ceramics, cement), paper, chemicals and refinery, as well as some transport applications such as maritime shipping and aviation. Heavy industry contributes to over 17% of global CO_2 emissions, including an 8% from cement production and 7% from iron and steel, which account for more than twice as much CO_2 as shipping (3%) and aviation (2.5%) (Oxford Institute for Energy Studies 2023). In the EU, heavy industry sectors account for roughly 21% of total emissions (European Environment Agency 2023), while Italian HTA industries represent 16% of total CO_2 emissions in the country (ISPRA 2022)[1]. The value added of Italy's HTA sectors is around €94 billion, representing about 7% of Italy's gross added value, while these sectors' employees are 1.25 million, or 5% of total employment (The European House - Ambrosetti 2023).

[1] Total emissions are roughly 418 Mt of CO_2 equivalent, while those of HTA sectors amount to 64 Mt/CO_2eq (ISPRA 2022).

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Book References DOI 10.36253/979-12-215-1013-3.references

The feature that all these sectors have in common is the technical inability to partly or completely electrify their energy inputs, thereby requiring other solutions to reduce their emission intensity. Indeed, electricity is expected to contribute mainly to decarbonisation in the light industries, while for HTA sectors, hydrogen will play a more important role, reaching around 31% of total energy consumption compared to an electricity demand of 25% by 2050 (Eurelectric 2023). The significance of hydrogen for decarbonising hard-to-abate sectors has been also stressed in the recently adopted Hydrogen and Decarbonised Gas Markets Package at the EU level (see Chapter 2). The rules set the playing field for investments into hydrogen, prioritising HTA industries like steel and chemicals (Kurmayer 2023). By considering the average estimated hydrogen demand by sector in the EU from 2022 to 2050 (Figure 26), it becomes clear that industry - and in particular HTA sectors - will drive H_2 demand in the medium-to-long term. According to the European Hydrogen Observatory (2023), the refining sector currently stands out as the primary driver of conventional hydrogen consumption in most countries accounting for 57% of the total demand, while Germany, Italy and Spain had the largest consumption, contributing to 10.7%, 6.1% and 5.9% of the total demand, respectively. In many countries such as Italy, Greece, Finland, Slovakia, Portugal, Croatia, Denmark and Ireland, the refining industry accounts for most of the domestic conventional hydrogen consumption (>80%)[2]. Following is the ammonia industry with 24% of total H_2 demand, and another 12% is consumed for methanol production and other uses in the chemical industry (European Hydrogen Observatory 2023).

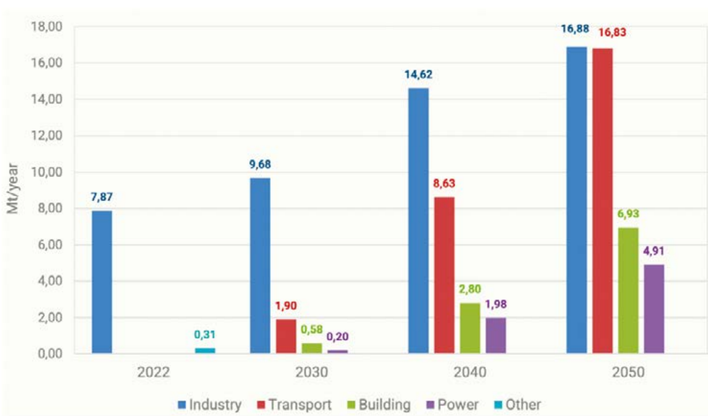

Figure 26 – Average projected hydrogen demand by sector in the EU [Mt/year]. Source: European Hydrogen Observatory (2023).

[2] In refineries, hydrogen plays a pivotal role in hydrotreating and hydrocracking operations. Hydrotreatment constitutes a vital component of diesel refining, encompassing various processes such as hydrogenation, hydrodesulfurization, hydrodenitrification, and hydrodemetallization (European Hydrogen Observatory 2023).

While progressively adopting non-polluting hydrogen in their production processes, HTA sectors will need to accelerate the reduction of their CO_2 emissions in the next decade. The entry into the new phase of the EU Emission Trading System will involve an increase in the price of carbon allowances, since it will be coupled with a progressive reduction of available permits until 2030 and with the elimination of allowances allocated free of charge to HTA sectors. For this reason, carbon capture and storage (CCS) technologies can be further developed, to penetrate energy-intensive industries and contribute to the separation of CO_2 emissions from industrial processes (Oxford Institute for Energy Studies 2023).

If we consider the current scenario in Europe and in Italy, in particular, CCS can complement hydrogen in enabling decarbonisation. In Chapter 1 we argued that (clean) hydrogen will compete with bioenergy and fossil fuels with CCS in decarbonising HTA sectors. Such competition can however be replaced by the progressive integration of grey H_2 production coupled with CCS, especially because - as we have seen in Chapter 3 - many EU countries will not be able to replace their unabated H_2 consumption with renewable hydrogen in the near term. If we consider just the steel sector, for instance, nearly half of Europe's current wind and solar output would have to be dedicated to the region's steel plants (Oxford Institute for Energy Studies 2023). As we outlined in the examination of the EU hydrogen supply corridors, CCS facilities in Europe are mostly located around the North Sea (IOGP 2023). However, a new project specifically involves the establishment of a CCS hub in the offshore depleted gas fields off the coast of Ravenna, in the Italian part of the Adriatic Sea. After having created a Joint Venture, the Italian energy company Eni and the Italian gas TSO Snam have been implementing the project, whose initial phase started in 2024, with the perspective to capture CO_2 from multiple industrial sources in the Po Valley.

As far as technologies for producing renewable hydrogen are concerned, Italy is potentially well positioned in the European manufacturing ecosystem. The country has had a 25% share of the total EU production value in technologies potentially related to green hydrogen production, second only to Germany (29%) (The European House - Ambrosetti 2020). Core technologies include electrolysers, blue hydrogen production technologies and plants, and fuel cells. In the cluster of ancillary technologies are included thermal (burners, exchangers), mechanical (pipes, valves, filters), electrical (inverters, photovoltaic panels, electric motors), control and plants for using hydrogen as feedstock. Notwithstanding such a solid H_2 technology manufacturing base, Italy has been lagging behind its major European partners in the development of new hydrogen projects. By looking at the International Energy Agency's hydrogen projects database, we can indeed see that Italy is home to only around 40 projects (most of which are in the concept or feasibility study phase), while France, Germany and Spain are hosting 121, 198 and 142 hydrogen projects respectively (IEA 2023).

As we saw in Chapters 2 and 3, besides the single technologies enabling H_2 production and a favourable regulatory framework, the development of regional and national hydrogen markets requires the presence of an integrated infrastructure, capable of moving ever-increasing amounts of low-carbon and renewable hydrogen, and of transporting clean energy to where it is consumed or transformed into H_2. This is why the first section of this chapter examines the status and planning of Italy's gas and electricity networks from a broader perspective, in view of cross-vector and hydrogen integration needs. The second section will analyse the dynamics around the transition from natural gas and grey hydrogen to blue and green H_2 in hard-to-abate sectors, while the last section will provide an overview of a case study on the adoption of clean hydrogen in the production process of ceramics, one of Italy's most important and innovative energy-intensive sectors, as Italy is the seventh largest ceramics manufacturer in the world and more than four fifths of the sector's revenue is given by exports (Confindustria Ceramica 2023).

4.1 Fine-tuning the electricity and gas networks for hydrogen integration

The process for developing Italy's energy scenarios is characterised by cooperation between the two main national transmission system operators: Terna (for electricity) and Snam (for gas). As we stated in the previous chapters, close collaboration between the electricity and gas sectors is key to enable sector coupling and energy system integration, thus eventually carving out a role for hydrogen. If we consider the planning of gas and electricity networks in Italy until 2030, the only document that is drawn up jointly (every two years) by the gas and electricity TSOs is the so-called «Scenarios Description Document» (*Documento di Descrizione degli Scenari* - DDS), which is a preliminary evaluation of the gas and electricity grid development plans, that are prepared separately by Terna and Snam. Because the DDS is a comprehensive document representing a declination at the national level of the European ENTSO-G and ENTSO-E scenarios, it is important to consider it when analysing potential hydrogen integration in the policy scenario towards 2030 and 2040, in continuity with what we outlined in chapters 2 and 3 regarding hydrogen infrastructural needs, both for production and for import.

Just as the target set by Italy's 2023 National Energy and Climate Plan (NECP), so too has Terna (2022) foreseen a share of 65% of renewables in total electricity consumption by 2030, thus increasing the potential contribution of green hydrogen to the total H_2 that will be produced in Italy. The country's renewable installed capacity starts however from a relatively narrow level, totalling around 63 GW at the end of 2022 (Terna 2023), compared to the 2024 NECP target of 131 GW by 2030, meaning that new RES capacity would need to be installed at a rate of more than 9 GW per year to achieve such objective. Both the 2022 level and the 2030 target include hydropower in the calculation of total RES capacity, but the NECP does not provide for an increase in hydro until 2030, which remains stable at around 19 GW[3]. This means that solar and

[3] These numbers are in line both with the 2022 and with the latest 2024 Scenarios Description Document of Snam and Terna. The 2030 policy (NECP) scenario envisages that around 110

wind power will need to make the largest contribution to achieving the 2030 RES goals. In 2022 there has been a significant acceleration of new RES installed capacity, with more than 3 GW of new renewable plants available compared to the previous year, in which only around 1.3 GW were installed (Terna 2023). Such increase was mainly due to the ramp-up of PV capacity, which at the end of 2022 totalled 25 GW, while wind power plants were at 11.8 GW, all on-shore (IRENA 2023). Table 34 compares the data for 2022 with the targets of the old (2019) and the new (2024) NECP, thus providing a clearer picture of the evolution of the electricity system.

Table 34 – Electricity consumption and RES targets in Italy by 2030. Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2023a; 2023b; 2024) and Ministero dello Sviluppo Economico (2019).

Year	Situation in 2022	2030 (2024 NECP)	2030 (2019 NECP)
Electricity consumption [TWh]	316	350	339.5
RES installed capacity (total) [GW]	63	131.3	95.2
Solar PV [GW]	25	79.9	52
Wind [GW]	11.8	28 of which offshore: 2.1	19.3 of which offshore: 0.9

Notwithstanding its ambitious RES targets, the new NECP also claims that natural gas will continue to play a major role for the Italian energy system in the near future. The diversification of supply channels combined with the new demand for transit of gas through Italy to supply adjacent European markets determine new needs for the development and maintenance of the gas transport infrastructure system in full efficiency (Ministero dell'Ambiente e della Sicurezza Energetica 2023b). Moreover, on a national level, the projected increase in RES capacity will need to be followed by an adequate amount of back-up capacity, which will be provided by new thermal power plants, since natural gas will remain more competitive than hydrogen at least until after 2030, as demonstrated when we compared methane and hydrogen prices in 2030 and 2040 (see Chapter 3).

Such scenario has two main implications for the gas sector. On the one hand, an extended use of natural gas will require continued maintenance and

GW of new installed solar and wind capacity will be required, corresponding to an increase of around +65 GW compared to the 42 GW installed in 2023 (+49 GW of solar and +16 GW of wind) (Terna 2024). If we take the new 110 GW and add the already existing hydropower capacity, we achieve around 130 GW, which corresponds to the 2030 objective foreseen by the Italian National Energy and Climate Plan (see below).

investment in transmission infrastructure. On the other hand, however, with the projected increases in electrification and use of hydrogen and the corresponding decreases in natural gas demand in the long term, it can be expected that grid expansion investments will become less relevant when compared to replacement investments by natural gas TSOs (Grote et al. 2022). This development can facilitate the creation of a new hydrogen transport network, which can largely rely on the repurposing of existing natural gas pipelines, thus being quicker and cheaper than the construction of new H_2 infrastructure and allowing to avoid pipelines' decommissioning costs. This is also why more than 70% of the southern (North Africa-Italy) hydrogen supply corridor is expected to be constituted by repurposed pipelines.

When focusing on hydrogen use, both the NECP and the National Recovery and Resilience Plan (NRRP) foresee a primary role for HTA sectors, whose current main feedstock and fuel is natural gas. Indeed, around 17% of the natural gas consumed in Italy in 2022 was used in industry (Ministero dell'Ambiente e della Sicurezza Energetica 2023a). If we look at the Scenario Description Document (Terna 2022), while natural gas will continue to play a predominant role, its use in HTA sectors will decrease to around 9.9 bcm (100 TWh) by 2030, and hydrogen consumption will increase to around 2.2 bcm (23 TWh), as was estimated in Chapter 3 by the European Hydrogen Backbone Initiative. Such amount of H_2 will continue to be used mostly in refining and chemical sectors, but it will start to expand also to other HTA sectors. Table 35 summarises the above data and compares the current natural gas and hydrogen uses with the future scenarios.

Table 35 – Natural gas and hydrogen consumption scenarios in Italy by 2030 and 2040 [TWh]. Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2023a) and Terna (2022).

Year	Situation in 2022	2030 (DDS)	2040 (DDS)
Natural gas consumption	674 (69 bcm)	566 (58 bcm)	375 (35 bcm)
Industrial natural gas consumption	117 (12 bcm)	100 (9.9 bcm)	58 (~6 bcm)
Industrial HTA hydrogen consumption	~16	23	21-40

These estimations on H_2 consumption in the industrial hard-to-abate sectors up to 2040 (21-40 TWh) can be considered in line with the value indicated by the new Italian hydrogen strategy, which is equal to 43 TWh (1.29 Mt of H_2) by 2050. Table 36 outlines the potential (not only green) hydrogen demand in the HTA sectors in the high diffusion scenario by 2050, as foreseen in the Strategy.

Table 36 – Hydrogen Demand in Hard-to-Abate Sectors (2050, High Diffusion Scenario). Source: own elaboration based on Ministero dell'Ambiente e della Sicurezza Energetica (2024b).

Sector	Hydrogen Demand [Mt H_2]	Hydrogen Demand [TWh]
Hard-to-abate industry (total)	~1.29	~43
Chemicals (feedstock)	~0.41	~13.7
Steel	~0.39	~13
Glass	~0.17	~5.7
Refineries (feedstock)	~0.12	~4
Ceramics	~0.1	~3.3
Cement	~0.07	~2.3
Foundries	~0.03	~1

4.1.1 Gas network development

The Italian gas TSO Snam adopted a medium-term plan covering the years 2022-2031 which envisages investments both in the development and maintenance of pipelines and storage facilities and in the realisation of the «Italian Hydrogen Backbone» to support the creation of a national H_2 market and to export the additional volumes available from domestic production and import. Within such plan, according to which there could be over €20 billion of investment opportunities in 2022-2031, in late January 2024 Snam released the «2023-2027 Strategic plan», that provides for €11.5 billion in total investments of which €10.3 billion are directly related to infrastructure development (Snam 2024). €7.4 billion are earmarked for the gas transport component, that includes the construction of the «Adriatic pipeline» to increase the south-north gas and, in the future, hydrogen transport capacity; €1.4 billion will be used for expanding and upgrading storage sites; €1.5 billion dedicated to the purchasing and installation of two LNG regasification plants[4] and the related infrastructure. However, by considering the whole 2022-2031 plan, we can see that maintenance interventions (around 30) far outnumber the construction of new pipelines (6), thus confirming that grid expansion investments are likely to become less relevant compared to replacement investments by gas TSOs.

It is important to emphasise that investments for the development and modernisation of Snam's transportation and storage infrastructure are being made with a view to H_2 asset readiness, while Snam is carrying out H_2 certification activities on the existing network and checks on storage, compressor stations and the metering system. To this effect, the Italian H_2 backbone (Figure 27) has been developed with a view to reusing the pipelines of the methane transporta-

[4] These consist of two floating storage and regasification units (FSRUs).

tion network «as far as possible through repurposing activities» (Snam 2023), which firstly involve verifying the suitability of existing pipelines to carry H_2. The pipelines' adaptation process needs to consider that the existing natural gas consumption will gradually diminish but it will still be present for several years, and therefore the transport of methane must be ensured. This is why Snam is also conducting transport and demand coverage checks on the downstream transport network, to ensure that natural gas transport continues to be reliable and secure, taking into account the expected medium-to-long term demand (Snam 2023). According to Snam's strategic planning document, initial assessments on the repurposing activities suggest that the capacities of the resulting natural gas network will in any case be sufficient to meet the system's demand for natural gas.

Figure 27 – The planned Italian Hydrogen Backbone. Source: Snam (2023).

The Italian Hydrogen Backbone project, with a total CAPEX of about €3.2 billion (Snam 2023)[5], is currently in its pre-feasibility stage, and it envisages the preparation of the H_2 network to cover the needs of the hydrogen market until 2040, developing sufficient import capacity from Africa to guarantee coverage of the expected demand. The project is also set up to allow export to and import from Austria and Switzerland, ensuring flexibility and security of supply to the Italian and European hydrogen transport system as soon as these interconnections are developed.

[5] In Snam's new 2023-2027 Strategic Plan, €100 million are scheduled to be invested in the hydrogen business, of which 20 million in the engineering phase of the SoutH2 Corridor (Snam 2024).

The future domestic hydrogen network will mainly consist of grid sections converted for H_2 transport, with small exceptions. We can see that in northern Italy the H_2 backbone essentially splits into two sections, each of which will serve an interconnection with Austria and Switzerland respectively. In addition to the main backbone, six branches have been defined that will constitute the first connection between the hydrogen backbone and the main consumption and/or production centres. In particular, the areas planned to be reached are those where a significant switch from the consumption of natural gas or other fossil fuels to hydrogen is envisaged, namely the hard-to-abate sectors (in particular petrochemicals and steelworks) (Snam 2023).

It is interesting to notice that Snam's gas grid development plan includes a section dedicated to the Poseidon pipeline (Figure 28), which is the final stretch of a Greece-Italy interconnection system that would connect the Italian grid to the gas volumes available in the Eastern Mediterranean (the Levantine Basin), thanks to the «EastMed» pipeline project[6] and to the gas volumes available at the Turkish/Greek border through an overland extension in Greece. With a total length of around 2000 km, the project (expected to become operational in 2026) would serve Europe's gas supply diversification strategy in the short term, while in the longer term it could also be used as a hydrogen supply route (Snam 2023). However, despite having been kept in the list of Projects of Common Interest (PCI) published in November 2023 by the European Commission, the EastMed-Poseidon pipeline project, has been subject to both economic and geopolitical difficulties. On the one hand, the commercial viability of a new natural gas pipeline to Europe has been questioned due to the Green Deal objectives for the next decades which would see a lower demand for natural gas. On the other hand, Turkey, whose territory is bypassed by the current project, has raised doubts about the pipeline's feasibility.

Figure 28 – The EastMed-Poseidon pipeline complex. Source: Agenzia Nova (2022).

[6] The EastMed project is being carried out by IGI Poseidon, a joint-venture of EDISON S.p.A. (Italy) and DEPA International Projects SA (Greece).

4.1.2 Electricity network development

The evolution of the electricity transport network is increasingly dependent on the shift of power installed capacity from demand centres, thus being critical for deciding where to establish renewable hydrogen production plants. In order to achieve the Fit-for-55, REPowerEU and national RES targets, Italy's electricity TSO Terna has been investing around €11 billion in new gird development interventions, under the umbrella of the so-called «Hypergrid» project (Terna 2023)[7]. The latter will exploit high-voltage direct current (HVDC) transmission technologies which will imply a massive modernisation of existing power lines on the country's east and west ridges, including the southern regions and islands, accompanied by new submarine connections. According to Terna's 2023 grid development plan, «Hypergrid» will increase the performance of power lines, minimising their environmental impact and transferring more and more power generated by renewables in southern Italy to the load areas in the north, where the bulk of demand is concentrated. The «Hypergrid» project consists of five main cable backbones (Terna 2023): «HVDC Montalto di Castro-Milan» (to transfer electrons from central to northern Italy), «Central link» (to move electricity from central Italy to the main consumption areas in Tuscany), «Sardinian backbone» (to enable better RES integration on the island, including electricity produced by future off-shore power plants), «Ionian-Tyrrhenian backbone» (to transport renewable energy produced in Sicily and other southern areas towards northern Italy), «Adriatic backbone» (connecting Apulia with Emilia-Romagna and allowing to reduce grid congestion in areas with high renewable generation like Apulia).

The planned and ongoing interventions on the electricity network also arise from an increasing number of requests for connection to the national transmission grid from new renewable power plants. At the end of 2022, Terna had received approximately 311 GW of active requests for connection to the national transmission grid (high and extra-high voltage) for RES electricity, of which 302 GW for photovoltaic and wind power plants (on-shore and off-shore) (Terna 2023). Although the forwarding of the connection request does not guarantee the actual construction of the plant[8], such numbers signal a clear tendency towards exploiting Italy's renewable potential. Around 80% of connection requests are indeed located in southern Italy and on the islands (Figure 29), which are characterised by greater windiness and irradiation (Terna 2023).

[7] Terna (2023) estimates that the total costs of investments in RES, storage and grid infrastructures necessary to reach the 2030 targets are in the range of €150-180 billion.

[8] Following the user's request for connection, the preliminary phase begins in which Terna draws up the connection estimate containing the General Minimum Technical Solution (*Soluzione Tecnica Minima Generale*), expressing the time and cost of the planned grid interventions necessary for connection. If the request is accepted, there are two more steps, concerning authorisation procedures and the signing of a connection contract. Only then can the construction phase begin (Terna 2023a).

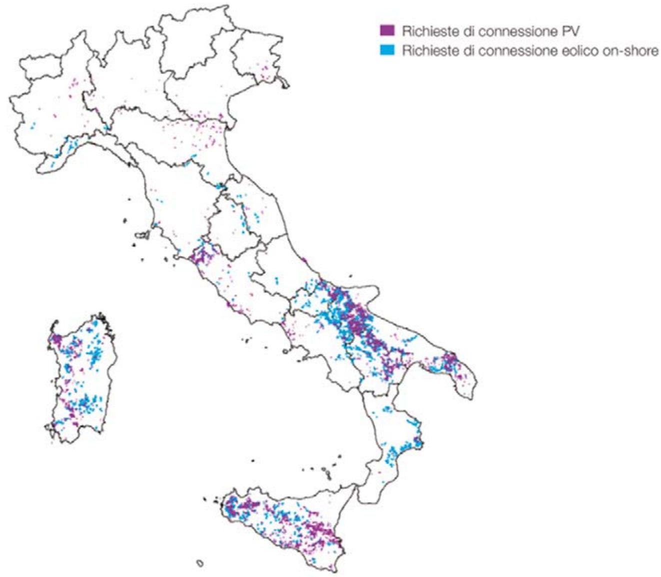

Figure 29 – Localisation of connection requests for photovoltaic and wind power plants in Italy. Source: Terna (2023).

With a view to a coordinated planning of the various resources to 2030, the high increase in RES and thus in intermittent electricity generation implies an increase in periods of overgeneration and, consequently, curtailment of renewable electricity. Here is where hydrogen comes into play, as electrolysers represent an opportunity to exploit system overgeneration to produce and store green H_2, and use it in turn in other sectors. Given that, according to Terna and Snam's DDS (Terna 2022), around 3.5 out of 5 GW of the planned electrolysis capacity will be installed in southern (including islands) and central Italy, the potential matching of overgeneration from renewables in the South with hydrogen production could give a decisive breakthrough to the creation of a national hydrogen market. However, the «additionality» rule imposed by the RFNBO Delegated Acts (DA) at the EU level means that electrolyser operation should coincide with hours when the RES production can neither be utilised nor exported. In its energy scenarios, Terna expects a renewable hydrogen production from electrolysis in Italy of around 10 TWh and 20 TWh for 2030 and 2040 respectively (Terna, 2024). Such numbers, especially the projection for 2030, are close to the amount of renewable H_2 consumption that we estimated in Chapter 3 when we considered the 2023 version of NECP, which expects around 9 TWh of green hydrogen to be used at a national level in 2030.

Further elements suggest the potential creation of renewable hydrogen production hubs in southern Italy in particular. Snam's ten-year plan 2022-2031 includes the construction of electrolysers in Apulia and Sicily collecting (renewable) electricity otherwise subject to curtailment (due to overgeneration) and transforming it into an energy vector that can be transported and stored (Snam 2023). A first phase of the project will involve the installation of a 90 MW electrolyser by 2026 near the pipeline dedicated to natural gas import from Azerbaijan (the Trans Adriatic Pipeline) so that the hydrogen produced can be blended into the natural gas network up to a maximum percentage of 2% (Snam 2023). The second phase of the initiative will instead facilitate the recovery of the increasing volumes of overgeneration envisaged by the above-mentioned scenarios, and it will require the installation of a further 800 MW of electrolyser capacity near the most congested grid nodes. According to Snam (2023) the electrolyser's commissioning date is scheduled for 2031 following the development of the Italian hydrogen backbone, so that the H_2 produced can then be injected into a dedicated grid and destined for hard-to-abate consumer sectors first.

It is important to emphasise that green hydrogen production will mostly be based on off-grid renewable electricity at least in the short term, as grid electricity feeding electrolysers would not be decarbonised enough to allow for the resulting hydrogen to be considered renewable under the EU rules. If we consider the carbon intensity (measured in gCO_2eq/MJ) of the electricity system in the different EU Member States (Figure 30), we can see that Italy is currently far from the carbon intensity targets for the power grid set at the EU level by the RFNBO DA. The first DA, in particular, outlines the main alternative options under which it can be demonstrated that grid electricity used in the electrolyser is renewable: either in a bidding zone with 90%+ renewables in the electricity mix, or in a «low-carbon» bidding zone with a carbon intensity lower than 18 gCO_2eq/MJ, or any other grid solution where however the additionality, spatial and temporal correlation criteria must be met.

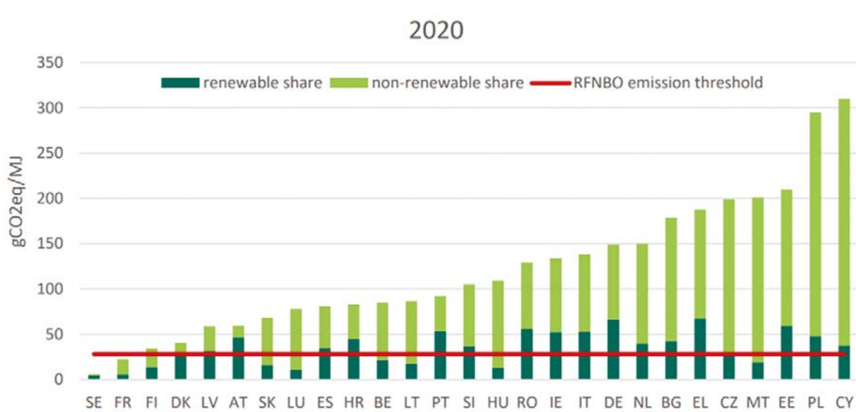

Figure 30 – hydrogen GHG emission intensity and renewable energy share from grid electricity in 2020 [gCO_2eq/MJ]. Source: Hydrogen Europe (2023).

Although the emission intensity of Italy's electricity grid is likely to remain above the RFNBO threshold also by 2030 (Hydrogen Europe 2023), this situation could change if we consider the regional development of renewable energy installed capacity. Given that Italy's electricity market is split into different bidding zones[9] - contrary to most EU countries whose entire national territory corresponds to one large bidding zone - the requirements for producing renewable hydrogen could materialise in the bidding zones (mainly in the South of the country) where large new renewable power plants will be built. This means that in those southern bidding zones - especially «Sud», «Calabria», «Sicilia» and «Sardegna» - we could see over 90% of the electricity mix covered by renewables, and prior to this, such bidding zones could become «low-carbon», thus needing to meet the spatial and temporal correlation criteria. This means that the electrolysers should be in the same bidding zones as the renewable power plants, thereby creating the need for hydrogen transport towards the North.

4.2 Demand and supply dynamics in Italy's hard to abate sectors

4.2.1 From grey hydrogen to green H_2

Hydrogen used in hard-to-abate (HTA) sectors is currently almost entirely represented by grey H_2, produced mainly through the steam-methane reformation (SMR) process (using natural gas), that results in high levels of CO_2 emissions into the atmosphere. Enabling the penetration of renewable hydrogen in HTA sectors is thus extremely important to achieve the decarbonisation targets and meet the specific objectives for RFNBOs enshrined in the Renewable Energy Directive. As we saw in Chapter 2 regarding industry, the RED III sets both minimum thresholds for green hydrogen usage by 2030 (42% of all H_2 used in industry must be renewable) and upper limits for fossil-based unabated hydrogen (up to 23% of all H_2 used in industry can be produced using fossil fuels). The bulk of the grey hydrogen used in HTA industries is directly produced by the same companies that use it for their production process, as a feedstock (e.g. in the chemical sector) or as a fuel for industrial heat (e.g. in the paper, steel or ceramics sectors). Such configuration is known as "captive production", taking place within the limits of the industrial plant's H_2 generation capacity. To have a specific order of magnitude, Table 37 reports the amounts of unabated hydrogen produced and used in the main energy-intensive industries in Italy.

Refineries are by far the largest hydrogen consumer, and they also use the SMR process for producing most of their H_2. According to Confindustria (2024), between 40 and 50% of that hydrogen is produced through SMR in plants lo-

[9] Italy's electricity market bidding zones as revised in 2021 are: Nord, Centro-Nord, Centro-Sud, Sud, Calabria, Sicilia, Sardegna (Terna 2022). The difference in the number of market zones compared to other EU countries stems from the geographical conformation of the Italian peninsula, which results in almost all interconnections with foreign countries on the northern border and the need to optimise energy flows with the islands.

cated within refineries, while between 30 and 35% comes from the catalytic reforming of gasoline, and the remainder is purchased from specialised operators, who produce hydrogen by SMR and transport it to the refinery. In the chemical sector, around two thirds of the hydrogen used is produced through SMR and it is destined to produce ammonia and derivatives (Confindustria 2024).

Table 37 – Grey hydrogen used in the hard to abate sectors [Mt/year]. Source: own elaboration based on Confindustria (2024).

Sector	Refining	Chemicals	Total
Total H_2 produced and used	0.361	0.153	0.514
Of which produced using SMR	0.240	0.108	0.348

If we compare the numbers of the above-mentioned sectors with the targets for renewable hydrogen included in the Italian NECP, discussed in Chapter 3, we can clearly conclude that those targets are not ambitious enough to achieve the 42% renewable hydrogen (RFNBO) target in industry by 2030 foreseen by the RED III. Indeed, Italy's NECP provides for 0,115 Mt of renewable H_2 to be used in industry (see section 3.2.4.), which however correspond to just around 22.4% of the total amount used in refining and chemicals today (0.514 Mt). A 42% renewable hydrogen target would instead require an almost double quantity (0.215 Mt) compared to what is currently indicated in the NECP for industry (0.115 Mt).

As we saw in Chapter 1, however, today's green hydrogen production cost is still not competitive with grey H_2 generation methods. Therefore, besides setting more ambitious quantitative targets, the levelized cost of hydrogen (LCOH), i.e. the price at which the hydrogen produced would have to be sold to offset the total production costs over the lifetime of the project, should be supported through incentive mechanisms. The structure and the amount of support should be determined taking into account two factors in particular: the electricity costs faced by national producers and the equivalent hours of operation of electrolysers, which are conditioned by the type of renewable electricity sources that can be used (e.g. Italy cannot currently count on the high load factors that are accessible to northern European countries that have a high generation from offshore wind) (Confindustria 2024). It could be thus interesting to assess whether such gap in the quantity of decarbonised hydrogen could be compensated, at least in the medium term, by blue hydrogen.

4.2.2 The blue hydrogen factor

The transition from production modes with a high environmental impact to sustainable ones in the hard-to-abate industrial sectors could see blue hydrogen as a bridging opportunity in the short to medium term. Nevertheless, investment in research and development is needed to build industrial-scale plants that will demonstrate its viability for widespread applications, as the production of blue hydrogen requires efficient carbon capture and storage (CCS) to drastically reduce emissions from the steam methane reforming process. CO_2 can be captured through three main types of processes: post-combustion, pre-combustion or combustion in oxygen. All methodologies have either an intermediate or high technology readiness level, and the average demonstrated carbon capture efficiency of the capture methodologies is about 90% (The European House - Ambrosetti 2022).

As we saw in Chapter 1, blue hydrogen can serve as a complementary technology to green hydrogen for various reasons. First, blue H_2 can facilitate the uptake of hydrogen in marginal demand sectors thus lowering the overall cost of hydrogen in the longer term and putting significant pressure on the CO_2 price, as demand for CO_2 would increase when a market is created. Second, using blue hydrogen to meet the short-to-medium term H_2 demand significantly reduces the necessary investments into renewable power generation capacity, leading to savings in the energy system (Durakovic et al. 2023). Third, low-carbon hydrogen can be exploited especially in areas not particularly favourable to the development of renewable sources - both because of geographic characteristics, as well as for scarce land availability (The European House - Ambrosetti 2023).

The new CCS project off the coast of Ravenna in the Adriatic Sea could become a potential enabler of blue hydrogen supply to the HTA sectors soon. This new CCS facility can prove critical to the decarbonisation of the unabated hydrogen that is currently used in energy-intensive industries in northern Italy that use it either as a feedstock (chemicals, refineries) or as a fuel for combustion. By removing the CO_2 produced when grey hydrogen is generated, H2 could thus become «low-carbon». The project, implemented jointly by the Italian TSO Snam and by Eni and officially named «Callisto» (CArbon LIquefaction transportation and STOrage) is one of the few CCS projects in southern Europe compared to the North Sea area (IOGP 2023), and it will be one of the largest CO_2 storage sites in the world and the largest in the Mediterranean[10]. The project envisages an initial phase, which started in 2024, aimed at capturing 25,000 tonnes of CO_2 from Eni's natural gas processing plant in Casalborsetti (Eni 2023). Once captured, the CO_2 will be piped to the «Porto Corsini Mare Ovest» platform and injected into the depleted gas field of the same name in the Ravenna offshore area. In the second phase, from 2026, 4 million tonnes of CO_2 are expected to be stored to contribute to the decarbonisation of the hard-to-abate industries in the Ravenna area and Northern Italy (Eni 2023). From 2030 onwards, the large capacity of the reservoirs would make it possible to increase the project's capacity to 16 or more million tonnes per year, depending on market demand.

While at the infrastructural level projects are being developed, we should assess the actual possibility to introduce low-carbon hydrogen in the H_2 mix in accordance with EU and therefore national legislation. The European Commis-

[10] Callisto was selected by the European Commission to be part of the new list of Projects of Common Interest (PCI), released in late 2023.

sion's Delegated Act on low-carbon hydrogen (see Chapter 2) defines the concept of low-carbon hydrogen and sets out the methodology for calculating the required 70% greenhouse gas emission savings compared to unabated fossil fuels, in line with the methodology established in the RFNBO Delegated Act of 2023. The 70% threshold applies to blue hydrogen produced from natural gas using CCS technology, low-carbon electrolytic hydrogen produced by electrolysis using electricity from the grid, and hydrogen produced from methane pyrolysis (European Parliament 2025). The delegated act aims to standardise the calculation of emissions savings by accounting for the full life-cycle emissions from producing low-carbon fuels, including indirect emissions, as well as upstream methane emissions and actual carbon capture rates (European Parliament 2025). Nonetheless, there exists a loophole in the Renewable Energy Directive III that allows to reduce the share of RFNBO (green hydrogen) foreseen by the industry-specific target, thus potentially enabling Member States to increase the share of other types of hydrogen in their total H_2 amount. Whereas the green H_2 target for the industry sector is set at 42%, Article 22b of the RED III states that «A Member State may reduce the contribution of renewable fuels of non-biological origin [...] by 20% in 2030», meaning that green hydrogen can be 22% instead of 42% in industry. Such possibility would perfectly fit the NECP's projections, that foresee a 22% share of green hydrogen in industry by 2030 (see previous section). This scenario can however be employed only under two conditions: first, the country has to be on track to meet its national contribution to the EU's overall target of 42.5% renewables in final energy consumption by 2030; second, the share of hydrogen made using fossil fuels has to be 23% or below in 2030 (Official Journal of the European Union 2023). Italy is not close to either objective, as its renewable share in final energy consumption was just around 19% in 2022 (Ministero dell'Ambiente e della Sicurezza Energetica 2023a) and it has currently no nuclear plants that can power electrolysers to produce hydrogen, which would not be renewable but neither would it be fossil. Despite being largely decarbonised thanks to CCS, blue hydrogen instead remains a fossil-based H_2 type, thus not being able to fulfil the requirements of the more flexible scenario foreseen by the RED III.

4.3 Decarbonising the ceramics industry using hydrogen

A recent study by Confindustria (2024) explores the feasibility of hydrogen use in different hard-to-abate and energy-intensive sectors of the Italian industrial landscape. One of the sectors analysed is the ceramics industry, which comprises six product sectors: ceramic tiles, bricks, sanitary ware, tableware, refractory materials, and technical ceramics. In Italy, these sectors consist of 260 companies and 300 plants, with an overall turnover of €7.5 billion, and count 27000 direct employees (Confindustria 2024). Ceramic manufacturers use natural gas as a fuel for creating heat (usually above 1000°C) needed in the production process. The most significant sub-sectors in terms of natural gas consumption and CO_2 emissions are the ceramic tile industry (85% gas, 15% electricity) and the brick industry (90% gas, 10% electricity) (Confindustria 2024), both sectors being subject to the CO_2 market regulated by the EU Emission Trading System.

Natural gas is used in different volumes along the production process, which for tiles involves five main steps. After the grinding of the raw material, the spray-drying[11] involves the first use of natural gas (5% of the overall volume used in the process). The third step consists of drying the resulting material, which consumes around 10% of the total natural gas required in tile production. After that and only for tiles, there is an additional step for decoration, which is followed (for all types of ceramics) by firing in an industrial oven, where the bulk of the natural gas is used (60%)[12]. Tile production also makes extensive use of high-efficiency cogeneration[13], i.e. the combined generation of heat and electricity, fuelled by natural gas (25% of the total amount used in the production process), whose heat is used for spray-drying.

Considering that the use of hydrogen involves a higher flame temperature and an increase in the amount of generated steam (Confindustria 2024), issues with the quality of the final product could emerge. This aspect, however, still requires further investigation with process modelling and experimental tests, including on the quality and conformity of the final product itself. Precisely for this reason, in an initial phase, blending (i.e. mixing) hydrogen with natural gas up to 20% by volume is preferable (Confindustria 2024), instead of just abruptly shifting from one fuel to the other. It is however likely that H_2 utilisation will be limited, at least initially, to the firing stage. The compatibility of hydrogen use with the drying and spray-drying steps must indeed be further investigated, since - for the same heat output - the combustion of H_2 generates greater volumes of water (Confindustria 2024).

According to the Confindustria study, there are three different scenarios for hydrogen use in the ceramics industry, based on the blending percentage. If we consider that the average annual natural gas consumption of one ceramics plant is around 11 million cubic metres (or around 0.118 TWh), we can estimate the hydrogen and electrolyser capacity required to supply the plant with green hydrogen. The first two scenarios consider a H_2 blending of 20% and 50% respectively. The third scenario instead assumes twice as much hydrogen as the second, meaning that the ceramics company either wants to decarbonise two firing lines both using a 50% blending, or it wants to decarbonise 100%, the latter option requiring an appropriate repurposing of the plant, provided the available technology allows it. As to the hydrogen demand and the corresponding electrolyser capacity needs, Confindustria's estimates are reported in Table 38.

[11] Spray-drying is a method of forming a dry powder from a liquid or slurry by rapidly drying with a hot gas.

[12] The furnace is of a roller type and involves the contact of the flame with the tiles.

[13] «High-efficiency cogeneration» means cogeneration production resulting in primary energy savings of at least 10% compared to the generation of electricity and heat separately using the same type and quantity of fuel (DGEG 2021).

Table 38 – Three scenarios for green hydrogen use in the ceramics production process. Source: own elaboration based on Confindustria (2024).

	Hydrogen blending [%]	Hydrogen demand [t/y]	Electrolyser capacity [MW]
Scenario 1	20	200	2
Scenario 2	50	500	5
Scenario 3	100 (50+50)	1000	10

Given the different scale of the hydrogen production plants, economies of scale cannot be exploited in all three cases. The study selects proton exchange membrane (PEM) electrolyser for producing hydrogen from renewable energy sources, as this technology allows for a reduction in land occupation and better responds to intermittent loads typical of renewable profiles. However, as we saw in the Chapter 1, PEM electrolysers entail higher investment costs (CAPEX) and operational costs (OPEX) per unit of hydrogen produced, thus being less competitive for H_2 generation compared to their alkaline (ALK) counterparts.

Electrolyser costs are only one of the factors that determine the cost of hydrogen production (LCOH), the other major component being the cost of renewable electricity used during electrolysis. The cost of renewable power, in turn, largely depends on how and where the electricity is generated. As we saw when we analysed the RFNBO Delegated Acts, two options for producing renewable hydrogen are possible: with an off-grid renewable plant directly connected to the electrolyser, or with a grid-connected electrolyser using a Power Purchase Agreement (PPA) and meeting the additionality, spatial and temporal correlation criteria to demonstrate that the electricity is renewable. Moreover, since the ceramics plant needs a constant supply of fuel during the production process, hydrogen storage is necessary to compensate the intermittency of renewable plants.

The main advantage of having a dedicated renewable power plant at the ceramics site is the savings on the energy component of the grid charges (Confindustria 2024), provided, however, that the cost of electricity (LCOE) is not higher than the energy market price. The study simulates the installation of solar PV panels (located either on the roof of the ceramics facility or on adjacent plots of land, if present) to power the electrolysis. However, having one single renewable (intermittent) power plant can be a problem in terms of load factor, i.e. the ratio between the average electricity generation and the maximum (peak) generation over a specific period. A high load factor indicates that the load (the electrolyser) uses electricity more efficiently, because the peaks (the denominator) are lower. But Confindustria (2024) estimates that with only one solar plant, the load factor is between 25 and 39%, meaning that the electrolyser would be largely under-utilised if compared to a potential load factor of 63%, corresponding to 5500 hours per year.

Therefore, it is important to guarantee a renewable electricity supply for a greater number of hours. Such condition can be achieved only if either more renewable power capacity is installed at the ceramics site, or if the electrolyser is connected to the electricity grid (using a PPA). In most cases, and also due to the strong impact of the CAPEX for installing new renewable power plants, the grid option is preferable. As we saw in section 4.1.2., most renewable energy generation potential is in southern Italy, but most ceramic manufacturing plants are located in the North of the country (mainly in the «Sassuolo» ceramics district). This example, like with other hard-to-abate industries, further shows that the installation of electrolysers in areas with greater renewable potential (in the South) could create a significant demand for centralised hydrogen production and the subsequent development of a transport network towards end-use sites.

4.3.1 The case of Iris Ceramica Group

A case in point is provided by Iris Ceramica Group, one of Italy's top-three ceramics manufacturers with an annual revenue of over €500 million. This company, whose main production facilities are distributed between the Provinces of Modena and Reggio Emilia[14], has become the first ceramics manufacturer in the world to develop hydrogen-based ceramic production. Iris Ceramica Group signed two different agreements in 2021 and in 2023 with the Italian gas TSO Snam and with Edison Next[15], respectively, in order to implement the use of green hydrogen - initially in a blend with natural gas - in the firing stage of the ceramics production process.

In September 2021, Snam and Iris signed a memorandum of understanding aimed at developing a project for producing ceramics surfaces using a blend of green hydrogen and natural gas. The H_2 is produced from solar energy, via a dedicated 2.5 MW photovoltaic plant, installed on the rooftop of one of Iris Ceramica's factories located in Castellarano, in the Province of Reggio Emilia (Snam 2021). The PV plant is coupled with an electrolyser and a storage system for on-site H_2 generation, while the company's long-term aim is to switch to a fully decarbonised production.

For this very reason, in July 2023, Iris Ceramica Group signed an agreement with Edison Next to develop what has been named the «H2 Factory™», a new project always located in the Castellarano production facility, that will develop green hydrogen generated thanks to a custom-made system installed on site (Edison Next 2023). The partnership between Iris Ceramica Group and Edison Next has marked the beginning of the second phase of the project that was launched through the 2021 agreement with Snam. The first step towards decarbonisation, which saw Iris Ceramica Group engaged over the last two years in the feasibility study and construction of the H2 Factory™ site, suitable for hosting the green hydrogen production plant, has been successfully completed (Edison Next 2023).

[14] Retrieved from Iris Ceramica Group official website.

[15] Edison Next belongs to the Edison group and it has been created in 2022 to assist businesses and territories in the energy transition and decarbonisation processes.

In order to enable the hydrogen blend, and even more for a 100% hydrogen system, several arrangements are required. Technical modifications do not only concern the plant engineering, such as the furnace engineered to be fuelled with a blend of hydrogen and natural gas, but involve also strategic site works, including the construction of rainwater collection tanks, the installation of the PV panel system on the roof of the ceramics facility, and ad hoc hydrogen production and storage areas. Iris Ceramica Group has set up the entire infrastructure for the distribution of hydrogen within the plant.

Edison Next will provide an electrolyser with a capacity of 1 MW, fuelled by renewable energy, as part of a €50 million investment by Iris Ceramica Group (Edison Next 2023). The renewable hydrogen production plant (splitting water into H_2 and oxygen) will use rainwater from the collection tanks, thus also promoting virtuous water management, and it will take the electricity from a new PV plant of around 1.2 MW in addition to the existing plant of 2.5 MW mentioned above. Hydrogen will be used in particular to fuel the furnace, which will be mixed with natural gas up to a percentage of about 50%, while a furnace that will run on 100% hydrogen is being studied (Edison Next 2023). The expected production of about 132 tonnes of green hydrogen per year will replace about 500,000 cubic metres of natural gas per year, starting from 2025 (Edison Next 2023).

Conclusions

By carrying out the above analysis with regard to the hard-to-abate sectors, we can conclude that hydrogen does not represent the development of a single technology, but it entails the development of a portion of the entire future energy system, which must combine industrial development, investments in manufacturing, and the parallel construction of a market framework able to ground such investments. Hydrogen requires a national plan consisting of progressive steps starting from the current situation. This mandates the adoption of a technologically neutral approach, based on the understanding that multiple sources can contribute to decarbonisation.

At the infrastructural level, while new investments are being implemented to repurpose the natural gas transmission network to carry hydrogen, with a focus on the transport from South to North, identifying the areas where electrolysers (producing green hydrogen) can have the highest possible load factor proves critical. This, in turn, means that the installation of renewable power plants must be accelerated, but to realise Italy's potential in terms of RES electricity, where possible, not only solar technology should be considered, but also wind or other types of renewables.

For the creation of an effective hydrogen supply chain and market, Italy should favour a commercial scale-up of electrolysers, also with centralised production solutions (in southern Italy) and the transport of high volumes of renewable hydrogen (to the north of Italy), to allow for cost reduction and economies of scale. An incentive mechanism that is not only limited to partial financing of the projects' CAPEX but which is also extended to OPEX can prove useful to make renewable hydrogen competitive with fuels currently used in hard-to-abate sectors, also in light of the temporal and geographic constraints foreseen by the EU rules on RFNBOs.

Given that hard-to-abate industries use hydrogen both as a fuel (ceramics) and as feedstock (e.g. chemicals) and that our analysis showed the gap that exists between the EU targets for sectoral green H_2 use and Italian policy targets, it could be interesting to explore the gradual replacement of the current grey hydrogen with blue H_2 in the short term. This scenario could potentially materialise also thanks to the CCS projects under development and thanks to those that will emerge in the years to come.

To kick-start the decarbonisation process in those sectors and industries that can afford - both in financial and spatial terms - to install renewable power plants inside their production areas, it can be appealing to implement initial projects aimed at introducing green hydrogen produced on-site in a blend with natural gas. While progressively increasing the H_2 contribution, technology and innovation will have to move accordingly to satisfy the needs of the industry for new components (such as ceramics furnaces) of a decarbonised production process.

Conclusion

In this thesis we have conducted a comprehensive analysis of hydrogen production, transmission, and end-uses, with a specific focus on H_2 integration into the European energy system and its potential role in enhancing Italy's contribution to the EU's energy transition goals, both externally (to enable the import of clean hydrogen from neighbouring countries) and domestically (to decarbonise hard-to-abate and energy-intensive sectors). In order to outline the relevant implications of this work, our key findings will be divided into the three main components of the hydrogen value chain: generation, transport and utilisation. Observations on the element of H_2 storage will be also included, as storage needs are linked to both H_2 production and end-use.

Hydrogen generation

As emerged from the examination of hydrogen production methods, the steam methane reformation (SMR) process is still the predominant mode of H_2 generation at a global, European and Italian level. This is not only due to the large availability of natural gas as a source for producing hydrogen via SMR, but it is given mainly by the existing challenges in reducing the cost of the technologies (i.e. electrolysers) for producing green hydrogen. The cost of electrolytic H_2 generation is greatly influenced by the electrolyser capital cost, as well as by the electrolyser's current low load factor (i.e. the average generation over peak

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Book References DOI 10.36253/979-12-215-1013-3.references

generation within a specific period). On the contrary, the SMR's high efficiency leads to larger hydrogen yield per unit of feedstock (methane) employed. This is also why there are currently less than 200 MW of electrolyser installed capacity in the EU, while the European hydrogen industry estimates that no less than 100 GW would be needed if the Union wants to achieve the REPowerEU target of 10 million tonnes (Mt) of domestic renewable H_2 production per year by 2030.

However, where the electrolysis is not powered by renewable energy, the hydrogen produced cannot be recognised as renewable under EU rules. Therefore, to achieve the above electrolyser capacity, approximately twice the capacity in terms of installed renewables is required at the EU level. Indeed, we have seen that 10 Mt of hydrogen have an energy value of around 330 terawatt hour (TWh), but if we consider that the capacity factors of renewable energy sources such as wind and solar PV are lower than 30% (which correspond to 2000-3000 hours in a year), this means that 330 TWh of hydrogen would require around 500 TWh of renewable power production. This in turn suggests that around 150-200 GW of new renewable installed capacity should be only dedicated to the production of green hydrogen in the EU.

For this reason, major financial efforts are needed to decarbonise the still largely fossil-based hydrogen generation, while the competitiveness of clean hydrogen production also depends on the cost of renewable electricity. As reported in Chapter 1, several economic analyses of mature alkaline electrolyser technologies in Europe have shown that one major driver of the higher cost for renewable hydrogen is the cost of the electricity. The use of power purchase agreements (PPAs) - contracts signed between a producer and a consumer of electricity that fix a certain price - can help insulate the counterparts from market price volatility. In instances where part or all renewable generation is sold to electrolyser operators through PPAs, hydrogen from renewable electricity could create a new downstream market for renewable power, facilitating the integration of high levels of variable renewable energy (e.g. solar, wind) into the energy system, because the electricity consumption of electrolysers can be adjusted to follow renewable generation.

Regarding electricity and hydrogen production, the recently revised EU regulatory framework encourages the signing of PPAs with renewable generators, but it imposes strict criteria for recognizing the production of H_2 as renewable (RFNBO). Such requirements range from additionality, i.e. the need to match the production of green hydrogen with electricity generated by new (additional) renewable installed capacity, to spatial and temporal correlation, ensuring that the additional renewables are located in the same area where H_2 is produced and that renewable electricity generation and hydrogen production coincide temporally. The EU Delegated Acts on renewable H_2 also define a 70% threshold for GHG emission savings during the RFNBO production process. Although Europe hosts more than one third of proposed hydrogen investments globally, the vast majority of H_2 projects is still at a planning stage. This is due partly to the uncertainty in the ability to comply with the EU's new criteria and to the lack of demand visibility. This is part of the so-called «chicken-or-egg» dilemma, whereby the demand from customers will not materialise until there are no appropriate infrastructures (including production facilities and renewable power plants) that ensure cheap hydrogen supply, but without that demand, investors will not finance hydrogen projects, which in turn means zero demand.

The EU has been attempting to solve such dilemma by channelling different EU revenue sources (e.g. the EU Emission Trading System, EU bonds, the Multiannual Financial Framework) through the European Hydrogen Bank, Next Generation EU, and the IPCEI (which imply direct State aid) to encourage European hydrogen production projects while linking the future estimated European H_2 demand with international hydrogen supplies. The key element that must be considered in such a process is the identification of potential hydrogen off-takers, who can drive demand in different sectors, since setting specific supply targets is not enough of an incentive. In addition, the recently adopted definition of «low-carbon hydrogen» by the EU could enable blue H_2 to serve as a bridge technology, facilitating the uptake of hydrogen in different demand sectors. Low-carbon can be exploited especially in areas not particularly favourable to the development of renewable sources - both because of geographic characteristics and scarce land availability. Blue hydrogen could carve out a role in the EU's H_2 demand, at least until green H_2 has become cost-competitive, and in the short-to-medium term especially because of the requirement for a largely decarbonised electricity grid, to which currently almost no Member State is able to comply.

Among the EU countries, we have seen that although the emission intensity of Italy's electricity system is expected to remain above the RFNBO threshold also by 2030, this situation could change if we consider the development of renewable energy installed capacity at a regional level. Given that Italy's electricity market is split into different bidding zones - contrary to most EU countries whose entire national territory corresponds to one large bidding zone - the requirements for producing renewable hydrogen could materialise in the bidding zones where large new renewable power plants will be built, which are mainly in Italy's southern regions. According to the analysis we carried out in Chapter 4, we could see in the future over 90% of the electricity mix covered by renewables in Italy's South and islands, a condition which can enable the production of renewable hydrogen by taking electricity directly from the grid. Even prior to this, such bidding zones could become «low-carbon», thus needing to meet the spatial and temporal correlation criteria set out in the RFNBO Delegated Acts, which means that the electrolysers must be located in the same bidding zones as the renewable power plants, thereby creating the need for hydrogen transport from the production areas in the South towards the main demand centres in the North, where most of Italy's (hard-to-abate) industries are located.

Hydrogen transmission

Hydrogen transport infrastructure is indeed essential to enable the hydrogen market to reach its maturity. Due to uncertainty about future hydrogen demand in each country, the architecture of the H_2 transport infrastructure is highly context-dependent. We have seen that pipelines (transporting compressed H_2) remain the cheapest option up to a distance of around 2000 km, thus being potentially suitable, for instance, to transport green H_2 from southern to northern Italy. We have also seen that hydrogen projects - despite being for the most part at the «less advanced» stage - represent the highest share of infrastructural projects included in the Ten-Year Network Development Plan (TYNDP) developed by ENTSO-G, thus showing the willingness of project promoters to commit to the creation of an EU hydrogen market. This is also why initiatives such as the European Hydrogen Backbone have been involving several natural gas transmission system operators (TSOs) in designing an almost 60 000 km-long interconnected hydrogen grid in Europe by 2040. This future H_2 network could consists of approximately 70% repurposed pipelines, as we have demonstrated that both the upfront investment cost and the levelised cost of hydrogen transmission (LCOT) are significantly lower for repurposed lines than for new ones. However, while pipelines are being reconverted to carry H_2, operators need to simultaneously ensure the security of natural gas supply. As we saw in Chapter 2 when considering the EU's gaseous fuels consumption, by 2040 no less than 160 billion cubic metres (bcm) of natural gas will still be used in the EU, of which around 35 bcm in Italy.

The creation of a hydrogen infrastructure network is currently on the political agenda of both EU institutions and the largest Member States. In early 2024 the EU adopted the new Hydrogen and Decarbonised Gas Markets Package, consisting of the revised Gas Directive and Gas Regulation. One major aim of these new legislative measures is to ensure a more integrated network planning between electricity, gas and the future hydrogen network, as emphasised by the EU Strategy for Energy System Integration, that was released in 2020 together with the EU Hydrogen Strategy. The simultaneous publication of both strategic documents by the European Commission was not a coincidence, as (green) hydrogen can play an important role in «sector coupling». Power-to-hydrogen (P2H) technologies, like electrolysers, can serve the double purpose of converting curtailed electricity into renewable (or low-carbon) hydrogen (depending on the type of electricity used) for storage or direct use, and even into natural gas (after methanisation). This is why we have stressed the need for improved cooperation between the electricity and gas TSOs in each country, with the development of joint scenarios that cover electricity, natural gas and hydrogen network planning, thus making it possible to identify potential synergies in the system and save on investments in the networks. Currently, in the Italian case, we have seen that Terna (the electricity TSOs) and Snam (the gas TSO) jointly develop the Scenario Description Document every 2 years, covering energy scenarios for gas and electricity, but when planning the development of both networks, they draw up separate documents that do not identify potential synergies between different energy sources and vectors.

Addressing the issues related to the creation of a European hydrogen network is crucial, but the EU and its Member States will not manage to achieve the renewable hydrogen production targets only by relying on the EU's renewable capacity. We have seen (in Chapter 3) that due to higher costs, limited space for installing renewable power plants and the slow pace of new hydrogen capacity projects in Europe, H_2 imports (also in form of its chemical derivatives) can appear more attractive. This was demonstrated as we looked at the H_2 production cost (LCOH) in Latin America and North Africa, where in both cases the LCOH is lower than 2 $\$/kg_{H2}$, whereas the cost in Europe - depending on the specific country or region - can be as high 10 $\$/kg_{H2}$ or more, but nowhere in the EU is the LCOH lower than 3-5 $\$/kg_{H2}$. Therefore, in the long term, both Latin America and North Africa could become established green hydrogen suppliers to the EU, but in order to meet the Union's short-to-medium term needs, the cheapest - and closest - option among those considered is the export of H_2 via pipeline from North Africa. This import route is indeed one of the three hydrogen supply corridors mentioned in the REPowerEU Communication, the other two being the North Sea route (with Norway and the UK as major suppliers) and the Eastern European (Ukrainian) route. The key feature that these three corridors have in common is the H_2 transport mode, namely pipelines. As with gas pipelines instead of LNG deliveries, hydrogen pipelines do not involve conversion, liquefaction, reconversion and regasification costs, that add up to the transport cost.

In Chapter 3 we evaluated six potential European hydrogen import corridors, which include the above three and which are all planned to end in Germany, whose economy is driving the EU's renewable hydrogen demand across different sectors. In this scenario, we explored the potentially strategic role that the EU's second largest manufacturer, Italy, could play in enabling the import and integration of renewable hydrogen into the EU's energy system. From an economic point of view, the North Africa-Italy H_2 supply corridor could give the EU access to the cheapest green hydrogen available in all corridors by 2040, together with the south-western corridor, which however suffers from a significant lack of energy (electricity and gas) interconnections between the Iberian Peninsula and the rest of Europe. Nonetheless, the limited renewable energy infrastructure and the low renewable penetration in the energy systems of the North African countries constitutes a significant obstacle. Although countries like Tunisia and Algeria have been taking part in some renewable and hydrogen development projects and they are already interconnected to Italy via a single pipeline (the TransMed), the flow of hydrogen towards Europe largely depends on the repurposing of pipelines connecting Algeria and Tunisia and on their respective financing. Moreover, the North African region is currently affected by severe political instability, that can significantly raise the cost of investment and hinder the establishment of energy partnerships.

Despite the above-mentioned obstacles, the Italian gas TSO Snam has already started to carry out the first feasibility studies for the so-called «Italian Hydrogen Backbone», a 2300 km-long corridor, with a view to its commissioning immediately after 2030. The project, that is part of a wider initiative aimed at creating a hydrogen corridor from North Africa to Germany, can serve a dual purpose: on the one hand, the H_2 backbone can enable future green H_2 flows to reach the demand centres in northern and central Europe; on the other hand, it can facilitate the decarbonisation of Italian hard-to-abate industries (mainly located in the North of the country) by transporting renewable hydrogen produced in southern Italy both because of the higher renewable potential in this part of the country and because of the above mentioned EU rules that impose strict criteria for defining hydrogen as renewable.

Hydrogen utilisation

This leads us to the analysis we developed on the current and potential hydrogen end-uses, for which we can conclude that hard-to-abate industrial sectors should be, and in some cases already are, the primary offtakers, both at the EU and Italian level. Some of the EU's newly approved pieces of legislation, such as the Hydrogen and Decarbonised Gas Markets Package and also the Net-Zero Industry Act, identify hard-to-decarbonise sectors as priority sectors for the uptake of clean H_2. In addition, as we showed in Chapter 4, hydrogen projects and feasibility studies for H_2 use in industrial processes, as well as statistical projections at the EU level show that industry will drive the increase in hydrogen demand at least up to 2050. Also, based on the «clean hydrogen ladder» presented in Chapter 1, we learned that H_2 use in steel and chemical industries, for instance, is almost unavoidable, if those sectors aim to be part of a net-zero future. Long-term electricity storage, long-haul aviation and shipping are also included in the upper part of the ladder, meaning that hydrogen use needs to be scaled up in those sectors as well. Some other uses, such as domestic heating, urban and short-range transport are in the bottom part of the ladder mainly because of the current lack of proper infrastructure (like distribution lines or hydrogen refuelling stations) and the presence of more efficient electricity solutions (e.g. heat pumps), thus entailing higher overall costs in adopting hydrogen - not to mention renewable H_2. Any type of policy initiative should therefore focus on stimulating the use of H_2 where it can represent the most efficient application.

Indeed, according to the latest (2024) version of the Italian National Energy and Climate Plan (NECP), around 0,25 Mt (or 9 TWh) of green hydrogen are expected to be used in the Italian industry and transport sectors by 2030. As our case study on hard-to-abate sectors showed, more than 0.5 Mt of unabated hydrogen are currently used in industry (mostly as a feedstock for chemicals and refineries). However, if we compare this number with the targets for renewable hydrogen included in the Italian NECP, we can clearly conclude that those targets are not ambitious enough to achieve the 42% renewable hydrogen (RFNBO) target in industry by 2030 foreseen by the EU's Renewable Energy Directive (RED III). Indeed, Italy's NECP provides for 0,115 Mt of renewable H_2 to be used in industry, which however correspond to just around 22.4% of the total amount used in refining and chemicals today (0.514 Mt). A 42% renewable hydrogen target would instead require an almost double quantity (0.215 Mt) compared to what is currently indicated in the NECP for industry (0.115 Mt).

On a broader perspective, Italy's newly adopted National Hydrogen Strategy claims that H_2 contribution to the national energy mix could rise from the current 1% to 2% by 2030, and up to 20% by 2050 (in the high-diffusion scenario), even though no specific form of hydrogen is mentioned. In Chapter 3 we clearly showed that only if we consider unabated (grey) H_2 in the future mix, we could see an increase up to over 2% of hydrogen in Italy's energy mix. The above-mentioned renewable hydrogen consumption expected by 2030 (8 TWh) indeed corresponds to barely 0.7% of Italy's final energy demand, whereas by adding the current grey H_2 consumption (19 TWh), we see that hydrogen contribution to the national energy mix increases to around 2.3%, in line with the Preliminary Guidelines' targets.

As to the financing component, the bulk of public support for the development of hydrogen projects in Italy has been delivered through the National Recovery and Resilience Plan (NRRP), with an initial amount of around €3.6 billion, which is just a small part compared to what is envisaged by the National Hydrogen Strategy. Based on the estimated need for 15–30 GW of electrolyser capacity, according to the Strategy cumulative investments are projected to range between €8 and €16 billion. Since there is no specific form of hydrogen mentioned, but given the importance accorded by the Italian Government to the principle of technological neutrality, we could add another €10 billion to account for other hydrogen production technologies, such as steam methane reforming (grey H_2) or CCS (blue H_2). Notwithstanding the increase in the amount of public support (€500 million) for Hydrogen Valleys (aimed at creating local clean hydrogen markets and whose projects are mostly located in southern Italy), the initial €2 billion foreseen by the NRRP for the uptake of renewable H_2 in hard-to-abate sectors have been reduced to €1 billion.

In general, the 2024 Italian National Hydrogen Strategy remains largely silent on the financial dimension of implementation. This lack of detailed financial planning makes it difficult to assess the feasibility of the proposed targets, to estimate the scale of private and public funding needed, and to monitor progress over time. Consequently, while the Strategy is valuable as a policy framework and roadmap, it falls short of providing a concrete, actionable financial plan that would allow stakeholders and policymakers to gauge the economic requirements for the effective deployment of hydrogen in Italy.

Therefore, to avoid stranded investments and an inefficient allocation of public resources to uncertain hydrogen projects, initial efforts in Italy should be on decarbonising the current unabated fossil-based hydrogen consumption, by setting precise financial and investment targets. This is especially true when trying to boost the production and use of renewable hydrogen. Since its production process involves the consumption of significant amounts of renewable electricity, there is an opportunity cost involved in using that electricity to produce hydrogen or using it to electrify or decarbonise other sectors (e.g. transportation). That is why the additionality rule imposed by the new RED Delegated Acts on RFNBOs is crucial to prevent the different EU and national decarbonisation initiatives from competing for the same renewable electricity. Nevertheless, unsubsidised renewable hydrogen typically remains uncompetitive with fossil H_2, thus requiring targeted public support.

The case study on the uptake of clean hydrogen in the Italian ceramics sector has shown that there can be an advantage in installing a dedicated renewable power plant at the ceramics site to feed an electrolyser, provided that the cost of electricity is not higher than the energy market price. However, since the ceramics industry would need a constat supply of hydrogen if it were to use H_2 instead of natural gas to provide the heat needed, having one single renewable (intermittent) power plant could be a problem in terms of load factor. We saw that with only one solar plant (located either on the ceramics facility roof or in an area nearby), the load factor is between 25 and 39%, meaning that the electrolyser would be largely under-utilised if compared to a potential load factor of 63%, corresponding to 5500 hours per year. Therefore, to guarantee a renewable electricity supply for a greater number of hours, either more renewable power capacity must be installed at the ceramics site, or the electrolyser must be connected to the electricity grid (using a PPA). In most cases, and mainly due to the strong impact of the CAPEX and also limited space for installing new renewable power plants, the grid option is preferable. While most renewable energy generation potential is in southern Italy, the bulk of ceramic manufacturing plants are located in the North of the country, in the provinces of Reggio Emilia and Modena. This example, like with other hard-to-abate industries, further shows that the installation of electrolysers in areas with greater renewable potential (in the South) could create a significant demand for centralised hydrogen production and the subsequent development of a transport network towards end-use sites.

The 2024 Italian hydrogen strategy acknowledges the ceramic industry among the hard-to-abate industrial sectors where hydrogen could play a role in long-term decarbonisation, mainly as a substitute for natural gas in high-temperature thermal processes. The document provides indicative estimates of hydrogen consumption in the ceramic sector under long-term scenarios, thereby implicitly recognising its technical relevance within the Italian industrial landscape. However, the Strategy remains largely high-level and generic in its treatment of the ceramic industry. In particular, it does not clearly differentiate between renewable (green) hydrogen and hydrogen produced from fossil sources, nor does it explicitly link the envisaged hydrogen uptake in the ceramic sector to specific decarbonisation pathways, technology readiness levels, or cost and infrastructure constraints.

This lack of distinction risks overestimating the decarbonisation potential of hydrogen deployment, as the climate benefits critically depend on the production pathway of the hydrogen used. Moreover, the Strategy does not clarify whether hydrogen use is expected to be transitional or structural in the long term. As a result, while the Strategy signals a potential role for hydrogen in the ceramic sector, it falls short of providing a robust, technology-specific and climate-consistent framework for its effective and sustainable deployment.

This notwithstanding, before being able to play a significant role in the European strategy for upscaling hydrogen, Italy should clearly define a more ambitious and long-term industrial investment vision. This could lead to useful actions and could create a competitive advantage for national industrial supply chains. Implementing the regulatory framework, which the EU has already put in place, and identifying specific financial incentives to stimulate investment in renewable and low-carbon hydrogen infrastructures is essential.

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This thesis analyses hydrogen production, transport, and end uses, assessing its integration into the European energy system and Italy's role in the EU energy transition. Hydrogen, with no CO_2 emissions at use, is key for decarbonisation and industrial policy, but its scale-up is hindered by a demand-supply dilemma. Adopting an economic perspective, the study examines the EU regulatory framework, infrastructure investment needs, and import corridors, highlighting Italy's strategic position along hydrogen supply routes from the southern and south-eastern Mediterranean. Despite adopting a national hydrogen strategy, Italy still needs clearer quantitative targets for renewable and low-carbon hydrogen to accelerate decarbonisation in hard-to-abate sectors and transition away from fossil fuels.

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