CEPS RESEARCH REPORT

IS RENEWABLE HYDROGEN A SILVER BULLET FOR DECARBONISATION?

A critical analysis of hydrogen pathways in the EU

Mihnea Cătuți, Edoardo Righetti,
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Abstract

Clean hydrogen will offer decarbonisation solutions for sectors where direct electrification would be either technologically impossible or too costly, though future demand should not be overestimated. Hydrogen will most likely be used in hard-to-decarbonise industrial processes, some segments of the transport sector, as well as for long-term energy storage. For hydrogen to contribute to decarbonisation, it needs to be produced with minimal greenhouse gas emissions. Therefore, hydrogen obtained through electrolysis using renewable electricity will represent the priority for the EU. However, this does come with a set of trade-offs, all of which are explored at length in this report. A key challenge will be the interaction with the already-strained electricity market. New renewable energy installations are facing deployment obstacles, therefore the decarbonisation of the electricity mix and the deployment of renewable hydrogen need to be developed together to avoid tensions. This report also focuses on two other potential hydrogen sources. Nuclear hydrogen could create more opportunities for producing low-carbon hydrogen from electricity, whilst imports could cover potential supply deficits and provide further access to inexpensive renewable hydrogen for domestic consumption. Robust criteria will be needed for certifying the renewable nature of hydrogen, based on clear temporal and geographical connection requirements between the electrolyser and the renewable installations. However, the separate certification of low-carbon hydrogen produced from electricity that meets similar emissions savings requirements should also be established, without labelling it as renewable.

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Executive summary

The European Union's objective to reach net-zero greenhouse gas (GHG) emissions by 2050 requires, most importantly, the direct electrification of the economy, which could cover more than 60 % of end-uses according to various scenarios. This makes sense from an efficiency perspective. Nonetheless, there are limits to the extent to which direct electrification can be implemented. Hydrogen is considered to be a potential solution, particularly for sectors where full electrification would be either technologically impossible or too costly, mostly in hard-to-decarbonise industrial processes (such as ammonia, basic chemicals and primary steel production) and some segments of the transport sector (particularly maritime and long-haul aviation). Hydrogen may also provide solutions for long-term energy storage. Hydrogen's contribution to the buildings sector is expected to be limited.

For hydrogen to enable the decarbonisation of these sectors, it needs to be produced with minimal GHG emissions. While this can be achieved in multiple ways, including through pyrolysis or from sustainable biomass, the European Commission's hydrogen strategy outlines a central role for renewable hydrogen – produced from water electrolysis using renewable electricity. Consequently, the proposals made in the Fit for 55 package aim at setting sectorial targets that will stimulate renewable hydrogen consumption.

Therefore, the main focus over the next decades will be on the large-scale deployment of electrolysers. Electrolysis technologies are at different levels of technological readiness, with alkaline water and polymer electrolyte membrane being the most commercially available. The upfront capital expenditure for electrolysers remains high and further cost reductions are needed for making renewable hydrogen competitive. Ensuring a sufficiently high load factor for electrolysers – between 3 000 and 6 000 hours – can also reduce the influence of the capital expenditure on hydrogen production costs. When electrolysers have a high utilisation rate, the price of electricity becomes the dominant cost factor. Under such circumstances, access to high amounts of renewable electricity is a key driver of the competitiveness of renewable hydrogen. This will mostly rest on the ability to deploy sufficient new renewable energy capacities and on the selection of criteria based on which hydrogen will be labelled as renewable.

Regarding the first aspect, new renewable energy installations are already facing obstacles to deployment – mainly related to public acceptability, grid development and strenuous planning and permitting processes. Under such conditions, there may be difficulties in meeting the renewable capacity requirements for decarbonising the electricity mix and for covering the increased demand from the further direct electrification of end-uses, which will require an expansion in renewable capacities of previously unseen pace and magnitude. It has been estimated that for the 40 GW of electrolysis capacity planned by the European Commission for 2030, 80-120 GW of additional solar and wind capacities would be needed, which is equivalent to three times the Europe-wide renewables capacity increase from 2019.

By 2030, it is expected that around 70 % of electricity output – renewables and nuclear combined – will have nearly zero marginal costs. This will transform the economics of the power sector. In spite of the currently high energy prices, there have been concerns that the market price signal and with it, the ability to remunerate existing assets, is insufficient to drive new investments. Moreover, there are concerns that the addition of renewable hydrogen production could create further tensions with the already challenging decarbonisation of the electricity mix. To name but a few issues, hydrogen production and support policies could affect electricity prices, competition for renewable resources, grid congestion and renewable electricity targets.

To avoid such problems, the decarbonisation of the electricity mix and the deployment of renewable hydrogen production need to be developed together. One way of ensuring that renewable hydrogen does not cannibalise the renewable electricity needed for decarbonisation would be for Member States to take into account the new projected electricity demand for producing hydrogen when preparing national energy and climate plans.

The second important aspect related to access to renewable electricity for hydrogen production is the criteria that will be used for certifying the renewable credentials of electrolytic hydrogen. These will be set by the end of 2021 through the implementing acts for the revised Renewable Energy Directive. Debate centres around the application of the principle of additionality, which seeks to ensure that the electricity for hydrogen production is only sourced from new renewable capacities that would not have been developed otherwise. This requirement stems from fears that the renewable power used for hydrogen would be compensated by dispatching additional fossil fuel-fired capacities, leading to a subsequent increase in CO_2 emissions.

The way in which the additionality principle is implemented will have an impact on the availability of renewable electricity for hydrogen production. A physical connection would be the simplest way to ensure that hydrogen is produced from renewable electricity, but this may not provide a sufficiently high load factor for cost-effective hydrogen production and comes with logistical hurdles for hydrogen transport. Moreover, the lead times associated with renewable investments compared with electrolysers are also considered potential barriers. Directly linking electrolysers to specific renewable installations could go against a 'whole-system' approach, which is especially important from the perspective of sector integration. The contribution of electrolysers to providing grid flexibility would be diminished and hydrogen would not be produced from other climate-neutral electricity sources, such as nuclear energy or existing renewable energy sources. Renewable power generation and hydrogen production could also be matched on a 'system level', but this loose form of connection may fail to appropriately certify the renewable nature of hydrogen. Usage of guarantees of origin is not sufficient – geographical and temporal connections are also needed.

Thus, robust criteria for certifying the renewable nature of hydrogen should be established, while also allowing for the certification of low-carbon hydrogen produced from electricity that meets the requirement of 70 % GHG emissions savings and the carbon intensity set out in the taxonomy. In line with the strategies for hydrogen and energy system integration, the upcoming hydrogen and decarbonised gas package is expected to recognise the role of low-carbon hydrogen. Labelling just part of the electrolytic hydrogen production using grid electricity as renewable could improve the economics of electrolysis, particularly in countries with a lower carbon intensity of the electricity mix, where on-grid electrolysis could be achieved below the taxonomy threshold. Ultimately, ensuring that sufficient safeguards are in place for reaching climate neutrality by 2050 is most important. If such low-carbon hydrogen could be certified based on strict estimates of the CO_2 content of the grid electricity, it could still find potential customers even if it is not labelled as renewable. This could help avoid oversizing and underutilising the electrolyser, which could reduce the capital expenditure (CAPEX).

For meeting the expected hydrogen demand – though this should not be overestimated – the EU should make use of all available sources of low-carbon electrolytic hydrogen. Hence, this report looks at two other potential sources – imports and nuclear energy-based hydrogen.

While the hydrogen economy value chain is of strategic importance to the EU, it is likely that not all demand will be (or needs to be) fulfilled domestically. Similar to other energy carriers today, trade is possible and for some Member States facing supply deficits it will even be desirable from a diversification perspective. Imports can also offer further access to inexpensive renewable hydrogen, which can enable a lower cost pathway to decarbonisation. The desirability of renewable hydrogen imports rests on two determinants: the costs associated with production and transport and the climate credentials of imported hydrogen, which ought to be measurable and verifiable.

Based on current estimates, no major cost advantage is expected for imports, given the higher transport, conversion and reconversion costs. Yet, imported hydrogen could be required irrespective of price competitiveness to cover a supply deficit, should that occur. Imported hydrogen would need to be subjected to a proper certification system based on a life-cycle assessment, which should also cover transport-related emissions. Consistent international rules and a rigorous regulatory framework would have to guarantee that the same standards that apply to hydrogen that is considered clean when produced within the EU are required for imports.

Meanwhile, nuclear energy could also provide opportunities for producing low-carbon hydrogen from electricity. But it does come with additional challenges. One is related to certification. While bringing similar reductions in emissions, nuclear energy cannot be labelled as renewable. Therefore, it would not contribute to the achievement of renewable targets and may have even lower value recognition than renewable hydrogen. Nuclear energy is also associated with safety and non-climate environmental concerns and public acceptance. For those Member States where acceptability is not a concern, low-carbon hydrogen certification could allow usage of decarbonised electricity from the grid, including nuclear, which could enable greater access to low-carbon electricity for hydrogen production. Generally, nuclear reactors use relatively small land areas per MWh of electricity produced, thus leading to less land utilisation. Hydrogen could also be produced on the site of nuclear power plants, allowing for high load factors. Several new innovative concepts could provide additional advantages for electrolysis.

1. Introduction and context

The EU's efforts to create an appropriate policy framework for reaching net-zero greenhouse gas (GHG) emissions by 2050 have been significantly strengthened by the European Commission over the past two years. The European Green Deal[1] outlines some of the most consequential policy changes that will reshape the European economy towards decarbonisation over the next 30 years. The Climate Law enshrines the climate neutrality objective in legislation. The sustainable Europe investment plan[2] establishes the pillars on which the EU will finance the transition. The European Investment Bank will stop financing fossil fuel projects as of 2022[3]. The Fit for 55 package[4] outlines a set of wide-ranging legislative revisions to help reach the new 55 % GHG emissions reduction target for 2030. The funds allocated through the 2021-2027 multiannual financial framework, as well as NextGenerationEU[5] (aimed at providing financial recovery aid after the economic slowdown of the coronavirus pandemic) will further contribute to these objectives. Together they amount to EUR 1.82 trillion, 30 % of which will target climate-related projects. This plethora of instruments provides the legislative framework and the financial firepower for achieving net-zero GHG emissions, efforts which now move into the implementation phase.

In practice, reaching the objectives of the European Green Deal rests on a combination of improvements in energy efficiency, decarbonisation of the electricity and energy mix, increased electrification, mobilisation of the circular economy, and decarbonisation of transport, buildings, industrial processes, agriculture and residual emissions. It also involves behavioural change.

For achieving climate neutrality, direct electrification of end-uses is one of the efficient means and is expected to increase from the present level of around 24 % to at least 60 % by 2050, but there are limits to this trend[6]. For example, processes in difficult-to-decarbonise sectors, such as certain transport modes (aviation and long-haul shipping) and industry (especially for feedstock in the steel and chemical industries), may rely on molecules to achieve the climate objectives in an efficient manner[7].

Hydrogen could represent a decarbonised molecule suitable for these processes. At this time, hydrogen is largely used as a chemical feedstock for the production of ammonia and methanol, as well as in the process of crude oil refining. Its role is set to expand significantly over the next few decades. According to the European Commission's plans, while about 2 % of today's EU

[1] European Commission (2019), *The European Green Deal*, COM(2019) 640 final, 11 December.

[2] European Commission (2020), *Sustainable Europe investment plan: European green deal investment plan*, COM(2020) 21 final, 14 January.

[3] European Investment Bank (2019), *EU bank launches ambitious new climate strategy and energy lending policy*, Press Release 2019-313-EN, 14 November.

[4] European Commission (2021), *European Green Deal: Commission proposes transformation of EU economy and society to meet climate ambitions*, Press Release IP/21/3541, 14 July.

[5] European Council (2020), *Special meeting of the European Council (17, 18, 19, 20 and 21 July 2020) – Conclusions*, 21 July.

[6] See European Parliament (2019), European Commission (2018), Eurelectric (2018).

[7] See Belmans and Vingerhoets (2020).

final energy demand comes from hydrogen[8], its share could reach more than 15 % by 2050, as part of decarbonisation efforts[9]. However, almost the entirety of the current hydrogen production is sourced from fossil fuels. For hydrogen to be best aligned with the net-zero target, it would ideally be produced from electrolysis using zero-emissions electricity. The European Commission prioritises renewable forms of hydrogen, in order to maximise the climate benefits of the emerging hydrogen economy[10].

In July 2020, the Commission released its energy sector integration[11] and hydrogen strategies[12]. Together, they provide roadmaps for the development of two key areas that are essential for reaching climate neutrality by 2050 in a cost-effective manner. They identify some of the measures and investments that will be needed for both encouraging the uptake of clean hydrogen[13] and pursuing a more holistic approach for the energy sector.

The **energy sector integration strategy** sets out to enable the coordination and operation of the energy system 'as a whole', in order to increase efficiency, minimise the transition costs towards climate neutrality and better integrate an increasing share of renewable energy sources. One of the basic premises of the strategy is a greater level of electrification among end-use sectors. Molecules will still be needed in sectors where there is – to date – no clear technological or cost-efficient pathway to electrification. Hydrogen may also help increase the flexibility and resilience of the overall energy system. For this to happen, renewable and low-carbon gaseous fuels should be well integrated with the electricity and end-use sectors to exploit synergies beneficial for the system as a whole. Renewable hydrogen, obtained through electrolysis using solar and wind energy, can provide long-term storage and buffering capability for renewable-energy power generation. The strategy also highlights some of the regulatory reforms that will be required for the gas market in order to support the further uptake of renewable gases.

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[8] European Commission (2020).

[9] According to Agora Energiewende and Agora Industry (2021), in European scenarios hydrogen can reach 16-25 % of final energy demand.

[10] There are also other potential sources of climate-neutral hydrogen, including electrolysis using nuclear energy, pyrolysis of natural gas, provided that there are no fugitive methane emissions, and hydrogen produced from sustainable biomass using carbon capture and storage (CCS), which may even be able to deliver negative emissions. Nonetheless, under the definition of the European Commission's hydrogen strategy, clean hydrogen is to be sourced from renewable electricity.

[11] European Commission (2020), *Powering a climate-neutral economy: an EU Strategy for Energy System Integration*, COM(2020) 299 final, Brussels, 8 July.

[12] European Commission (2020), *A hydrogen strategy for a climate-neutral Europe*, COM(2020) 301 final, Brussels, 7 July.

[13] Similar to the terminology used in the European Commission's hydrogen strategy, for the purposes of this report, clean and renewable hydrogen are used interchangeably to refer to hydrogen produced through the electrolysis of water (but it does not include other forms of renewable hydrogen, such as those produced from sustainable biomass). Electrolytic hydrogen refers to hydrogen produced from the electrolysis of water irrespective of the electricity source. The European Commission's strategy refers to electricity-based hydrogen that does not use renewable energy as 'low-carbon hydrogen'. Nuclear-based hydrogen refers to electrolytic hydrogen produced with nuclear electricity. Fossil-based hydrogen mainly refers to hydrogen produced through the reforming of natural gas. For the sake of clarity, hydrogen from steam methane reforming (SMR) is also used to clearly indicate the process through which it is produced (it does not include pyrolysis, also called turquoise hydrogen). Fossil-based hydrogen with carbon capture and low-carbon hydrogen are used interchangeably to refer to hydrogen produced from fossil fuels (mainly natural gas reforming) where up to 90 % of the CO_2 emissions are captured. This is generally called blue hydrogen.

The hydrogen strategy lays out a roadmap for the roll-out of investments in electrolysers, setting the goal of installing at least 6 GW of renewable hydrogen in the EU by 2024 and 40 GW by 2030. The launch of the European Clean Hydrogen Alliance, also announced in the European Commission's industrial strategy, will constitute one of the pillars through which the investments will materialise into concrete projects.

While the European Commission's priority is to develop facilities for renewable hydrogen production facilities on a continental scale, there is a role in the strategy for low-carbon fossil-based hydrogen (with carbon capture technology) and electricity-based low-carbon hydrogen, especially to decarbonise current hydrogen production, yet also to potentially support the development and scale-up of a hydrogen market. In order to differentiate between various methods of producing hydrogen based on their carbon footprint, a terminology list is provided, emphasising the fact that hydrogen may only be considered 'clean' if it comes from renewable energy sources. The European Commission will further propose common standards for low-carbon hydrogen production based on full life-cycle GHG emissions.

Initially, hydrogen infrastructure is expected to develop within local hydrogen clusters, also called 'hydrogen valleys'. The long-term objective – most likely beyond 2030 – is to establish a liquid pan-European market. The uptake of hydrogen will be incentivised through a combination of market-based support schemes, targeted research and development funding, the identification of lead markets, and possibly targets or quotas for renewable hydrogen in end-use sectors. The deployment of a hydrogen economy will furthermore rely upon the development of transport infrastructure, which could come in many forms. The strategy sees a potential role for both newly built, dedicated hydrogen infrastructure and retrofitted natural gas pipelines.

Complementary with the EU strategies, Member States such as Germany, Spain, Portugal, France and the Netherlands have developed their own national hydrogen strategies, with more expected to be elaborated in the near future. Based on these cumulative objectives, clean hydrogen-production capacities will ramp up significantly over the coming years. Concrete policy actions in this regard have been outlined in more recent legislative proposals.

In July 2021, the European Commission released the comprehensive Fit for 55 package, designed to deliver 55 % GHG emissions reduction in the EU by 2030. The proposed legislative revisions are aligned with the ambitions set out in the hydrogen strategy, notably through a set of sub-targets proposed for the revision of the Renewable Energy Directive (RED II), which aims to increase the target for renewable energy sources to 40 % from the current 32 %. As part of the revision, the European Commission is seeking a binding target of 50 % of the hydrogen used for feedstock and energy in the industrial sector to be provided from renewable fuels of non-biological origin (RFNBOs), in addition to a 2.6 % target for RFNBOs in the transport sector. Moreover, the ReFuelEU Aviation initiative further stipulates that fuel suppliers should use 5 % sustainable aviation fuels (SAFs) by 2030, 0.7 % of which are to come from RFNBOs. The proposed targets would increase by 2050 to 63 % and 28 % respectively.

RFNBOs represent fuels that are produced from renewable sources other than biomass. In practice, this will largely consist of fuels produced from renewable electricity, such as renewable hydrogen, that could be used directly in some applications, as well as fuels like ammonia and synthetic hydrocarbons, both of which would need to be produced using renewable hydrogen. Consequently, the proposed RFNBOs targets – if adopted – are expected to provide a significant boost to the demand for renewable hydrogen, to levels similar to those set out in the European Commission's hydrogen strategy. To ensure the positive climate effect of these provisions, certain criteria will be applied. The delegated acts for RED II (to be published by the end of 2021) on GHG emissions accounting and renewable energy sourcing requirements for RFNBOs will propose solutions for this aspect.

Issues of market design, infrastructure planning and the role of market actors are expected to be clarified later this year in the **hydrogen and decarbonised gases market package**. A revision of EU gas rules is envisaged to further facilitate the development of a European hydrogen market and the gradual transition to decarbonised molecules. This will bring much needed clarity for the deployment of hydrogen and the decarbonisation of gaseous fuels over the next years by removing some barriers and creating the baseline conditions for these developments. At the same time, it will not provide a one-size-fits-all answer to the main trade-offs associated with different hydrogen-production pathways. That will require further discussion and contemplation.

This report seeks to bring some clarity regarding the development of the future EU hydrogen economy and some of the main choices that will need to be made. The report is organised as follows. Section 2 focuses on the future sources of demand for hydrogen, while Section 3 discusses the main dilemmas related to renewable hydrogen production. Section 4 discusses possible alternatives for meeting the EU's growing hydrogen demand, i.e. trade-offs associated with nuclear-based hydrogen production and imports of renewable hydrogen from outside the EU respectively. Section 5 brings together the main issues raised in the report, with recommendations.

The analysis is based on a literature review of the most recent reports on the deployment of hydrogen as a decarbonisation solution. This assessment is enriched with information extracted from expert workshops and bilateral discussions organised by CEPS over the past year.

2. The role of hydrogen and the likely sources of demand

While crucial for reaching climate neutrality, the extent to which the expansion of the hydrogen economy is desirable is still not fully clear. There are some fears that a 'hydrogen bubble' is being created, which may artificially inflate the scope of hydrogen demand in a future net-zero emissions economy.

If possible, direct electrification is always a more efficient route for decarbonisation. According to the basic laws of thermodynamics, every time energy is changed from one vector to another (electricity to hydrogen, for example), a significant amount of energy is lost[14]. Producing hydrogen through electrolysis has conversion losses amounting to up to a third of the energy used[15]. For every 1 MWh of hydrogen, 1.5 MWh of electricity is needed. Many processes that currently cannot be electrified efficiently may lend themselves to electrification in the future due to technological progress or new infrastructure development.

Low- or zero-emissions[16] hydrogen is possible for an array of applications in sectors spanning from energy-intensive industry and transport to energy storage and perhaps to some extent the heating of buildings[17]. Projections of future final hydrogen demand range from current levels to a tenfold increase[18]. Based on a systematic review of scenarios, Aurora Energy Research (2021) estimates that hydrogen could provide anywhere between 7 and 21 % of final energy demand in 2050. Ultimately, the extent to which renewable hydrogen deployment is desirable will be determined by a combination of overall efficiency considerations and the availability of other decarbonisation options.

Renewable hydrogen will most likely be necessary in sectors that have few other credible decarbonisation options. These include ammonia, basic chemicals and primary steel production in the industrial sector, as well as long-haul aviation and maritime shipping in the transport sector. To a lesser extent, hydrogen may also represent one of the few viable options for long-term storage in the power sector, part of heavy-duty transportation, and for decarbonising the existing district heating systems in the buildings sector. Table 1 ranks potential hydrogen uses in different sectors from most to least likely.

Industry

The highest future **value** of hydrogen will likely be in industry. Worldwide, hydrogen use is already well-established in the industrial sector, with about 4 % of production from electrolysis[19]. The production of low-carbon fuels, fertilisers and petrochemicals may be dependent on the development of low-emission, economically competitive hydrogen[20]. Ammonia, currently used mostly in agriculture, has the potential to develop into a safe hydrogen carrier, having the advantage of higher energy density and an already developed worldwide infrastructure[21]. While electrification can replace fossil fuel use for the production

[14] Belmans et al. (2021) show that an electrification strategy can bring tremendous efficiency gains in all sectors of the economy.

[15] IRENA (2021).

[16] Low-emissions hydrogen, such as that produced through steam methane reforming using CCS might provide an early solution for incentivising the development of hydrogen infrastructure, but it will likely be incompatible when approaching net-zero emission by 2050. Zero-emissions hydrogen can be produced, for example, through the electrolysis of water using renewable electricity, but electricity-based alternatives are more expensive and have a slower cost-reduction curve than SMR with CCS (see Section 3). Hydrogen from pyrolysis or produced from biomass could also represent low- to zero-carbon hydrogen pathways, but they are not discussed in this report.

[17] Quarton et al. (2020).

[18] McWilliams & Zachmann (2021).

[19] Molloy and Baronett (2019).

[20] Parkinson et al. (2018).

[21] The Royal Society (2020).

of low-temperature heat, fewer alternatives exist for processes that require heat with temperatures higher than 1 000°C, which could be obtained with hydrogen[22].

Table 1. Likely uses of hydrogen as a decarbonisation solution by sector

Future uses of hydrogen	Very likely	→				Very unlikely
Industry	Feedstock for ammonia and basic chemicals	Reduction agent in DRI for primary steel	High temperature heat			Low-temperature heat
Transport	Long-haul aviation Maritime shipping			HDV	Rail transport LDV	Passenger vehicles
Power		Long-term electricity storage				Baseload power
Buildings		Existing large-scale district heating systems			New district heating systems	Individual dwellings

Sources: Own assessment, based on Agora Energiewende (2021), p. 10; McWilliams & Zachmann (2021), p. 7; Belmans and Vingerhoets (2020); European Commission (2018).

Note: Includes hydrogen used in the production of synthetic fuels or other RFNBOs. DRI refers to direct reduced iron.

Transport

In transport, long-haul aviation and maritime shipping will likely require energy-dense fuels, such as synthetic fuels or ammonia, that cannot currently otherwise be provided in the form of batteries. Fuel-cell electric vehicles may provide alternatives to battery electric vehicles in the long-term[23]. In a limited number of cases where electrification would be either prohibitively expensive or not technically feasible, hydrogen may also be used in rail transport.

Buildings

For the buildings sector, the renovation wave strategy envisages that the majority of energy demand will be eliminated through the deep renovation of the existing building stock and the implementation of nZEB standards. For the remaining energy requirements, especially for the provision of heating, heat pumps represent the most efficient solution, especially for individual dwellings. Hydrogen may represent a viable option for the decarbonisation of existing district heating systems, especially in central and eastern Europe, where large-scale systems were developed before 1990. In areas where new district heating systems are developed (which will tend to be smaller in scale), other climate-neutral options are more likely, including renewables, utility-scale heat pumps and waste heat. Therefore, hydrogen is only expected to have limited applications in the heating of buildings sector.

[22] Some alternatives, such as power-to-heat, may become available in the future on this segment as well, as explained by Agora Energiewende (2021).

[23] IRENA (2018).

Sector integration

Hydrogen might also prove useful for managing fluctuations in electricity production. While battery storage costs are expected to continue dropping based on technology learning curves and economies of scale for manufacturing, their use will mostly address short-term intra-daily or weekly fluctuations[24]. For long-term seasonal storage, power-to-hydrogen could represent a cost-efficient alternative to battery storage[25]. Meanwhile, direct combustion for producing baseload power, either in dedicated facilities or blended with natural gas, represents one of the least efficient uses of hydrogen and should generally be avoided.

Thus, hydrogen is a versatile energy carrier for which there are multiple technically feasible applications. Ultimately, demand will depend on costs, availability and the convenience of its use compared with alternatives. Costs depend on feedstock (e.g. the costs of electricity or natural gas) and technology learning curves, but also carbon pricing – which will likewise affect the viability of alternatives. Availability is partly a function of infrastructure, especially considering whether a pan-European infrastructure backbone will exist or not. In this transition period, until the market decides on hydrogen applications, demand will be driven to a large extent by policy in the form of regulation, sectorial targets, subsidies, infrastructure planning and public financing. The present policy framework offers few incentives for renewable hydrogen compared with fossil alternatives. The lack of value recognition for renewable hydrogen today could affect the deployment of electrolysers in the short and medium term. The main focus should thus be on the sectors most likely to require hydrogen for decarbonisation. This could help overcome the current deadlock in the 'chicken-and-egg' problem – renewable hydrogen production cannot ramp up in the absence of a steady source of demand, while no significant demand is likely to emerge without a credible supply of renewable hydrogen[26].

3. Renewable hydrogen supply: costs and emissions

The general expectation is that the currently more costly renewable hydrogen will experience cost reductions to levels below those of fossil-based alternatives after 2030. Figure 1 presents average production costs for fossil-based and renewable hydrogen according to a series of recent reports. In the studies assessed for this analysis, the costs of fossil-based hydrogen with carbon capture either remain stable or slightly increase over time. This is the result of the combined effect of higher natural gas and carbon prices, which will affect the role that low-carbon hydrogen has in decarbonising the current hydrogen supply and in supporting the uptake of hydrogen among end-users in the short and medium term. Meanwhile, as shown in Figure 2, there are significant expectations of cost reductions for renewable hydrogen production in the EU. While this is not evident from the range of price estimations collected for

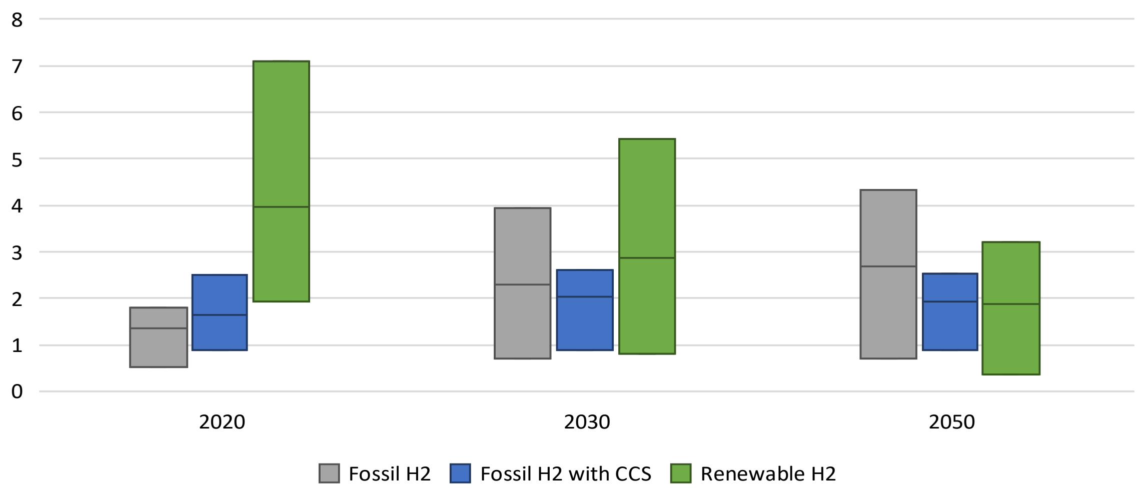
[24] McWilliams & Zachmann (2021).

[25] Given the current high costs of storing hydrogen due to its low volumetric density, power-to-methane may be more competitive than power-to-hydrogen. See Yao et al. (2019).

[26] Agora Energiewende and Agora Industry (2021).

this report, as carbon prices increase, renewable hydrogen should develop a cost-advantage compared to fossil alternatives. The economics of electrolytic hydrogen are further discussed in Section 3.1.

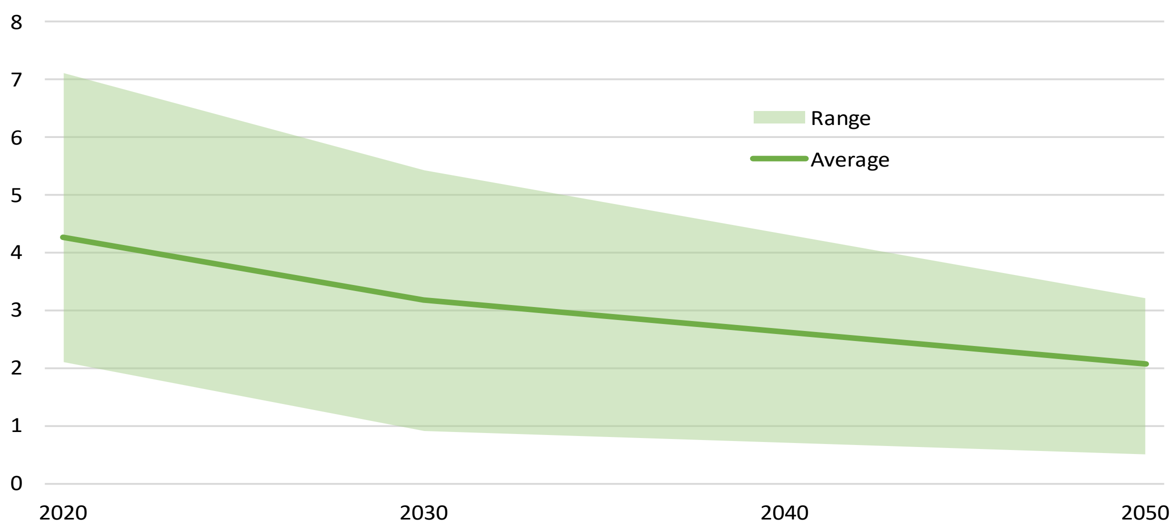
Figure 1. Ranges of LCOH for different technologies (€/kgH_2)



Sources: Piebalgs et al. (2020), Aurora Energy Research (2020; 2021), Agora Energiewende and Guidehouse (2021), Trinomics and LBST (2020), IEA (2019; 2021), DNV GL (2021), Oxford Institute for Energy Studies (2021), Dos Reis (2021), IRENA (2019) and Hydrogen Council (2021b).

Notes: The graph represent ranges based on the reports assessed; hydrogen production through pyrolysis was not considered; for the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).

Figure 2. Range and average levelised costs of renewable hydrogen in the EU (€/kgH_2)



Sources: Piebalgs et al. (2020), Aurora Energy Research (2020; 2021), Agora Energiewende and Guidehouse (2021), Trinomics and LBST (2020), IEA (2019; 2021), DNV GL (2021), Oxford Institute for Energy Studies (2021), Gas for Climate (2020), Dos Reis (2021).

Notes: The graph represents the range and average based on the reports assessed. For the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).

The other important consideration is emissions. Different production methods have different sources of emissions. For hydrogen produced through steam methane reforming (SMR), the majority of emissions are the CO_2 and CH_4 associated with the unabated use of natural gas. At present, production of hydrogen from natural gas generates about 10 $kgCO_2e/kgH_2$[27].

For hydrogen obtained from SMR with carbon capture, most emissions stem from the natural gas supply chain, while the process of carbon capture adds an efficiency penalty and higher fuel consumption. Capture rates for CO_2 of 75-90 % are commonly assumed[28]. High methane leakage rates (up to 20 %) could eliminate any climate benefits provided by this type of hydrogen, as shown by ICCT (2021).

For electrolysis, they arise from the carbon intensity of electricity production and the emissions related to the manufacture of the electricity-generation technologies, such as solar panels and wind turbines, if using a full life-cycle analysis[29]. The lowest emissions are associated with hydrogen produced from electricity generated with few or no GHG emissions. The carbon intensity of electrolytic hydrogen is about 1 $kgCO_{2e}/kgH_2$ for solar, 0.5 $kgCO_{2e}/kgH_2$ for wind[30], and 0.6 $kgCO_{2e}/kgH_2$ for nuclear power[31].

Meanwhile, for electrolysers directly linked to the grid, emission levels vary with the carbon intensity of the grid. It has been estimated that the emissions intensity of electricity must be below 190 gCO_{2e}/kWh for electrolytic hydrogen to have lower emissions than fossil-based hydrogen without carbon capture[32]. Today's average electricity-related emissions in the EU are 285 gCO_{2e}/kWh, which would result in 430 gCO_{2e}/kWh average emissions for electrolytic hydrogen produced from the European electricity grid[33]. Figure 3 shows that in some cases, as in that of Germany, the carbon intensity of electrolytic hydrogen produced with electricity from the grid can be even higher than that of fossil-based hydrogen.

[27] IEA (2019).

[28] Hydrogen production from natural gas utilising autothermal reforming technology could allow for higher capture rates with minimal energy efficiency penalties. Capture rates as high as 94-97 % could be achieved. See https://zeroemissionsplatform.eu/wp-content/uploads/ZEP-paper-Facts-on-low-carbon-hydrogen-%E2%80%93-A-European-perspective-October-2021.pdf

[29] Additionally, in the case of energy carriers resulting from the processing of biomass, most emissions originate from the supply chain of the cultivation of crops, the transportation of biomass and changes in land use.

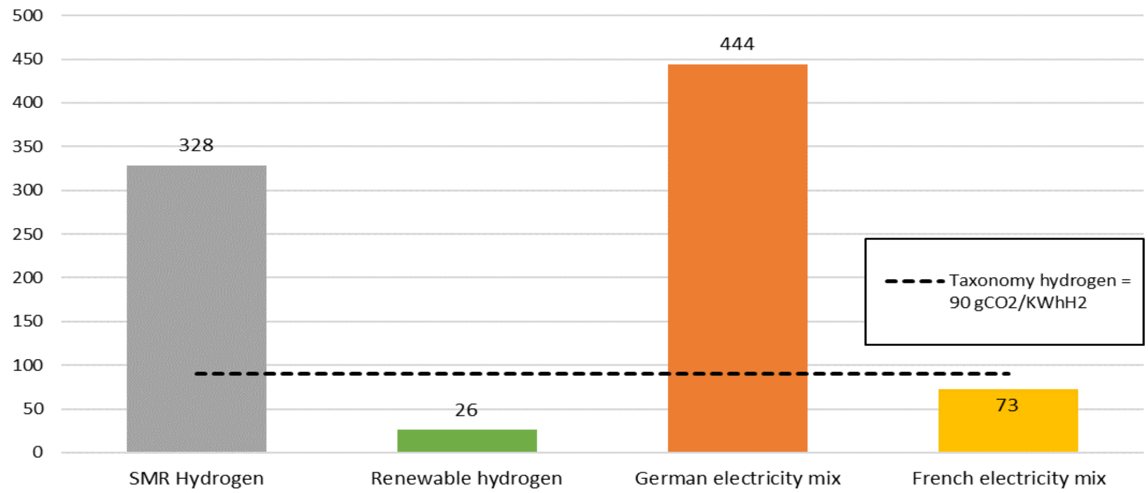
[30] The difference in carbon intensity between solar and wind emerges from the higher embedded CAPEX emissions.

[31] Hydrogen Council (2021).

[32] IRENA (2021).

[33] McWilliams & Zachmann (2021).

Figure 3. Carbon intensity of different types of hydrogen ($gCO_{2e}/kWhH_2$)



Source: EEA (2021), European Commission (2020).

Note: Based on EEA data, the French and the German electricity mixes have a carbon intensity of 51.1gCO2e/KWh and 311 gCO2e/KWh respectively. An electrolyser efficiency of 70% was used for calculating the carbon intensity of electrolytic hydrogen production.

Based on the combination of very low emissions and expected cost reductions, the European Commission prioritises renewable hydrogen supply. Currently, for hydrogen to be considered renewable, RED II requires 70 % GHG savings compared with fossil fuel production routes. Meanwhile, the EU taxonomy for sustainable activities sets the carbon intensity for clean hydrogen at 3 $kgCO_2/kgH_2$, equivalent to life-cycle GHG emission savings of 73.4 %. According to Bellona (2021), in the EU only grid electricity from Sweden, France and Lithuania[34] could meet the taxonomy standards. As national power mixes further decarbonise, increasingly more countries will be added to this list[35].

Section 3.2 further discusses how the renewable credentials of hydrogen can be ensured.

3.1 Hydrogen supply: technologies and economics of the electrolyser

Electrolyser technologies

Renewable hydrogen can be produced through multiple electrolyser technologies, with different associated costs and technological readiness levels. Table 2 compares three of the most widely acknowledged technologies that are commonly taken into consideration when developing hydrogen scenarios. Alkaline water, polymer electrolyte membrane (PEM) and solid oxide (SOEC) electrolysers are compared based on their relative efficiency, costs, stack lifetime (operating time), and operating temperature and pressure. Present costs and projections for both 2030 and 2050 are used.

[34] Based on annual averages, as values can vary significantly over the year.

[35] According to estimations by Aurora Energy Research (2021) using Ember data, by 2030 at least seven EU countries could produce hydrogen from electrolysers connected to the grid that meets the 70 % emissions reduction threshold imposed by RED II.

Table 2. Comparison of different electrolyser technologies

Electrolyser technology	Alkaline			PEM			SOEC		
	Today	2030	2050	Today	2030	2050	Today	2030	2050
Capex (EUR/kW)	180 - 1235	105 - 750	70 - 615	617- 1590	575 - 1325	175 - 795	1765 -4940	705 -2470	440 - 880
Efficiency (%)	63 – 70	63 - 72	72 - 80	56 - 63	61 - 69	67 - 74	74 - 81	74 - 84	77 – 90
Stack lifetime (thousand hours)	50 - 90	72 - 100	100 - 150	30 - 90	60 - 90	100 - 150	10 - 30	40 - 60	70 - 100
Operating temperature (°C)	60-90			50-80			650-1 000		
Operating pressure (bar)	1-30			30-80			1		

Sources: Compilation based on data from Agora Energiewende (2019), European Commission (2020), Gas for Climate (2020), IEA (2019), IRENA (2019; 2020).

Note: Average figures are presented based on all the estimations presented in the sources consulted.

Alkaline and PEM electrolysers have reached the greatest level of maturity, with module sizes of up to 3-4 MW already available[36]. At the moment, alkaline electrolysers are less expensive than PEM, but produce hydrogen at lower pressures, which would likely require further compression, adding to costs. PEM electrolysers also have a greater dynamic response capability that is more suitable for intermittent renewable energy. Despite their higher level of technological readiness, both alkaline and PEM electrolysers are still considered expensive compared with fossil fuel-based hydrogen production[37]. Nonetheless, both are expected to achieve significant cost reductions through economies of scale. SOEC electrolysers are seen as promising, but the technology is still under development and with limited commercial availability. The advantage is that they could deliver high conversion efficiencies: the higher temperatures under which they operate can decrease the voltage required for electrolysis[38].

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[36] DNV GL (2021).

[37] IRENA (2020).

[38] DNV GL (2021).

Large-scale deployment of electrolysers will rely on significant advancements in both technological improvements and cost reductions. Overall manufacturing capacity also needs to expand. Global manufacturing capacity in 2018 was merely 135 MW/year[39], expected to increase to 3.1 GW/year by the end of 2021[40]. However, to reach the necessary capacity by 2050, a global manufacturing capacity of 130-160 GW/year would be needed[41]. Therefore, a rapid expansion of renewable hydrogen production is reliant on a substantial increase in electrolyser manufacturing capacities.

The economics of renewable hydrogen: costs of electrolysers and renewable energy

Learning curves (i.e. decreases in the cost of electrolysers) are essential for the competitiveness of renewable hydrogen. Investments in renewable hydrogen are generally CAPEX-intensive. The main price components for both PEM and alkaline electrolysers are stack components (45 %) and balance of plant (55 %)[42].

Generally, this means that the more hours the electrolyser is utilised, the quicker the upfront costs are recovered. With medium load factors (over 3 000 hours per year), the CAPEX becomes less important in determining the cost of producing renewable hydrogen; as a result, the price of electricity becomes the dominant cost factor. Hydrogen produced by electrolysers running on dedicated renewable-electricity capacities tends to have a lower load factor, hence the CAPEX component is more important than with electrolysers linked directly to the electricity grid[43]. Indeed, grid-connected electrolysers can reach a load factor over 6 000 hours a year. Lower load factors can also lead to lower utilisation rates of transport and storage infrastructure for hydrogen, which will affect the economics[44].

From the perspective of operational costs, the two main factors to be considered are the number of hours the electrolyser is used per year and the price of the electricity it is fed[45]. As renewable electricity prices go down, so do the expectations for cost reductions in renewable hydrogen production, as shown in Figure 4. Under these circumstances, based on a combination of sufficient amounts of cheap electricity and decreased electrolyser costs, reductions of up to 85 % in the cost of renewable hydrogen could be expected compared with current levels in the most optimistic scenarios[46].

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[39] IRENA (2020).

[40] BNEF (2021).

[41] IRENA (2021).

[42] IRENA (2020).

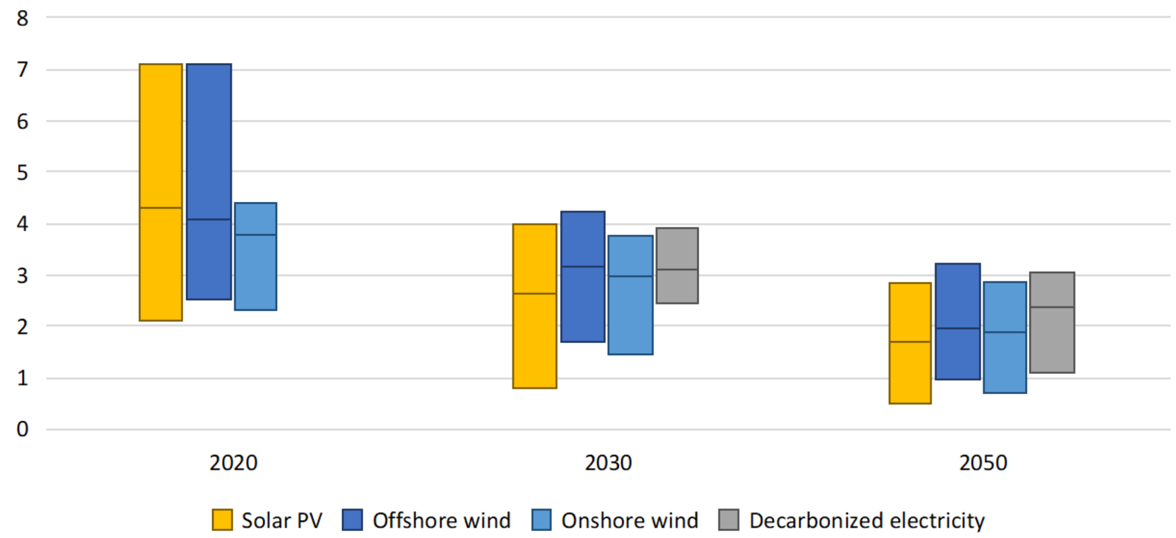
[43] IEA (2019).

[44] Cloete et al. (2021).

[45] Water represents less than 2 % of the total hydrogen production costs according to Agora Energiewende and AFRY (2021). About 9 kg of water are needed per 1 kg of hydrogen. If water demineralisation is also needed, the ratio can reach as high as 24 kg per kg of hydrogen.

[46] IRENA (2020).

Figure 4. Range of levelised costs of renewable hydrogen by source (€/kgH₂)



Sources: Piebalgs et al. (2020), Aurora Energy Research (2021), Oxford Institute for Energy Studies (2021), Gas for Climate (2020), Dos Reis (2021), Hydrogen Council (2021b), IRENA (2019).

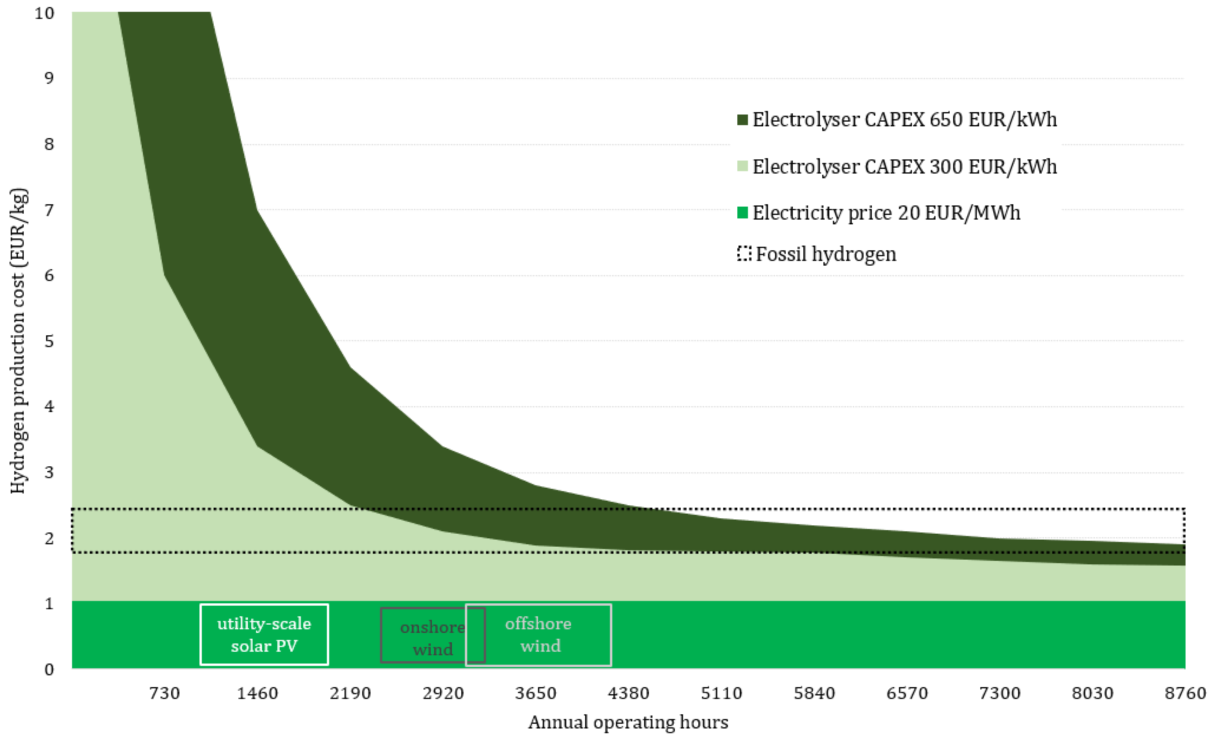
Notes: For the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).

Still, ensuring sufficiently high load factors based on dedicated renewable installations is difficult. Figure 5 explains the relationship between the load factor and the costs of hydrogen production. There is a steep decline in costs until approximately 2 000 hours, after which hydrogen costs further, but slowly, decline to a minimum at optimal running hours. Depending on electricity prices, the optimal load time ranges between 3 000 and 6 000 hours[47], but there are some variations between studies when it comes to what the precise 'optimal' load is. Aurora Energy Research (2021) finds that the most cost-competitive scenario for hydrogen production is at a load of 80-85 %, while scenarios developed in IRENA (2019) show nearly optimal hydrogen costs start being achievable from a load factor of at least 35 %. IEA (2019) assumes about 4 000 full load hours at the best locations for their price estimations for Europe, for the value at which renewable hydrogen is considered to become competitive with hydrogen produced from steam methane reforming with carbon capture and storage (CCS). IRENA (2021) also finds that renewable electrolytic hydrogen can be competitive with fossil-based hydrogen at 3-4 000 hours per year. If the price of electricity is constant, there is a negative correlation between the electrolyser load factor and the levelised cost of hydrogen (LCOH). Generally, the more operating hours for the electrolyser, the lower is the importance of CAPEX as a cost component in LCOH estimations[48].

[47] DNV GL (2021).

[48] LCOH represents a methodology used to account for all of the capital and operating costs of producing hydrogen, similar to the levelized cost of electricity.

Figure 5. Graphic representation of the relation between the load factor and LCOH



Source: Own calculations; similar renderings have been done by IRENA (2020) and Agora Energiewende (2021).

Note: Figures for illustrative purposes only are based on an alkaline electrolyser; efficiency 68 %; discount rate 8 %; lifetime 20 years; interest rate 8 %.

Under some scenarios in which the electrolyser is fed electricity from the grid, the lowest hydrogen costs are achieved in mid-load operation, given the potential challenges related to securing sufficient amounts of cheap electricity for feeding the electrolyser at a high load factor. IEA (2019) shows that electrolysers that run for more than 6 000 hours in such scenarios imply higher average prices for the electricity. Very low-cost electricity is usually available only for a very few hours within a year. Higher electricity prices during peak hours required for higher electrolyser load factors thus lead to an increase in hydrogen unit production costs. In other words, after reaching the minimum production costs, the cost rises as higher-priced electricity is required to feed the electrolyser[49]. Yet, if the electrolyser is fed directly from a renewable energy source (RES) installation with zero marginal cost, LCOH decreases with the load factor for as long as that renewable capacity generates electricity[50].

[49] DNV GL (2021).

[50] In many cases, the supply of renewable electricity will likely be ensured through power purchase agreements (PPAs). Based on the contract specificities, renewable energy producers might need to purchase additional renewable electricity to fulfil contractual obligations, which could affect costs.

How the location of electrolysers can affect the economics of renewable hydrogen

The economics of renewable hydrogen are also affected by the location of the electrolyser, which can be placed either closer to the source of renewable electricity or to the point of demand. Location can affect costs in two ways: on the one hand, through its implications for load factors and price of electricity, and on the other hand, through the associated costs of transport and storage[51].

Currently, the vast majority of EU hydrogen production happens on-site, with just about 15 % of the total production being produced centrally and delivered to the point of demand[52]. Whether the electrolyser is directly fed from renewable capacities through a physical connection is likely to be the most important determinant of its location. Electrolysers that are fed electricity from the grid could theoretically be located closer to the source of hydrogen demand.

To ensure cost-efficiency, electrolysers require a minimum of 2 000 load hours, with an optimal load at around 4 000 hours and with further potential for reductions in the levelized cost of hydrogen at even higher operating hours. However, if the electrolyser runs on dedicated renewable capacities, there might be challenges for achieving the ideal load.

Based on average capacity factors, dedicated utility-scale solar PV capacities could only deliver 1 000 to 1 800 hours of running time for the electrolyser. The capacity factor of onshore wind parks would allow for 2 500 to 3 200 operating hours. The prospects are most promising in the case of offshore wind turbines, which can provide between 3 000 and 4 100 load hours and potentially even higher in a few specific locations[53].

Feeding the electrolyser directly from renewable installations could theoretically ensure consistently low renewable electricity prices, avoiding price fluctuations on the electricity markets. Given the importance of electricity prices in the overall cost of hydrogen at loads higher than 2 000 hours, hydrogen produced from dedicated wind turbines could lead to highly competitive costs for renewable hydrogen, especially at locations with significant renewable potential. At the same time, the remote location of the most promising wind turbine parks (in particular those offshore) may raise additional logistical challenges for installing an electrolyser.

While offshore wind can provide a sufficient load depending on the location, linking the electrolyser directly to the electricity grid would be the more reliable way to ensure higher operating hours. Theoretically, this could allow access to the use of other decarbonised forms of low-carbon electricity, including hydropower and nuclear.

Nevertheless, as discussed in Section 3.2, it is important to ensure that electrolysers linked to the grid do not decrease the ability of new RES installations to decarbonise other parts of the economy and the electricity mix, which could be detrimental to decarbonisation efforts,

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[51] The difference between electrolysers run on dedicated renewable capacities or linked to the electricity grid bears important consequences for the climate credentials of hydrogen production. This issue is discussed at length in Section 3.2.

[52] European Commission (2020).

[53] It should be noted that through the use of PPAs it is possible to combine different renewable electricity sources, located at different places, to increase the load factor of the electrolyser.

especially in the short and medium term (i.e. until the entire electricity mix is decarbonised). Certification through guarantees of origin (GOs) for hydrogen sources would also be needed to ensure transparency for consumers. Policy decisions will determine which types of hydrogen are deemed renewable and upcoming legislative proposals should aim to define low-carbon hydrogen and how it can be certified.

For electrolysers linked to the grid, one possible option to ensure the renewable nature of the hydrogen is to feed them curtailed electricity. Hydrogen may prove helpful for alleviating grid constraints, especially as more fossil fuel-fired power plants are retired, but curtailed electricity cannot by itself provide a solid business case for hydrogen production due to the usually low availability of a few hours per day.

Another way in which the location of the electrolyser can influence the cost of renewable hydrogen is the associated transport and storage needs. According to estimations presented by Aurora Energy Research (2021), overall transport costs would be 25 % lower in grid-based scenarios. The higher the reliance on newly built renewable sources for hydrogen production, the greater the average distance hydrogen would need to be transported. If electricity is transported instead via grid connection, the electrolyser can be located closer to the source of demand, resulting in lower transport costs and avoiding the necessity of installing electrolysers in remote locations that are geographically close to renewable capacities. Thus, there could be advantages from a cost perspective of using the electricity grids that already exist and are in the process of expanding. Ultimately, the closer the electrolyser is to the point of demand, the lower the impact of hydrogen transport costs.

Even so, in such cases, electricity transmission costs would need to be taken into account, as well as the availability of physical infrastructure. Some of the best locations for renewable energy are not located close to the sources of demand, with generally weak transmission networks in remote locations. Without the necessary grid expansion, this issue will only be exacerbated with a higher uptake of renewable energy.

Depending on the local context, electrolysers co-located with renewable sources could lead to cost savings from avoiding grid expansion. The reverse could also be true: the need for larger storage capacity and additional pipeline infrastructure to deliver hydrogen to distant points of demand could surmount the avoided costs of electricity grid expansion[54]. In practice, these considerations will be highly location-specific, with significant variation between Member States.

Precise estimations are difficult, as there are still many uncertainties regarding hydrogen transportation costs and the pace and extent to which such infrastructure will develop. Some regions with very high renewable potential will likely have excess production volumes that would need to be transported to locations where demand cannot be met through local production. Transport via pipelines, trucks and even ships could ensure that sufficient hydrogen arrives in those areas where it is most needed. Conversion of hydrogen to ammonia benefits from existing infrastructure and demand.

[54] Cloete et al. (2020).

All these various transport modalities bear different costs. It is estimated that the compression process for trucks adds EUR 0.85-1.28/kgH_2 and the liquefaction process EUR 1.7-2.5/kgH_2, while the cost of conversion to ammonia is about EUR 0.34-0.77/kgH_2[55].

According to some scenarios, a large-scale hydrogen economy requires the development of a pan-European transport infrastructure, such as a hydrogen backbone[56]. Other scenarios favour the transmission of electrons instead of molecules over long distances, with more minimal hydrogen-pipeline development[57]. Another important aspect that will need to be considered is the GHG emissions associated with different transport methods. For example, according to IRENA (2021), transporting compressed hydrogen for 400 km in a truck using diesel would emit about 3 kgCO_{2e}/kgH_2.

Storage needs, especially from an availability perspective, can matter but normally only represent a relatively minor component of the total cost of a hydrogen economy[58]. Table 3 outlines cost estimations for different storage options. Above-ground storage bears significantly higher costs than the options presented in Table 3. Aurora Energy Research (2021) estimates that above-ground storage would cost EUR 6.37/kgH_2, compared with EUR 0.27/kgH_2 in salt caverns. IRENA (2021) similarly shows that the costs of pressurised tanks with a daily cycle would result in a premium on the overall cost of hydrogen, making it eight times higher than repurposed salt caverns cycling twice a year[59].

Table 3. Cost of storage by type (€/MWh H_2)

Storage type	Min.	Max	Comments
Salt caverns	6	26	300-10 000 tonnes, monthly and bi-annual cycling
Rock caverns	19	104	300-2 500 tonnes, monthly and bi-annual cycling
Depleted gas field	51	76	Annual cycling, including compression and piping

Source: European Commission (2020), compilation based on BNEF (2019).

Transport and storage infrastructure for hydrogen development will largely be policy driven and should not be taken for granted. They will be highly important for the development of the renewable hydrogen economy, as investment decisions will need to take into consideration all the factors outlined above, as well as the climate considerations discussed in the following section.

[55] IRENA (2021).

[56] Gas for Climate (2021).

[57] Aurora Energy Research (2021).

[58] Ibid.

[59] IRENA (2021).

3.2 Regulatory aspects: certification and the additionality principle

Besides technical and economic considerations, there is also a set of trade-offs associated with regulatory choices. The renewable nature of hydrogen is fully dependent on the renewable nature of the electricity used. This needs to be certified through guarantees of origin, for example, though this may not be sufficient. GOs are meant to serve as a transparency tool for consumers and are not specifically designed for counting towards a renewable target or benefiting from a support scheme. As explained later, a temporal connection between the renewable capacity and the electrolyser would also be needed.

There are also some concerns that the production of electrolytic hydrogen could result in increases in emissions in other sectors, at least in the short and medium term. There are fears that the power used to produce hydrogen would be compensated by dispatching additional fossil fuel-fired capacities, leading to a subsequent increase in CO_2 emissions[60]. This risk is exacerbated by the fact that renewable electricity is already scarce and there are challenges related to keeping up with the necessary renewable energy uptake for the decarbonisation of the electricity mix and increased electrification.

The principle of **additionality** seeks to ensure that the electricity for hydrogen production is only sourced from new renewable capacities that would not have been developed otherwise. But its application comes with its own set of challenges. Should the electrolyser be physically linked to the new renewable installation? Or is it sufficient for the electrolyser to be fed electricity from renewable installations in the same geographical area proven through GOs? Moreover, should the electrolyser be allowed to produce hydrogen that is certified as renewable only when its dedicated renewable installation generates electricity? With a cap-and-trade system for emissions already in place, are additional measures necessary from the perspective of long-term decarbonisation?

The upcoming delegated acts implementing Article 27(3) of RED II on the methodology used for RFNBOs will set the regime under which hydrogen (local or imported) can be labelled as renewable in the transport sector (and is expected to be extended to other sectors as well), subsequentially determining its sustainability. This will be highly important because it will likely also affect the eligibility for subsidies offered to renewable installations. A key task will be to explain the requirements for geographical and temporal connections between electrolysers and renewable energy capacities.

According to the most recent discussions, both direct and virtual connections could be allowed, insofar as the renewable nature of hydrogen is proven through power purchase agreements (PPAs) or GOs, besides a geographical and temporal connection. It remains to be seen whether

[60] Belmans and Vingerhoets (2020).

only new renewable installations would be considered, or whether existing capacities that no longer receive subsidies could also qualify[61].

A physical connection is the simplest way to ensure that hydrogen is produced from renewable electricity, but as previously explained, this may not provide a sufficiently high load factor for cost-effective hydrogen production and comes with logistical challenges for hydrogen transport. Alternatively, a virtual connection would allow the electrolyser to be linked to the grid, as long as the renewable installation functions within the same bidding zone. A temporal connection would also be required to guarantee that the electrolyser only produces hydrogen that is labelled as renewable when the contracted renewable installation generates electricity. Such a temporal connection would still reduce the load factor of the electrolyser, especially if it is linked to a single renewable installation. The requirement would also go beyond the mere utilisation of GOs and would rely on a robust certification system.

Another proposal, such as 'system-level matching', seeks to overcome this problem by loosening the connection requirements. Such an approach would allow hydrogen to be labelled as renewable when renewable electricity is produced in higher volumes than average. The total additional demand for electricity by the electrolysers would still need to be matched with new renewable installations, but no physical or virtual connection would be required. However, some organisations[62] have been highly critical of such plans for failing to defend the principle of additionality and for potentially jeopardising the decarbonisation of the electricity grid.

A very loose application of the additionality principle could even fail to properly certify the renewable credentials of hydrogen. Focusing excessively on incentivising renewable hydrogen production might also overinflate the necessary demand for hydrogen, which is not always the optimal approach from a climate perspective, especially if double subsidies are created. Direct electrification is more efficient in many cases, so the incentives designed for renewable hydrogen should not supersede the wider climate objectives.

Striking the right balance between ensuring the renewable nature of electrolytic hydrogen and incentivising market uptake is difficult. Strict connection requirements could prove hard and costly for developers to implement. The longer lead times associated with renewable investments compared with electrolysers are also considered by some to be potential barriers. At the same time, linking electrolysers to specific renewable installations could go against a 'whole-system' approach, which is especially important from the perspective of sector integration. The contribution of electrolysers to providing grid flexibility would be diminished and hydrogen could not be produced from other climate-neutral electricity sources, such as nuclear energy and existing RES capacities. A strict application of the additionality principle could alleviate concerns that the carbon intensity of the electricity mix does not increase in the

[61] As proposed by organisations such as SolarPower Europe (2021), FuelEurope (2021), efuel Alliance (2021) and the Global Alliance for Powerfuels (2021).

[62] Bellona (2021), Transport & Environment (2021), Global Witness (2021).

short and medium term. Yet it would not ensure that sufficient RES capacities could be rolled out for both hydrogen production and the decarbonisation of the electricity mix, as long as additionality is designed to be applied at the project level rather than the system level. One way to ensure that renewable hydrogen does not cannibalise the renewable electricity needed for the decarbonisation of other sectors and that sufficient RES capacities are planned would be for Member States to take into account the new projected electricity demand for producing hydrogen when drawing up National Energy and Climate Plans (NECPs).

If sufficient safeguards are put in place for ensuring the renewable nature of hydrogen, matching renewable energy and the usage of electrolysers on a system level could have an additional theoretical advantage if implemented correctly – it could allow for only part of the electrolytic hydrogen production using grid electricity to be labelled as renewable. This could improve the economics of electrolysis, particularly in countries with a lower carbon intensity of the electricity mix, where on-grid electrolysis could be produced below the taxonomy threshold. If such low-carbon hydrogen could be certified based on strict estimates of the CO_2 content of the grid electricity, it could still find potential customers even if it is not labelled as renewable. This could help avoid oversizing and underutilising the electrolyser, which can decrease the CAPEX.

Still, this may prove difficult to implement in practice, as the carbon intensity of electricity can vary substantially. This logic is also not applicable for countries with a high carbon-intensity average of the electricity mix, which would only be able to produce high-carbon electrolytic hydrogen when renewable energy cannot be fed into the electrolyser. Utilisation of such hydrogen would not deliver climate benefits. Ultimately, the decarbonisation of the electricity mix and the deployment of renewable hydrogen production need to be developed together.

Reaching a balance between these trade-offs will be difficult and the political decision regarding the way in which the principle of additionality is applied will have an impact on the quantities of renewable hydrogen produced. Ultimately, ensuring that sufficient safeguards are in place for reaching climate neutrality by 2050 is most important. The risk of short- and medium-term increases in emissions also merits consideration, but this should not *a priori* exclude options that can bring emission reductions. Some form of certification should be created for low-carbon hydrogen produced from electricity that meets the requirements for 70 % GHG emission savings and the carbon intensity set out in the taxonomy, besides a robust application of the additionality principle for certifying renewable hydrogen.

3.3 SWOT analysis for renewable hydrogen in the EU

Table 4 presents a SWOT analysis summarising the main trade-offs associated with the production and use of renewable hydrogen.

Table 4. SWOT analysis for renewable hydrogen

	Strengths	Weaknesses
Internal	▪ Climate-neutral and scalable energy carrier ▪ Technology readiness level ▪ Electrolyser costs will keep decreasing ▪ Costs expected to reach lower levels compared with fossil alternatives ▪ Flexibility on the geographical location of the electrolyser	▪ Conversion and efficiency losses associated with production ▪ High current production costs compared with alternatives ▪ Economically inefficient at low electrolyser load factors ▪ Regulatory difficulties for certifying renewable credentials
	Opportunities	**Threats**
External	▪ Expectations of cost reductions for renewable electricity ▪ Contribution to the decarbonisation of hard-to-abate sectors ▪ System integration (curtailed electricity, storage, synthetic fuels) ▪ Commitments to climate neutrality	▪ Lack of value recognition compared with alternatives ▪ Potential impact of regulation on load factors and climate credentials ▪ Reliance on the availability of renewable capacities and relation to the electricity market

Source: Own assessment.

The main strengths consist of the general technological readiness of electrolysers and the current high level of understanding of the electrolysis process. In addition, learning curves and economies of scale are envisaged, further decreasing the electrolyser CAPEX. The expectation is that the average renewable hydrogen costs will become lower compared with fossil alternatives after 2030. If the correct standards of certification are applied, renewable hydrogen can also represent a scalable, climate-neutral energy carrier with diverse applications. Furthermore, there is significant flexibility related to the location of the electrolyser, which could result in lower costs for hydrogen transportation.

The associated weaknesses are linked to the conversion losses stemming from the production process, which lead to lower overall efficiencies, especially when compared with direct electrification. Current production costs are higher than for fossil alternatives. The economics of the electrolyser are even more precarious at low load factors. Moreover, there are difficulties associated with certifying the renewable nature of hydrogen, especially if higher operating hours for the electrolyser are to be reached.

A key opportunity is related to the expected decrease in the cost of renewable electricity, which represents the dominant cost factor for electrolytic hydrogen at more than 2 000 operating hours of the electrolyser. Renewable hydrogen could also provide one of the few available solutions for the decarbonisation of some hard-to-abate industrial processes and modes of transportation. Through its ability to be stored long term and be converted into synthetic fuels, renewable hydrogen could additionally contribute to system integration. EU and Member State commitments to climate neutrality create the broad policy framework necessary for the deployment of renewable hydrogen.

However, at present there is a lack of value recognition for renewable hydrogen compared with fossil alternatives, which could delay deployment[63]. The current free allocation mechanism of the EU Emissions Trading System does not provide any further incentives for renewable hydrogen compared with hydrogen obtained from SMR[64]. Another threat comes from the impact that regulation could have on either limiting the load factor at which electrolysers are operated, eventually limiting quantities that could be cost-effectively produced, or failing to provide sufficiently robust criteria for certifying the renewable nature and climate credentials. Lastly, reliance on the availability of renewable capacities, which could be scarce and necessary for the electricity sector, could represent one of the most significant threats. This merits further discussion.

The relationship between renewable hydrogen and the electricity market

Today, electricity meets 21 % of the final energy and feedstock consumption in the EU, 37 % of which comes from renewable energy. Reaching a 55 % reduction in GHG emissions by 2030 will already require at least 60 % of the electricity to be sourced from renewables[65]. The investments outlined in the current NECPs, would lead to renewables covering 65 % of the current electricity demand[66]. This will require an expansion in renewable capacities of previously unseen pace and magnitude.

For most countries, investment plans do not take into consideration the RES capacities needed for renewable hydrogen. It has been estimated that for the 40 GW of electrolysis capacity planned by the European Commission for 2030, 80-120 GW of additional solar and wind capacities would be needed, which is equivalent to three times the Europe-wide renewables capacity increase from 2019[67]. Therefore, a successful hydrogen strategy would most likely need to be integrated and interlinked with renewables policy and the internal electricity market. To name but a few challenges, hydrogen production and support policies will probably affect electricity prices, competition for renewable resources, grid congestion and renewable electricity deployment targets[68]. These could come at a sensitive time for electricity markets and may build on already existing issues regarding the electricity market design.

During discussions on this autumn's energy prices, some national governments (such as Spain) and even possibly the European Commission have questioned whether it makes sense to price marginality when there is a very high share of near-zero marginal cost capacities connected to the grid. The debate is driven by twin concerns.

[63] Low-carbon hydrogen produced from electricity likely has an even lower value recognition given the proposed RFNBO sub-targets in RED II.

[64] See Sandbag (2021).

[65] Belmans et al. (2021).

[66] Ibid.

[67] E3G (2021).

[68] Bellona (2021).

In a situation where fossil fuels, mainly gas, are de facto price-makers in the wholesale electricity market, the EU continues to remain highly dependent on global gas prices. In practice, the implication is that despite a continually increasing share of renewables with zero marginal cost, the EU can and will experience high power prices. Most likely, price volatility will increase with the share of renewables[69]. Under these circumstances, there have been calls, including by European Commission President Ursula von der Leyen, to decouple[70] zero marginal-cost sources from fossil fuels.

Another concern has been whether the market price signal and with it, the ability to remunerate existing assets, is sufficiently robust to drive new investments and thus suitable to deliver on the EU's climate ambitions. As previously stated by the European Commission's report on energy pricing and costs[71], a decoupling effect between investments and price signals can be observed. By 2030, it is expected that around 70 % of electricity output – renewables and nuclear combined – will have nearly zero marginal costs. This will transform the economics of the power sector. The 2019 clean energy for all Europeans package has focused mainly on dispatching, and less so on the way new electricity markets work in the context of an ever-growing share of renewable generation[72]. Hence, despite the currently high electricity prices, there is still a debate on how to provide effective signals to unlock investments. These could come, for example, in the form of a newly conceived long-term price signal, remuneration for flexibility or other services and instruments such as contracts for difference[73].

The fact that competitive renewable hydrogen – a precondition for a cost-effective energy transition – depends on high load factors and the availability low-cost low-carbon electricity (see Section 3.1) could add an additional layer of reasoning regarding the future market design and whether it should be conceived differently from today's.

Nonetheless, the largest obstacles to the deployment of additional renewable capacities are probably public acceptability of installations and grid development, as well as long planning and permitting processes. The European Commission's periodic progress reports on renewable energy continue to identify national spatial and environmental planning requirements, grid shortcomings and more generally, acceptability and NIMBYism as the main bottlenecks[74]. These issues will require solutions beyond electricity market design.

Given such concerns regarding the ability to sufficiently stimulate the deployment of additional renewable capacities, necessary for both the decarbonisation of the electricity mix and the production of renewable hydrogen, it is important to also consider what the alternatives are.

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[69] Cornillie et al. (2021)

[70] '"If electricity prices are high, it is because of the high gas prices, and we have to look at the possibility to decouple within the market because we have much cheaper energy like renewables", Commission President Ursula von der Leyen said during a visit to Estonia on 5 October'. Source: 'EuractivLEAK: The EU's "toolbox" against soaring energy prices' by Frédéric Simon, *Euractiv*, 7 October 2021.

[71] European Commission (2019).

[72] Kustova and Egenhofer (2019).

[73] Such long-term price signals could also be helpful for electrolyser investments.

[74] European Commission (2020), *Renewable Energy Progress Report*, COM(2020) 952.

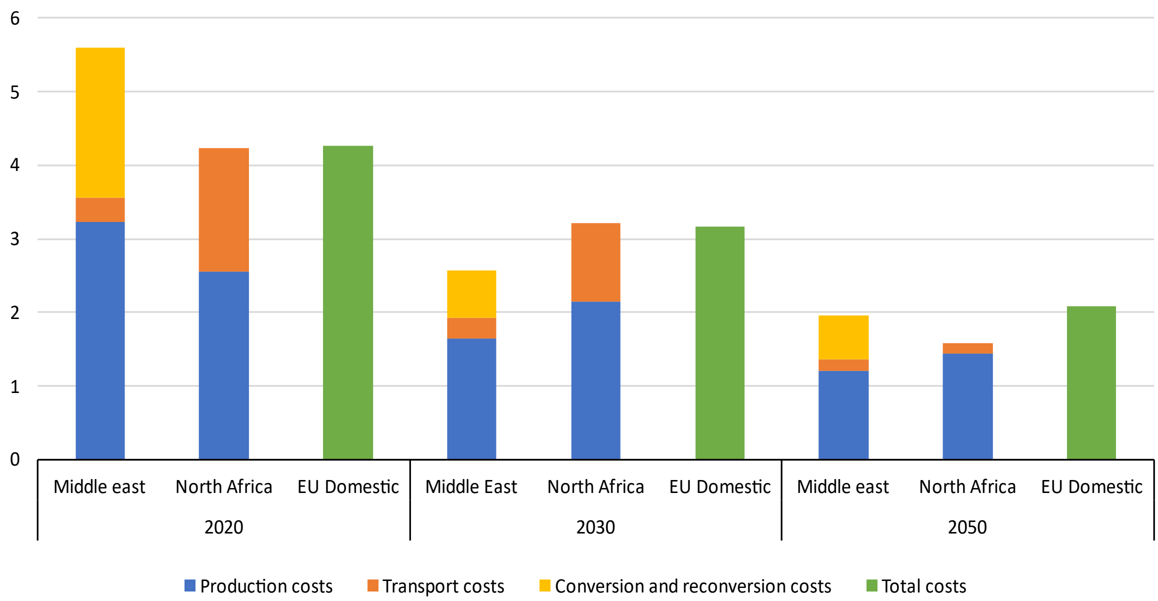
Section 4 discusses the trade-offs associated with imported renewable and nuclear energy-based hydrogen.

4. Alternatives to renewable hydrogen

4.1 Imported renewable hydrogen

Imports represent one option. While the hydrogen economy value chain is of strategic importance to the EU, it is likely that not all demand will be (or needs to be) fulfilled domestically. Similar to other energy carriers today, trade is possible and for some Member States facing supply deficits it will even be desirable from a diversification perspective. Imports can also offer further access to inexpensive renewable hydrogen, which can provide a lower cost pathway to decarbonisation[75]. The desirability of renewable hydrogen imports rests on two determinants: the costs associated with production and transport and the climate credentials of imported hydrogen, which ought to be measurable and verifiable.

Figure 6. Levelized costs of imported vs domestic renewable hydrogen (€/kgH$_2$)



Sources: McWilliams & Zachmann (2021), European Commission (2020), Aurora Energy Research (2020; 2021), IEA (2019; 2021), Piebalgs et al. (2020), DNV GL (2021), Agora Energiewende and Guidehouse (2021), Trinomics and LBST (2020), Oxford Institute for Energy Studies (2021), Gas for Climate (2020), Dos Reis (2021).

Notes: Imports from North Africa only refer to imports of gaseous hydrogen by pipelines; imports from the Middle East only refer to imports of ammonia by ship; a full breakdown can be found in the Annexes. 'Other costs' include conversion, reconversion and transport (transmission and distribution) costs. All values are own calculations based on averages of the estimates of the reports assessed. For the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH$_2$ was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH$_2$ the following exchange rate was used: EUR/USD = 1.1833 (updated 9.9.2021).

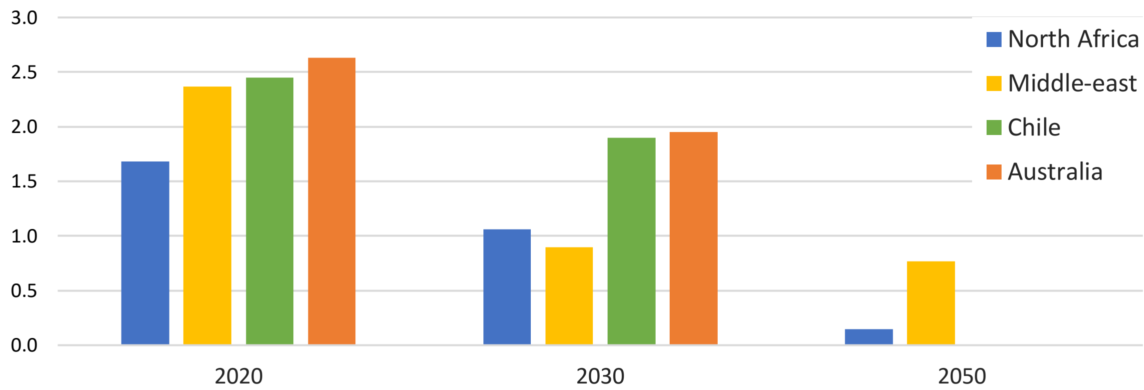
[75] See Agora Energiewende and Agora Industry (2021).

Figure 6 summarises the costs associated with importing hydrogen from various locations compared with domestically-produced renewable hydrogen, with a breakdown of cost components. Only figures for renewable hydrogen are presented. According to available projections, some of the lowest-cost imports could come from North Africa, especially Morocco. Imports, notably those from the Middle East, are expected to experience rapid cost reductions. But in the long run, no major cost advantage is expected for imports, given transport, conversion and reconversion costs.

For example, transport costs represent more than a third of total costs for most renewable hydrogen imported from North Africa[76]. The share of transport from other destinations could be even more significant. Figure 7 shows estimations on current and future costs for importing hydrogen from regions with high potential for renewable energy, such as North Africa, the Middle East, Chile and Australia.

In the long term, transport could be secured using some of the natural gas pipeline infrastructure that already links Algeria and Libya to Italy and Spain, but it would have to be retrofitted[77]. Alternatively, some argue that importing renewable electricity rather than hydrogen would be more advantageous[78]. Hydrogen could be imported via other transport modes as well, including maritime shipping in the form of ammonia or methanol[79]. These alternatives come with varying costs for transport, conversion and reconversion, among other trade-offs discussed in Section 3.1.

Figure 7. Development of conversion, reconversion and transport costs of imported hydrogen, from different exporting regions (€/kg H_2)



Sources: McWilliams & Zachmann (2021), European Commission (2020), Aurora Energy Research (2021), IEA (2021), Piebalgs et al. (2020), DNV GL (2021).

Notes: Imports from North Africa only refer to imports of gaseous hydrogen by pipelines; imports from the Middle East, Chile and Australia only refer to imports of ammonia by ship. All values are own calculations based on averages of the estimates of the reports assessed. For the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1833 (updated 9.9.2021).

[76] IEA (2019) and McWilliams & Zachmann (2021).

[77] Piebalgs et al. (2020).

[78] Belmans et al. (2021).

[79] See Annex III for further details on transport modes.

Based on expected costs for transport, conversion and reconversion, according to IEA (2019) scenarios, imports would only be desirable by 2050 if the EU were to face difficulties in deploying sufficient renewable capacities domestically and provided that investment costs in regions such as North Africa further declined. Basically, the difference in price between producing renewable hydrogen abroad and producing it domestically would need to be greater than the additional costs incurred by transport, conversion and reconversion. Importantly, other countries such as Japan and South Korea have stated in their hydrogen strategies that hydrogen imports will be used to cover their consumption needs. Competition for hydrogen imports could put upward pressure on the price of hydrogen when demand is higher than supply, as can be seen in today's global market for liquefied natural gas.

Yet, imported hydrogen could be required irrespective of price competitiveness to cover a supply deficit, should that occur[80]. Technological choices and resource constraints in the EU could limit domestic production potential and, implicitly, create the need for imports[81]. Calculations by Aurora Energy Research (2021), for example, show that the EU could meet its own hydrogen demand through domestic production only if all decarbonised forms of electricity are included. The regulatory choices for implementing the additionality principle could create supply bottlenecks in domestic production, leading to higher costs and increased reliance on imports.

Imported hydrogen would need to be subject to an appropriate certification system. Consistent international rules and a rigorous regulatory framework would have to guarantee that the same standards that apply to hydrogen that is considered clean when produced within the EU are required for imported renewable hydrogen. Transporting hydrogen can lead to further emissions which add to the overall life-cycle emissions.

International hydrogen standards could not only be difficult to enforce, but also have broader repercussions for the trade and climate policy debate, including production versus consumption emissions. The degree of openness to trade has infrastructure implications too, and in some cases, hydrogen imports may carry geopolitical consequences. Right before the release of the European Commission's proposal for a carbon border adjustment mechanism (which does cover fertilisers), a coalition of electricity companies including EDF, Enel, Iberdrola and Ørsted [82] called for carbon tariffs on hydrogen imports. Still, there are divergent opinions among Member States on this matter, with disagreements in the EU Energy Council between ministers regarding the desirability of imports.

[80] DNV GL (2021).

[81] WEC (2021).

[82] Euractiv (2021).

4.2 Nuclear energy-based hydrogen

There are two main ways in which nuclear energy could contribute to electrolytic hydrogen production: on grid and on-site.

The simplest option is to feed electrolysers connected to the power grid electricity from nuclear power plants. Aurora Energy Research (2021) finds the most cost-competitive hydrogen production scenario, at a load of 80-85 %, is achieved by using all forms of decarbonised electricity available on the grid, which includes nuclear energy and existing renewables. Moreover, such an approach could increase the availability of generation capacities that may be needed for meeting future domestic hydrogen demand. On the economics of the electrolyser, similar trade-offs to those discussed in Sections 3.1 and 3.2 apply.

At the same time, there are additional challenges. One is related to certification. While bringing similar reductions in emissions, nuclear energy cannot be labelled as renewable. Consequently, it would not contribute to the achievement of renewable targets and may have even lower value recognition than renewable hydrogen, irrespective of the climate benefits. Another issue is that nuclear energy is associated with safety and non-climate environmental concerns and may face low public acceptance. A number of Member States have reduced (or plan to reduce) their nuclear capacity. Other Member States are constructing new nuclear power stations, albeit at a slow pace and with delays. The very high upfront costs associated with the construction of new nuclear power plants may set back future deployment and require targeted solutions, such as a regulated asset base. Availability may therefore remain a constraint. If only existing nuclear power plants were considered, they would entail the same risks for short- and medium-term emission increases of the electricity grid as for existing renewable capacities. However, a certification scheme for low-carbon hydrogen could enable its usage by demonstrating its climate benefits.

The way in which nuclear-related concerns affect future investments will partly be influenced by the final version of the implementing acts of the EU taxonomy for sustainable finance. Most important will be the question of whether activities related to nuclear power production will be counted as making a substantial contribution to climate mitigation, while also respecting the *do no significant harm* criteria for the other taxonomy objectives. The recommendations of a Joint Research Centre report[83], based on which the European Commission will make its decision, concluded that nuclear power could meet the necessary requirements.

Besides grid-based solutions, the other option would be to produce hydrogen on the site of the nuclear power plant. Nuclear power plants generate electricity at higher loads, which could help the economics of the electrolyser.

The stable electricity output of nuclear can be suitable for the large-scale production of hydrogen by cold electrolysis of water, for example in industrial clusters. Higher load factors could also arguably lead to slower electrolyser degradation. Nuclear reactors use relatively

[83] European Commission (2021).

small land areas per MWh of electricity produced, thus leading to less land utilisation. A number of demonstration projects have been or are being launched, for example in Sweden and the UK. In the UK, the Hydrogen2Heysham two-year demonstration project[84] tested the feasibility of directly connecting electrolyser systems to the Heysham 2 nuclear power plant. The HYBRIT (Hydrogen Breakthrough Ironmaking Technology) project in Sweden produces hydrogen from low-carbon electricity, including nuclear, for use in steel manufacturing[85].

Nuclear reactors could generate heat as well, a particularly difficult area for decarbonisation[86]. The MIT-Japan Study (2017)[87] argues that coupling nuclear plants to heat storage can facilitate the matching of energy demand in a market with a high share of renewables, especially considering economic incentives from the large cost difference between electricity storage and thermal storage. In the UK, Sizewell C is looking at how it can extract heat which can then be used for other purposes – for instance, steam-assisted electrolysis is more efficient than traditional electrolysis. Additionally, Sizewell C is exploring use of the heat for a direct air capture process to capture carbon dioxide; this captured carbon dioxide could be combined with hydrogen to form synthetic fuels[88]. During periods of high electricity demand, steam is used to generate electricity, while during low demand, some steam can be diverted to hydrogen production.

Another theoretical advantage could be increased efficiency for some electrolyser technologies that require higher heat temperatures. The US Department of Energy announced funding for, among others, two projects that would advance first-of-a-kind technologies[89]. *High-temperature steam electrolysis* – using heat at 550-750 °C or more and electricity – is considered to be a promising option, although no project exists yet. *High-temperature thermochemical production* using nuclear heat at elevated temperatures (800-1 000 °C) creates an opportunity to bypass the inefficiencies of electricity generation and uses the reactor heat to drive processes like the thermal decomposition of water directly, thus decreasing costs in comparison with electrolysis. By-products such as industrial steam and heat supplies could complement the hydrogen-to-energy process. Although several reactors[90] could be suitable for this technology, currently only high temperature gas-cooled reactors (HTGRs) are more technologically ready. Small modular HTGR designs may in future offer efficient electricity generation and combined heat and power applications. Light water reactors, such as those developed in the US[91], could also be promising for solid oxide electrolysis.

Nonetheless, while some of the technologies listed may become technically and economically viable, they are still at the demonstration stage and will not be commercially available until at least 2030. Their

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[84] EDF Energy R&D UK Centre (2019).

[85] Vattenfall (2021).

[86] The Royal Society (2020b).

[87] MIT (2017).

[88] Friedmann et al. (2019).

[89] US Department of Energy (2020).

[90] For instance, the high temperature gas-cooled reactor, advanced high-temperature reactor and lead-cooled fast reactor.

[91] Ibid.

applicability is also dependent on local circumstances. As such, they offer no immediate solutions for the hydrogen economy. There may be additional regulatory hurdles as well, for example whether electrolysers could be placed within the exclusion zones of nuclear power plants, which is presently uncertain. All these issues come on top of the aforementioned challenges related to nuclear energy: lack of value recognition, safety and non-climate environmental costs, and low public acceptance, which would have to be overcome for nuclear energy-based hydrogen to become a viable alternative/complement to renewable hydrogen. The issues related to the future of nuclear energy in the EU context will be further discussed in an upcoming CEPS publication.

5. Conclusion and way forward

In parallel with direct electrification and efficiency measures, hydrogen will make an important contribution to decarbonisation efforts, particularly for hard-to-abate emissions in industrial processes (such as ammonia, basic chemicals and primary steel production) and some segments of the transport sector (particularly maritime and long-haul aviation). Electrolytic hydrogen may also provide solutions for long-term energy storage for the electricity sector.

For hydrogen to enable the decarbonisation of these sectors, it needs to be produced with minimal GHG emissions. There appears to be a clear preference in the EU for renewable hydrogen produced from the electrolysis of water using renewable electricity. The proposals under the Fit for 55 package have already set sectorial targets that will stimulate consumption of renewable hydrogen. The policy decisions made in the forthcoming hydrogen and decarbonised gas market package and implementing acts of the revised Renewable Energy Directive will further determine the criteria based on which hydrogen can be labelled as renewable, and will facilitate the development of a European hydrogen market and gradual transition to decarbonised molecules. This will bring much needed clarity for the deployment of hydrogen and the decarbonisation of gaseous fuels over the next years by removing some barriers and creating the baseline conditions for the development of hydrogen markets.

But this will not be sufficient to solve all the potential issues outlined in this report. The deployment of renewable hydrogen will require an understanding of the multiple trade-offs associated with the location of the electrolyser, load factor, source of electricity used and hydrogen transport costs. Probably the most important is the impact that access to sufficient amounts of cheap renewable electricity will have for cost-effective production of renewable hydrogen. This will depend to a large extent on the ability to deploy new renewable energy capacities and the interaction with the already strained electricity market. There are concerns that the deployment of renewable hydrogen could cause tensions with the electricity market by cannibalising the renewable capacities needed for the decarbonisation of the electricity mix. Moreover, hydrogen production and support policies could affect electricity prices, competition for renewable resources, grid congestion and renewable electricity targets.

Therefore, for meeting the future expected demand for hydrogen – though this should not be overestimated – the EU will likely turn to other sources of low-carbon hydrogen as well. This report has focused two other potential sources – imports and nuclear energy-based hydrogen. Nuclear hydrogen could create more opportunities for producing low-carbon hydrogen from electricity, while imports could cover potential supply deficits and provide further access to inexpensive renewable hydrogen for domestic consumption.

Based on the assessment of the trade-offs presented in this report, two main conclusions can be drawn, together with some recommendations for the way forward.

First, the decarbonisation of the electricity mix and the deployment of renewable hydrogen production need to be developed together. One way to harmonise these objectives would be for Member States to take into account the new, projected electricity demand for producing hydrogen when preparing national energy and climate plans. This could enable integrated, whole-system planning that might dissipate potential tensions between the two objectives. Priority should still generally be given to direct electrification over less-efficient hydrogen use, as long as this is technically possible and cost-effective. Technology-neutral support mechanisms, such as competitive carbon contracts for difference, (CCfD) could be valuable solutions in this regard.

Dedicated support for renewable hydrogen will also be needed, and should first be targeted at industrial clusters. While the upcoming hydrogen and decarbonised gas package is expected to foster the conditions for open and non-discriminatory access to pipeline networks with a view to safeguarding competition on hydrogen markets, initial exemptions could be made for isolated hydrogen clusters before they are connected to a wider grid.

Second, a robust certification framework will be needed for attesting the climate credentials of hydrogen, irrespective of source. Ultimately, ensuring that sufficient safeguards are in place for reaching climate neutrality by 2050 is most important. Nonetheless, given the current lack of value recognition for clean hydrogen, appropriate criteria for certifying the renewable nature of hydrogen should be established. Usage of PPAs or guarantees of origin is not sufficient – strong geographical and temporal connections are also needed. Furthermore, consistent international rules and a rigorous regulatory framework would have to guarantee that the same standards that apply to hydrogen that is considered clean when produced within the EU are required for imports.

Simultaneously, parallel certification should be possible for low-carbon hydrogen produced from electricity that meets the 70 % GHG emissions savings requirement and the carbon intensity set out in the taxonomy. In line with the strategies for hydrogen and energy system integration, the upcoming hydrogen and decarbonised gas package is expected to recognise the role of low-carbon hydrogen. Labelling only part of the electrolytic hydrogen production using grid electricity as renewable could improve the economics of electrolysis, particularly in countries with lower carbon intensity of the electricity mix, where on-grid electrolysis could be produced below the taxonomy threshold. This should be based on a life-cycle assessment of total GHG emissions with strict estimations of the CO_2 content of the grid electricity, calculated on an hourly basis. That would enable a system-level approach that takes into account all energy sources that make meaningful contributions to GHG emission reductions – including nuclear – without labelling them as renewable. Further clarifications will be needed for State aid and eligibility for subsidies for low-carbon hydrogen.

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Annex I. Production costs of hydrogen, for different technologies sources

(€/kgH_2)

Report	Scope		Fossil H_2 2020	Fossil H_2 2030	Fossil H_2 2050	Fossil H_2 with CCS 2020	Fossil H_2 with CCS 2030	Fossil H_2 with CCS 2050	Renewable H_2 2020	Renewable H_2 2030	Renewable H_2 2050
Hydrogen Council (2021a)	Global	Maximum	1.68	1.85	4.32	1.94	1.85	2.29	5.38	2.38	1.68
		Minimum	0.53	0.71	0.71	0.88	0.88	0.88	3.26	1.59	0.79
		Average	**1.10***	**1.28***	**2.51***	**1.41***	**1.37***	**1.59***	**4.32***	**1.99***	**1.24***
IRENA (2019)	Global	Maximum				1.99	2.29	2.54	5.58		2.29
		Minimum				1.31	1.15	1.48	2.32		0.71
		Average				**1.65***	**1.72***	**2.01***	**4.59***		**1.41***
IRENA (2021)	Global	Maximum	1.76						5.29		
		Minimum	0.88						3.53		
		Average	**1.32***						**4.41***		
Piebalgs et al. (2020)	EU	Maximum				2.50	2.50	2.50	7.10	4.00	2.85
		Minimum				1.00	1.00	1.00	2.15	0.9	0.50
		Average				**1.70**	**1.95**	**1.70**	**4.18***	**2.35***	**1.53***
Aurora Energy Research (2021)	EU	Maximum					2.62	2.48		3.92	3.43
		Minimum					2.48	2.39		2.46	2.05
		Average					**2.55***	**2.44***		**3.30***	**2.77***
Agora Energiewende and Guidehouse (2021)	EU	Maximum							6.6	5.38	
		Minimum							3.4	2.00	
		Average	**1.80**	**2.36**		**2.20**	**2.49**		**5.00**	**3.74**	
Agora Energiewende, Agora Industry (2021)		Maximum		3.93			2,60			5,43	
		Minimum		1.40			2,10			2,00	
		Average		**2.67***			**2.35***			**3,71***	
Trinomics and LBST (2020)	EU	Maximum									
		Minimum									
		Average		**3.00**			**2.50**			**3.50**	
IEA (2019)	EU	Maximum		3.62			2.96		5.29	3.53	
		Minimum		1.18			1.37		2.21	1.68	
		Average	**1.54**	**2.11**	**2.82**	**2.06**	**2.06**	**2.08**	**3.18**	**2.55**	
IEA (2021)	EU	Maximum							6.49		1.76
		Minimum							3.69		0.96
		Average	**0.79**		**2.74**	**1.44**		**1.79**	**4,68***		**1.42***
Aurora Energy Research (2020)	North West Europe	Maximum									
		Minimum									
		Average	**1.60**			**1.90**	**1.90**	**1.90**	**3.20**	**2.43**	**2.00**
Oxford Institute for Energy Studies (2021)	EU	Maximum								4.24	2.96
		Minimum								2.60	1.94
		Average								**3.34***	**2.35***
DNV GL (2021)	EU	Maximum								1.29	0.44
		Minimum								1.04	0.37
		Average				**1.52**			**1.94**	**1.16***	**0.41***
Gas for Climate (2020) (Accelerated Decarbonization Pathway)	EU	Maximum				1.36	1.5	1.85	3.30	2.52	2.06
		Minimum				1.23	1.4	1.71	2.59	2.06	1.48
		Average				**1.30***	**1.45***	**1.78***	**2.82***	**2.27***	**1.77***
Gas for Climate (2020) (Global Climate Action Pathway)	EU	Maximum							2.59	1.89	1.07
		Minimum							2.42	0.81	0.58
		Average				**1.23**	**1.33**	**1.56**	**2.51***	**1.45***	**0.75***
Dos Reis (2021)	EU	Maximum	1.5			2.41			7.10		2.70
		Minimum	1.00			1.17			2.10		0.60
		Average	**1.25**			**1.66**			**4.19***		**1.57***

Source: Hydrogen Council (2021a), IRENA (2019), IRENA (2021), Piebalgs et al. (2020), Aurora Energy Research (2020; 2021), Agora Energiewende and Guidehouse (2021), Agora Energiewende, Agora Industry (2021), Trinomics and LBST (2020), IEA (2019; 2021), Oxford Institute for Energy Studies (2021), DNV GL (2021), Gas for Climate (2020), Dos Reis (2021).

Notes: *Own calculation; for the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1833 (updated 9.9.2021).

Annex II. Production costs of renewable hydrogen by source

(€/kgH_2)

Report	*Scope*		*Solar PV*			*Onshore wind*			*Offshore wind*			*Decarbonized electricity*		
			2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
IRENA (2019)	Global	Maximum	5,58		2,29	4,41		1,13						
		Minimum	2,81	1,67	1,04	2,32	1,46	0,71						
		Avgerage	**5,29**	**2,89**	**1,76**	**3,88**	**2,47**	**1,06**						
Piebalgs et al. (2020)	EU	Maximum	7.10	4	2.85				7.10	4	2.85			
		Minimum	2.15	0.9	0.5				3.3	1.7	1.3			
		Avgerage	**3.45**	**2.1**	**1.4**				**4.9**	**2.6**	**1.65**			
Aurora Energy Research (2021)	EU	Maximum								4.52	3.43		3.92	3.06
		Minimum								4.11	3.22		2.46	2.05
		Avgerage		**3.46**	**2.67**		**3.25**	**2.51**		**4.32***	**3.33***		**3.19***	**2.56***
IEA (2021)	EU	Maximum												
		Minimum												
		Avgerage	**6.49**		**1.76**				**3.85**		**0.96**	**3.69**		**1.53**
Oxford Institute for Energy Studies (2021)	EU	Maximum					3.75	2.87		4.24	2.96			
		Minimum					2.60	1.99		3.44	2.43			
		Avgerage		**3.02**	**1.94**		**3.18***	**2.43***		**3.84***	**2.69***			
Gas for Climate (2020) (Accelerated Decarbonization Pathway)	EU	Maximum	3.30	2.52	1.94				2.67	2.36	2.06			
		Minimum	2.72	2.06	1.48				2.59	2.14	1.62			
		Avgerage	**3.01**	**2.29**	**1.71**				**2.62**	**2.25**	**1.84**			
Gas for Climate (2020) (Global Climate Action Pathway)	EU	Maximum	2.50	1.47	0.70				2.59	1.89	1.07			
		Minimum	2.42	0.81	0.58				2.54	1.84	1.00			
		Avgerage	**2.46**	**1.14**	**0.46**				**2.57**	**1.75**	**1.03**			
Dos Reis, P.C. (2021)	North West Europe	Maximum	7.10		1.60				7.10		2.10			2.7
		Minimum	2.10		0.60				3.30		1.30			1.1
		Avgerage	**3.46***		**1.10***				**4.92***		**1.70***			**1.9***

Source: IRENA (2019), Piebalgs et al. (2020), Aurora Energy Research (2021), Oxford Institute for Energy Studies (2021), DNV GL (2021), Gas for Climate (2020), Dos Reis (2021).
Notes: *Own calculation; for the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).

Annex III. Levelised costs of imported renewable hydrogen, different routes

Source	*Year*	*Exporting region*	*Exporting location*	*Importing location*	*Distance (km)*	*Mode of transport*	*Carrier*	*Tot cost EUR/kg*	*Cost breakdown, EUR/kg (%)*			
									Production	*Transport*	*Conversion*	*Reconversion*
Aurora Energy Research (2021)	2030	North Africa	Morocco	Germany		Ship		3.63	2,10 (57,9)	0,20 (5,5)	0,68 (18,7)	0,65 (17,9)
	2030	North Africa	Morocco	Germany		Pipeline		3.21	2,15 (67,0)	0,88 (27,4)	0,12 (3,7)	0,06 (1,9)
	2030	Chile	Chile	Germany		Ship	Ammonia	5.07	3,17 (62,5)	0,57 (11,2)	0,68 (13,4)	0,65 (12,8)
	2030	Australia	Australia	Germany		Ship	Ammonia	5.82	3,87 (66,5)	0,62 (10,7)	0,68 (11,7)	0,65 (11,2)
European Commission (2020)	2020	Australia	Australia north-west	Port of Rotterdam	20 972	Ship	Liquid hydrogen	8.26	3,63 (44,0)	2,17 (26,2)	2,47 (29,8)	
	2020	Australia	Australia north-west	Port of Rotterdam	20 972	Ship	Ammonia	6.30	3,63 (57,7)	0,63 (10,1)	2,03 (32,3)	
	2020	Chile	Iquique, Chile	Port of Rotterdam	14 267	Ship	Liquid hydrogen	5.36	1,43 (26,7)	1,47 (27,3)	2,47 (46,0)	
	2020	Chile	Iquique, Chile	Port of Rotterdam	14 267	Ship	Ammonia	3.90	1,43 (36,8)	0,43 (11,1)	2,03 (52,1)	
	2020	Middle-East	Saudi Arabia	Port of Rotterdam	12 036	Ship	Liquid hydrogen	6.93	3,23 (46,6)	1,23 (17,8)	2,47 (35,6)	
	2020	Middle-East	Saudi Arabia	Port of Rotterdam	12 036	Ship	Ammonia	5.63	3,23 (57,4)	0,37 (6,5)	2,03 (36,1)	
	2020	Australia	Australia north-west	Algeciras (Spain)	18 584	Ship	Liquid hydrogen	8.00	3,63 (45,4)	1,90 (23,8)	2,47 (30,8)	
	2020	Australia	Australia north-west	Algeciras (Spain)	18 584	Ship	Ammonia	6.23	3,63 (58,3)	0,57 (9,1)	2,03 (32,6)	
	2020	Chile	Iquique, Chile	Algeciras (Spain)	13 418	Ship	Liquid hydrogen	5.26	1,43 (27,2)	1,37 (25,9)	2,47 (46,8)	
	2020	Chile	Iquique, Chile	Algeciras (Spain)	13 418	Ship	Ammonia	3.86	1,43 (37,1)	0,40 (10,3)	2,03 (52,6)	
	2020	Middle-East	Saudi Arabia	Algeciras (Spain)	9 549	Ship	Liquid hydrogen	6.70	3,23 (48,3)	1,00 (14,9)	2,47 (36,8)	
	2020	Middle-East	Saudi Arabia	Algeciras (Spain)	9 549	Ship	Ammonia	5.56	3,23 (58,1)	0,30 (5,4)	2,03 (36,5)	
	2050	North Africa	Midelt, Morocco	Port of Rotterdam	2 600	Pipeline	Gaseous hydrogen	2.17	2,00 (92,3)	0,17 (7,7)	-	
	2050	North Africa	Hassi R'Mel, Algeria	Port of Rotterdam	3 600	Pipeline	Gaseous hydrogen	2.23	2,00 (89,6)	0,23 (10,4)	-	
	2050	North Africa	Midelt, Morocco	Cordoba (Spain)	600	Pipeline	Gaseous hydrogen	2.03	2,00 (98,4)	0,03 (1,6)	-	
	2050	North Africa	Hassi R'Mel, Algeria	Cordoba (Spain)	1 600	Pipeline	Gaseous hydrogen	2.10	2,00 (95,2)	0,10 (4,8)	-	
McWilliams et al. (2021)	2020	North Africa			3 000	Pipeline	Gaseous hydrogen	4.23	2,55 (60,3)	1,68 (39,7)	-	
Piebalgs et al. (2020)	2050	Middle-East	Saudi Arabia			Ship	Liquid hydrogen	2.77	0,61 (76,3)	0,19 (23,0)	-	
	2050	North Africa	Algeria			Pipeline		0.8	0,72 (26,0)	2,05 (74,0)	-	
IEA (2019)	2030	North Africa				Ship	Ammonia	4.11	3,38 (82,2)	-	-	0,73 (17,8)
	2030	North Africa				Ship	Liquid hydrogen (Centralised reconversion)	5.47	2,82 (51,6)	1,73 (31,6)	0,92 (16,8)	-
	2030	North Africa				Ship	LOHC (Centralised reconversion)	4.69	2,82 (60,3)	0,64 (13,6)	0,38 (8,1)	0,85 (18,1)
	2030	North Africa				Ship	Ammonia (Centralised reconversion)	4.43	2,82 (63,7)	0,62 (13,9)	0,32 (7,2)	0,67 (15,1)
	2030	North Africa				Ship	Liquid hydrogen (Decentralised reconversion)	5.22	2,82 (54,1)	1,48 (28,4)	0,92 (17,6)	-
	2030	North Africa				Ship	LOHC (Decentralized reconversion)	5.66	2,82 (49,8)	0,61 (10,7)	0,38 (6,7)	1,85 (32,7)
	2030	North Africa				Ship	Ammonia (Decentralised reconversion)	4.38	2,82 (64,5)	0,35 (8,1)	0,32 (7,3)	0,88 (20,2)
IEA (2021)	2030	Middle-East				Ship	Liquid hydrogen	3,37	1,23 (36,4)	1,20 (35,6)	0,94 (28,0)	-
	2030	Middle-East				Ship	LOHC	2,94	1,23 (41,7)	0,57 (19,5)	0,40 (13,5)	0,74 (25,2)
	2030	Middle-East				Ship	Ammonia	2,16	1,23 (56,7)	0,28 (13,1)	0,03 (1,2)	0,63 (29,0)
Aurora Energy Research (2020)	2040	North Africa	North Africa	North-West EU		Pipeline (new)		1.97	1,87 (95,2)	0,10 (4,8)	-	
	2040	North Africa	North Africa	North-West EU		Pipeline (repurposed)		2.50	1,87 (74,7)	0,63 (25,3)	-	
	2040	Middle-east	Middle-East	North-West EU		Ship		3.30	1,93 (58,6)	1,37 (41,4)	-	
DNV GL (2021)	2050	Middle-east	Oman	Port of Rotterdam	12 000	Ship	Ammonia	1.97	1,20 (61,0)	0,17 (8,5)	0,60 (30,5)	
	2050	Middle-east	Oman	Port of Rotterdam	12 000	Ship	Liquid hydrogen	4.43	1,20 (27,1)	2,60 (58,6)	0,63 (14,3)	
	2050	Middle-east	Oman	Port of Rotterdam	12 000	Ship	Liquid methane	2.50	1,20 (48,0)	0,07 (2,7)	1,23 (49,3)	
Hydrogen Council (2020)	2030	Middle-east	Saudi Arabia			Ship	Liquid hydrogen	3.00	1,76 (58,8)		1,24 (41,2)	

Source: Aurora Energy Research (2020; 2021), European Commision (2020), McWilliams et al. (2021), Piebalgs et al. (2020), IEA (2019; 2021), DNV GL (2021), Hydrogen Council (2020).
Notes: LOHC: liquid organic hydrogen carriers; for the conversion of costs expressed in EUR/MWh a lower heating value equal to 0.0333 MWh/kgH_2 was used (source: Belmans and Vingerhoets, 2020); for the conversion of costs expressed in USD/kgH_2 the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).

Annex IV. Techno-economic characteristics of different electrolyser technologies

	Study		Alkaline			PEM			AEM			SOEC		
			2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
CAPEX (EUR/kWe)	*IEA (2019)*	Maximum	1 235	750	618	1 588	1324	794				2 471	706	441
		Minimum	441	353	176	971	574	176				4 941	2 471	882
		Average	838*	551*	397*	1 279*	949*	485*				3 706*	1 588*	662*
	Gas for Climate (2020)	Maximum												
		Minimum	180	105	70									
		Average	715		420									
	IRENA (2019)	Maximum	741	476	326									
		Minimum	679	476	176									
		Average	710*	476*	251*									
	IRENA (2020b)	Maximum	882			618								
		Minimum	441		176	1235		176			176			265
		Average	662*			926*								
	IRENA (2021)	Maximum												
		Minimum										1765		
		Average	529			882								
Efficiency (%)	*IEA (2019)*	Maximum	70	71	80	60	68	74				81	84	90
		Minimum	63	65	70	56	63	67				74	74	77
		Average	66,5*	68*	75*	58*	65,5*	70,5*				77,5	79	83,5
	European Commission (2021)	Maximum	70	72	80	63	69	74				81	84	84
		Minimum	63	63	70	56	61	67				74	74	77
		Average	66,5*	67,5*	75*	59,5*	65*	70,5*				77,5*	79*	80,5*
	Gas for Climate (2020)	Maximum	70											
		Minimum	65											
		Average	67,5*											
Stack Lifetime (operating hours)	*IEA (2019)*	Maximum	90 000	100 000	15 0000	90 000	90 000	150 000				30 000	60 000	10 000
		Minimum	60 000	90 000	100 000	30 000	60 000	100 000				10 000	40 000	75 000
		Average	75 000	95 000	125 000	60 000	75 000	125 000				20 000	50 000	42 500
	European Commission (2021)	Maximum	90 000	100 000	150 000	90 000	90 000	150 000				30 000	60 000	100 000
		Minimum	50 000	72 500	100 000	30 000	60 000	100 000				10 000	40 000	75 000
		Average	70 000	86 250	125 000	60 000	75 000	125 000				20 000	50 000	87 500
	IRENA (2020b)	Maximum				80 000		120 000				20 000		
		Minimum				50 000		100 000	5 000					
		Average	60 000		100 000	65 000		110 000			100 000			80 000
	IRENA (2021)	Average	50 000			60 000			5 000			20 000		
Operating Pressure (bar)	*IEA (2019)*	Minimum	1			30						1		
		Maximum	30			80						1		
	IRENA (2020b)	Minimum	1											
		Maximum	30			70			35					
	IRENA (2021)	Maximum	30			70			35					
Operating Temperature (°C)	*IEA (2019)*	Minimum	60			50						650		
		Maximum	80			80						1000		

	IRENA (2020b)	Minimum	70	50	40	700
		Maximum	90	80	60	850
	IRENA (2021)	Minimum	70	50	40	700
		Maximum	90	80	60	850

Source IRENA (2019; 2020b; 2021), IEA (2019; 2021), European commission (2021), Gas for Climate (2020).
Notes: PEM: polymer electrolyte membrane; AEM: anion exchange membrane; SOEC: solid oxide electrolyzer cell; for the conversion of costs expressed in USD/kWe the following exchange rate was used: EUR/USD = 1.1333 (updated 18.11.2021).