LA REVUE DE L'ÉNERGIE

Octobre 2021

Decarbonised hydrogen imports into the European Union: challenges and opportunities

WORLD ENERGY COUNCIL | EUROPE

Foreword

It is a great pleasure for me to present this report on decarbonised hydrogen and its imports to the European Union.

Importing hydrogen is a key issue that needs to be addressed as we work toward carbon neutrality in 2050. European members of the World Energy Council (WEC) believed it was important to forge a shared vision that is precise and fact-based, and takes into consideration the views of potential exporters.

Very little research - based on quantified data and factoring in the views of all potential actors – is currently available on this subject. This timely document sought to fill that gap by posing three simple questions and providing scientific answers based on consensus: Why import hydrogen? How would imports work in practice? What challenges might arise in terms of public policies?

This report, prepared as part of WEC-Europe's action plan for 2021 in cooperation with the Observatoire Méditerranéen de l'Energie (OME), is the product of a dialogue and exchange of ideas within WEC-Europe as well as with actors on the southern shore of the Mediterranean. Conducted over a six-month period, the report brought together many experts and skill sets within the WEC and OME which I am particularly grateful to for fully mobilising its network of expertise.

If this report has fulfilled its purpose, it is thanks to the diversity of its contributors, the rigour with which numerical data was used, and the quality of sources.

My warmest thanks to all who helped create a document that will make a valuable contribution to the debate about Europe's decarbonised energy future.

Alexandre Perra
Regional Vice Chair Europe, WEC

WORLD ENERGY COUNCIL | EUROPE

SOMMAIRE

LA REVUE DE L'ÉNERGIE

Octobre 2021

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

TABLE OF BOXES

DECARBONISED HYDROGEN IMPORTS INTO THE EUROPEAN UNION: CHALLENGES AND OPPORTUNITIES

Abstract

Concerns on the environmental impact of how we produce and consume energy have joined the two major traditional energy issues – energy security and affordability. Hydrogen has the potential to become the second main energy vector after electricity for the decarbonisation of energy consumption in end-use sectors. Its role in deep decarbonisation scenarios has been increasing in recent years, together with dedicated roadmaps and strategies that have been published in several countries. This paper explores possible scenarios for consumption and production of decarbonised hydrogen in the European Union (EU), in line with its net-zero greenhouse gas (GHG) emissions goals. It finds that the EU is likely to need to import about half of the estimated 60 million tonnes of decarbonised hydrogen and derivatives it will use by 2050, due to resource constraints and technological choices. Cost estimates for the production and transportation of decarbonised hydrogen are presented for several European and neighbouring countries, from wind, solar photovoltaic (PV) and nuclear power-based electrolysis, as well as steam methane reforming (SMR) with carbon capture utilisation and storage (CCUS) and pyrolysis technologies, out to the 2030 and 2050 time horizons. All these technologies can contribute to the future production of decarbonised hydrogen, provided that they respect stringent life-cycle CO_2 emissions limits. Cheaper production from SMR with CCUS and nuclear power can help the initial deployment of a decarbonised market in the medium term, and renewable sources will be essential in the long term both for domestic production and imported hydrogen. Nonetheless, limiting import options would reduce diversification, potentially increasing costs and negatively affecting security of hydrogen supply. Large investments are needed for production and transport infrastructure to import decarbonised hydrogen to the EU, estimated at around $900 billion (around EUR 760 billion) over the next three decades. A set of well-designed, clear and stable standards and regulations for both exporting and importing countries will be needed to ensure that life-cycle CO_2 emissions conditions are met and that the necessary investments are made in a timely fashion.

Keywords: *hydrogen, decarbonisation, European imports, energy transition, industrial development, energy security*

Note: This study was developed under the guidance of a Steering Committee of the European members of the World Energy Council (WEC – see acknowledgements section). The views and opinions expressed are solely the views of the author and do not represent a statement of the views of any other person or entity.

Key takeaways

1. Include hydrogen strategy in overall energy strategy and vision. Integrating and coordinating the hydrogen strategy with the electricity sector strategy – the future two main vectors for final energy uses – is going to be crucial for the full and efficient decarbonisation of the energy system, and to achieve the EU Green Deal's targets. Support measures need to be carefully designed to ensure that new renewable capacity related to hydrogen production is additional to that required to reach the electricity sector targets and to avoid cross subsidies between sectors.

2. Hydrogen production within the European Union (EU) is set to be insufficient to satisfy demand, with significant imports likely to be needed. Domestic hydrogen supply in some EU countries will be limited by technological choices and as cost-effective renewable potentials get exhausted. A potential total demand for hydrogen and derivatives could reach 60 million tonnes (Mt) by 2050, well beyond the current industrial use. We estimate that domestic decarbonised hydrogen production would be able to meet only 20% of the projected hydrogen demand in 2030 and less than 50% in 2050. Establishing strategic links with key potential exporting partners will therefore be critical for the EU.

3. Renewable sources will be crucial to the decarbonised production of hydrogen, but limiting the long-term choice of low-carbon technologies could prevent reaching the decarbonisation target or, at the least, would increase costs. Decarbonised hydrogen production from steam methane reforming (SMR) with carbon capture utilisation and storage (CCUS) and nuclear power can provide a significant contribution in the medium term in some countries. In the long run, offshore wind is set to become one of the cheapest sources of domestic production in the EU, together with production from solar photovoltaic (PV) in the best locations. Nuclear-based electrolysis could provide 11% of domestic decarbonised hydrogen production in 2050 simply by increasing the utilisation rate of the nuclear fleet. Pyrolysis and SMR with CCUS can play an important part also in long-term imports of decarbonised hydrogen, provided that they can respect stringent life-cycle CO_2 emissions limits. Restricting these import options limits the possibility of diversification, and could potentially increase costs and have a significant impact on security of supply.

4. The economics and financing of infrastructure will play a key role for hydrogen imports and the deployment of a cost-effective hydrogen market. The timely development of pipelines, storage and facilities for seaborne trade will be essential to bring hydrogen from cheap production areas to consumption centers. North African countries hold excellent renewable resources, and several neighbouring countries of the EU with large gas reserves (such as Russia, Norway, Algeria) can produce decarbonised hydrogen through SMR with CCUS at significantly low prices. The relative cost of pipeline transport and shipping will be decisive in allowing neighbouring countries to compete with other sources such as from Gulf Countries or more distant ones such as Chile and Australia. Repurposed and new pipelines are cost-effective choices for hydrogen imports for distances of up to few thousand kilometres.

5. Some \$900 billion (around EUR 760 billion) will be needed for hydrogen production and import infrastructure projects outside the EU over 2021-2050. To export about 30 Mt of hydrogen to Europe by 2050, EU neighbouring countries will need to invest about \$500 billion in hydrogen production plants (electrolysers, SMR with CCUS and pyrolysis plants), related wind and solar PV plants and gas supply spending. An additional \$250-500 billion will be needed for pipelines, port terminals and ships over the next three decades. Access to capital and coordination of infrastructure will be key elements for these investments to materialise.

6. The implementation of a clear regulatory framework is of fundamental importance to ensure that investment will be forthcoming in a timely manner. The most important and urgent measures to be adopted include: well-designed certification of the decarbonised nature of hydrogen; technology neutrality while respecting strict emission targets; international hydrogen and derivatives quality, technical and safety standards; accurate legal definitions; and a robust regulatory framework to enable and coordinate the deployment of EU hydrogen infrastructure. A key aspect to be addressed is the regulation of the electricity that will feed the electrolysers through wind and solar PV sources and their eventual on-grid connections.

7. National and European policies need to provide clarity and visibility to investors, both within and outside the EU, including potential exporting countries. An important step to go beyond the current bilateral and national approaches could be the creation of a high-level roundtable between European and exporting countries' main actors. The development of a joint roadmap with concrete milestones could facilitate the realisation of a decarbonised hydrogen economy while also ensuring security of supply. An important mutual benefit can arise from maintaining and expanding the European industry while creating the conditions for the long-term development of domestic industry in the exporting countries.

Introduction

Two main topics have traditionally been at the centre of energy policies: energy security and energy affordability for consumers. These two core concerns have led countries to develop resources and technologies depending on their domestic endowments and capabilities, resulting in very different energy mixes and levels of consumption across the globe.

Over the recent decades, environmental considerations on how we produce and consume energy have gained growing importance. The Paris Agreement signed in 2015 was a fundamental milestone in this process. Energy policies to steer towards a more sustainable path are being implemented or are under consideration in most countries, with varying levels of ambition. The European Union was the first to set a goal of net-zero greenhouse-gas (GHG) emissions by 2050 (EC, 2019a).

Energy accounts for the majority of current human-related GHG emissions. Reaching the net-zero goals will require unprecedented actions, but the energy sector changes slowly due to the size of the investments required and to its long-lasting infrastructure. Achieving the decarbonisation goals within such a "short" timeframe is therefore going to be challenging for many sectors and uses.

Newer technologies (such as wind power and solar PV) are now being deployed on a large scale, alongside more well-established renewable technologies (such as hydropower) and other low-carbon[1] technologies (such as nuclear power), as part of the effort to reduce the carbon footprint of electricity production. Other technologies such as fossil-fuelled plants fitted with CCUS, bioenergy, solar thermal, geothermal, tide and wave energy and nuclear small modular reactors are expected to contribute further in the coming years.

1. In this report, the term "low-carbon" is adopted as no technology can be considered to be fully zero-carbon when calculated on a life-cycle basis. There are different levels of emissions among low-carbon technologies, and the overall definition is provided in the next pages.

The deployment of these technologies – in different mixes in different countries – is often thought to be sufficient to decarbonise the power generation sector, fully or to a very high degree. In the EU, the use of electricity in end-use sectors increases from about 20% today to between 40% and 50% by 2050 depending on the scenario considered (EC, 2018). While this will contribute greatly to decarbonisation, it is far from being sufficient on its own. The additional direct use of renewable energy sources and CCUS technologies (particularly in industry) will complement the vast effort in large-scale deployment of energy efficiency measures. Some sectors remain more difficult to decarbonise than others, often due to the limited alternatives, to end-of-life or process emissions, to the high costs involved, or to public acceptance issues.

The current ambitious decarbonisation goals (such as the EU's net-zero target for 2050) have provided hydrogen with new momentum as a possible low-carbon energy vector, through direct use or derivatives. Several countries around the globe have published roadmaps, guidelines or strategies for future consumption and production of hydrogen, with provisions for several billion dollars of spending. The interest in hydrogen is not new: it saw several waves of attention over the past four decades (Rifkin, 2001) that did not materialise as hoped for. Turning the current ambitions into concrete actions and investment will be crucial for success.

Hydrogen is an energy carrier that encompasses most energy consumption sectors, with applications ranging from industrial uses to mobility, from power generation to use in the buildings sector. It has a stronger role to play in hard-to-abate sectors (such as heavy industry), where alternative choices are limited, in some cases through its derivatives. Its share in deep decarbonisation scenarios has been increasing in recent years. In the net-zero scenarios presented by the European Commission, the share of hydrogen and derivatives in total final consumption reaches around 20% in 2050, compared to less than 3% today. This share is similar to that of electricity today, and the amount corresponds to about 40% of current methane consumption in the EU. This strong evolution must not be taken for granted. Several challenges need to be resolved to accelerate the development of the entire hydrogen value chain. There are significant uncertainties for demand and domestic production within the EU, with clear implications for imports and energy security. Several technological challenges need to be addressed, most equipment having yet to be proven to scale. Costs today remain high, and the industry must prove its ability to reduce costs through economies of scale and technological development. Water availability might create additional strains in certain countries. Many regulatory aspects still need to be addressed, and there are uncertainties related to the deployment of infrastructure.

The EU has set very ambitious goals, and its member states are committed to ramping up the consumption of decarbonised hydrogen. Domestic hydrogen production is likely to fall short for many European countries, mainly due to limitations of indigenous renewables resources but also to the availability of good resources in possible exporting regions.

Cooperation with the EU's neighbouring regions – such as Russia and Southern and Eastern Mediterranean countries – will be essential to the successful penetration of high shares of hydrogen in the energy mix. Determining a common set of carbon reduction goals and developing a shared vision on how to achieve them will be crucial.

This study will examine potential demand and production volumes in different countries and the costs of different production and transportation technologies, with the aim of offering a fact-based analysis for moving toward the implementation of a well-integrated and effective hydrogen future.

1. Setting the scene

1.1. Hydrogen production and consumption in Europe

1.1.1. Hydrogen today

Today, the EU consumes about 10 million tonnes (Mt) of hydrogen (EC, 2020c) (equivalent to about 340 TWh[2]), which represents around 11% of global demand for hydrogen[3]. It is consumed either in pure form (mainly for ammonia production and in refineries) or mixed (mainly for methanol and steel production) (IEA, 2019).

Most of this hydrogen is produced locally, through steam methane reforming (SMR), with around 5% being produced as a by-product of industrial processes and only a minor fraction through water electrolysis. The largest hydrogen consumers in the EU today are Germany, the Netherlands, Poland, Belgium, France, Spain and Italy. These six countries account for around 60% of total hydrogen use in the EU (see Figure 1).

Steam methane reforming is a CO_2-intensive process, with CO_2 emissions of around 10 tonnes of CO_2 per tonne of hydrogen produced. The CO_2 emissions involved in this process in the EU today can therefore be estimated at around 100 Mt, or about 14% of total CO_2 emissions due to methane consumption in the EU.

Hydrogen produced with the SMR process is often referred to as "grey" hydrogen. Several colour coding conventions have been introduced to identify the origin of hydrogen production (see Box 1). In this study, a broader approach is taken, concentrating on the distinction between carbon-intensive emitting processes and decarbonised production of hydrogen. Decarbonised hydrogen is defined by the European Union as having a life-cycle

2. All data presented in this study use lower heating value (LHV) with 33.36 kWh/kg of hydrogen.

3. Total global hydrogen demand is estimated at 90 Mt (IEA, 2021c).

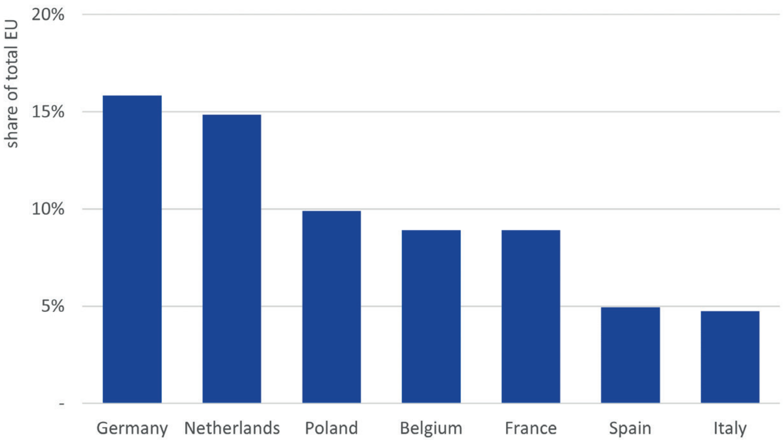


Figure 1. Share of largest consumers in total European Union hydrogen demand, 2019

Sources: EC, 2020c; IEA, 2021a; EWI, 2021

Box 1. The colours of hydrogen

The production of hydrogen is often categorised according to the colours listed hereafter. Nonetheless, the same colour is sometimes used for two different sources, and there is no universally accepted colour coding. To avoid possible confusion, and to keep a technology-neutral approach across all low-carbon technologies, in this study we will distinguish between emitting and decarbonised hydrogen-producing technologies.

The most common colours used to define hydrogen production are:

	White	found in nature, in underground deposits, or produced as a by-product of industrial processes.
Emitting	**Black**	from hard coal gasification, without CCUS.
	Brown	from lignite gasification, without CCUS.
	Grey	from steam methane reforming, without CCUS[1].
Decarbonised	**Blue**	from fossil fuels with CCUS with very high capture rates.
	Turquoise	from methane using pyrolysis[2].
	Yellow / **Pink** / **Violet**	from electrolysis using nuclear power[3].
	Green	from electrolysis using renewable energy sources, from biogas reforming or biomass gasification.

1. Sometimes used also for hydrogen production from electrolysis using non-fully decarbonised on-grid power.
2. Production of hydrogen through the thermal decomposition of methane.
3. Sometimes yellow has been used for electrolysis from technologies using solar energy.

GHG emissions intensity of less than 25 gCO_2/MJ, or 3 tCO_2/tH_2 (EC, 2021).

Hydrogen can be used directly or transformed into derivatives for use in specific sectors or processes. It can also be transformed into other products for ease of transport, such as in the case of liquid organic hydrogen carriers (LOHC). In this case, efficiency and costs of conversion and reconversion must be taken into account in any economic consideration. Some derivatives (for instance ammonia) can either be used directly in final sectors (e.g. for fertiliser production) or reconverted to pure hydrogen.

Among derivatives, two have a very important role in the long-term scenarios of the EU, and will be included in the analysis of this study: e-methane and e-liquids. They are obtained by combining decarbonised hydrogen with CO_2 emissions obtained either through Direct Air Capture (DAC) or through biomass-fired power plants fitted with CCUS.

Hydrogen has several characteristics. Among the most relevant ones: it has a high energy per unit of mass (120.1 MJ/kg), about 3 times higher than gasoline; it has a low volumetric energy density, at around one-third that of methane; it has a very low boiling point, at -253°C, about 90°C lower than methane (IEA, 2019). Direct consequences of these characteristics are that capacity in terms of energy transported in pipelines is about half as high as for methane, and transport through shipping is likely to be costlier than for LNG. Another element to take into account for both repurposing and building new metallic pipelines is the possible loss of ductility (embrittlement), which might require an "inner coating" to protect the internal part of the pipeline (ENTSO-G, GIE, HE, 2021).

There are several decarbonised hydrogen-producing technologies, with very different levels of maturity and deployment, using different processes and energy sources (Bruegel, 2021). In this study, we will focus mainly on two gas-based technologies (SMR with CCUS and pyrolysis) and three electricity-based electrolysers (alkaline, proton exchange membrane (PEM), and solid oxide electrolysis cells (SOEC))[4].

SMR with CCUS, applying an assumed 90% capture rate, involves emissions of 1 tonne of CO_2 per tonne of hydrogen produced and requires sizeable carbon storage facilities. There are several pyrolysis technologies at different stages of maturity. The advantages of pyrolysis include the absence of direct CO_2 emissions due to the process (only pure carbon or graphite are produced), much lower electricity consumption than for electrolysis, and no water consumption. Carbon and graphite, produced in solid form, currently have a sizeable market that could be extended to other sectors, or it can be disposed of. If biomethane is used as a feedstock, pyrolysis technology can generate negative emissions. Overall lifecycle GHG emissions for both SMR with CCUS and pyrolysis are estimated to be comparable (Timmerberg et al., 2020), with the biggest contributions coming from potential fugitive emissions along the methane value chain and the possible CO_2 emissions associated with heat demand for pyrolysis.

Among electrolysers, the alkaline type is the most mature technology, accounting for the lion's share of electrolyser capacity installed today. PEM technology accounts for the majority of the rest, while SOEC are still at a precommercial stage. Alkaline electrolysers have the lowest costs and have reached bigger sizes, while PEM are smaller with higher costs, and SOEC have the highest costs, although largely based on estimates (see section 1.2.1). Alkaline electrolysers typically have a minimum load of 10%-20% and are less flexible than PEM or SOEC. PEM usually have a shorter lifetime, mainly due to the membrane lifetime, the substitution of which can significantly increase O&M costs. SOEC have a higher electrical efficiency but require an additional heat source,

4. Other electrolyser technologies (such as the Anion Exchange Membrane (AEM) – see Furfari and Clerici, 2021) are showing promising developments but are not the focus of this analysis.

making them suitable to work well for the production of e-liquids and e-gas.

1.1.2. Hydrogen tomorrow

Most scenarios with climate objectives above 2°C do not require significant hydrogen volumes (IPCC, 2018). A substantial increase in hydrogen demand in final uses can therefore be closely linked to its decarbonised production. The current renewed interest in many countries for the consumption and production of decarbonised hydrogen confirms this pattern, as it is strongly linked to the high level of decarbonisation ambition of the energy system in the long term.

In the EU, the net-zero emission target by 2050 is the leading goal that provides the sense of direction and scale of ambition. In July 2020, the European Commission published its hydrogen strategy (EC, 2020a). Many European countries have since published national roadmaps or guidelines with national targets and the intended investments to reach these goals (see Table 1). While keeping the 2050 ambition and sometimes giving broad targets by this date, most roadmaps concentrate on more concrete action and goals to be realised in a shorter timeframe, often by 2030. This study will therefore concentrate on these two dates: 2030 and 2050.

The hydrogen strategy released by the European Commission sets out a goal of 40 GW of renewable hydrogen electrolysers by 2030, with an intermediate goal of at least 6 GW by 2024, and mentions a possible deployment of 500 GW by 2050[5]. The level of implementation is at different stages across countries, with several projects under construction, many having

5. The European strategy also outlines the ambitions of the European industry to develop an additional 40 GW of electrolyser capacity in Europe's neighbouring countries for export to the EU.

	Roadmaps/strategies	Electrolyser capacity target in 2030 [GW]	Date of release
France	(FR Gov, 2020b)	6,5	Sep 2020
Germany	(BMWi, 2020a)	5	Jun 2020
Italy	(MISE, 2020)	5	Nov 2020
Spain	(MITECOb, 2020)	4	Jul 2020
Netherlands	(NL Gov, 2020)	3-4	Apr 2020
Sweden	-	3[1]	To be released
Portugal	(PT Gov, 2020)	2-2.5	Aug 2020
Belgium	-	2,2[2]	To be released
Poland	(PL MKiS, 2021)	2	Draft
European Union	(EC, 2020a)	**40**	July 2020

1. The roadmap is under preparation. The estimate comes from the Fossil Free Sweden Initiative.
2. The estimate is cited in the FCH JU, 2019 study. The roadmap has not yet been released.

Table 1. Roadmaps, strategies and targets by 2030 in selected countries in the European Union

reached final investment decisions and many more in the feasibility stage.

Several other countries have published hydrogen roadmaps or strategies over the last 2-3 years, including several neighbouring countries to the EU (see Box 2), as well as many others, including the United States (2020), Canada (2020), Chile, Brazil (2017), China (2019), India (2018), Japan (2019), South Korea (2018) and Australia (2019) (IPHE, 2021 and WEC Germany, 2021).

The hydrogen market today is mostly based on CO_2-emitting technologies. In the near term, the initial development of domestic decarbonised hydrogen production is intended to meet all new additional hydrogen demand and to start replacing current production from carbon-intensive SMR.

Box 2. Status of hydrogen roadmaps in neighbouring countries: North Africa, Russia, Norway, United Kingdom and Ukraine

Russia presented its energy strategy for the period through 2035 in June 2020 (RU Gov, 2020a). A major goal of the strategy is to become a world leader in the production and export of decarbonised hydrogen, with export targets of 0.2 Mt by 2024 and 2 Mt by 2035. In October 2020, the Russian government released an Actions Plan (roadmap) to 2024 (RU Gov, 2020b), while a further Hydrogen Development Concept is expected to be released in 2021 with goals for the short, medium and long terms. Several companies in Russia have expressed an interest in producing and exporting decarbonised hydrogen, among them Gazprom, Rosatom and Novatek. Their primary interest is in pyrolysis, nuclear and renewable power electrolysis and in hydrogen/ammonia production based on methane reforming with CCUS, respectively. Furthermore, in the longer term, Rosatom intends to produce hydrogen using high-temperature gas-cooled reactors (HTGR).

North Africa[1]

Morocco is currently the most active country in North Africa with respect to international partnerships for renewables-based hydrogen exports. A national hydrogen strategy is currently in preparation.

Egypt signed agreements with Siemens Energy and with a Belgium consortium in 2021 for the development of production, trading and export of decarbonised hydrogen.

Algeria, a country with significant methane resources, has expressed an interest in developing hydrogen for export.

Ukraine intends to export renewable hydrogen to the European Union. Partnerships are being considered with Germany and other countries, and in 2018, the Ukrainian Hydrogen Council was established.

Norway presented its national hydrogen strategy in June 2020 (NO Gov, 2020). The government allocated NOK 120 million (about $12.4 million) to the Research Council of Norway for innovation projects, with a strong focus on hydrogen-related projects.

United Kingdom. The Government presented the national hydrogen strategy in August 2021 (BEIS, 2021) introducing a target of 5 GW of low-carbon hydrogen production capacity by 2030. Hydrogen production from renewable sources, nuclear and SMR with CCUS are being considered.

Sources: WEC Germany, 2021; IPHE, 2021.

1. North Africa in this report includes Morocco, Mauritania, Algeria, Tunisia, Libya and Egypt.

Box 3. Integrating power and hydrogen generation: the case of spare nuclear generation

Hydrogen production and use can bring important benefits to the energy system, but its long-term strategy and planning need to be well integrated with other energy sectors, and with the power system in particular. One clear example is provided by wind and solar PV generation used to produce hydrogen. Another interesting one can be represented by the use of the spare capacity factor of the European nuclear fleet.

In 2019, nuclear installed capacity in Europe amounted to 112 GW, with corresponding electricity generation of 760 TWh, for an average capacity factor of 78%[1]. In Europe, several countries had a capacity factor of 90% or more (e.g. Germany, Sweden, Finland, Spain), while others had a much lower utilisation rate. The most notable exception is France, where the high share of nuclear in the mix and the flexible operation of its fleet allowed for a 70% capacity factor. The relatively low capacity factor in France is due to its low generating cost, which led to a high share of nuclear power in the mix and the operation of plants also for mid-load.

By 2030, nuclear installed capacity in the EU is set to shrink to about 88 GW, as some countries opt out of nuclear power and additional plants are retired. The International Energy Agency (IEA, 2020) estimates a decrease of the utilisation rate of the European nuclear fleet by 2030 to 72%, mainly due to the flexible operation of nuclear reactors following the increase of wind and solar PV shares in total electricity generation.

Increasing the generation of the European nuclear fleet from 72% to 90% by 2030 could provide an additional 140 TWh of electricity. This additional generation would be sufficient to power more than 25 GW of electrolysers (out of the 40 GW targeted in the European hydrogen strategy) with a utilisation rate of about 65% by 2030[2], resulting in the production of about 3 Mt of decarbonised hydrogen per year at less than $\$2/kgH_2$[3].

Some 70% of the potential additional generation can be produced by France. However, part of this potential is unlikely to be available in the medium term due to the refurbishment and lifetime extensions of several French reactors. Limiting the potential to half, the resulting incremental electricity generation could be used to operate all the country's targeted 6.5 GW of electrolyser capacity by 2030 (see section 3.2). The resulting domestic generation of hydrogen in France amounts to 1 MtH_2, and the potential incremental nuclear generation in other European countries could power an additional 7.5 GW, resulting in decarbonised hydrogen production of 0.8 MtH_2.

The potential to produce hydrogen from incremental nuclear power generation in the EU by 2050 depends on several factors, including the level of integration and the flexibility of the power and hydrogen systems, the amount of capacity present in the system, and the capacity factor of the nuclear fleet. Based on the data in the EU's 1.5TECH scenario, the additional nuclear electricity generation could power almost 30 GW of electrolyser capacity, generating 3.3 Mt of decarbonised hydrogen.

Note: The opportunity cost considered for the additional generation in nuclear plants is lower than for the levelised cost of electricity (LCOE), as most of the incremental generation would occur during off-peak hours (see Table 3 and section 3.2).

1. This is much lower than the typical high capacity factor of nuclear in many countries. In the United States, which account for about one-quarter of global nuclear capacity, the average utilisation factor across the entire fleet is 93%.
2. Lower than the 90% capacity for electricity production from nuclear plants due to the seasonality of electricity demand.
3. All costs, prices and investments presented in this study are expressed in real terms in year-2020 US dollars.

Developing a liquid market in the long term requires simultaneously developing decarbonised hydrogen production and demand to reach critical volumes. Several options are being considered. One is the creation of so-called "hydrogen valleys", with the development of localised demand (mainly from energy-intensive industries), production and local infrastructure. This option is included in many national roadmaps.

Another way to increase demand for decarbonised hydrogen is to set a minimum level of blending in gas transmission and distribution networks. This option is considered in some roadmaps, but can present difficulties due to the technical tolerance of some equipment to different levels of blending. Additionally, different shares of blending in European countries can create additional problems, due to the high level of interconnection. Moreover, given the lower volumetric energy density of hydrogen relative to methane, a lower amount of energy would be transported and delivered to end-users. An EU-wide blending mandate set at a low share could generate additional demand out to 2030, stimulating decarbonised production. A mandate of 5% (in volume terms) in the overall European gas grid could result in additional demand for decarbonised hydrogen

[Mt H_2]	2019	2030		2050		
	Demand	Demand	Production	Demand	Production	Imports [%]
Austria	0.1	0.2	0.1	0.6 – 1.5	0.2 – 0.4	63% – 71%
Belgium	0.9	1.1	0.1	2.8 – 3.3	1.8 – 2	35% – 39%
France	0.9	1.0	1.0	1.1 – 4.5	1.8 – 4	-60% – 12%
Germany	1.6	3.3	0.4	11 – 21	3.2 – 5.5	72% – 74%
Italy	0.5	0.7	0.2	6 – 8	2.2 – 2.6	64% – 67%
Netherlands	1.5	1.7	0.2	3.9 – 4.7	2.6 – 3	33% – 36%
Poland	1.0	1.1	0.1	3.6 – 4	1.5 – 1.8	58% – 56%
Spain	0.5	0.6	0.2	2.6 – 3.5	2.9 – 3.9	-12% – -11%
Other EU	3.1	3.5	0.4	8 – 9.5	5.1 – 6.3	36% – 33%
Total EU	10.1	13.2	2.6	40 – 60	21.3 – 29.6	47% – 51%

Table 2. Hydrogen demand and supply in the European Union in high hydrogen demand scenarios[1], 2019-2030-2050

Source: Analysis by the authors

Notes: Hydrogen demand in 2019 and 2030 is met both by carbon-emitting production and by decarbonised hydrogen. Hydrogen production in 2030 includes only generation from electrolysers operated with decarbonised sources, while all hydrogen produced in 2050 is decarbonised. The figures presented in this table do not include possible EU-wide blending mandates. Negative import figures represent exports. For ranges of demand, production and imports, see also section 3 for individual country profiles.

1. The figures presented for 2050 are a result of analysis by the authors. Total demand in 2050 in the EU is compatible with the scenarios of the European Commission (EC, 2018).

of around 1.5 Mt in the short to medium term. This amount is much lower than the current hydrogen industrial demand that is satisfied by CO_2-emitting production. In the longer term, meeting the full decarbonisation goals to 2050 would require blending with e-methane and biomethane, and hydrogen would therefore be more likely to be transported in pure form in dedicated pipelines (see section 1.2.2).

Hydrogen production from the targeted 40 GW of electrolysers can be estimated at around 2.6 Mt in 2030. This is substantially lower than the "up to 10 Mt" envisaged in EC, 2020a, as it is calculated on a country-by-country basis using dedicated wind and solar PV power plants, and using additional generation from existing nuclear plants (see Box 3). This results in an average utilisation rate of electrolysers across the EU of 3 350 hours per year. A higher utilisation rate could be achieved by connecting the electrolysers to the grid (though this would increase costs and raise questions about the carbon neutrality of the hydrogen production), or downsizing the capacity of the electrolysers in comparison to that of the wind or solar PV plants (see section 1.2.1 and analysis around Figure 4). SMR with CCUS can be instrumental to create a supply market in the short and medium terms. In the absence of a significant retrofit with CCUS equipment of existing SMR facilities, a substantial share of hydrogen demand (about 80%) would need to either be imported or still used in its carbon-intensive form in 2030 (see Table 2).

The ability to import large volumes will hinge primarily on the regulatory framework and on the availability of importing infrastructure, while the attractiveness of investments in fossil fuel projects fitted with CCUS strongly depends on their long-term inclusion among permissible sources. Both these aspects will be discussed further in section 2.3.

The deployment phase to 2030 is a fundamental milestone on the way to wider use and production of decarbonised hydrogen by 2050. The transformation of the system requires several successive steps, and none can be given for granted. The development of decarbonised hydrogen infrastructure in parallel to the biomethane/e-methane grid is set to necessitate significant investment, as well as the substitution of end-use equipment. Competition with other energy sources and technologies in some sectors (e.g. in the buildings sector or for light-duty vehicles) is set to be strong. This competition, and the level of penetration of hydrogen and its derivatives in hard-to-abate sectors, will determine its overall share in the energy mix.

In the scenarios presented by the European Commission, the share of hydrogen and derivatives in total final consumption in 2050 ranges between 15% and 22%, or around 1 300-1 800 TWh. The share is highest in the 1.5TECH scenario, with e-methane and e-fuels accounting for more than half of this share in 2050. Of the total 1 900 TWh consumed by hydrogen-based fuels in this scenario, demand in the industrial sector accounts for one-quarter, the transport sector for over half, buildings for one-fifth and the remaining 6% is consumed in the power sector. Total demand for hydrogen, e-methane and e-liquids amounts to around 48-72 Mt[6]. In this study, we will take into account demand of 60 Mt of hydrogen in the EU in 2050, equivalent to 2 000 TWh.

Other studies indicate even higher hydrogen demand in 2050 than the European Commission scenarios. A new report from the European Hydrogen Backbone (EHB, 2021b) estimates demand up to 2 750 TWh (over 80 Mt of hydrogen) for the European Union and the United Kingdom, while a joint report from IFPEN, SINTEF and Deloitte for the International Association of Oil and Gas Producers highlights two pathways to 2050, both surpassing 100 Mt of hydrogen demand by 2050 (IFPEN-SINTEF-Deloitte, 2021). Higher hydrogen demand than the envisaged 60 Mt would require a combination of increased domestic production in the EU and much higher hydrogen imports.

6. Obtained using an 80% efficiency of the process to obtain e-gas and 75% for e-fuels.

The uncertainty on the demand side is mirrored by uncertainty on the domestic supply side. The two main elements of uncertainty are whether the estimated 500 GW of electrolyser capacity by 2050 (EC, 2020a) will be reached – or surpassed – in the EU, and the energy sources that would be used to generate the electricity.

Our country-by-country analysis of the plans and possible deployment of electrolysers shows a range of decarbonised hydrogen production between 21 and 30 Mt (see Figure 2), with electrolyser deployment of 350-500 GW. Higher deployment or increased utilisation factors (e.g. downsizing electrolyser capacity – see section 1.2.1) could lead to higher EU domestic production.

This uncertainty on the supply and demand sides results in an overall range of possible imports between 18 and 50 Mt, or 600 to 1 670 TWh. With 500 GW of electrolyser capacity in 2050, decarbonised hydrogen production would cover just under half of total demand of 60 Mt. The remaining 30.4 Mt of hydrogen would need to be imported. This level of imports corresponds to about one-third of today's methane imports into the EU in energy terms.

1.2. Technologies and costs

1.2.1. Production

Today, hydrogen is produced primarily through SMR and coal gasification (IEA, 2019). The share of hydrogen produced from electrolysis is still very small as the cost remains significantly higher than the alternatives. Ambitious deployment targets in Europe and several countries around the world are bringing forward high expectations of cost reductions for decarbonised hydrogen produced through electrolysis. Cost reductions are expected also for SMR equipped with CCUS, although to a lesser extent given the maturity of the technology, and for pyrolysis plants (see Annex A for all assumptions and results).

Several parameters affect hydrogen production costs. As for (almost) all low-carbon technologies, the cost of capital can have the largest impact on overall production costs.

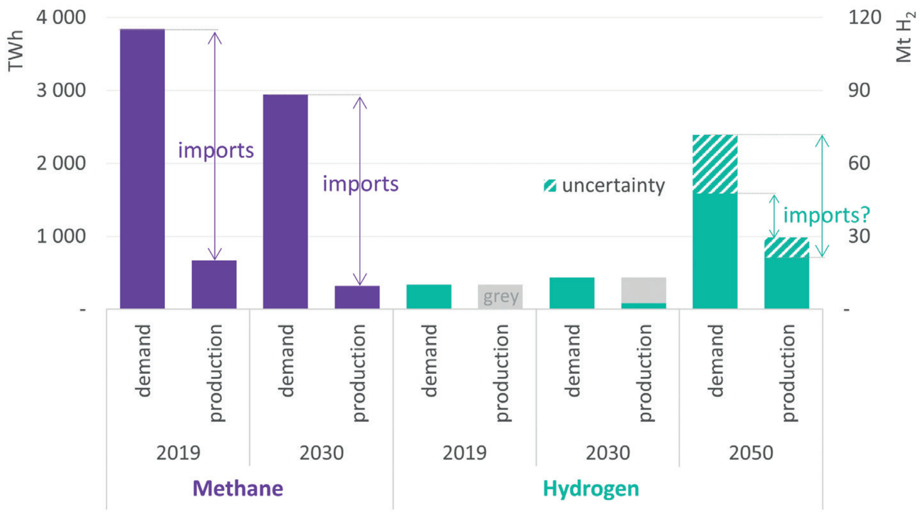


Figure 2. Methane and hydrogen demand and production in the European Union, 2019-2030-2050

Sources: IEA's Sustainable Development Scenario for methane data and analysis by the authors for hydrogen

Note: "grey" production refers to the CO_2-emitting production of hydrogen.

Box 4. Which Weighted Average Cost of Capital to use?

Discounting is the usual method used to compare the future value to present value. Insofar as our report deals with public policies, we follow a "socio-economic" approach (social welfare analysis based on first best policies), and explain here our choice from this point of view. Then we explain why we can apply this choice to the discount rate used by private companies that is their Weighted Average Cost of Capital (WACC).

The social discount rate is a key parameter for evaluating the socio-economic impact of public investment projects decades in the future[1].

- For projects with only idiosyncratic risk that can theoretically be fully diversified or insurable (no correlation with systemic risk), the discount or "risk-free" rate R is linked with the long-term economic growth g, based on the Ramsey formula (or "golden" rule) $R = \delta + \gamma g$ where δ is interpreted as a combination of pure time preference and risk of catastrophe, under which the future effects would be eliminated or severely altered, and γ is the elasticity of the marginal utility of consumption (inverse of elasticity of intertemporal substitution of consumption). Future consumption growth is uncertain. Thus, R is diminished with a term μ proportional to consumer risk-aversion and increasing with risk (proportional to risk-variance for a model with stochastic growth) $R = \delta + \gamma g - \mu$.
- For projects with risks correlated with systemic risk, the discount rate α is the sum of the risk-free rate R and a "risk premium" $\beta\,\Pi$ where Π is the average premium of the macroeconomic risk, and β is the correlation of the project with the macroeconomic risk. $\alpha = R + \beta\,\Pi = (\delta + \gamma g - \mu) + \beta\,\Pi$. By definition of Π, the average of β over all kinds of projects is 1.

This formula is the "Consumption-based Capital Asset Pricing Model" (CCAPM), or the "socio-economic" version of the Capital Asset Pricing Model" (CAPM) used in finance theory to determine WACC. All these formulae are in real terms, i.e. net of inflation.

The United Kingdom Treasury recommends R = 3.5% for 30 years, and lower R for longer terms to take into account increasing uncertainty on economic growth. Since 2013, the French administration has recommended a risk-free discount rate of 2.5% to 2070, gradually declining to 1.5% beyond 2070. A risk premium, specific to each project, is added according to its macroeconomic sensitivity (β) and systemic risk premium. It is set at 2.0% through 2070 and 3.0% beyond 2070. For our present analysis, we use the following parameters: R = 2.5% (associated with long-term uncertain growth assumptions of 0.5%-2% for g), $\beta = 1$ and $\Pi = 2\%$, resulting in α **= 2.5% + 2% = 4.5%**. The reconciliation between this socio-economic approach (first best policies with perfect markets) and the real life of private companies is sometimes difficult, depending on market conditions and the specific conditions of each project.

Focusing on the WACC used in the energy sector, an analysis presented by the International Energy Agency (IEA, 2020)[2] shows that thanks to appropriate long-term remuneration schemes implemented by public policies (through Power Purchase Agreement for example), the solar PV industry benefited from a low WACC, mirroring the socio-economic approach described above. Conversely, if solar projects were to be developed through a merchant plant model, their WACC would dramatically increase.

This study considers the role of hydrogen within the overall energy transformation towards a cleaner future. Almost all low-carbon technologies are capital-intensive, and reducing the cost of capital is a fundamental action for policymakers to ease the transformation and make it more affordable for end-users. Thus, our choice for a WACC is in line with the socio-economic approach which implicitly supposes that long-term remuneration schemes and efficient risk allocation among stakeholders are implemented by public policies to minimise the cost of the energy transition.

1. See: Nordhaus, 2018; Gollier, 2013; HM Treasury, 2003; US OMB, 2003; CGI, 2017.
2. (IEA, 2020), pp.234-236.

Throughout this report, we have assumed a weighted average cost of capital (WACC) of 4.5%. While this can be considerably lower than observed on single projects in different countries and for different sources today, this rate reflects the socio-economic approach that mirrors the actions needed from governments to ensure an affordable energy transition (see Box 4). The EU has established a classification system to list environmentally sustainable activities, with the aim of providing differential access to investment for emitting and non-emitting projects (EU taxonomy), while access to financing in non-European countries could be more difficult and cost more.

Other parameters that significantly influence hydrogen production costs are: the unit investment cost, the cost of electricity used, the utilisation rate and the efficiency of the process.

The reduction of the investment cost depends on several factors, primarily the level of deployment over time. Alkaline electrolysers costs today range between \$500-1 400/kW[7], PEM between \$1 100-1 800/kW and SOEC between \$2 800-5 600/kW (IEA, 2019). Other studies quote similar ranges, while BNEF has reported costs of \$200/kW for electrolysers manufactured in China today (Agora EW, 2019). This low cost could not only reduce the global average investment for electrolysers over time, but would have potentially significant implications for equipment manufacturing in Europe (see section 1.3.1).

Global electrolyser capacity is assumed to reach 150 GW by 2030 and 2 000 GW by 2050. With learning rates of 10%, 14% and 16% (in line with HC, 2020) respectively for alkaline, PEM and SOEC electrolysers, investment costs for alkaline and PEM are expected to decrease to \$350-760/kW by 2030 (see Figure 3). SOEC electrolyser costs and gas pyrolysis plant costs are expected to come down as well, but with limited capacity coming online by this time horizon. The decline in investment costs for SMR

7. All costs related to electrolysers refer to electric capacity (input), while for SMR and pyrolysis they refer to hydrogen capacity (output).

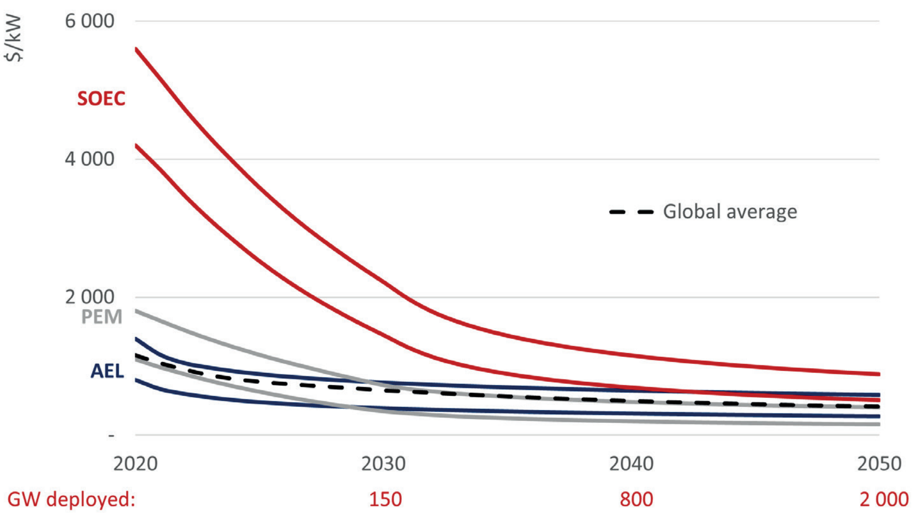


Figure 3. Electrolyser cost ranges, 2020-2050

Source: IEA, 2019 for base-year costs

Notes: Learning rates of 10%, 14% and 16% are respectively assumed for alkaline, PEM and SOEC technologies. A deployment of 150 GW and 2 000 GW is assumed by 2030 and 2050 respectively at the global level.

with CCUS is expected to be more limited, reaching \$1 360/kW in 2030, or about 20% lower than today (IEA, 2019a).

By 2050, with the deployment of around 2 000 GW of electrolyser capacity globally, investment costs reach a range of \$160-880/kW, with a global average of \$410/kW across alkaline, PEM and SOEC technologies. The lowest end of the spectrum is represented by the investment costs in large PEM plants and the highest cost in small SOEC systems. Increasing global capacity to 4 000 GW (similar to the global capacity envisaged by IEA, 2021c by 2050) would bring a further cost decrease of 10-15%.

Two other components that have a large impact on the overall cost of hydrogen production are the cost of electricity used to operate electrolysers and annual utilisation rates.

The cost of wind and solar PV generation has decreased very significantly over the past two decades. Further cost decreases are expected for these technologies, particularly for offshore wind. The latter is on track to make a large contribution to reaching the renewables targets and the decarbonisation of the power sector in Europe by 2050 (EC, 2020b), accounting for about 40% of total wind and solar generation in the EU by 2050. The levelised cost of electricity of solar PV is expected to reach values in the range of \$10-50/MWh by 2050 (IRENA, 2020a).

A contribution to cheap hydrogen production in Europe can also be made by incremental electricity generation from existing nuclear power plants, estimated at an opportunity cost of less than \$30/MWh today and at around \$45/MWh for plants operating in 2050, taking into account the remuneration of some fixed costs. This price reflects the increase in electricity generation from the expected low levels (around 75%) in the power system to average levels of 90%, mainly by increasing off-peak hour production (see Box 3). The potential of this contribution is limited to the amount of total installed nuclear capacity in the system.

Decreasing electricity-generating unit costs, together with decreasing investment costs for electrolysers, are expected to drive substantial drops in hydrogen production costs. The utilisation rates of electrolysers will play a significant part in this economic evaluation[8]. In general terms, the higher the utilisation rate, the cheaper the fixed cost component. The impact on overall price is greater in earlier years (e.g. in 2030 vs 2050), when the investment cost of electrolysers is higher.

The highest utilisation rates can be achieved by electrolysers connected to the grid. In this case, the hydrogen produced will be decarbonised only to the extent that overall electricity generation is. Several hydrogen projects are considering having only dedicated renewable sources to feed electricity to the electrolyser. Dispatchable plants offer the highest capacity factors, while those of wind and solar PV plants are generally lower. Mixed (hybrid) wind and solar PV projects can offer higher average capacity factors, depending on the correlation of the generation of the two sources. Other options involve taking electricity from the grid only during hours when decarbonised generation is at 100% (including additional electricity demand for hydrogen production), to ensure the decarbonised origin. This operation would require concrete regulation to guarantee the decarbonised origin. An additional cost component for the use of the grid should then be included in the hydrogen production cost.

PEM electrolysers are more flexible than alkaline ones[9]. Some studies are raising concerns about whether the variability and intermittency of solar PV and wind could significantly impact the operations of the electrolysers due not only to the minimum power required by the stack (for PEM, this is believed not to be a problem) but also for the actual behaviour of the complete electrolysis plant including its

8. Utilisation rates can span from as low as 12-15% up to 90% depending on the electricity source used.

9. For example, PEM electrolysers offer a wider load range, being able to temporarily surpass nominal capacity and with no minimum load factor (IEA, 2019).

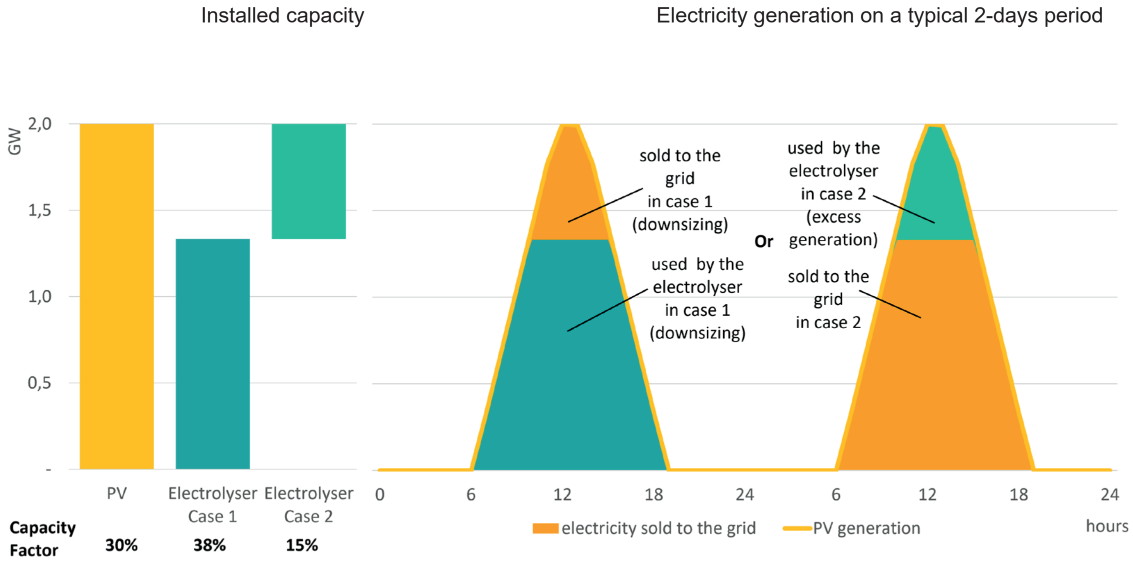


Figure 4. Solar PV and electrolyser capacity: Downsizing or using excess power
Source: Analysis by the authors

Note: Generation is assumed to be constant every day of the year.

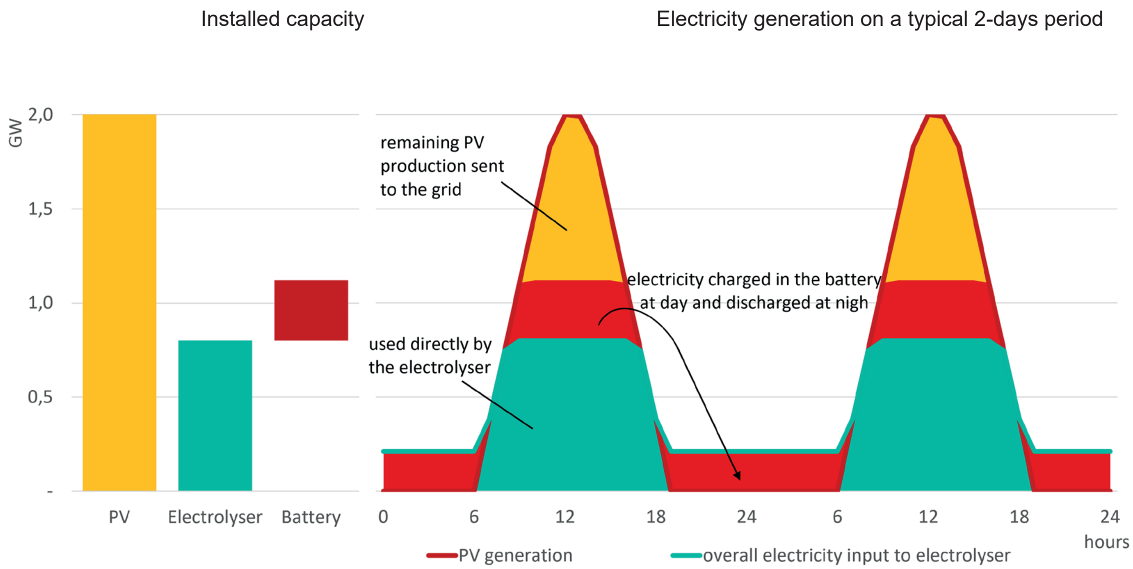


Figure 5. Solar PV, electrolyser capacity and battery storage
Source: Analysis by the authors

sophisticated balance of plant (BOP) (Furfari and Clerici, 2021).

Electrolysers operated at below their rated power can present a lower efficiency and can impact the overall efficiency of the process (calculated for optimal conditions) if more expensive solutions are not considered. These two aspects need to be further analysed.

Another possible solution to increase the utilisation rate of electrolysers connected to a dedicated plant and to reduce the variability of its electricity generation is to downsize the capacity of the electrolyser with respect to the capacity of the electricity-generating plant. In the example reported in Case 1 of Figure 4, downsizing the electrolyser to two-thirds of the solar PV capacity increases the utilisation factor by more than one-quarter (from 30% to 38% in the example). A further downsizing to one-third of the solar PV capacity would increase the utilisation rate of the electrolyser to 46%, an increase of 50% with respect to the capacity factor of the solar PV system in this example. An analysis of the relation between downsizing and increased capacity factor of the electrolyser is provided in Clerici and Furfari, 2021.

Given the higher capacity factors of offshore wind parks, a downsizing[10] of electrolysers would substantially increase their utilisation rates. The remainder of electricity generation from the wind or solar plant can then be curtailed or injected into the electricity grid. If curtailed, it would increase the cost of electricity supplied to the electrolyser. As the more stable part of electricity generation would be used for the electrolyser, the more variable part would be injected in the grid. If many projects follow this approach, it could have a significant impact on the power system and increase the overall cost of the system due to the integration measures that would need to be put in place to accommodate this generation (see section 1.3.1).

The reverse situation of Case 1 is presented in Case 2 of Figure 4, where the majority (two-thirds) of solar PV generation is mainly used to meet power demand and only the eventual excess generation is used to operate the dedicated electrolyser. In the case presented, without a further connection to the grid, the utilisation factor of the electrolyser would be cut in half or more with respect to the capacity factor of the solar PV system. While the value of this electricity is generally very low (in some cases near zero), the cost of producing it depends on the remuneration scheme of the plant (e.g. a power purchase agreement – PPA) and is most often non-zero. Even in the case of low value, the low utilisation factor significantly worsens the economics of this type of solution. Furthermore, the zero- or low-cost potential would be competing with other uses (e.g. batteries) and would not be enough to cover the power demand of synthetic fuel (Agora VW-EW-FE, 2018).

The use of electricity storage could further reduce the variability of generation from wind and solar plants, providing more continuous electricity generation to the electrolyser. Combining a substantial downsizing of the electrolyser with battery electricity storage could significantly increase the utilisation rate of the electrolyser (see Figure 5), almost doubling it with respect to the capacity factor of the solar PV plant in the example. Based on today's costs for battery packs, though, the cost of hydrogen production would rise by a factor 2.5, despite the strong increase in the utilisation rate. The battery storage system cost to 2030 would need to decrease by about 75-80% to be able to reach a breakeven point in the case without battery storage.

Hydrogen production costs for five European countries (Austria, France, Germany, Italy and Spain) and four possible exporting countries (Chile, Egypt, Morocco and Russia) have been analysed for several technologies. The production costs for two gas-based technologies (SMR and pyrolysis) and four electricity sources (onshore wind, offshore wind, large solar PV and nuclear power) for hydrogen

10. The possible downsizing of electrolyser capacity with respect to wind or solar PV capacity is not accounted for in the calculations presented further in the study as this measure is very project-dependent.

		Gas-based				Electrolysis							
		SMR with CCUS		Pyrolysis		Onshore Wind		Offshore Wind		Large PV		Nuclear	
		2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Austria	$/MWh	54	55	87	76	118	90	n.a.	n.a.	136	80	n.a.	n.a.
	$/kgH$_2$	1.8	1.8	2.9	2.5	3.9	3.0	n.a.	n.a.	4.5	2.7	n.a.	n.a.
France	$/MWh	54	55	85	72	113	87	109	71	116	70	54	69
	$/kgH$_2$	1.8	1.8	2.8	2.4	3.8	2.9	3.6	2.4	3.9	2.3	1.8	2.3
Germany	$/MWh	54	55	87	78	118	90	100	65	148	87	n.a.	n.a.
	$/kgH$_2$	1.8	1.8	2.9	2.6	3.9	3.0	3.3	2.2	4.9	2.9	n.a.	n.a.
Italy	$/MWh	54	55	89	80	132	100	n.a.	79	90	55	n.a.	n.a.
	$/kgH$_2$	1.8	1.8	3.0	2.7	4.4	3.4	n.a.	2.6	3.0	1.8	n.a.	n.a.
Spain	$/MWh	54	55	87	74	109	84	111	76	81	41	n.a.	n.a.
	$/kgH$_2$	1.8	1.8	2.9	2.5	3.7	2.8	3.7	2.5	2.7	1.4	n.a.	n.a.
Chile	$/MWh	49	47	83	75	106	79	111	71	63	37	n.a.	n.a.
	$/kgH$_2$	1.6	1.6	2.8	2.5	3.5	2.6	3.7	2.4	2.1	1.2	n.a.	n.a.
Egypt	$/MWh	52	50	87	78	106	81	119	79	57	36	105	95
	$/kgH$_2$	1.7	1.7	2.9	2.6	3.5	2.7	4.0	2.6	1.9	1.2	3.5	3.2
Morocco	$/MWh	52	50	87	78	96	72	119	79	65	40	n.a.	n.a.
	$/kgH$_2$	1.7	1.7	2.9	2.6	3.2	2.4	4.0	2.6	2.2	1.3	n.a.	n.a.
Russia	$/MWh	44	42	76	68	144	105	n.a.	n.a.	125	75	100	90
	$/kgH$_2$	1.5	1.4	2.5	2.3	4.8	3.5	n.a.	n.a.	4.2	2.5	3.3	3.0

Table 3. Hydrogen production costs for selected technologies and energy sources

Source: Analysis by the authors

Notes: Excludes transportation costs. All calculations are based on average investment costs (about $400/kW in 2050) and not the cheapest available ($160/kW) to reflect the average cost of production. Assumptions for calculations are shown in Annex A. For nuclear power in France, the hydrogen production cost is lower than for a new reactor, as the calculation takes into account only the additional generation obtained by increasing the capacity factor of the existing plants (see section 3.2).

production through electrolysis are presented in Table 3. The most relevant technologies for each country will be presented in chapter 3.

Hydrogen production costs in exporting countries with good resources (such as gas in Russia and renewable resources in North Africa) are often lower than in European countries. Whether the full cost delivered to European end-users will be lower, comparable or higher will depend primarily on the transportation cost and will be analysed in the following sections.

1.2.2. Transport, distribution and storage infrastructure

Transport and distribution infrastructure is needed to bring gas from producers to consumers. The same holds true for hydrogen, although with some notable differences. Hydrogen can be transferred either blended with methane, in its pure form, or through derivatives. Hydrogen blending into the existing gas infrastructure is the easiest (and cheapest) way to introduce initial hydrogen volumes into the gas system in the short term, particularly at low volume percentage. Standards and limitations can vary from country to country, and may represent an obstacle to international trade within and outside EU borders. A deblending process can be used if pure hydrogen is needed, though additional losses would be incurred.

Pure hydrogen can be imported through dedicated pipelines or through seaborne trade. In both cases, existing infrastructure can be repurposed[11] or new infrastructure can be built. In the case of repurposing, an additional evaluation of the cost and amortisation status of the infrastructure must be carried out. Assessments of the potential of existing European oil and gas infrastructure for hydrogen or CO_2 transportation are being conducted by several institutions[12]. For pipelines, compression stations can contribute significantly to overall costs, while import and export terminals, liquefaction facilities, local storage, vessels and travel cost all add to overall shipping costs.

Hydrogen can also be transported through derivatives that are easier to transport, such as ammonia and liquid organic hydrogen carriers (LOHC). Unless directly utilised in final use (as in the case of ammonia for fertilisers), both conversion and reconversion processes must be included in any economic evaluation. Conversion losses must be considered also for other derivatives such as e-methane and other e-liquids, though their ability to use existing infrastructure is a significant benefit.

Two main parts of hydrogen transport infrastructure can be identified:

- International pipelines and shipping bringing hydrogen and its derivatives from exporting countries to the EU. Pipelines are characterised by large diameters to allow for high volumes and economies of scale (typical size of 48”). Pipelines are also characterised by their metallurgy. Europe has many LNG terminals and large ports. Several of them, such as the port of Rotterdam (PoR, 2020) and the port of Antwerp (HIC, 2021), are very involved in the transformation towards hydrogen.
- The internal transmission grid within the EU. The European Hydrogen Backbone study, published in 2020 (EHB, 2020) and updated in 2021 (EHB, 2021a), envisages a deployment by 2040 of almost 40 000 km of repurposed and new dedicated hydrogen pipelines of three different sizes (48”, 36” and 24”), to serve as the initial hydrogen pipeline infrastructure in Europe. The study calls for investments in the range of \$50-100 billion and annual operating expenditure of \$2-4.5 billion, while other studies report higher costs (as summarised in table 16 of Agora EW, 2021). Significant uncertainties about the cost of repurposing and about hydrogen volumes have led other studies to point to a “no regret”

11. Repurposing is the conversion of an existing gas pipeline or LNG terminal to be solely dedicated to hydrogen transport. This is different from retrofitting of pipelines, which is an upgrade of the existing infrastructure to allow for hydrogen blending (ENTSO-G, GIE, HE, 2021).

12. Including a forthcoming report with the participation of ENTSO-G, GIE, IOGP and Concawe.

strategy based on local hydrogen networks including import infrastructures and on industrial clusters rather than the development of a cross-European network.

Alternatives to importing hydrogen could include imports of certified low-carbon electricity to be used in electrolysers in Europe and imports of methane to be used in pyrolysis plants. The first solution would require either significant submarine cable deployment or an increase of overhead lines across Europe, bearing in mind that the latter often faces strong local opposition. Smaller capacities for submarine electricity cables up to a few GW can be competitive for short and medium distances. These options need to be further analysed. The deployment of pyrolysis technology could allow for the use of existing methane infrastructure. A comparison of transport costs for different transport means is shown in Figure 6, where repurposed and new pipelines emerge as a clear cost-effective choice for hydrogen imports over distances up to a few thousand kilometres. International hydrogen pipelines are expected to connect the EU with Morocco, Algeria, Tunisia, Egypt (through Greece), Russia, Ukraine, Norway and the United Kingdom.

Distribution costs need to be included in the delivered cost to end-users, and depend on the type of user, on the distance considered, on the capillarity of the distribution system and on the type of distribution, i.e. by local distribution pipeline or by truck. The International Energy Agency estimates this cost to be in the \$0.2-0.3/kgH_2 range for distribution pipelines over a distance of 300 km, while truck distribution costs depend on the type of carrier used and on eventual reconversion costs (IEA, 2019).

Hydrogen storage is set to play a crucial role in the development of the hydrogen market. Similar to methane, hydrogen will not be consumed constantly over days, months and seasons. Matching supply with demand necessitates

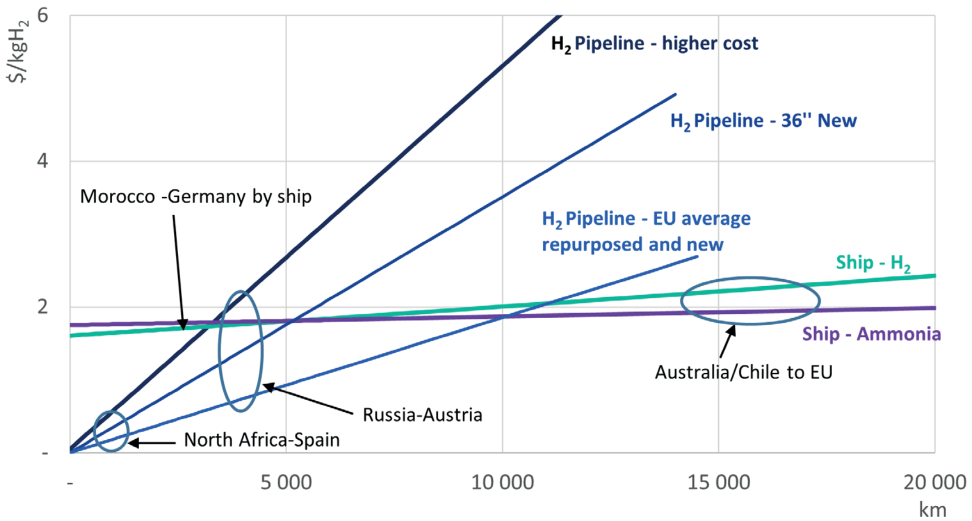


Figure 6. Comparison of hydrogen transport costs via pipeline and seaborne

Sources: IEA, 2019; EHB, 2021a; EWI, 2020; analysis by the authors

Note: Pipeline costs in the figure refer to land pipelines. Submarine pipelines in the analysis of this study are assumed to have a 25-30% higher cost and not to be longer than 1500-2000 km. For repurposed pipelines, the costs shown in the graph are those of the EHB costs study; an additional cost for the amortisation of current pipelines might need to be added. See Annex A for cost assumptions.

storage facilities with different duration times, capacities, injection and withdrawal costs, and different physical characteristics. Electricity – the largest energy vector in the transformation of the energy system – has similar requirements, but offers limited storage capabilities, in particular over medium and long periods of time. Pumped hydro storage is already playing an important role in this respect. Hydrogen storage could allow for much greater quantities, with varying availability and cost ranges across countries.

There are three main types of hydrogen storage: pressurised tanks, repurposed methane storage and salt caverns. The first is typically above-ground, high pressure (usually around 700 bars) and used more for short- and medium-term storage, while salt caverns are predominantly envisaged for long-term storage. The technical potential of salt cavern storage in Europe is estimated at around 2 500 MtH_2 (Caglayan, 2020), with the majority located in northwest Europe. A recent study estimates total hydrogen storage capacity requirements in Europe in 2050 at around 450 TWh (GIE, 2021). As with most infrastructure, these projects can have very long lead times. The same study estimates 1 to 7 years for repurposing storage assets and 3 to 10 years for new storage projects. The different type of use resides mainly in the relative share of capex vs opex cost, but the speed of injection and withdrawal plays a fundamental role too. Depleted natural gas or oil reservoirs and aquifers are additional possible storage options.

The amount of storage needed in a given region depends on multiple factors, such as the correlation between demand and supply over time and the amount of interregional interconnection. The electricity mix used for the production of hydrogen can play an important role, too. An analysis from AFRY (see Table 14 of Agora EW, 2021) shows that total storage capacity requirements would be highest in North Europe (at 12%), while total injected volumes would be highest in South Europe (with a number of full cycles about four times higher than in North Europe). The levelised cost of storage is still very uncertain and varies greatly with the type of storage facility and the number of full cycles in a year. The International Energy Agency indicates a cost of $0.6/$kgH_2$ (IEA, 2019), similar to the range presented by AFRY for Europe, at $0.19-0.79/$kgH_2$. The same study evaluates the cost of pressurised tanks in the range of $6.4-26.2/$kgH_2$.

1.2.3. Full delivered cost

A complete comparison of hydrogen costs delivered to final consumers should account for all components: cost of production (see section 1.2.1) and transportation (1.2.2) are only the first two.

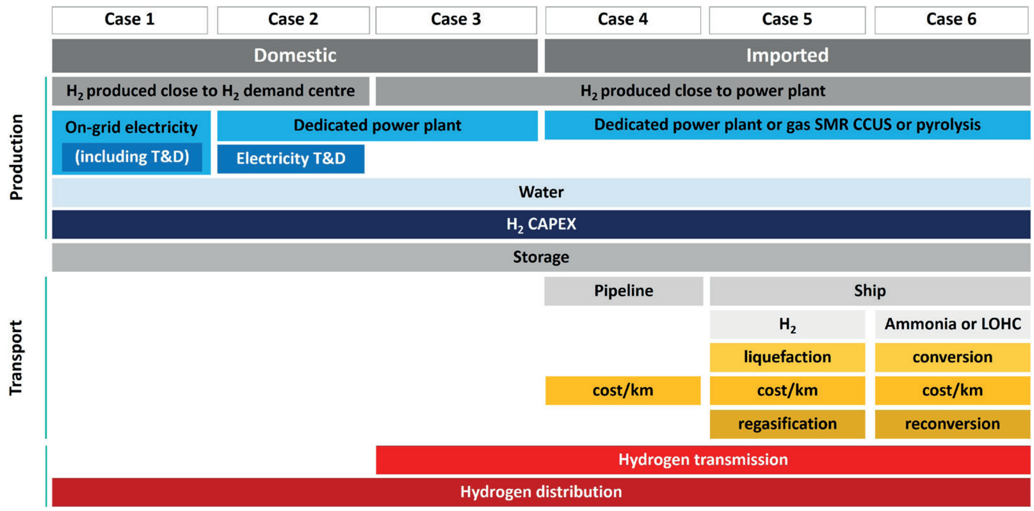
The price paid by an industrial end-user may include the cost of electricity transmission and distribution (T&D), hydrogen storage, pipeline or shipping, eventual conversion and reconversion, and hydrogen transmission and distribution pipelines. Additional distribution costs would need to be added for a more capillary system, such as delivery to refuelling stations.

Several characteristics need to be accounted for when analysing different technologies, energy sources and origins. First, whether the project is dedicated to hydrogen exports or domestic consumption. Second, its location with respect to the consumer, i.e. whether the hydrogen production plant (electrolysis or gas-based) is located close to the source of energy used (e.g. close to the dedicated PV plant) or close to the demand centre[13]. If the hydrogen project is intended for exports, the infrastructure available (pipeline/shipping) and related cost (see Figure 7a) must be taken into account. Cost components can have very different magnitudes depending on the type of technology, country of origin, and localisation of the project (see Figure 7b). These components have been used to estimate the costs presented in chapter 3.

13. Some electricity-generating projects can be developed close to hydrogen demand centres, greatly reducing the need (and associated costs) of both electricity and hydrogen networks. A detailed assessment of this potential needs to be analysed.

When looking at hydrogen production costs, it is important to remember that only a few projects exist, that most of the pipelines have yet to be repurposed or built, that investment cost reductions for electrolysers have yet to be achieved, and that some elements, such as the vessels, do not exist. The cost components associated with each of these elements therefore present an uncertainty that is represented in Figure 8. Uncertainties associated with each cost component can drive the overall cost up by as much as 50% or down by as much as 40%.

a. General overview



b. By plant type

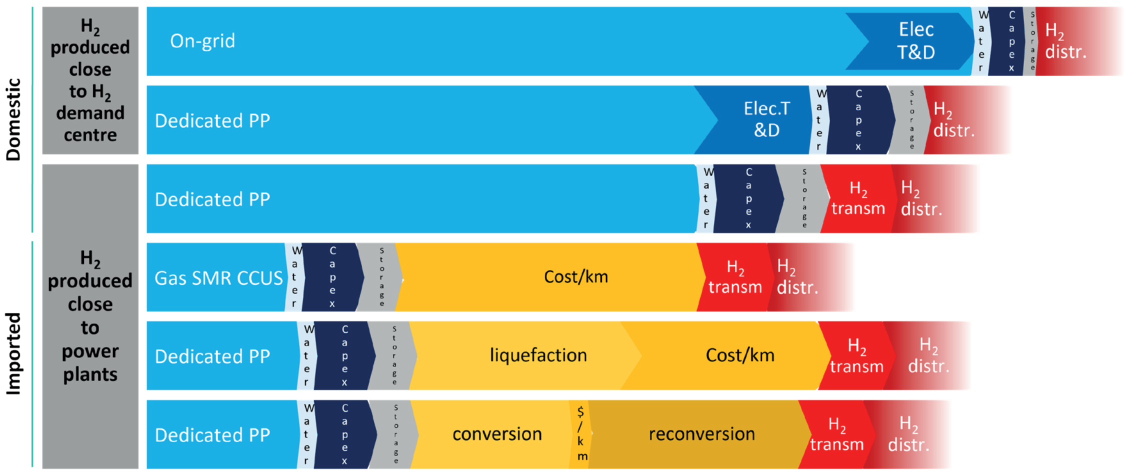


Figure 7. Cost components of delivered hydrogen

Note: These cost components are included in the analysis presented in chapter 3.

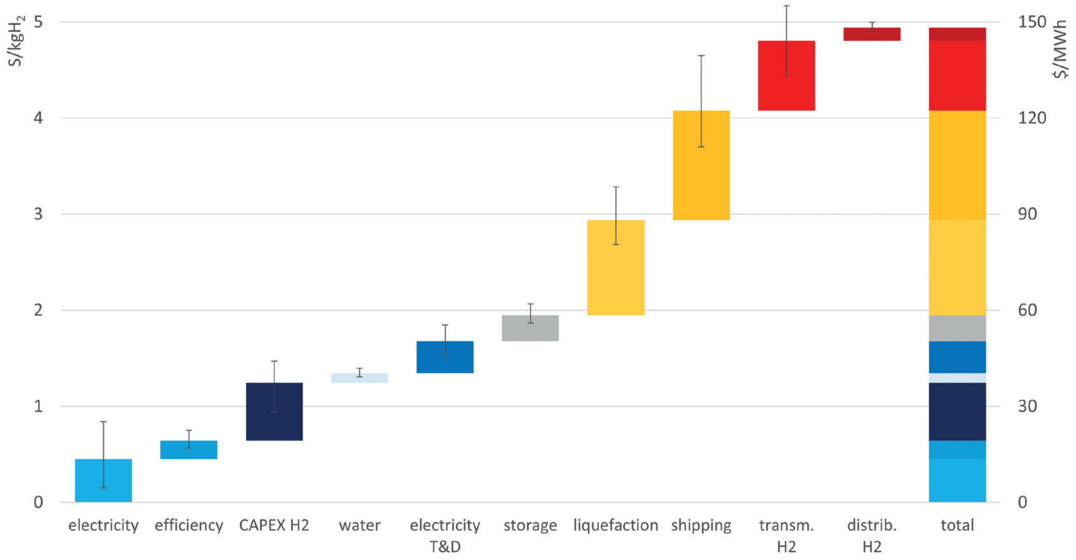


Figure 8. Uncertainties of cost components for imported hydrogen delivered to an industrial customer in 2050

Source: Analysis by the authors

Notes: See Annex A for cost assumptions.

1.3. Implications

1.3.1. For the power sector

Any strategy for the deployment of decarbonised hydrogen must be integrated within broader energy and climate strategies (see also EC, 2020d), particularly power sector strategy and planning. The sharp increase of electrolyser capacity, which reaches 500 GW by 2050 in the estimates presented in this study, will drive up electricity demand in the EU by an additional 1 400 TWh, which is equivalent to almost half of current total electricity generation in the EU and is equal to total electricity demand of the industrial sector in the EU in 2050 in the 1.5TECH scenario (EC, 2018).

The majority of the electricity consumed by electrolysers in the EU is expected to be produced by wind and solar PV plants, with most of the remainder coming from nuclear power[14] and a smaller portion from other renewable sources. The sheer size and flexibility of electrolysers' electricity demand makes them a very good candidate to serve as a demand-side management tool for the integration of wind and solar PV, as well as for the optimised use of dispatchable low-carbon sources. Additionally, hydrogen can be stored and reused for power generation when demand is peaking or flexibility needs are greater.

Some important aspects will need to be addressed to ensure the integration of hydrogen and power systems. The first – and maybe most crucial – is to ensure that the deployment of renewable energy sources for hydrogen production projects is a supplement to the deployment of renewable energy sources for electricity production. The risk of

14. For nuclear power, the analysis is in line with the projections of the European Commission, both for the 2030 and 2050 time horizons.

"cannibalisation" of renewables for hydrogen vs renewables for power generation is real, with possible arbitrage opportunities arising for developers of wind and solar PV projects to choose the highest support measure. Regulation has a very important role to play to avoid this risk (see section 2.3).

Another element to consider is the risk of cross-subsidisation between electricity consumers and gas consumers. The total average cost of electricity is expected to increase with higher shares of renewables, back-up and network needs (IEA, 2021c). This raises the question of the remuneration of fixed costs within the electricity sector and of the electricity price for hydrogen generation in order to avoid cross-subsidisation between hydrogen and electricity customers. Policymakers should ensure that the former do not pay for support measures for wind and solar PV deployed for the hydrogen consumed by the latter, nor for costs arising from additional measures such as lower or no grid charges or balancing costs. The case of downsizing presented in Figure 4 is being considered in several projects. A direct consequence is that the remaining electricity (much more variable) is injected into the electricity grid. Similar to the previous point, a transparent methodology must be put into place to fairly attribute costs and the value of the electricity produced.

1.3.2. On the economy and on energy and technology security

The development of the hydrogen economy has important links to and implications for the overall industrial ecosystems of the EU and for economic development in general. Given the current high cost of decarbonised hydrogen, many countries have included significant levels of public spending in recently released roadmaps. These investments are intended to foster industrial development and job creation and to increase the international competitiveness of European countries for the manufacturing of electrolyser plants and their components.

The creation of a European hydrogen industrial ecosystem could be put at risk by competition from other countries, notably China. The current cost of electrolysers in China reported by BNEF is three to four times lower than for European manufactured electrolysers. The role of innovation and the ability of the industry to deliver the expected cost reduction in a timely manner will therefore be crucial to maintain and consolidate Europe's leading position.

Energy security is becoming more and more linked with technological independence and security. Energy security is defined by *the uninterrupted availability of energy sources at an affordable price* (IEA, 2021b). While in the past, this was mainly determined by dependence on fossil fuel imports (mainly oil and gas), the energy transition is shifting the focus towards more capital-intensive low-carbon technologies. Maintaining and enlarging technological knowhow and manufacturing will be essential to reach this goal.

1.3.3. On water use and costs

Producing large quantities of decarbonised hydrogen will require significant amounts of water, depending on the technology used and the volumes of hydrogen produced. The highest water-demanding technologies are electrolysers, with a stoichiometric water consumption of 9 litres/kgH_2. SMR plants equipped with CCUS consume 5-7 litres/kgH_2 (IEAGHG, 2017), while the pyrolysis technology has negligible water use. Taking into account the overall water consumption of electrolysers (estimated at 18-24 litres/kgH_2 (IRENA, 2020b)), the production of 29.6 Mt of hydrogen in the EU by 2050 as envisaged in this study would drive up annual water consumption over the years to about 0.6 billion cubic meters in 2050. While this represents only 0.3% of European fresh water use (WB, 2021), it could pose limitations for the localisation of projects across the continent.

Water use by electrolysers could put additional strain on some potential hydrogen-exporting and water-scarce countries, for example some countries in the Middle East and North Africa region, increasing demand for desalinated water. Other potential exporters such as Russia, Norway and Ukraine are not expected to face significant water availability issues. Today, the cost component of water represents only a fraction of the total hydrogen production cost (of the order of \$0.1/kgH_2 or less), although its evolution will depend on trends in water costs.

2. Hydrogen imports

2.1. Drivers of hydrogen imports

Energy imports can have two main drivers: the scarcity of the good for domestic production or the clear economic case for cheaper imported goods. Significant amounts of energy imports can have an impact on energy security, in particular when geopolitical considerations are included. Increasing the number of supply sources generally reduces this risk, but the long-term relationships established with exporting countries necessarily play an essential role.

As shown in Table 3, hydrogen production costs are often lower in countries with very good quality renewable sources (such as North African countries) or with cheaper gas resources (such as Russia, Norway and Algeria) than in the EU. The relative competitiveness of the cost of hydrogen delivered to final users from different technologies, energy sources and origins is discussed in chapter 3 for select European countries, and can vary substantially for each project.

The annual amount of decarbonised hydrogen produced domestically from electrolysers in the EU by 2030 is expected to be less than 3 MtH_2 (100 TWh), while the amount of domestic production from SMR retrofitted with CCUS by this date has not been quantified in this study due to a lack of data. The differential between demand and domestic decarbonised production therefore leaves abundant possibility for additional imports of decarbonised hydrogen by 2030, provided that the appropriate conditions and incentives are in place.

Total annual hydrogen demand assumed in this study by 2050 in the EU is 60 MtH_2, or 2 000 TWh (see section 1.1.2 and Figure 2).

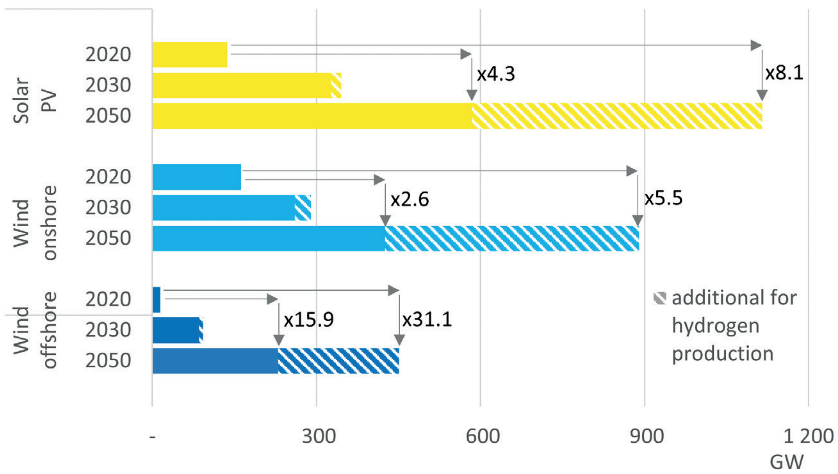


Figure 9. Installed capacity for solar PV and wind power in the European Union, including and excluding additional capacity for hydrogen production, 2020-2050

Source: Based on 1.5TECH and 1.5LIFE scenarios of the European Commission (EC, 2019b), complemented by analysis by the authors

If all hydrogen demand was to be met by production within the EU only through electrolysers, the resulting additional electricity demand would amount to around 2800-2900 TWh[15], almost equivalent to the electricity generation of the entire EU today.

Renewable energy sources are set to be the driving force of the decarbonisation of the power sector in Europe, with wind and solar PV expected to account for the majority of the growth of renewable-based electricity generation. The decarbonisation of power generation is a fundamental step for the decarbonisation of final-demand sectors through increased electrification. To reach this goal, wind and solar PV capacity in the EU will need to increase about fourfold by 2050 with respect to today (see Figure 9).

Increasing this deployment further to cover all additional electricity demand for hydrogen production would require an eightfold increase in the combined capacity of wind and solar PV relative to today. Furthermore, it would require a deployment of over 1000 GW of electrolyser capacity operating with a 30% average capacity factor, or of 730 GW with an average capacity factor of 45% (ca. 4000 hours). The latter would then require the adoption of integration measures to accommodate around 400 GW of additional wind and solar PV capacity in the electricity system.

While the overall technical potential of wind (both onshore and offshore) and solar resources in the EU is considered sufficient to cover this deployment, actual deployment in certain countries could face difficulties linked to land use and acceptability of some projects. Additional generation could come from resource-rich countries with lower population density (e.g. Spain), increasing intra-European trade, but additional national and international transmission grids would be needed, raising again the issue of acceptability to local populations.

15. The average efficiency of alkaline, PEM and SOEC electrolysers reaches 75% in 2050 for new installations, compared with an average 70% for the fleet as a whole.

For these reasons, in this study, it is assumed that 500 GW of electrolyser capacity would be deployed in the EU by 2050, in line with the figures in the European hydrogen strategy (EC, 2020a). This results in the production of about 29.6 Mt of hydrogen, or just short of 50% of total demand, and requires an additional 1400 TWh of electricity generation. With these figures, over half of hydrogen demand would be met with imports in 2050.

Increasing domestic production of decarbonised hydrogen, particularly in countries with renewables resources constraints, will also depend on technology choices. These choices will have significant consequences for intra-European trade and for the uncertainty of import volumes from non-European countries. The next section will outline possible origins and investment needs in exporting countries.

2.2. How to make imports possible?

The origins of hydrogen imports, the type of low-carbon technology, and the energy source used will depend on the volumes required and on the availability of infrastructure. By 2030, all new hydrogen demand must be met by decarbonised hydrogen production, while a portion of existing hydrogen demand is likely to still be met by grey hydrogen, as domestic production will not be sufficient for full substitution. This leaves ample space to develop frontrunner projects for the production and export of decarbonised hydrogen to Europe. Repurposing existing methane pipelines and using shipping carriers for derivative products such as ammonia are two possible solutions for imports (JRC, 2021) by this time horizon, as the long lead times required for the infrastructure are likely to limit new hydrogen pipeline and liquefied hydrogen carriers.

The range of potential import volumes in 2050 is wide. As indicated in Figure 2, a possible range between 10 and 45 MtH_2 could be needed to meet decarbonised hydrogen demand in the EU, with very different implications for exporting countries (see section 2.3). A low level of imports (around 10 MtH_2) would also entail low utilisation rates for importing infrastructure, making additional investments uneconomical and increasing operating costs due to lower volumes.

Imports of the order of 30 Mt of hydrogen are comparable to today's methane imports to the EU in volume terms, but only about one-third in energy terms. This level of imports of decarbonised hydrogen would be needed in the case analysed in section 1.1.2. In the European Commission's 1.5TECH scenario, a significant proportion (around 30%) of these requirements would be for e-liquids, leaving around 21 Mt of hydrogen in pure form and for e-methane. Additional analysis should be conducted to understand the impact on the unit costs of transported hydrogen, both via pipeline and seaborne.

In term of origins, while most initial hydrogen projects are likely to involve bilateral contracts and arrangements, in the longer run, competition among exporters is expected to be the prevailing mechanism. Neighbouring countries with good resources will be in a preferential position, with low hydrogen production costs and lower transport costs than more distant sources.

Countries in North Africa are well positioned in this respect. Nonetheless, like several developing countries, the region has seen and is expected to continue to see soaring electricity demand. By 2050, in the ProMed[16] scenario of the Observatoire Méditerranéen de l'Energie, electricity demand more than doubles with respect to today, even with strong energy efficiency measures that limit its growth. To decarbonise the power sector, wind and solar PV capacity combined are set to increase by a staggering 35 times over 2020-2050.

A very strong deployment of electrolysers for hydrogen exports could see a doubling of

16. The ProMED scenario – based on the expertise drawn from the extensive works of the EU's three UfM platforms on gas, electricity, renewable energy and energy efficiency – is a "Near Zero Carbon Scenario" which foresees more ambitious measures for energy efficiency, significant technology development to further curb CO_2 emissions, as well as increased diversification in the energy mix. It aims to reach carbon neutrality in 2050 for EU countries and 2060 for South Mediterranean countries. It enforces the European Commission's Green Deal to 2050.

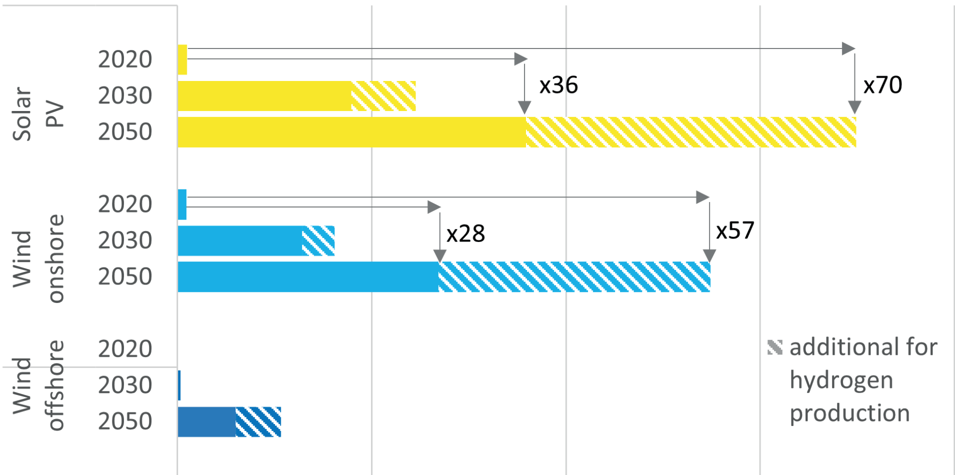


Figure 10. Installed capacity for solar PV and wind power in North Africa, including and excluding additional capacity for hydrogen production, 2020-2050

Sources: OME ProMed Scenario for electrical capacity used to meet power demand (OME, 2021); analysis by the authors for electrical capacity for hydrogen production wind and solar PV capacity additions in the region, multiplying by 70 times their combined capacity with respect to today (see Figure 10). This would result in total hydrogen production for export purposes of around 11.5 MtH_2[17], or about 40% of the total import needs of the EU. Most of this could be transported via pipeline – from Morocco and Algeria (and possibly Mauritania) to Spain, from Tunisia to Italy, and from Egypt (and possibly Libya) to Greece and Italy – although some smaller quantities could also by transported by ship, also in the form of decarbonised ammonia. Such a large deployment of wind and solar PV will require a strong mobilisation of capital and a coordination of infrastructure (gas, electricity and water), while removing regulatory barriers. Concerns may arise regarding this fast pace of deployment, project siting, and the availability of skilled workers. Measures will need to be adopted to ensure that the renewable projects for hydrogen exports are additional to those for domestic use, in line with the principles applied by the EU domestically.

The remaining 19 MtH_2 of imports needed in the EU in our analysis can be assured by several different countries or regions, including Gulf Countries, Chile, Australia, South Africa and others. Russia, Norway, Algeria and other gas-producing countries are well positioned and could provide decarbonised hydrogen at low cost from SMR with CCUS and from pyrolysis. Given low production costs in these countries, in the following calculations, we assume that this entire amount will be produced through gas-based technologies and exported to the EU from these countries.

The overall spending for hydrogen production projects and the infrastructure needed to export to the EU the 30 Mt by 2050 includes investments in hydrogen-producing plants,

17. The additional use of hydrogen for domestic uses is not included in these calculations.

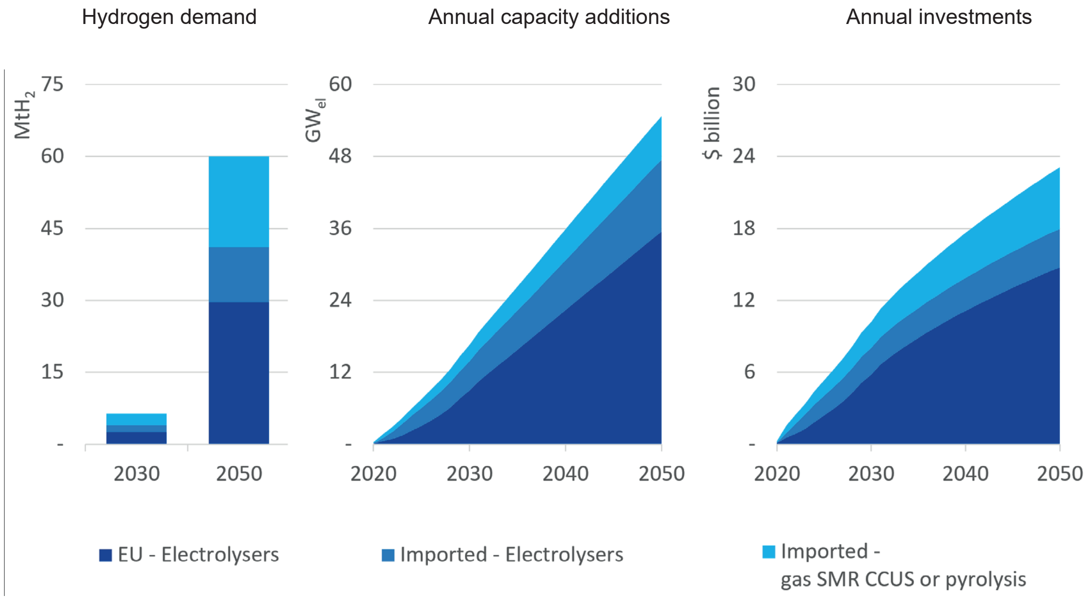


Figure 11. Hydrogen demand, annual capacity additions and investments in hydrogen-producing plants, 2020-2050

Source: Analysis by the authors

Note: Gas-based capacity in the second graph is expressed as a "GW electricity equivalent" for comparability purposes.

related wind and solar PV plants, gas supply spending, and export infrastructure.

An estimate of the investment necessary for the hydrogen-producing plants (electrolysers, SMR with CCUS and pyrolysis plants) needed to produce the 60 MtH_2 required to meet European hydrogen demand is provided in Figure 11. It is based on the following split: 500 GWel of electrolysers deployed in the EU, 200 GWel of electrolysers deployed outside the EU, and 80 GWH_2 of gas-based hydrogen production capacity deployed outside the EU.

The annual capacity additions of electrolysers and gas-based units increases over the projection period, reaching more than 50 GW of annual additions in 2050. Similarly, annual investments in hydrogen-producing plants are set to increase over time, reaching about $23 billion in 2050. The reduction of investment costs contributes to limiting investment needs over time. The capacity additions of gas-based producing facilities are smaller than those of electrolysers due to their higher capacity factors, while the unit investment costs are higher. The investment needs over 2021-2050 to install the 700 GW of electrolysers and the 80 GW of gas-based hydrogen amount to just over $410 billion. About 40% of this (or some $160 billion) is needed for investments outside the EU.

The investment needs for the wind and solar PV plants needed to generate the electricity for the 200 GW of electrolysers outside the EU amounts to $180 billion, and additional spending of about $140 billion is required for the methane used in SMR with CCUS and pyrolysis plants. Overall, total investments for hydrogen production projects outside the EU amount to $480 billion.

In addition to these investments, about $250 to $500 billion are needed for pipelines, port terminals and ships to transport the 30 Mt of hydrogen envisaged in the analysis to Europe. The large range of the estimate is due to major uncertainty about costs related to new and repurposed pipelines, to the current estimates for seaborne trade (ships and export terminals), to the relative share of trade between pipeline and seaborne, and to the mix of countries of origin (and the related distances). Furthermore, technologies such as pyrolysis could allow for the use of existing gas pipelines (avoiding further investment) if the hydrogen production plants are located close to demand centres. Two methodologies were used to produce this estimate, and they provided a similar range of overall investment needs. The first, bottom-up, estimates the number and size of pipelines, terminals and ships. The second, top-down, uses the CAPEX part of the cost of delivery in the LCOH analysis. Investment in storage facilities is not included in this estimate.

Taking the average of the estimated spending needs for infrastructure, total investment requirements for exports of hydrogen to the EU amount to around $900 billion. This level of investment will require some form of support through international partnerships and support measures paid to consumers within European countries, at least in the initial years of deployment. The initially low volumes of decarbonised hydrogen transiting both through infrastructure for imports to the EU and across European countries will require precise plans and a long-term tariff structure to avoid excessively high charges for initial users.

2.3. Conditions for mutual success

The simultaneous development of demand, production and infrastructure projects for decarbonised hydrogen within the EU will require considerable coordination efforts among policymakers, regulators, the supply industry and consumers. These coordination efforts will need to include exporting countries, including the development of all infrastructure (hydrogen, electricity, gas, heat) both within and outside the EU. Common rules and approaches will need to be put into place for the entire value chain, including the regulatory framework for hydrogen importing and transit routes to and within Europe.

The increased electrification and domestic production of hydrogen will decrease energy import needs in the EU. Nonetheless, significant imports will still be needed to meet the EU's overall hydrogen demand by 2050. As seen in the previous section, large investments in hydrogen production projects and supply infrastructure will be needed in exporting countries. These investments are going to be crucial for both exporting and importing countries. All targets, support policies and regulation developed in the EU should therefore aim to create a coherent set of measures that encompass all EU countries and beyond, including exporting countries, and to provide clear, transparent and long-lasting visibility to investors both inside and outside the EU. Access to low-cost financing is going to play a key role in most projects, including in exporting countries.

Respecting the principle of additionality also in exporting countries will be crucial for the successful deployment of export projects. Decarbonised hydrogen is set to remain more expensive than CO_2-emitting alternatives for many years or even decades. A clear and effective communication of the costs and benefits of the energy transition (and of hydrogen-based resources in particular) to the wider public will be key to ensure public acceptance.

A first important step for establishing a level playing field is to develop international quality standards on an EU-wide basis, with clear technical specifications for the quality of hydrogen consumed, transported or blended via dedicated hydrogen pipelines or seaborne carriers. Security standards will also be very important, as will monitoring, reporting and verification.

A second step is to establish an EU-wide criterion for both domestic and imported decarbonised hydrogen for the certification of the decarbonised nature of hydrogen production. A definition based on full life-cycle GHG emissions should be put into place, allowing for all low-carbon technologies and energy sources to have long-term visibility for their deployment.

Decarbonised hydrogen is today more expensive than other more polluting alternatives, and will thus require some form of government support. Particularly at the beginning of the deployment phase, when costs are higher and total volumes deployed do not allow for the establishment of a liquid market, bilateral agreements and international partnerships are likely to be the driving force for export projects. Support measures such as contracts for difference (CfD) or carbon contracts for difference (CCfD) for European customers could be used, in turn securing PPA-type agreements for suppliers. This support is likely to be paid for by taxpayers or consumers in Europe also for export projects, with possible implications on the European trade balance. A risk of cross-subsidisation between gas and hydrogen consumers can be created by the repurposing of gas assets such as pipelines, LNG terminals or storage (ACER CEER, 2021). An additional important aspect to consider is regulations on access, use and payment of the electricity grid for wind and solar PV plants, as this can have a significant impact on the utilisation factor of electrolysers.

A further benefit for both importers and exporters is represented by the industrial development associated with export projects. Demand for industrial components for the plants can foster the European industry, while the contemporary export of industrial know-how can spur local manufacturing and job creation, providing mutual benefits for the economies of trading partners.

Establishing a high-level roundtable between exporters and importers for the development of a joint hydrogen roadmap can provide certainty and accelerate hydrogen development, exploring potentials, conditions, possible milestones, the development of common infrastructure, and looking for mutual industrial benefits.

3. Country profiles

3.1. Austria

Key points:

1. Austria is situated at the heart of the continental Europe gas infrastructure and can play a central role in its transformation towards a hydrogen infrastructure. With a 60% share of hydropower in its total electricity mix – one of the highest in Europe – Austria can use its flexibility to integrate high shares of wind and solar PV, both for power and hydrogen production.
2. Today, hydrogen demand is estimated at around 0.14 MtH_2, mainly met by grey hydrogen production. A first phase includes its replacement through the deployment of renewable hydrogen for the decarbonisation of hard-to-electrify and hard-to-abate industrial applications. High decarbonisation ambitions and targets point to a significant level of import needs – around 70% by 2050. The deployment of the related infrastructure and sourcing will be crucial in achieving this goal.
3. Domestic hydrogen production can benefit from Austria's vast hydro resources, especially in the short and medium terms, to replace the current use of grey hydrogen. In the longer term, a shift towards imported hydrogen is expected, following the increase of hydrogen volume needs and the decrease of imported hydrogen costs.

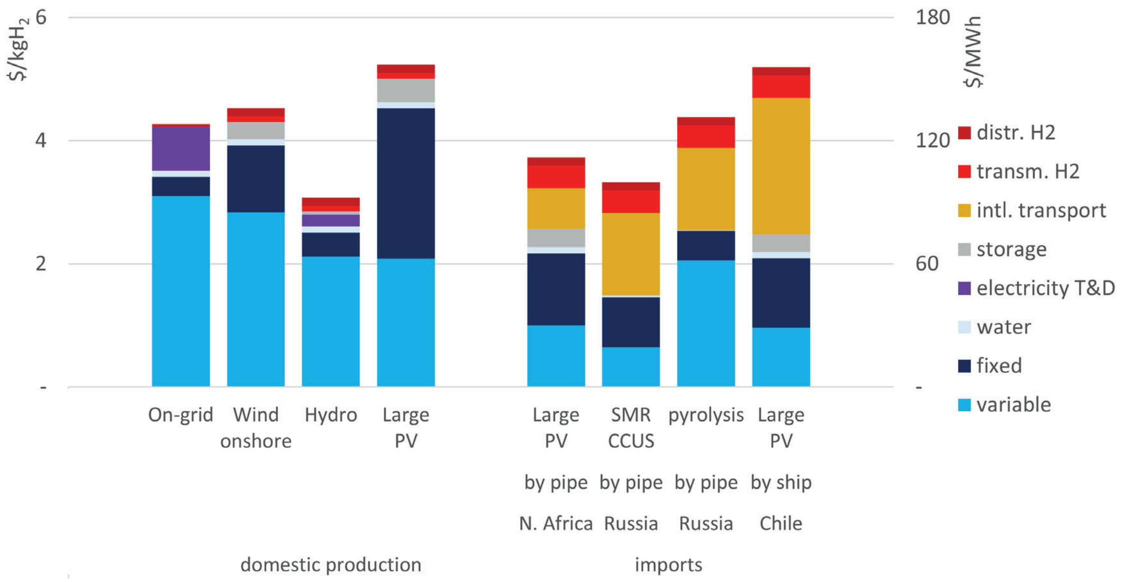
			planned/projected		additional due to hydrogen production	
		2020	2030	2050	2030	2050
Hydrogen demand	[Mt]	0.14	0.14 – 0.19	0.6 – 1.5	-	-
Hydrogen production	[Mt]	0.14	0.02 – 0.07	0.22 – 0.44	-	-
Hydrogen imports	[Mt]	-	0.11 – 0.12	0.4 – 1.1	-	-
Electrolyser capacity	[GW]	<0.01	0.6 – 2	5 – 10	-	-
Solar PV	[GW]	2.2	9 – 12	26 – 41	0.2 – 0.7	1.3 – 2.7
Onshore wind	[GW]	3.2	6 – 17	24	0.4 – 1.3	3.7 – 7.3
Offshore wind	[GW]	-	-	-	-	-
Total electricity generation in Austria	[TWh]	74	84 – 92	102 – 125	1.1 – 3.8	11 – 21
Investment in electrolyser capacity	[$ bill.]	-	0.6 – 2	4.4 – 8	-	-

Table 4. Main indicators in Austria

Sources: AT BMK, 2019a; AT BMK, 2019b; analysis by the authors

Notes: Hydrogen demand and production in 2020 refer to grey hydrogen. Hydrogen production in 2030 refers only to decarbonised hydrogen; the remainder of demand is met either by CO_2-emitting production or by imports. The symbol "-" represents either zero or not applicable. Negative imports represent exports. Electricity generation for 2020 refers to 2019. Investment refers to the periods 2021-2030 and 2031-2050 respectively.

a. 2030



b. 2050

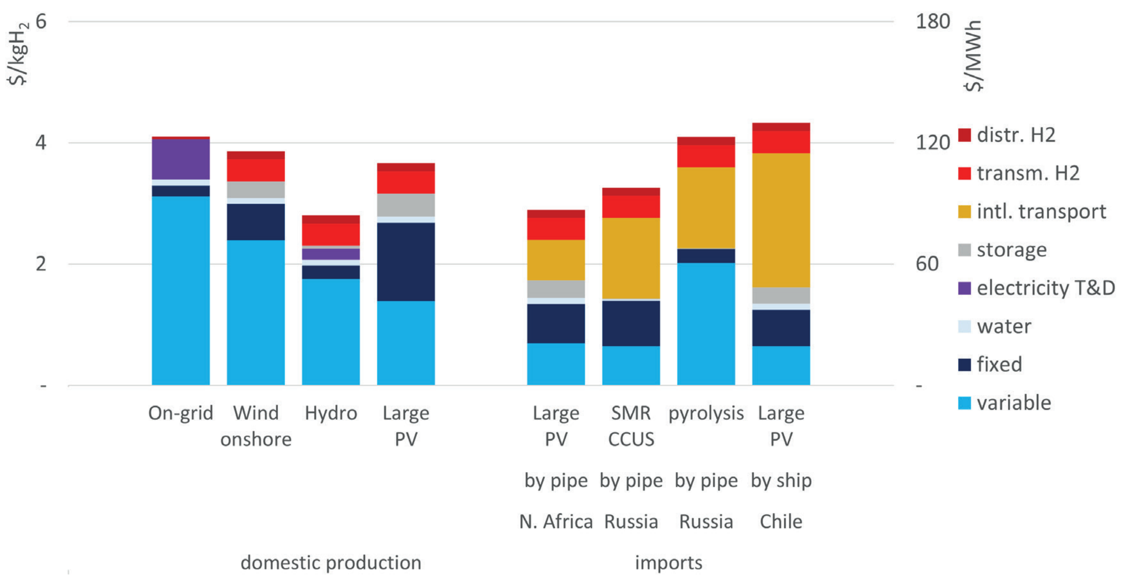


Figure 12. Indicative delivered hydrogen costs to a typical industrial customer in Austria from selected countries and technologies, 2030 and 2050

Source: Analysis by the authors

Notes: The cost indicated for on-grid refers to capacity used full time (utilisation rate of 93%). A lower utilisation rate can be envisaged to use predominantly off-peak hours. Hydrogen production from hydropower resources has limited potential. See Annex A for cost assumptions.

3.2. France

Key points:

1. Additional nuclear electricity generation from the existing fleet can provide hydrogen production of the order of 2 MtH_2 in 2030, more than double today's demand. Replacing current grey hydrogen production would require an increase in the utilisation factor of the nuclear fleet from an average of 70% to around 80%. This would be sufficient to feed the entire electrolyser capacity of 6.5 GW envisaged in the French national hydrogen strategy with a load factor of the electrolysers above 80% – about 3 times higher than for wind and solar PV.

2. Power generation in France is already highly decarbonised. Industry is the first target for decarbonisation through hydrogen, followed by the transport sector. France has the ambition to develop a fully integrated value chain for hydrogen to increase technological independence and boost energy security, with positive implications for industrial and economic development.

3. The production of decarbonised hydrogen through increased electricity generation in the existing nuclear fleet is the lowest-cost option in France in the near term. In the longer term, hydrogen production and electricity generation need to be fully integrated, with renewable-based hydrogen production becoming attractive, particularly from North Africa. Additional decarbonised hydrogen generation could come from removing the 50% cap on electricity generation from nuclear power.

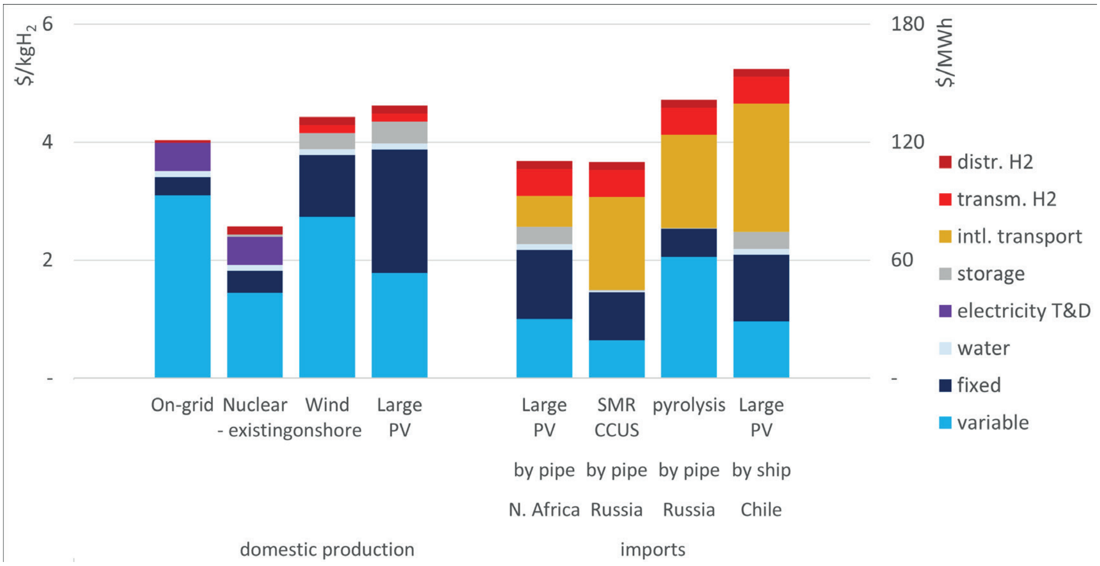
			planned/projected		additional due to hydrogen production	
		2020	2030	2050	2030	2050
Hydrogen demand	[Mt]	0.9	1.0	1.1 – 4.5	-	-
Hydrogen production	[Mt]	0.9	1.0	1.8 – 4	-	-
Hydrogen imports	[Mt]	-	-	-0.7 – 0.5	-	-
Electrolyser capacity	[GW]	<0.02	6.5	16 – 50	-	-
Solar PV	[GW]	11.7	41 – 46	65 – 68	-	0 – 3
Onshore wind	[GW]	17.4	35 – 37	62 – 64	-	0 – 7
Offshore wind	[GW]	0.002	2	10	-	0 – 2
Nuclear	[GW]	64	60	50 – 55		0 – 8
Total electricity generation in France	[TWh]	571	600 – 610	660 – 690	50	88 – 190
Investment in electrolyser capacity	[$ bill.]	-	4.8	5 – 21	-	-

Table 5. Main indicators in France

Sources: FR Gov, 2020a; FR Gov, 2020b; OME, 2021; analysis by the authors

Notes: Hydrogen demand and production in 2020 refer to grey hydrogen. Hydrogen production in 2030 refers only to decarbonised hydrogen; the remainder of demand is met either by CO_2-emitting production or by imports. The symbol "-" represents either zero or not applicable. Negative imports represent exports. Electricity generation for 2020 refers to 2019. Investment refers to the periods 2021-2030 and 2031-2050 respectively. Nuclear generation is capped at 50% of total electricity generation.

a. 2030



b. 2050

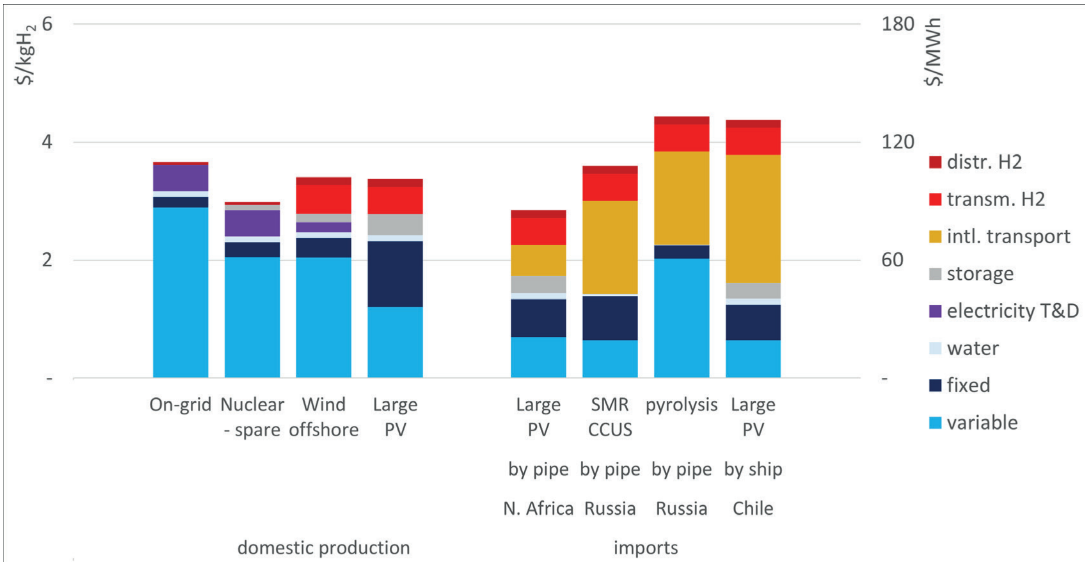


Figure 13. Indicative delivered hydrogen costs to a typical industrial customer in France from selected countries and technologies, 2030 and 2050

Source: Analysis by the authors

Notes: Hydrogen production from electricity generation from nuclear power in 2030 and 2050 is obtained by increasing the capacity factor of the nuclear fleet to 80% in 2030 and to 90% in 2050, with related hydrogen production of 1 Mt and 2 Mt respectively. For new plants in 2050, the price considered is lower than for the levelised cost of electricity (LCOE), given the higher number of off-peak hours of the incremental generation. The cost indicated for on-grid refers to capacity used full time (utilisation rate of 93%). A lower utilisation rate can be envisaged to use predominantly off-peak hours. See Annex A for cost assumptions.

3.3. Germany

Key points:

1. Germany accounts for almost a quarter of fossil fuel demand in the EU in final-consumption sectors. Hydrogen is envisaged as a key energy vector for their decarbonisation, in particular in the industrial and transport sectors. The focus for decarbonised hydrogen production is on renewable electricity, but SMR with CCUS and pyrolysis are expected to contribute in the medium term. Germany has a strong manufacturing industry, including for electrolysers and pyrolysis. According to the German national hydrogen strategy, about EUR 9 billion will support the first deployment phase, of which EUR 7 billion for domestic projects and EUR 2 billion for the implementation of international hydrogen partnerships.
2. In 2020, Germany accounted for about 40% of the EU's solar PV installed capacity, as well as for one-third of onshore wind capacity and over 50% of offshore wind capacity. Renewable sources today account for about 45% of the power mix, and these three technologies will be key to decarbonising it fully, with important implications for the remaining potential for hydrogen production from these sources.
3. Germany is set to become the largest importer of hydrogen in Europe and one of the largest in percentage terms, meeting about 70% of hydrogen demand through imports. Imported hydrogen can be cost-competitive relative to domestic renewable hydrogen production, in particular with imports from neighbouring countries such as Russia and North African countries. Uncertainties on long-term hydrogen demand and the deployment of electrolysers for domestic production can have significant implications for import volumes in Germany.

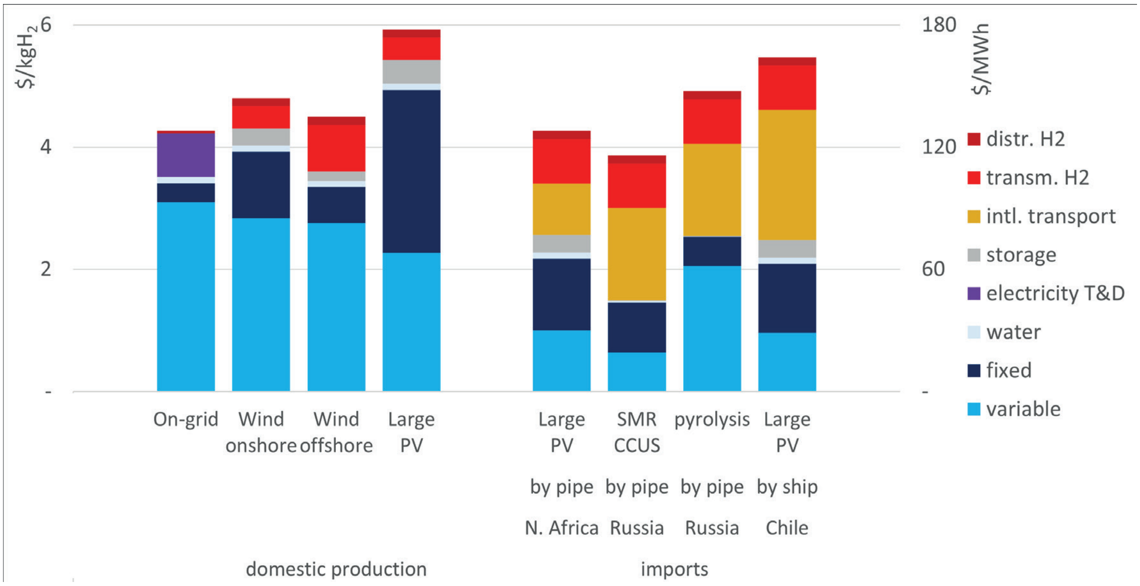
			planned/projected		additional due to hydrogen production	
		2020	2030	2050	2030	2050
Hydrogen demand	[Mt]	1.6	2.7 – 3.3	11.4 – 21	-	-
Hydrogen production	[Mt]	1.6	0.4	3.2 – 5.5	-	-
Hydrogen imports	[Mt]	-	1.1 – 2.9	8.2 – 15.5	-	-
Electrolyser capacity	[GW]	0.03	5	40 – 80	-	-
Solar PV	[GW]	53.8	100	145	-	0 – 10
Onshore wind	[GW]	54.4	71	97	1.0	15 – 33
Offshore wind	[GW]	7.7	20	43	4.0	25 – 37
Total electricity generation in Germany	[TWh]	618	630	650	20	150 – 260
Investment in electrolyser capacity	[$ bill.]	-	3.6	17 – 36	-	-

Table 6. Main indicators in Germany

Sources: BMWi, 2020a; BMWi, 2020b; WEC Germany et LBST, 2020; EEG, 2021; WindSeeG, 2016; DENA, 2018; analysis by the authors

Notes: Hydrogen demand and production in 2020 refer to grey hydrogen. Hydrogen production in 2030 refers only to decarbonised hydrogen; the remainder of demand is met either by CO_2-emitting production or by imports. The symbol "-" represents either zero or not applicable. Negative imports represent exports. Electricity generation for 2020 refers to 2019. Investment refers to the periods 2021-2030 and 2031-2050 respectively.

a. 2030



b. 2050

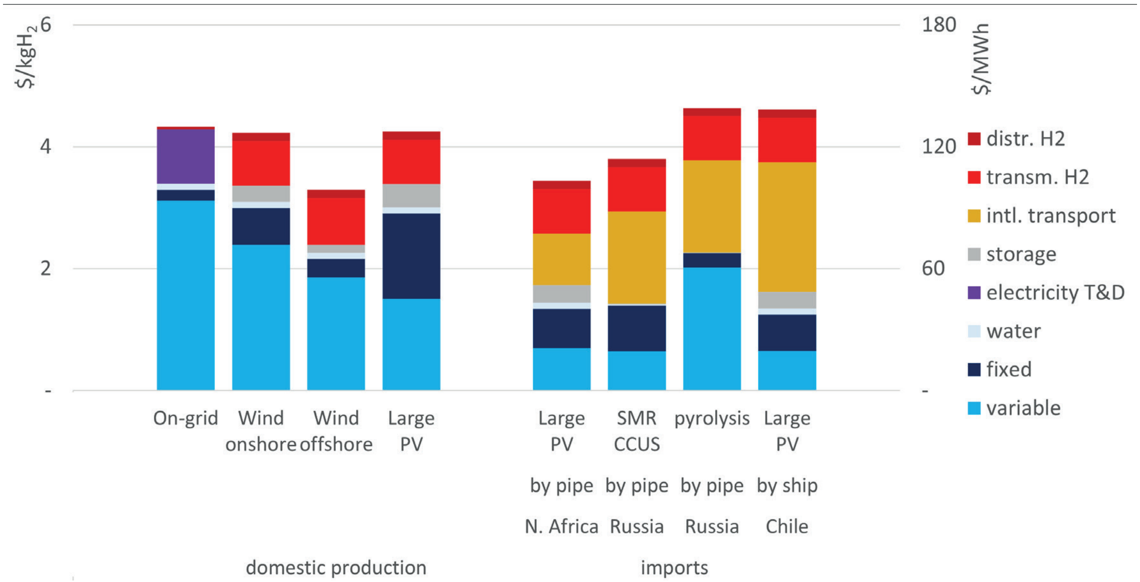


Figure 14. Indicative delivered hydrogen costs to a typical industrial customer in Germany from selected countries and technologies, 2030 and 2050

Source: Analysis by the authors

Notes: The cost indicated for on-grid refers to capacity used full time (utilisation rate of 93%). A lower utilisation rate can be envisaged to use predominantly off-peak hours. See Annex A for cost assumptions.

3.4. Italy

Key points:

1. Italy is centrally positioned in the Mediterranean and has ambitions to become an important hydrogen hub between North Africa and Europe. It possesses essential industrial demand centres, significant renewable resources, in particular in the southern part of the country, and a well-developed gas infrastructure. Repurposing at least a part of its existing importing infrastructure and possibly developing new connections through Greece could enhance its role in hydrogen trade.

2. The development of hydrogen valleys is a priority of the Italian hydrogen roadmap, sustaining the first inroads for decarbonised hydrogen demand and local production. In the long term, a sharp increase in demand is set to require significant imports to cover around two-thirds of total estimated consumption. This deployment can also have substantial implications for the manufacturing ecosystem of Italian small and medium enterprises (SMEs).

3. Decarbonised hydrogen production costs are comparable for domestic production and imports when resources are good, but imports from North Africa are likely to remain cheaper throughout the period to 2050. Pyrolysis and SMR with CCUS could prove to be an interesting additional option, though this will largely depend on the gas price (both biogas and methane) and on whether they are included in the long-term approaches of Italy and Europe.

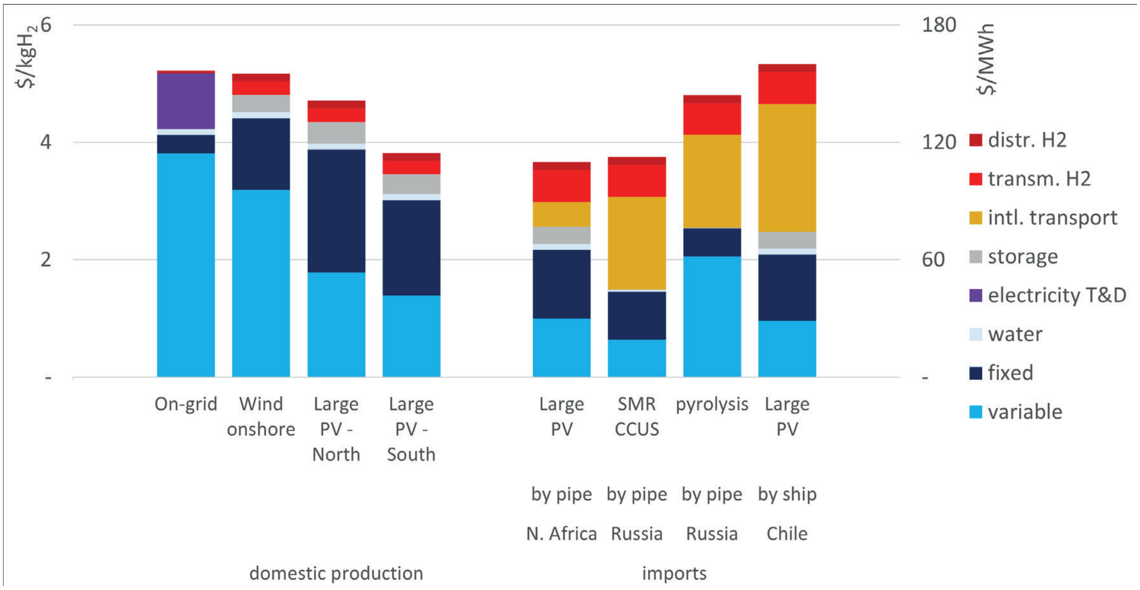
			planned/projected		additional due to hydrogen production	
		2020	2030	2050	2030	2050
Hydrogen demand	[Mt]	0.48	0.7	6 – 8	-	-
Hydrogen production	[Mt]	0.48	0.2	2.2 – 2.6	-	-
Hydrogen imports	[Mt]	-	0.5	3.8 – 5.4	-	-
Electrolyser capacity	[GW]	<0.01	5	50 – 60	-	-
Solar PV	[GW]	21.6	52	85	2.2	21 – 27
Onshore wind	[GW]	10.8	18	37	2.8	24 – 26
Offshore wind	[GW]	-	1	7	-	5 – 7
Total electricity generation in Italy	[TWh]	292	310	350	9	104 – 125
Investment in electrolyser capacity	[$ bill.]	-	3.6 – 4.5	22 – 27	-	-

Table 7. Main indicators in Italy

Sources: MISE, 2019; MISE, 2020; SNAM, 2019; OME, 2021; analysis by the authors

Notes: Hydrogen demand and production in 2020 refer to grey hydrogen. Hydrogen production in 2030 refers only to decarbonised hydrogen; the remainder of demand is met either by CO_2-emitting production or by imports. The symbol "-" represents either zero or not applicable. Negative imports represent exports. Electricity generation for 2020 refers to 2019. Investment refers to the periods 2021-2030 and 2031-2050 respectively.

a. 2030



b. 2050

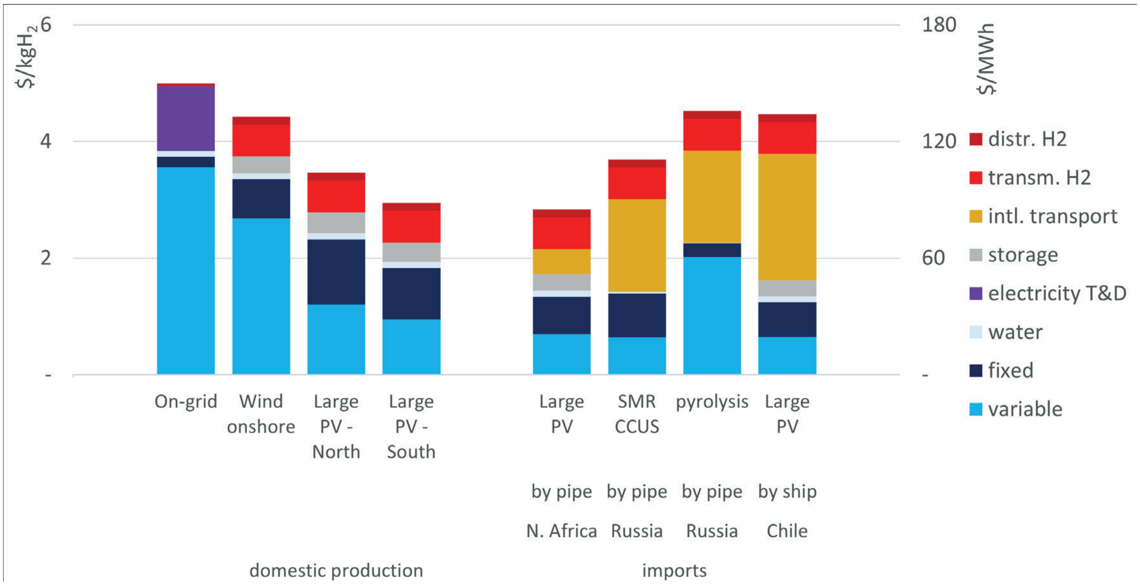


Figure 15. Indicative delivered hydrogen costs to a typical industrial customer in Italy from selected countries and technologies, 2030 and 2050

Source: Analysis by the authors

Notes: The cost indicated for on-grid refers to a capacity used full time (utilisation rate of 93%). A lower utilisation rate can be envisaged to use predominantly off-peak hours. See Annex A for cost assumptions.

3.5. Spain

Key points:

1. Spain has significant renewable resources, making its hydrogen production costs among the lowest in Europe. In the short and medium terms, its national hydrogen roadmap is focused on developing domestic industry and the hydrogen value chain. In the longer run, the country is well positioned to become a potential exporter to the rest of Europe, partly thanks to its lower density population than other European countries, and its well-developed energy infrastructure, including its electricity and methane grids that could be repurposed for hydrogen use.
2. The decarbonisation of final sectors and the 100% renewables target for power generation will require a significant step-up in the deployment of wind and solar resources. By 2050, solar PV will need to increase seven- to eight-fold and wind power four-fold to decarbonise electricity and meet the projected hydrogen production, 85% of which is set to meet demand, with the remainder available for exports. Exporting additional renewable hydrogen would require further renewable deployment.
3. Due to its strategic location close to North Africa and between the Mediterranean Sea and Atlantic Ocean, Spain is well positioned to become in the long term an important transit country. For this to happen, further deployment of infrastructures with North Africa and towards the rest of Europe will be necessary, requiring strengthened international collaboration and a clear regulatory framework.

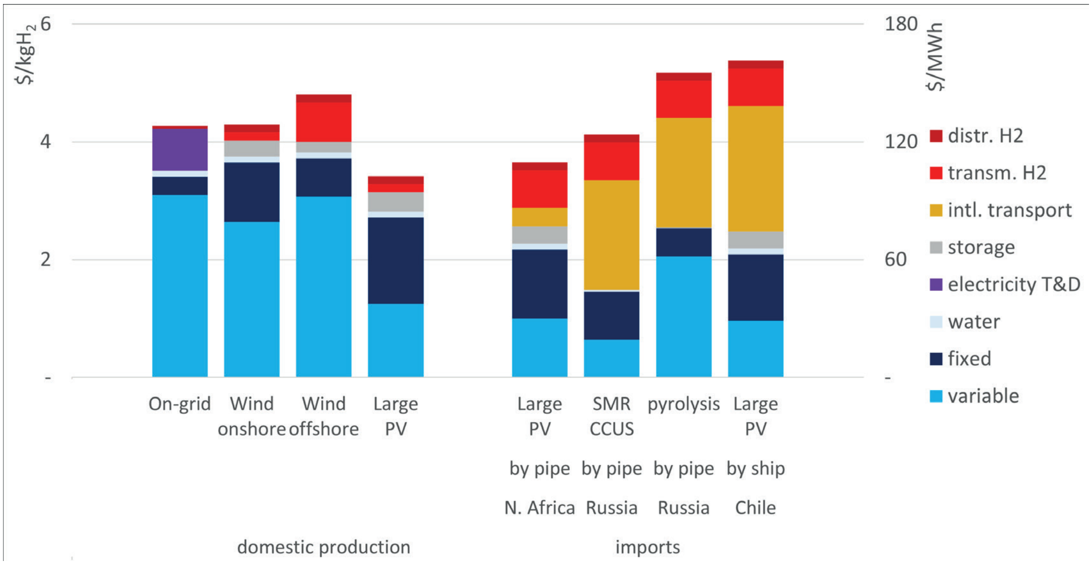
			planned/projected		additional due to hydrogen production	
		2020	2030	2050	2030	2050
Hydrogen demand	[Mt]	0.5	0.6	2.6 – 3.5	-	-
Hydrogen production	[Mt]	0.5	0.17	2.9 – 3.9	-	-
Hydrogen imports	[Mt]	-	-	-0.3 – -0.4	-	-
Electrolyser capacity	[GW]	<0.01	4	45 – 60	-	-
Solar PV	[GW]	11.8	39.2	52.0	1.5	30 – 43
Onshore wind	[GW]	27.1	49.3	64.9	2.5	24 – 30
Offshore wind	[GW]	-	1.0	6.0	-	5 – 7
Total electricity generation in Spain	[TWh]	274	337	360	9	140 – 186
Investment in electrolyser capacity	[$ bill.]	-	2.9	20 – 27	-	-

Table 8. Main indicators in Spain

Sources: MITECO, 2020a; MITECO, 2020b; SP Gov, 2021; OME, 2021; analysis by the authors

Notes: Hydrogen demand and production in 2020 refer to grey hydrogen. Hydrogen production in 2030 refers only to decarbonised hydrogen; the remainder of demand is met either by CO_2-emitting production or by imports. The symbol "-" represents either zero or not applicable. Negative imports represent exports. Electricity generation for 2020 refers to 2019. Investment refers to the periods 2021-2030 and 2031-2050 respectively.

a. 2030



b. 2050

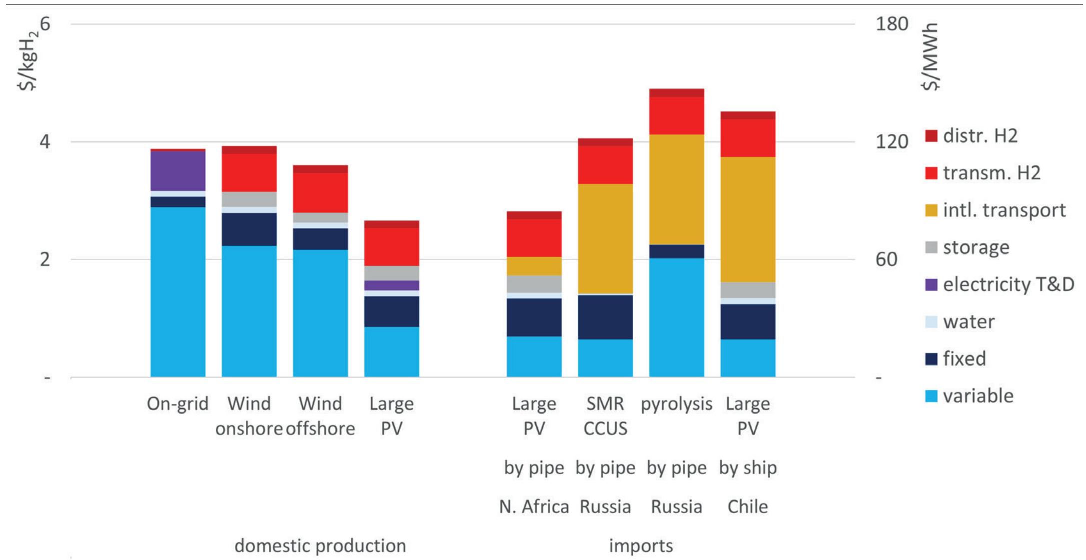


Figure 16. Indicative delivered hydrogen costs to a typical industrial customer in Spain from selected countries and technologies, 2030 and 2050

Source: Analysis by the authors

Notes: The cost of Large PV in 2050 includes generation from wind plants for a further 1000 hours of utilisation of the electrolyser. The cost indicated for on-grid refers to capacity used full time (utilisation rate of 93%). A lower utilisation rate can be envisaged to use predominantly off-peak hours. Gas transmission costs could be cheaper if the plants and dedicated electrolysers are both built close to demand centres. See Annex A for cost assumptions.

Conclusions

Meeting the EU's net-zero GHG emissions goal will require an unprecedented transformation, at unprecedented pace, using a mix of all clean energy sources and vectors available. Electricity is going to play a pivotal role, thanks to its decarbonisation and to the increased electrification of final sectors. But not all uses can be easily electrified. Hydrogen has the potential to become the second most important energy vector for the decarbonisation of the energy system, providing a greater contribution particularly in hard-to-abate sectors.

The EU has been a net energy importer for decades. Today, it imports more than 80% of the methane it uses and 95% of its oil. Demand is projected to decrease over the coming decades thanks to the switch to electricity, to energy efficiency measures and to the direct use of renewable sources in final uses. Domestic decarbonised hydrogen production can increase and maximise the use of low-carbon resources in Europe, further reducing the need for imports. Substantial uncertainty surrounds potential hydrogen imports, with volumes varying widely across scenarios. The range estimated in this study is 18-50 MtH_2 in 2050.

The level of penetration of decarbonised hydrogen and its derivatives will also depend on the relative economics with respect to other energy sources. To achieve economies of scale and the associated cost reductions, many projects are being planned and developed in Europe and around the globe. These projects will play a very crucial role not only for delivering the projected cost reductions, but also for establishing the viability of hydrogen production projects, in the case of both domestic supply and export projects in neighbouring countries. Keeping the cost of capital at low levels for all low-carbon projects, both in Europe and for exporting projects, will be of fundamental importance to keep the cost of the energy transition affordable.

These projects, and the gradual deployment of the necessary infrastructure in the shorter timeframe (2025 to 2030), will be essential to the longer term expansion of consumption, production and trade. Achieving significant demand volumes of decarbonised hydrogen and derivatives at affordable prices will hinge on several factors. First, the ability of policymakers to integrate the strategies of different sectors and fuels into one vision, providing fair economic support, ensuring that wind and solar PV projects are additional to those needed to meet electricity demand, avoiding cross-subsidisation among sectors, and establishing the appropriate regulatory measures for trading in a timely manner. Second, the ability of the energy industry to deliver the expected cost reductions, fostering innovation and industrial competitiveness. Third, creating stable relationships with key trading partners, developing the necessary infrastructure, providing long-term visibility to investors and allowing all decarbonised projects to contribute on a level playing field.

Annex A

	Unit	Value
WACC	%	4.5%
Exchange rate EUR vs USD over 2019-2050	-	1.18
Hydrogen - Energy per unit of mass (LHV)	MJ/kg	120.1
CO_2 emission factor of SMR	tonneCO_2/tH_2	10
CCUS capture rate	%	90%

Table 9. General indicators

		European countries		North Africa		Russia	
	Unit	2030	2050	2030	2050	2030	2050
gas prices	$/Mbtu	5.0	5.0	5.0	5.0	3.5	3.5
CO_2 prices	$/tonne$CO_2$	90	175	-	-	-	-
CO_2 transport and storage cost	$/tonne$CO_2$	20	20	20	20	20	20

Table 10. Gas and CO_2 prices in selected regions

		2030				2050			
	Unit	Large PV	Wind onshore	Wind offshore	Nuclear	Large PV	Wind onshore	Wind offshore	Nuclear
Austria	%	12%	27%	n.a.	n.a.	13%	28%	n.a.	n.a.
France	%	14%	28%	46%	90%	15%	29%	50%	90%
Germany	%	11%	27%	50%	n.a.	12%	28%	55%	n.a.
Italy	%	16%	24%	42%	n.a.	17%	25%	45%	n.a.
Spain	%	20%	29%	45%	n.a.	21%	30%	47%	n.a.
Egypt	%	30%	30%	42%	90%	31%	31%	45%	90%
Morocco	%	25%	33%	42%	n.a.	26%	35%	45%	n.a.
Russia	%	13%	22%	n.a.	90%	14%	24%	n.a.	90%
Australia	%	26%	32%	40%	n.a.	28%	34%	45%	n.a.
Chile	%	26%	30%	45%	n.a.	28%	32%	50%	n.a.
Investment cost	$/kW	450	1 380	2 200	4 200 - 5 500	350	1 300	1 750	4 200 - 4 500

Table 11. Capacity factors and unit investment costs of selected new electricity producing plant

	Unit	Electrolysis				Methane-based	
		Alkaline	PEM	SOEC	weighted average	SMR with CCS	Pyrolysis
		2030					
Investment costs	$/kW	390-760	350-730	1 450-2 200	450-850	1 360	950
Investment costs (used in graphs)	$/kW	570	530	1 900	640	1 360	950
Efficiency of new plants	%	65%	65%	72%	65%	69%	52%
Construction time	years	2	2	2	2	2	2
Lifetime	years	20	20	20	20	20	20
OPEX	%	4.0%	4.0%	3.0%	4.0%	3.5%	4.0%
		2050					
Investment costs	$/kW	270-590	160-400	500-880	270-560	1 280	500
Investment costs (used in graphs)	$/kW	430	280	700	400	1 280	500
Efficiency of new plants	%	75%	72%	82%	75%	76%	54%
Construction time	years	2	2	2	2	2	2
Lifetime	years	25	25	25	25	25	25
OPEX	%	4.0%	4.0%	3.0%	4.0%	3.5%	4.0%

Table 12. Investment costs and key parameters of hydrogen-producing plants

	CAPEX		Capacity		OPEX	Utilisa-tion rate	Construc-tion time	Lifetime
		unit		*unit*	*[% of CAPEX]*	*[%]*	*[years]*	*[years]*
Transmission pipeline	1.21	$ million / km	340	ktpa	5.0%	75%	5	40
Transmission pipeline (36»)	2.97	$ million / km	1 234	ktpa	1.5%	57%	5	40
Distribution pipeline	0.5	$ million / km	38	ktpa	5.0%	80%	3	40
Liquefaction	1.4	$ billion	260	ktpa	4.0%	90%	2	30
Export terminal	0.29	$ billion / tank	3 190	t/tank	4.0%	-	2	30
Shipping	0.412	$ billion / ship	11 000	t/ship	4.0%	-	2.5	30
Import terminal	0.32	$ billion / tank	3 550	t/tank	4.0%	-	2	30

Table 13. Investment costs and key parameters of hydrogen pipelines and seaborne

Acknowledgements

This study was led by Marco Baroni[18], in collaboration with several experts from European and neighbouring countries. It was prepared for the European members of the World Energy Council (WEC) under the guidance of a Steering Committee, whose members are:

–	Houda Ben Jannet Allal	Observatoire Méditerranéen de l'Energie
–	Kamel Ben Naceur	Society of Petroleum Engineers
–	Paolo D'Ermo	WEC Italy
–	Íñigo Diaz de Espada	WEC Spain
–	Alexey Gospodarev	WEC Russia
–	Robert Kobau	WEC Austria
–	Priit Mändmaa	WEC Estonia
–	Jean Eudes Moncomble	WEC France
–	Carsten Rolle	WEC Germany

The study was developed in collaboration with the Observatoire Méditerranéen de l'Energie. Lisa Guarrera provided essential input for energy demand and supply projections, and on methodological issues. Assaad Saab, Sohbet Karbuz and Matteo Urbani provided crucial input.

Paul de Montchenu (WEC France) provided key contributions throughout the entire study. Supplementary members and observers were: Adeliya Bulatova (WEC Russia), Maira Kusch (WEC Germany), Ana Padilla (WEC Spain), Paolo Storti (WEC Italy), Ivo Wakounig (WEC Austria) and Sjoerd Ammerlaan (WEC Europe). Felix Thomann (intern) provided valuable support.

A special thank goes to Alessandro Clerici (WEC Italy) for his support and all the useful discussions and inputs all throughout the study.

Valuable contributions and input were provided by Austrian Federal Ministry for Climate Action, Austrian Power Grid GmbH, E.ON SE, Électricité de France, Enagas, EnBW Energie Baden-Württemberg AG, Energie Burgenland AG, Energie Steiermark AG, Eni, Fronius International GmbH, Ludwig-Bölkow-Systemtechnik GmbH, Gas Connect Austria GmbH, Gazprom PJSC, Gazprom Germania GmbH, Novatek PJSC, Rusatom Overseas JSC, Russian Energy Agency, Saipem, Siemens Energy, SNAM, TÜV SÜD AG, Uniper SE, VERBUND AG, Wien Energie GmbH, Wiener Stadtwerke GmbH.

The study benefitted from continuous interaction with many experts and peer reviewers. A very important contribution was provided by the speakers at the webinar organised in February 2021. Experts, peer reviewers and speakers are:

–	Lahsen Amarof	Ministry of Energy, Mines and Environment, Morocco
–	Etienne Beeker	France Stratégie
–	Mauricio Belaunde	Austrian Federal Ministry for Climate Action
–	Abderraouf Benabou	Ministry of Energy, Mines and Environment, Morocco
–	Tudor Constantinescu	European Commission
–	Rachid Ben Daly	Ministry of Energy, Tunisia
–	François Dassa	Électricité de France

18. Energy expert, consultant and lecturer at Institut d'études politiques de Paris (Sciences Po). Former Head of Power Sector Analysis for the World Energy Outlook team of the International Energy Agency.

–	Denis Deryushkin	Russian Energy Agency
–	Hafez El Salmawy	Former Electricity Regulatory in Egypt
–	Mohamed El Sawy	Former Kuwaiti Petroleum Company
–	Eng. Sherif El Serafi	Former Ministry of Petroleum in Egypt
–	Mohamed El -Sobki	Cairo University and Former New and Renewable Energy Authority in Egypt
–	Valeria Ermakova	NOVATEK PJSC
–	Eugeniy Grin	Gazprom PJSC
–	Konstantin Grebennik	Russian Energy Agency
–	Haitam Hassan	Ministry of Energy, Mines and Environment, Morocco
–	Ines Kastil	Verbund
–	Maximilian Kuhn	Gazprom Germania GmbH
–	Khalil Lagtari	ONEE
–	Andrey Logatkin	Rosseti PJSC
–	Mohamed Ghazali	Ministry of Energy, Mines and Environment, Morocco
–	Vieri Maestrini	SNAM
–	Jan Michalski	Ludwig-Bölkow-Systemtechnik GmbH (LBST)
–	Mohamed Ouhmed	Ministry of Energy, Mines and Environment, Morocco
–	Elena Pashina	Rusatom Overseas JSC
–	Uwe Remme	International Energy Agency
–	Xavier Lorenzo Rousseau	SNAM
–	Deger Saygin	Shura Energy Transition Center, Turkey
–	Jean-Michel Trochet	Électricité de France
–	Michael Zakaria	Gas Connect Austria GmbH
–	Rudolf Zauner	Verbund

References

(ACER CEER, 2021) ACER CEER, When and How to Regulate Hydrogen Networks?, February 2021

https://acer.europa.eu/Media/News/Pages/ACER-and-CEER-recommend-when-and-how-to-regulate-pure-hydrogen-networks.aspx

(Agora VW-EW-FE, 2018) Agora Verkehrswende, Agora Energiewende and Frontier Economics, The Future Cost of Electricity-Based Synthetic Fuels, 2018

www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf

(Agora EW, 2019) Agora Energiewende, EU-wide innovation support is key to the success of electrolysis manufacturing in Europe, November 2019

https://www.agora-energiewende.de/en/blog/eu-wide-innovation-support-is-key-to-the-success-of-electrolysis-manufacturing-in-europe/

(Agora EW, 2021) Agora Energiewende and AFRY Management Consulting, No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe, 2021

https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf (agora-energiewende.de)

(AT BMK, 2019a) Bundesministerium Klimaschutz, Energie, Mobilität, Innovation und Technologie, Umwelt, Integrated National Energy and Climate Plan for Austria, 2019

Österreichs integrierter nationaler Energie- und Klimaplan, https://www.bmk.gv.at/themen/klima_umwelt/klimaschutz/nat_klimapolitik/energie_klimaplan.html (bmk.gv.at)

(AT BMK, 2019b) Bundesministerium Klimaschutz, Energie, Mobilität, Innovation und Technologie, Umwelt, Preliminary discussions for the Austrian Hydrogen Strategy, 2019

Österreichische Wasserstoffstrategie, https://www.bmk.gv.at/themen/energie/energieversorgung/wasserstoff/oe_wasserstoffstrategie.html (bmk.gv.at)

(BEIS, 2021) Business, Energy & Industrial Strategy, UK Hydrogen Strategy, August 2021

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

(BMWi, 2020a) German Bundesministerium für Wirtschaft und Energie (BMWi): National Wasserstoffstrategie, Berlin, Jun 2020

https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html

(BMWi, 2020b) German Bundesministerium für Wirtschaft und Energie (BMWi) Integrated National Energy and Climate Plan for Germany, June 2020

https://www.bmwi-energiewende.de/EWD/Redaktion/EN/Newsletter/2020/06/Meldung/news2.html

(Bruegel, 2021) McWilliams, B. and G. Zachmann, Navigating through hydrogen, Policy Contribution April 2021, Bruegel

https://www.bruegel.org/2021/04/navigating-through-hydrogen/

(Caglayan, 2020) D. G. Caglayan et al. (2020): Technical potential of salt caverns for hydrogen storage in Europe. ELSEVIER, 45(11), pp. 6793–6805

Technical potential of salt caverns for hydrogen storage in Europe – ScienceDirect, https://www.sciencedirect.com/science/article/abs/pii/S0360319919347299

(CGI, 2017) Commissariat Général à l'investissement, The discount rate in the evaluation of public investment project, Ministère de la Transition Ecologique et Solidaire. France, 2017

https://www.strategie.gouv.fr/debats/taux-dactualisation-levaluation-projets-dinvestissement-public

(Clerici and Furfari, 2021) Clerici, A., Furfari, S., Present and future green hydrogen production cost, July 2021
https://www.science-climat-energie.be/2021/07/16/the-present-and-future-green-hydrogen-production-cost/

(DENA, 2018) German Energy Agency, Integrated Energy Transition – Impulses to shape the energy system up to 2050, 2018
https://www.dena.de/fileadmin/dena/Dokumente/Pdf/9283_dena_Study_Integrated_Energy_Transition.PDF

(EC, 2018) European Commission: A Clean Planet for all, 2018
https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

(EC, 2019a) European Commission The European Green Deal COM/2019/640 Final (2019)
https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF

(EC, 2019b) European Commission long-term analysis in depth analysis figures 20190722
https://ec.europa.eu/clima/sites/default/files/strategies/2050/docs/long-term_analysis_in_depth_analysis_figures_20190722_en.pdf

(EC, 2020a) European Commission Communication. A Hydrogen Strategy for a Climate-Neutral Europe COM/2020/301 Final (2020)
https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

(EC, 2020b) European Commission Communication. An EU Strategy to Harness the Potential of Offshore Renewable Energy for a Climate Neutral Future, COM (2020) 741 Final (2020)
https://ec.europa.eu/energy/sites/ener/files/offshore_renewable_energy_strategy.pdf

(EC, 2020c) European Commission, Hydrogen generation in Europe: Overview of key costs and benefits, Jul 2020
https://op.europa.eu/en/publication-detail/-/publication/7e4afa7d-d077-11ea-adf7-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

(EC, 2020d) European Commission, Powering a climate-neutral economy – An EU Strategy for Energy System Integration, Brussels, Jul 2020
https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf

(EC, 2021) European Commission, Annex to supplementing Regulation (EU) 2020/852, Brussels, June 2021
https://eur-lex.europa.eu/resource.html?uri=cellar:d84ec73c-c773-11eb-a925-01aa75ed71a1.0021.02/DOC_2&format=PDF

(EEG, 2021) German Renewable Energy Sources Act, 2021
https://www.gesetze-im-internet.de/eeg_2014/EEG_2021.pdf

(EHB, 2020) European Hydrogen Backbone, How a Dedicated Hydrogen Infrastructure can be created, July 2020
https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf

(EHB, 2021a) European Hydrogen Backbone, A European Hydrogen Infrastructure Vision Covering 21 Countries, April 2021
https://gasforclimate2050.eu/wp-content/uploads/2021/04/European-Hydrogen-Backbone_April-2021_V2.pdf

(EHB, 2021b) European Hydrogen Backbone, Analysing future demand, supply, and transport of hydrogen, June 2021
https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf

(ENTSO-G, GIE, HE, 2021) ENTSO-G, Gas Infrastructure Europe, Hydrogen Europe, How

to transport and store hydrogen – Facts and Figures, 2021
https://www.gie.eu/wp-content/uploads/filr/3429/entsog_gie_he_QandA_hydrogen_transport_and_storage_210521.pdf

(EWI, 2020) Institute of Energy Economics at the University of Cologne gGmbH (EWI) Brändle, Gregor; Schönfisch, Max; Schulte, Simon, Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen, EWI Working Paper No. 20/04, Cologne, November 2020
https://www.ewi.uni-koeln.de/cms/wp-content/uploads/2021/05/EWI_WP_20-04_Estimating_long-term_global_supply_costs_for_low-carbon_Schoenfisch_Braendle_Schulte.pdf

(EWI, 2021) Institute of Energy Economics, University of Cologne, The Oxford Institute for Energy Studies, Contrasting European hydrogen pathways: An analysis of differing approaches in key markets, March 2021
https://www.ewi.uni-koeln.de/cms/wp-content/uploads/2021/04/Contrasting-European-hydrogen-pathways-An-analysis-of-differing-approaches-in-key-markets-NG166.pdf

(FCH JU, 2019) Fuel Cells and Hydrogen Joint Undertaking, Hydrogen Roadmap Europe, 2019
https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

(FR Gouv, 2020a) Ministère de la Transition Écologique et Solidaire, Stratégie nationale bas-carbone, France, March 2020
https://www.ecologie.gouv.fr/sites/default/files/2020-03-25_MTES_SNBC2.pdf#page=19&zoom=100,76,420

(FR Gouv, 2020b) Gouvernement Français, Stratégie nationale pour le développement de l'hydrogène décarboné en France, France, September 2020
https://www.ecologie.gouv.fr/sites/default/files/DP%20-%20Strat%C3%A9gie%20nationale%20pour%20le%20d%C3%A9veloppement%20de%20l%27hydrog%C3%A8ne%20d%C3%A9carbon%C3%A9%20en%20France.pdf

(Furfari and Clerici, 2021) Furfari, S., Clerici, A., Green hydrogen: the crucial performance of electrolysers fed by variable and intermittent renewable electricity. Eur. Phys. J. Plus 136, 509, May 2021
https://link.springer.com/epdf/10.1140/epjp/s13360-021-01445-5?sharing_token=6hn6MudJzDNQJ6ZKzpyUfosPkCdkOxEKPl2JoxdvwqEAWvjInh-bY_2PoGU36O8QsxBu-9BxkSz_AShNlUQSMKHkvcwiYLaxohu-RRGHtYRc37d-DeQftQOralVQUNsj0FZ2yj17FL0ZGN1WK8PvRw5kuTykDIV3dCKcUPYNhuy0%3D

(GIE, 2021) Gas Infrastructure Europe, Picturing the value of underground gas storage to the European hydrogen system, June 2021
https://www.gie.eu/publications/studies/

(Gollier, 2013) Gollier C. (2013) Pricing the Planet's Future: The Economics of Discounting in an Uncertain World, Princeton University Press
https://press.princeton.edu/books/hardcover/9780691148762/pricing-the-planets-future

(HC, 2020) Hydrogen Council, Path to hydrogen competiveness: a cost perspective, 2020
https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

(HIC, 2021) Hydrogen Import Coalition, Shipping sun and wind to Belgium is key in climate neutral economy, 2021
https://newsroom.portofantwerp.com/ready-for-the-next-step-towards-the-belgian-hydrogen-economy

(HM Treasury, 2003) HM Treasury, The Green Book – Appraisal and evaluation in central government, London, 2003
https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

(IEA, 2019) International Energy Agency, The Future of Hydrogen, Paris, June 2019
https://www.iea.org/reports/the-future-of-hydrogen

(IEA, 2020) International Energy Agency, World Energy Outlook 2020, Paris, October 2020
https://www.iea.org/reports/world-energy-outlook-2020

(IEA, 2021a) International Energy Agency, Hydrogen in North Western Europe, Paris, April 2021
https://www.iea.org/reports/hydrogen-in-north-western-europe

(IEA, 2021b) International Energy Agency, Energy security page, Paris, web page retrieved in June 2021
https://www.iea.org/topics/energy-security

(IEA, 2021c) International Energy Agency, Net Zero by 2050: A Roadmap for the Global Energy Sector, Paris, May 2021
https://iea.blob.core.windows.net/assets/405543d2-054d-4cbd-9b89-d174831643a4/NetZeroby2050-ARoadmapfor-theGlobalEnergySector_CORR.pdf

(IEAGHG, 2017) IEAGHG Technical Report 2017-02. Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS, Cheltenham, United Kingdom, February 2017
https://ieaghg.org/exco_docs/2017-02.pdf

(IFPEN-SINTEF-Deloitte, 2021) IFP Energies Nouvelles, SINTEF Energi AS and Deloitte Finance, Hydrogen for Europe study: Charting Pathways to Enable Net Zero, May 2021
https://2d214584-e7cb-4bc2-bea8-d8b7122be636.filesusr.com/ugd/2c85cf_69f4b1bd94c5439f9b1f87b55af46afd.pdf

(IPCC, 2018) Intergovernmental Panel on Climate Change, Special Report on Global Warming of 1.5°C, 2018
https://www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf

(IPHE, 2021) International Partnership for Hydrogen and Fuel Cells in the Economy, web page retrieved in June 2021
https://www.iphe.net/copy-of-partners

(IRENA, 2020a) International Renewable Energy Agency, Wind and Solar PV – what we need by 2050, Abu Dhabi, January 2020
https://www.irena.org/-/media/Files/IRENA/Agency/Webinars/07012020_INSIGHTS_webinar_Wind-and-Solar.pdf?la=en&hash=BC60764A90CC2C4D80B374C1D169A47FB59C3F9D

(IRENA, 2020b) International Renewable Energy Agency, Green Hydrogen Cost Reduction – scaling up electrolysers to meet the 1.5C climate coal, Abu Dhabi, 2020
https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

(JRC, 2011) Joint Research Centre, Assessment of Hydrogen Delivery Options, Brussels, June 2021
https://ec.europa.eu/jrc/sites/default/files/jrc124206_assessment_of_hydrogen_delivery_options.pdf

(MISE, 2019) Ministry of Economic Development, Integrated National Energy and Climate Plan, Italy, December 2019
https://www.mise.gov.it/images/stories/documenti/it_final_necp_main_en.pdf

(MISE, 2020) Ministry of Economic Development, Strategia Nazionale Idrogeno Linee guida preliminari, Italy, November 2020
https://www.mise.gov.it/images/stories/documenti/Strategia_Nazionale_Idrogeno_Linee_guida_preliminari_nov20.pdf

(MITECO, 2020a) Ministerio para la Transición Ecológica y el Reto Demográfico, Plan Nacional Integrado de Energía y Clima 2021-2030, Spain, January 2020 https://www.miteco.gob.es/images/es/pnieccompleto_tcm30-508410.pdf (miteco.gob.es)

(MITECO, 2020b) Ministerio para la Transición Ecológica y el Reto Demográfico, Hoja de Ruta del Hidrógeno: una apuesta por el hidrógeno renovable, Spain, July 2020
https://www.miteco.gob.es/images/es/hojarutahidrogenorenovable_tcm30-525000.PDF

(NL Gov, 2020) The Netherlands Government Hydrogen Strategy, April 2020
https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen

(NO Gov, 2020) The Norwegian Government Hydrogen Strategy, June 2020
https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf

(Nordhaus, 2018) Nordhaus, W.D., A Question of Balance: Weighing the Options on Global Warming Policies, Yale University Press, 2018
https://yalebooks.yale.edu/book/9780300209396/question-balance

(OME, 2021) Observatoire Méditerranéen de l'Energie, MEPto2050, 2021
https://www.ome.org/mep-2021-to-be-released-in-jun-2021/

(PL MKiS, 2021) Ministry of Climate and Environment, Hydrogen Strategy to 2030 with outlook for 2040 in Poland, draft for public consultation opened in January 2021, Warsaw, 2021
https://bip.mos.gov.pl/strategie-plany-programy/polska-strategia-wodorowa-do-roku-2030-z-perspektywa-do-2040-r/

(PoR, 2020) Port of Rotterdam, Port of Rotterdam Becomes International Hydrogen Hub, Rotterdam, May 2020
https://www.portofrotterdam.com/sites/default/files/hydrogen-vision-port-of-rotterdam-authority-may-2020.pdf?token=06Wpgm7R

(PT Gov, 2020) Estratégia Nacional para o Hidrogénio, Portugal, August 2020
https://www.dgeg.gov.pt/pt/areas-transversais/relacoes-internacionais/politica-energetica/estrategia-nacional-para-o-hidrogenio/

(Rifkin, 2001) Jeremy Rifkin, The Hydrogen Economy, 2001
https://link.springer.com/chapter/10.1007/978-1-84882-511-6_8

(RU Gov, 2020a) Energy Strategy of the Russian Federation for the period until 2035 ("Energeticheskaya strategiya Rossiyskoy Federatsii na period do 2035 goda"), June 2020
https://minenergo.gov.ru/node/1026

(RU Gov, 2020b) Roadmap for the development of hydrogen energy in the Russian Federation until 2024, October 2020
https://minenergo.gov.ru/node/19194

(SNAM, 2019) The Hydrogen Challenge: The potential of hydrogen in Italy, 2019
https://www.snam.it/it/hydrogen_challenge/repository_hy/file/The-H2-challenge-Position-Paper.pdf (snam.it)

(SP Gov, 2021) Boletín Oficial del Estado, 25 March 2021
https://www.boe.es/boe/dias/2021/03/31/pdfs/BOE-A-2021-5106.pdf

(Timmerberg et al., 2020) Timmerberg S., Kaltschmitt M., Finkbeiner M., Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs, Energy Conversion and Management: X, 7, art. no. 100043, September 2020
https://www.sciencedirect.com/science/article/pii/S2590174520300155

(US OMB, 2003) US Office of Management and Budget, Circular N. A-4 To the Heads of Executive Department Establishments, Subject: Regulatory Analysis. Washington: Executive Office of the President, Washington, September 2003 https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/

(WB, 2021) World Bank annual freshwater withdrawals, web page retrieved in June 2021
https://data.worldbank.org/indicator/ER.H2O.FWTL.K3?locations=EU

(WEC Germany et LBST, 2020) World Energy Council Germany and Ludwig Bölkow Systemtechnik, International Hydrogen Strategies, September 2020
https://www.weltenergierat.de/wp-content/uploads/2020/09/WEC_H2_Strategies_finalreport_200922.pdf

(WEC Germany, 2021) World Energy Council Germany, Hydrogen: essential element of a decarbonised energy system, web page retrieved in June 2021
https://www.weltenergierat.de/international-hydrogen-strategies/

(WindSeeG, 2016) German Wind Offshore Act, 2016
http://www.gesetze-im-internet.de/windseeg/WindSeeG.pdf

List of Abbreviations and Acronyms

AEM	Anion Exchange Membrane
CAPEX	Capital expenditure
CCfD	Carbon contracts for difference
CCUS	Carbon capture, utilisation and storage
DAC	Direct Air Capture
EC	European Commission
FCH JU	Fuel Cell and Hydrogen Joint Undertaking
FiT	Feed-in tariff
GHG	Greenhouse gas
GW	Gigawatt
H_2	Hydrogen
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCOH	Levelised Cost of Hydrogen
LOHC	Liquid Organic Hydrogen Carriers
MWh	Megawatt-hour
OPEX	Operational expenditure
PEM	Proton Exchange Membrane
PPA	Power-purchase agreements
PV	Photovoltaic
SDS	Sustainable Development Scenario (IEA)
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cells