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How can green hydrogen from North Africa support EU decarbonization? Scenario analyses on competitive pathways for trade

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ABSTRACT

The carbon-neutrality target set by the European Union for 2050 drives the increasing relevance of green hydrogen as key player in the energy transition. This work uses the JRC-EU-TIMES energy system model to assess opportunities and challenges for green hydrogen trade from North Africa to Europe, analysing to what extent it can support its decarbonization. An important novelty is addressing uncertainty regarding hydrogen economy development. Alternative scenarios are built considering volumes available for import, production costs and transport options, affecting hydrogen cost-effectiveness. Both pipelines and ships are modelled assuming favourable market conditions and pessimistic ones. From 2040 on, all available North African hydrogen is imported regardless of its costs. In Europe this imported hydrogen is mainly converted into synfuels and heat. The study aims to support policymakers to implement effective strategies, focusing on the crucial role of green hydrogen in the decarbonization process, if new competitive cooperations are developed.

1. Introduction

To effectively reach the goal of limiting global temperature increase to 1.5 °C, the transition away from fossil fuels is vital, addressing the energy-related challenges involving traditional energy systems [1–3]. Among carbon-neutral solutions, clean hydrogen is identified as a key player for this energy transition [4–6]. Its adoption must be integrated in the broader decarbonization framework including the deployment of renewable energy, the strategic implementation of energy efficiency measures, the enhancement of electrification and the adoption of carbon capture processes [1,7]. Nevertheless, the large-scale uptake of all these low-carbon solutions is not happening fast enough [8–10]. Experiencing a crucial innovation turning point, hydrogen development should be accelerated, addressing the status of the clean hydrogen technologies available, the different sectors and multi-interest actors involved [11]. Currently 95% of the hydrogen produced worldwide is based on fossil fuels, mainly produced through steam methane reforming process [12], while the two viable alternatives for a cleaner production are: (i) green hydrogen – produced through water electrolysis enabled by renewable energy – and (ii) blue hydrogen, based on natural gas reforming coupled with the carbon capture and storage (CCS) processes. The International Energy Agency (IEA) estimates a share of around 20% of blue hydrogen on total production to achieve long-term climate targets, while the remaining percentage will be associated to green hydrogen [13]. To properly realize these pathways, it is crucial to develop advanced and cost-effective solutions for renewable electricity generation, electrolysers and storage technologies. Besides production-related challenges, there are other criticalities impacting the current hydrogen market, namely it is used almost exclusively as a feedstock and mostly produced to be consumed on-site [14]. On the other hand, there are positive signals related to the increase in hydrogen demand, although all the increase falls in the traditional applications such as refining and chemical sector, requiring a strong development in new applications like transport, production of hydrogen-based fuels, high temperature heating in industry, electricity storage and generation [15]. To support hydrogen development and boost up its uptake, governments worldwide are effectively integrating hydrogen in their energy strategies [16,17]. According to the IEA update in September 2023 [15], currently a total of 41 governments – responsible for around the 80% of global energy-related CO_2 emissions – have adopted their own hydrogen

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strategies. Nevertheless, looking at 2050, future hydrogen demand will depend on a wide range of possibilities, regarding the maturity of technologies, their costs, the direct electrification potential and CCS deployment [18]. Barriers as high production costs, lack of infrastructure and energy losses must be overcome, while drivers like low renewable energy costs, scale up of technologies and power system benefits must be enhanced [18].

Moreover, being strongly affected by the availability of primary energy and water resources, the hydrogen economy could completely reshape energy trade relationships, leading to the establishment of new geopolitical winners through reduced or renewed conflicts [19]. Thus, it is highly relevant to address the significance and uncertainty of trade options, considering not only the disposal of resources, but also infrastructure availability, economic and financial risks, technological maturity and overall trade attractiveness for selected areas. Several countries in Europe or Korea are likely to become hydrogen importers, while Australia, Middle East and North Africa have promising ambitions for export [14], due to high renewables and freshwater availability and infrastructure potential. Specifically, Morocco, Norway, Chile, Australia and the United States are emerging as hydrogen export leaders worldwide [20–23]. According to Ref. [24], Africa, South America, Canada and Australia will be potentially global hydrogen exporters because of land and water availability; nevertheless, hydrogen production could exacerbate water scarcity in North Africa, even though water withdrawal for hydrogen is negligible compared to its use in other sectors [24]. Considering the announced projects, major trade routes will connect Australia to Europe and to Japan and Korea, while some Latin American countries aim to trade with Europe, and North America with the Asian countries [15]. Focusing on North Africa, there are countries that are experiencing an unprecedented series of demographic, social, political and economic changes which are going to significantly reshape the energy landscape in the region and also in the neighboured countries [25]. If from one side Europe is looking for increasing hydrogen domestic production [26–28], on the other hand it can be open to hydrogen trade with North Africa [29]. Specifically, concerning the potential exploitation of hydrogen pipelines, North Africa becomes a key partner for Europe, with Italy and Spain becoming crucial hubs for the rest of the European countries [21]. Within this context, besides techno-economic features, there are other important influencing factors determining international hydrogen trade often affected by limitations and uncertainty, which are very likely to create an indefinite delay on effective realization of projects, e.g. corruption and authoritarianism, inflated expectations, ecological and social externalities, fragmentation of stakeholders [30–32]. Recognizing the role that North Africa potentially will have in this new hydrogen-based game, this paper aims to analyse to what extent green hydrogen imports from North Africa could support European Union's (EU) carbon-neutrality goal.

The work is novel in studying how uncertainties in the hydrogen economy could affect the competitiveness of trade with North Africa till 2050, building ad-hoc energy scenario analysis. Specifically, the countries which are analysed in terms of competitiveness of green hydrogen trade are Morocco (MAR), Tunisia (TUN) and Algeria (DZA), ranked as the most predisposed to green hydrogen production according to the analysis conducted for [33] and detailed in Ref. [34]. At this point it is worthwhile to mention the work of [29], using the TIAM-ECN energy system model to analyse future electricity and hydrogen exchanges between Europe and North Africa. The present work builds on that by modelling each European country, instead of focusing only on West Europe, has [29] have done. Two main other aspects are addressed in this study: i) development of a detailed hydrogen production costs for each analysed North African country and ii) focus on cost uncertainties associated to hydrogen transport options into Europe.

The paper is structured as follows: section 2 reviews the uncertainty of parameters affecting green hydrogen deployment, while the step-by step procedure adopted is detailed in section 3, to finally study the alternative scenarios modelled and discuss the related results in section 4, while conclusions and future work are reported in section 5.

2. The evolution of green hydrogen deployment under uncertainty

This section reviews and highlights the significance of different parameters that could affect the implementation of pathways for hydrogen deployment, slowing down or speeding up the adoption of specific solutions and strategies. Assuming that there are wide ranges for hydrogen costs and demand relying on different assumptions, the evolution of hydrogen market is strongly influenced not only by economic challenges, but also by political, social and environmental issues [19]. This is captured across several studies and scenarios estimating varied global hydrogen demand volumes up to 2050. One of the highest amounts of hydrogen demand is foreseen by IRENA within the most ambitious path to emission reduction consistent with the 1.5 °C goal - corresponding to more than 600 Mt hydrogen worldwide in 2050 [1]. On the other side of the range, limiting the global temperature increase to 2 °C translates deploying smaller hydrogen volumes, below 200 Mt in 2050, according to the World Energy Council [18] while for the JRC's Global Energy and Climate Outlook (GECO) 2020-2C scenario this value decreases up to 100 Mt [35,36]. As reviewed and detailed by Ref. [36], the hydrogen demand will increase up to 2050, but the magnitude of this increase will rely on (i) climate change mitigation ambitions, (ii) total final energy consumption, (iii) final sectors involved (iv) different treatments of hydrogen and synfuels and influence of competing technologies. Despite different constraints and objectives, the majority of the studies, with different spatial and temporal resolutions, stresses the need to overcome key challenges in terms of investment costs and infrastructure requirements, in order to really unlock hydrogen deployment by 2040, when its role will be determinant in a carbon-constrained world [37]. Focusing on the EU, where the hydrogen demand could reach by 2050 an amount that is 9 times 2020 levels [38], in the framework of the European Green Deal released on December 2020 [39] and the European Climate Law set in July 2021 [40], there are two main policies driving hydrogen: the Fit-for-55 (FF55) package released in July 2021, pushing for 55% GHG emissions reduction by 2030 [41], and, as a response to the Russia's invasion of Ukraine, the REPowerEU – presented in May 2022 – which includes 10 Mt of renewable hydrogen domestically produced and 10 Mt imported by 2030 [42]. This is a huge and ambitious increase compared to the objectives of the European Hydrogen Strategy released in December 2020, in which only hard-to-abate sectors were accounted for hydrogen deployment [43]. Concerning the most recent updates and improvements within the EU context, the Renewable Energy Directive (RED) III [44] was published at the end of October 2023 and sets obligations for hydrogen consumption in transport and industry sectors by 2030. Across different scenarios, the transport sector shows the highest hydrogen demand share worldwide, ranging from 4% to 17% in 2050, – confirming a high level of uncertainty – and followed by industry, with a very few applications for buildings [36]. In the review of decarbonization scenarios elaborated by the Joint Research Centre (JRC) [38], it is found that most of the scenario analyses identify transport and industry as the two main sectors where hydrogen will play a key role, together with electrification. On the production side, it is estimated that by 2050 around the 95% of the electrolysers will be powered by a direct connection to wind and solar plants – if the share of renewable energy supply in gross final energy consumption is pushed up to 80% [45]. Fig. 1 summarises the main factors having an impact on the hydrogen demand, which is affected by uncertainties at different levels, including production technologies, CO_2 emissions reduction targets, consumption sectors, strategies and obligations.

Within this context, new forms of cooperation and trade become crucial to effectively ramp up hydrogen deployment worldwide; thanks to the international trade it will be possible to ensure the matching of hydrogen supply and demand [46]. By 2050 it is foreseen that a quarter of total hydrogen demand will be traded [1,21], with a 55% transported

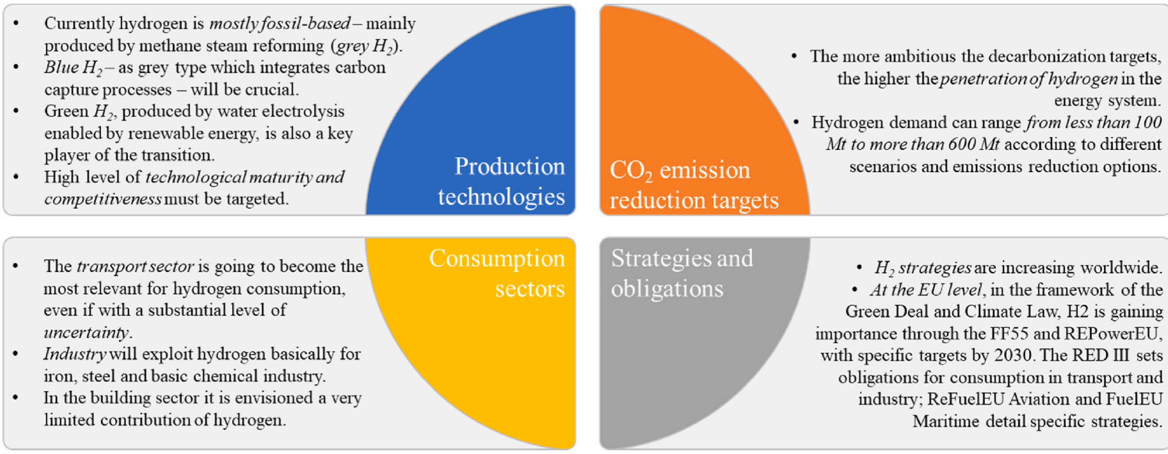

Fig. 1. Summary of factors affecting hydrogen demand [1,35,36].

by pipelines and the remaining amount by shipping – predominantly of ammonia [21]; the former will consist mostly on repurposed gas pipelines which are considered a cheaper option with respect to the new ones [21,47–49]. Because of the proximity to Europe, the high potential of resources and historical energy trade relationships, North Africa can consolidate its role of energy leader for Europe, also with respect to hydrogen [50]. estimates the future viability of blending hydrogen in existing pipelines from North Africa to Europe, while [29] investigates the export of electricity and hydrogen from North Africa to Europe by modelling existing pipelines as transport option. Specifically, North Africa can effectively become hydrogen export-oriented, due to the huge potential of resources and infrastructure, even if the cost-effectiveness decreases with more constrained trade amounts [29]. Benefitting of huge trade revenues, North Africa can become a major player in the hydrogen game, even if there are still several uncertainties to be investigated [29]. Estimating an import from neighbouring countries (i.e. North Africa, Ukraine, Middle East and Russia) ranging from 10% to 15% of the total EU demand, Seck et al. [45] model pipelines and shipping of ammonia and liquefied hydrogen, highlighting the critical advantage of existing cross-border pipeline infrastructure with respect to maritime transport.

Therefore, to deliver the more or less ambitious amounts of green hydrogen needed, the whole hydrogen value chain must be considered. This means to exploit affordable options covering the cost of renewable electricity, the investments and maintenance of the electrolysers, as well as the required infrastructure, making a solution more viable than another, based on technological readiness and development, market growth and financial risks [15,51]. A long-term view is needed; due to innovation, optimized supply chains and economies of scale, future hydrogen costs could be more than halved [51]. Specifically, even if in the short-term there are technical and infrastructure barriers making green hydrogen still hardly competitive with fossil-based one [52,53] highlights that by 2030 if solar photovoltaic cost decreases in parallel with a very high penetration in the power distribution network, the Levelized Cost of Hydrogen (LCOH) can be reduced up to 35%. According to Ref. [54], it is required a Levelized Cost of Electricity (LCOE) lower than 30 €/MWh to obtain a competitive price for green hydrogen. Having clear the strong influence of renewables in making green hydrogen cost-effective, it is relevant to also address the critical role of financial and economic risks for projects, in the form of the Weighted Average Cost of Capital (WACC). WACC could determine the export or import status of a country with respect to hydrogen trade [21,47]. Moreover, the possible evolution of electrolysers' costs, specifically Alkaline (ALK) and Proton Exchange Membrane (PEM) will have a huge impact in green hydrogen development, with their future costs, efficiencies and overall performances affected by uncertainty [55]. Overall, the most influencing parameters competing for the cost-effectiveness of green hydrogen production are the cost of renewable electricity and the financial risk in the form of WACC, followed by the technological development and maturity of the electrolysers [23,53].

In addition to this, the hydrogen transport option – pipelines or ships – is determinant for the overall import/export cost; it is influenced by technological performances over time, but also on volumes to be transported and distances to be covered. While the cost of pipelines increases linearly with distances, making them more convenient for shorter routes, ammonia or liquefied hydrogen shipping could be the appropriate alternatives for large transport volumes over long distances [47]. In each case, to effectively address the competitiveness of green hydrogen it must be clear that factors like energy security, diplomatic relationships, existing infrastructure, political stability must be addressed beside the techno-economic framework [47]. To model the cost-effectiveness of green hydrogen imports into EU from Algeria, Tunisia and Morocco, assumptions referred to all these parameters addressing competitiveness must be considered; it is needed to focus on the production and transport costs and on traded amounts to better define and discuss the optional pathways for hydrogen trade.

3. Materials and methods

To understand the relevance of hydrogen imports, a step-by-step procedure is developed, as shown in Fig. 2. The approach is applicable to any case study of interest related to potential green hydrogen trade, although here the focus is on the role that North African hydrogen imports can have in the European decarbonization. After reviewing the different factors making the hydrogen system evolution strongly sensitive to uncertainty (section 2), the main steps shown here deal with the elaboration of variables and assumptions for scenario development and results analysis (complemented with a sensitivity analysis). Within step 1 (section 3.1) an in-depth analysis of national hydrogen strategies and technical studies of the countries of interest is undertaken to estimate the hydrogen amounts available for trade. This is followed by calculating the corresponding country-specific LCOH for green hydrogen production, through the analysis of specific technological datasets. Lastly, the different available pathways to transport it from North Africa to Europe, i.e., by pipelines or ships (liquified hydrogen shipping), are assessed to evaluate the different cost ranges for transport. After this step, all the inputs are collected to model different options for import processes, building ad-hoc scenarios on the JRC-EU-TIMES model (section 3.2). Finally, the last step is devoted to the analysis of the results (section 4).

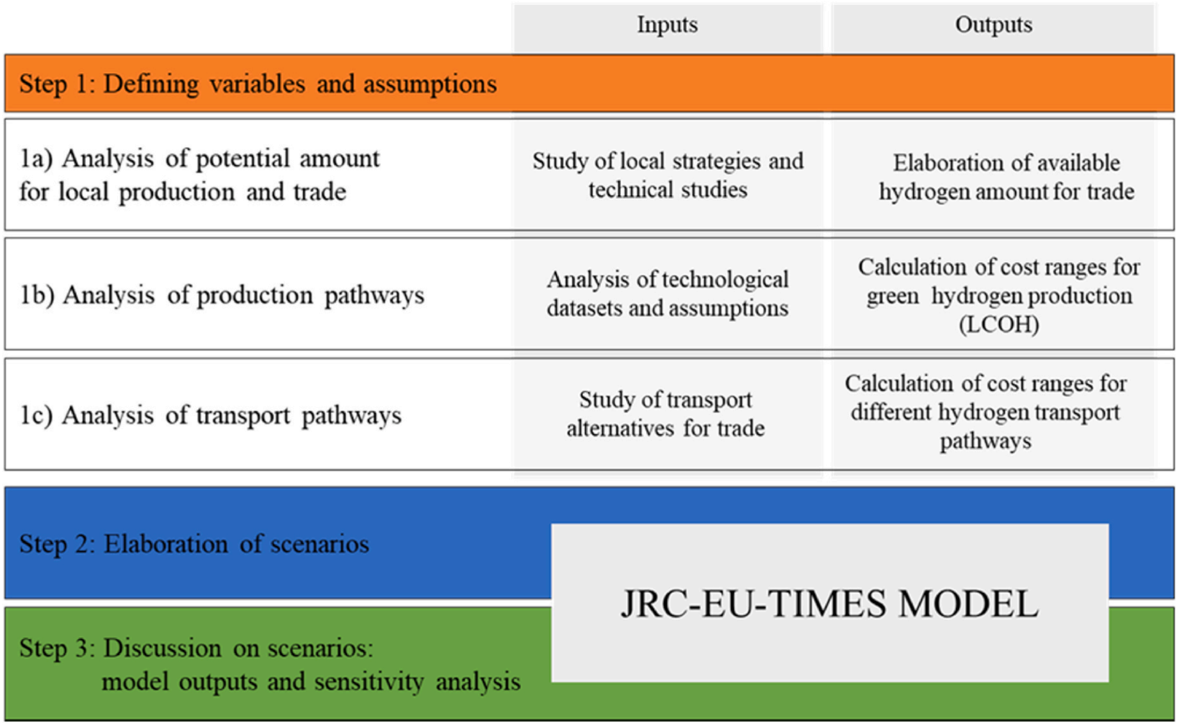

Fig. 2. The workflow of the study under assessment.

3.1. *Defining variables and assumptions to model uncertainty*

To determine potential maximum traded volumes of green hydrogen, the national strategies and roadmaps of Algeria, Tunisia and Morocco are assessed. Morocco has developed a long-term low-carbon strategy for 2050, that includes a significant interest in the green hydrogen market and confirming its potential role as hydrogen export-oriented country [56]. Its own national hydrogen strategy was published, in the form of a green hydrogen roadmap, in January 2021 [57]; besides a detailed analysis of the Moroccan hydrogen demand, hydrogen export potential is also addressed by the government [57,58]. Algeria is identified as one of the most exposed countries to the EU decarbonization targets, and, through government declaration, has determined a potential hydrogen supply to EU, aiming to export from 110 to 145 PJ of hydrogen by 2040 (around 1 Mt of hydrogen), as in its upcoming hydrogen roadmap [59]. In this regard, it is interesting to notice how the importable amount by both Tunisia and Algeria is set to about 540 PJ according to technical studies which account for an optimistic development of the renewable sector and hydrogen infrastructure [48]. Tunisia had plans for publishing its hydrogen strategy in March 2023, but it is not yet available at the time of writing [60,61]. Nonetheless, it is planning to reach carbon-neutrality in 2050, aiming also to develop a competitive export-oriented hydrogen industry [62]; its General director of the Electricity and Energy Transition at the Ministry of Industry, Mines and Energy, making reference to the outputs of the European Hydrogen Backbone (EHB) initiative [63], announced the ambition of Tunisia to import 5.5 Mt of hydrogen by 2050 to Europe (around 660 PJ) [64].

The following step concerns the elaboration of the hydrogen costs for production and transport of the countries of interest. Alternative technological pathways must be considered, also influenced by economic stability and financial risks. An LCOH approach was used to estimate the production cost for the imported hydrogen from North Africa, starting from the work made by Ref. [23] and then elaborated by authors in Ref. [34]. All data reported in tables and figures referred to 2021 currency; the calculation of production costs is based on collection and elaboration of different ranges of costs, starting from Refs. [65,66].

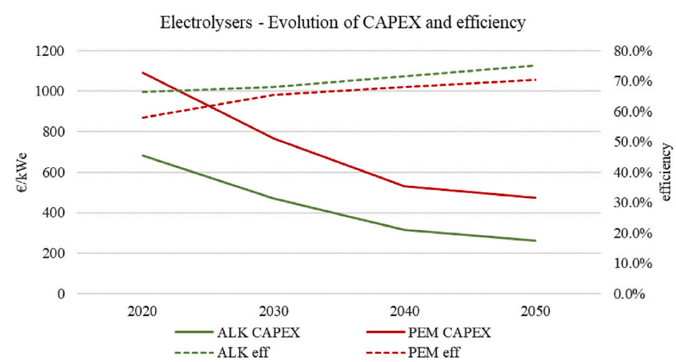

Fig. 3. CAPEX and efficiency inputs to calculate the LCOH of the imported hydrogen volumes, elaborated starting from Refs. [65,66].

Fig. 3 reports the evolution trends of CAPEX and efficiency for the ALK PEM electrolysers, from 2020 to 2050, elaborated starting from Refs. [65,66]; O&M costs are fixed to 2% for ALK and 4% for PEM along the whole time horizon.

An important parameter influencing the costs effectiveness of trade and impacting the LCOH calculation is related to the risks on energy supply projects, that influence hydrogen markets and costs and affect the affordability and availability of trade [15,21,51,67]. Specifically, there are differences across regions in the technological risks when considering financing renewable power [68]; these are reflected in specific WACCs for the different technologies. Moreover, there are other externalities affecting WACC and making trade more or less competitive, such as changing trajectories of cooperation and international markets [68]. To this regard, also the influence of this parameter results in the elaboration of the production costs for green hydrogen, as elaborated and detailed in Ref. [34]. **Table 1** reports the LCOH calculated in the form of ranges for the main technologies producing green hydrogen; the focus on the formulas and related variables exploited for the calculation is conducted in Appendix A. The reported technologies make reference to the exploitation of photovoltaic plants (i.e. PV) or wind onshore (i.e.

Table 1
The elaboration of LCOH for green hydrogen production, per each technology and country, for 2030 and 2050.

LCOH for production based on specific technology [€/kg$_{H2}$]						
	Algeria		Morocco		Tunisia	
	2030	2050	2030	2050	2030	2050
PV + ALK	2.33 ÷ 5.34	1.45 ÷ 3.27	2.33 ÷ 5.34	1.45 ÷ 2.61	2.46 ÷ 5.18	1.54 ÷ 3.18
PV + PEM	3.08 ÷ 6.72	1.95 ÷ 4.25	3.10 ÷ 5.39	1.96 ÷ 3.41	3.26 ÷ 6.52	2.07 ÷ 4.14
WO + ALK	2.16 ÷ 4.95	1.67 ÷ 3.82	2.00 ÷ 3.62	1.54 ÷ 2.79	2.29 ÷ 4.80	1.76 ÷ 3.70
WO + PEM	2.60 ÷ 5.75	1.97 ÷ 4.45	2.40 ÷ 4.24	1.83 ÷ 3.27	2.75 ÷ 5.59	2.09 ÷ 4.32

WO) to enable ALK or PEM electrolysers; the cheapest values of the range refer to a 3% WACC, while the most expensive costs reflect an increase of +5% of the country-specific WACC, starting from the updated values of IRENA related to renewable projects [68].

Concerning transport, the options to trade hydrogen through gaseous hydrogen pipelines or via liquefied hydrogen shipping are analysed, considering that the trade path Europe-North Africa could include both [47,48]. In fact, even if pipelines are more economically attractive than ships, there are other factors influencing their feasibility, e.g. a pipeline is a physical connection that lasts 40 years or more, while ships can exploit offtake agreements of 10 years and change the target market afterwards [47]. In this work is decided to consider liquified hydrogen and not ammonia – even if the latter is currently the most affordable option in the majority of the cases –, because if electricity in the exporting country is abundant and sufficiently cheaper than in the importing one, liquid hydrogen shipping over ammonia can be the solution [47]. Looking at Fig. 4, onshore pipelines are always more cost-effective than the offshore ones, while shipping option becomes cheaper only in 2050 and still for longer distances, representing definitely the cheapest option in case of distances of more than 10′000 km to be covered. Concerning pipelines, it is made a distinction between the onshore and offshore infrastructure – with the latter requiring higher costs – and the specific cost assumptions are based on an average of new and repurposed pipelines [48]. As all other parameters involved in these calculations, there are different shipping costs in the long-term, ranging from 0.84 to 1.59 €/kg per each 10′000 km [3], to 0.78 to 1.31 €/kg per 10′000 km [49]. Therefore, two cost options are considered for the available transport options distinguishing between an optimistic case (i.e. “OPT”), which represents the most favourable conditions and a pessimistic one (i.e. “PESS”), to take into account uncertainty on pipeline and shipping cost ranges. Specifically, in the following section (3.2) it is shown how the elaboration of the costs is exploited to define ad-hoc routes for trade scenarios.

3.2. Definition and modelling of scenarios for trade

As summarised in Fig. 5, the definition of scenarios aims to address if and how the uncertainty on the available hydrogen trade routes, on the traded volumes and on the economic/financing risks affects the competitiveness of green hydrogen trade from North Africa to Europe. The term “optimistic” accounts for the most favourable conditions of market push and strength, i.e. higher importable hydrogen volumes at lower costs, while “pessimistic” refers to lower global coordination and higher risks, i.e. lower importable volumes at higher costs. Five scenarios are modelled: S0 (without hydrogen trade with North Africa), S1 and S2 (large hydrogen amounts at cheapest cost transported by pipeline and shipping, respectively) and S3 and S4, which are identical to S1 and S2 but translate lower hydrogen volumes and higher production costs.

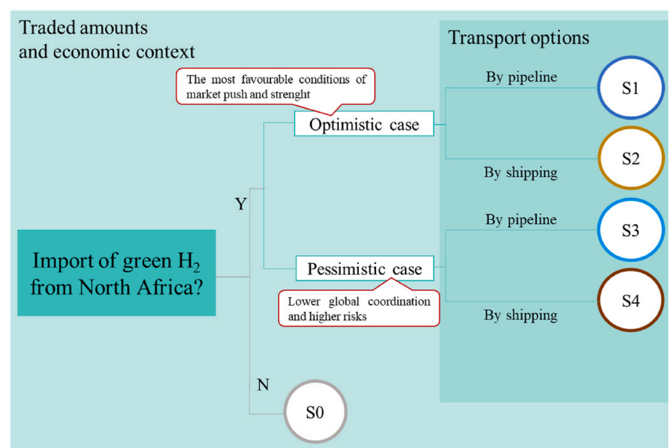

Fig. 5. The identification of the alternative scenarios under assessment.

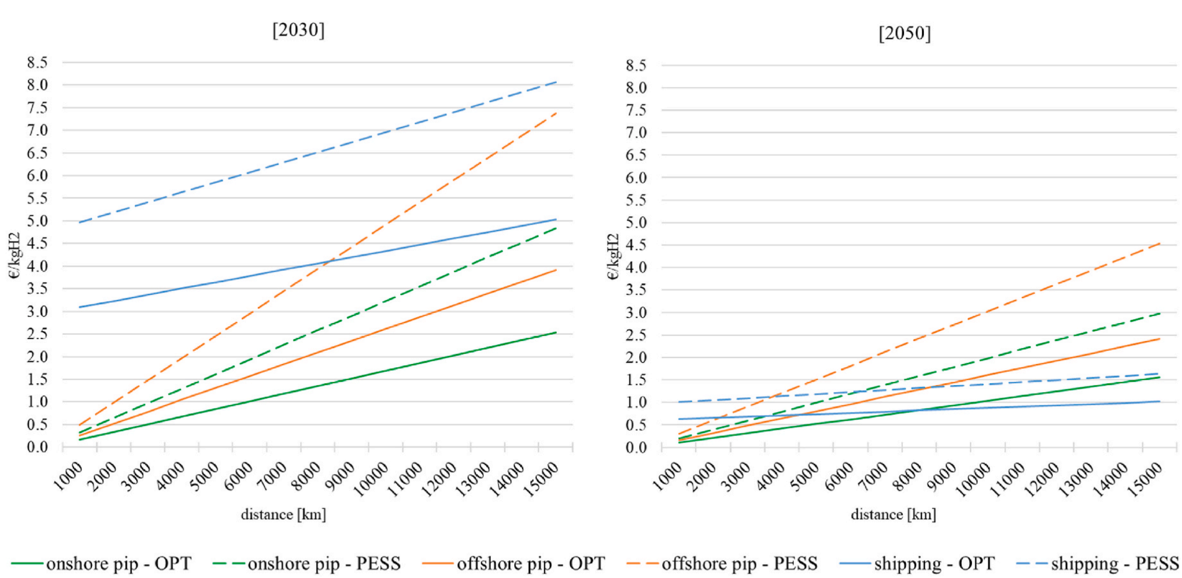

Fig. 4. The cost evolution over distance in optimistic and pessimistic case for the hydrogen transport options in 2030 and 2050, own elaboration starting from Refs. [47,49].

The scenarios identified in Fig. 5 are modelled on TIMES [69], specifically starting from the JRC-EU TIMES model (JET) [70,71]. As a technology rich bottom-up model generator, TIMES represents an appropriate instrument to conduct this assessment; through the use of linear-programming, it produces a least-cost energy system, optimized according to a number of user constraints, over medium to long-term time horizons [72,73]. The JET model, as European-wide partial-equilibrium model with disaggregation at a country level, was developed and released in 2013 by the JRC and has been widely use to model EU's energy system decarbonization, including hydrogen economy [37,70]. Concerning the model setup, the spatial coverage of the JET involves all the 27 EU Member States, plus United Kingdom, Norway, Switzerland, and Iceland (namely EU+); each year is modelled through 12 time-slices, representing an average of day, night and peak demand seasonally. The reference fossil primary energy import prices into EU are as in the Energy 2050 Roadmap [74], while the extraction of RES and fossils and conversion in EU+ is modelled endogenously, relying on country-specific resource extraction and conversion costs. More details on JET model can be found in Refs. [70,71] and are better detailed in appendix B which is dedicated to the model setup. With respect to hydrogen, the original modelling is exploited [37,75,76]; only the electrolysis processes are modified, (i) exploiting the CAPEX assumptions used for the LCOH in North Africa (Fig. 3), (ii) modelling off-grid PV panels to be coupled with electrolysers and (iii) allowing to store green hydrogen by both underground storage and tanks. In terms of trade, it is left the possibility to locally trade hydrogen through the same links modelled for natural gas, while to unlock extra-EU trade six different processes are added, to import green hydrogen from Algeria, Morocco and Tunisia, through pipelines or ships. Aiming to address the long-term competitiveness of trade, all scenarios and related results are focused on 2050 as target-year, with the objective to reach a 95% reduction of EU-wide CO_2 energy-related emissions in 2050 with respect to 1990 levels. Specifically, TIMES is an energy system model taking into account the energy combustion emissions and industrial processes emissions; the 95% emission reduction was set assuming that Land Use, Land-Use Change and Forestry (LULUCF) will be responsible to offset the remaining emissions to reach the EU carbon-neutrality by 2050 [77].

Regarding the maximum possible hydrogen imports from Algeria, Morocco and Tunisia, local strategies are used and adapted to the optimistic and pessimistic scenario options, while the LCOH is calculated as the average costs of the four technological combinations available, i.e. PV + ALK, PV + PEM, wind onshore + ALK, wind onshore + PEM. Specifically, according to **Table 1**, the minimum values (i.e. the lowest calculated costs) of the range are used as input for the optimistic scenarios (S1 and S2), while the pessimistic cases (S3 and S4) are based on the highest LCOH calculated (detailed in Appendix A).

Finally, concerning the transport options, the values already shown in Fig. 4 are used, distinguishing among the optimistic and pessimistic projections from 2030 to 2050; the natural gas pipelines routes to Spain, Italy and Portugal are exploited to assess distances in S1 and S3, while for S2 and S4 the shipping routes are based on the average distances from North Africa to the Liquefied Natural Gas (LNG) terminals available, under construction and planned for the EU+ countries [78]. Specifically, while modelling the shipping routes, the terminals of Oran, Jorf Lasfar and Sfax are considered, respectively for Algeria, Morocco and Tunisia; on the European side the countries that can benefit from the trade in this case are Italy, Spain, Portugal, France, the United Kingdom, Belgium, the Netherlands, Germany, Poland, Malta, Cyprus, Croatia, Greece, Norway, Sweden, Finland, Ireland, Estonia, Latvia, Lithuania, having all of them one or more terminals available or under development.

There are limitations in the model to be taken into account while analysing results and for future development of the work. Concerning the grid modelling, the expansion capacity of the power grid is very limited, while as off-grid option only PV panels are modelled as direct input of renewable electricity for electrolysis process. Moreover, in the current JET model version direct hydrogen consumption in industry is not possible yet. The following table summarises the assumptions and inputs for the scenarios introduced in **Table 2**; concerning the transport costs for shipping, it is reported at 1'000 km and 6'000 km, highlighting how it can be affordable while increasing distances. It is worth to stress that the transport costs are tailored on the distances from North Africa to Spain, Italy and Portugal for the scenarios S1 and S3, while are calculated for twenty of the EU+ countries in S2 and S4 cases which model the shipping option.

4. Results and discussions

In order to investigate the outputs of the modelled scenarios this section addresses the following questions: 1) How much will EU+ rely on green hydrogen trade from North Africa? How do the transport options affect the trade? 2) How EU+ countries are impacted by green hydrogen trade from North Africa? 3) Which EU+ economic sectors are affected by this trade? 4) What does this trade mean in terms of mitigation for EU+?

4.1. EU + green hydrogen production and North African import

According to the modelled scenarios, in the short-term (2030), only Morocco exports hydrogen into Spain via pipeline but only in the optimistic case – only 22% of the hydrogen amount available for trade (see Fig. 6). In 2040 all hydrogen available for trade from North Africa is imported by EU+ in each modelled scenario.

The same pattern is observed in 2050 with the maximum importable hydrogen volumes traded in all scenarios, for both the optimistic and pessimistic cases. Therefore, even if EU+ can afford to satisfy the majority of its hydrogen demand with EU + own production, all available hydrogen from North Africa is required as part of the solution to reach decarbonization with lower energy system costs. However, the traded hydrogen amounts in 2050 cover only around 16.5% of the EU+ demand in scenarios S1 and S2 (i.e., the optimistic cases) and only around 9% in scenarios S3 and S4 (i.e., the pessimistic cases). It is relevant to mention that Moroccan hydrogen is responsible of almost half of this trade. This

Table 2
The summary of assumptions and inputs for the scenarios.

	Traded H_2 volumes		Production cost		Transport cost	
	2030	2050	2030	2050	2030	2050
S0	–	–	–	–	–	–
S1	DZA: 36 PJ MAR: 78.1 PJ TUN: 58.7 PJ	DZA: 360 PJ MAR: 826.2 PJ TUN: 659.9 PJ	DZA: 2.43 €/kg_{H2} MAR: 2.35 €/kg_{H2} TUN: 2.57 €/kg_{H2}	DZA: 1.68 €/kg_{H2} MAR: 1.61 €/kg_{H2} TUN: 1.77 €/kg_{H2}	On. pip.: 0.15 €/kg_{H2}/1000 km Off. pip.: 0.23 €/kg_{H2}/1000 km	On. pip.: 0.09 €/kg_{H2}/1000 km Off. pip.: 0.14 €/kg_{H2}/1000 km
S2					By shipping: @1000 km: 2.94 €/kg_{H2} @6000 km: 3.60 €/kg_{H2}	By shipping: @1000 km: 0.60 €/kg_{H2} @6000 km: 0.73 €/kg_{H2}
S3	DZA: 27 PJ MAR: 37.1 PJ TUN: 29.3 PJ	DZA: 260 PJ MAR: 412.9 PJ TUN: 330 PJ	DZA: 5.44 €/kg_{H2} MAR: 4.17 €/kg_{H2} TUN: 5.27 €/kg_{H2}	DZA: 3.77 €/kg_{H2} MAR: 3.88 €/kg_{H2} TUN: 3.66 €/kg_{H2}	On. pip.: 0.27 €/kg_{H2}/1000 km Off. pip.: 0.42 €/kg_{H2}/1000 km	On. pip.: 0.17 €/kg_{H2}/1000 km Off. pip.: 0.26 €/kg_{H2}/1000 km
S4					By shipping: @1000 km: 4.72 €/kg_{H2} @6000 km: 5.78 €/kg_{H2}	By shipping: @1000 km: 0.96 €/kg_{H2} @6000 km: 1.17 €/kg_{H2}

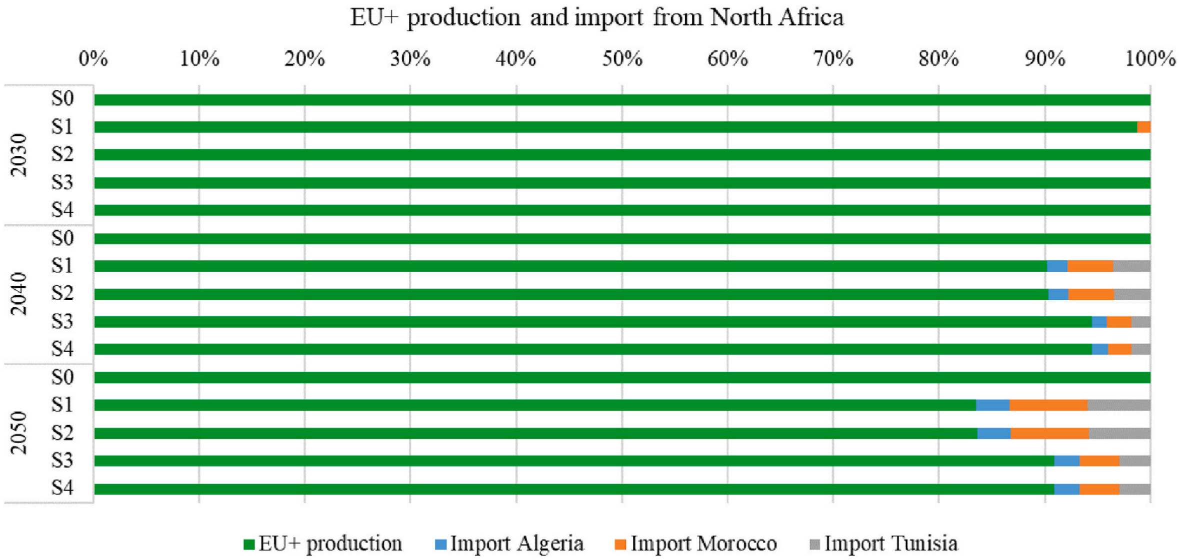

Fig. 6. The contribution to the EU+ hydrogen demand of the local production and of the North African import.

is in line with the fact that Morocco is the only country among the three analysed to have a structured hydrogen roadmap, considering exports [57].

Focusing on transport options, liquefied hydrogen shipping becomes competitive from 2040, but only for the countries that cannot exploit the pipelines option; this means that the adoption of alternative transport routes could diversify the trade pathways, involving different countries which can directly benefit from green hydrogen produced in North Africa. Figs. 7 and 8 detail the distribution of trade flows from Algeria, Morocco and Tunisia to specific EU+ countries, respectively by pipelines (S1 and S3) or shipping (S2 and S4). As a result, it is found that Italy and Spain import the majority of hydrogen from North Africa in the case of pipelines; when liquid hydrogen shipping is exploited, other countries like Poland, the Netherlands or Germany enter trade. Other countries can also import hydrogen via shipping, but in smaller volumes, namely the Baltic countries and Ireland. These results make clear the importance of addressing uncertainty in costs and routes in the EU+ hydrogen trade. On the other side, it is worth mentioning that Portugal has a marginal role in trade, importing hydrogen only in 2040, specifically from Morocco in S1 and from Algeria in S3.

Focusing on ships (Fig. 8), it is interesting to note that by 2040 Poland imports most of the hydrogen available both in the optimistic and pessimistic cases, while in 2050 according to S2 scenario Germany becomes the major importer from Tunisia and the Netherlands from

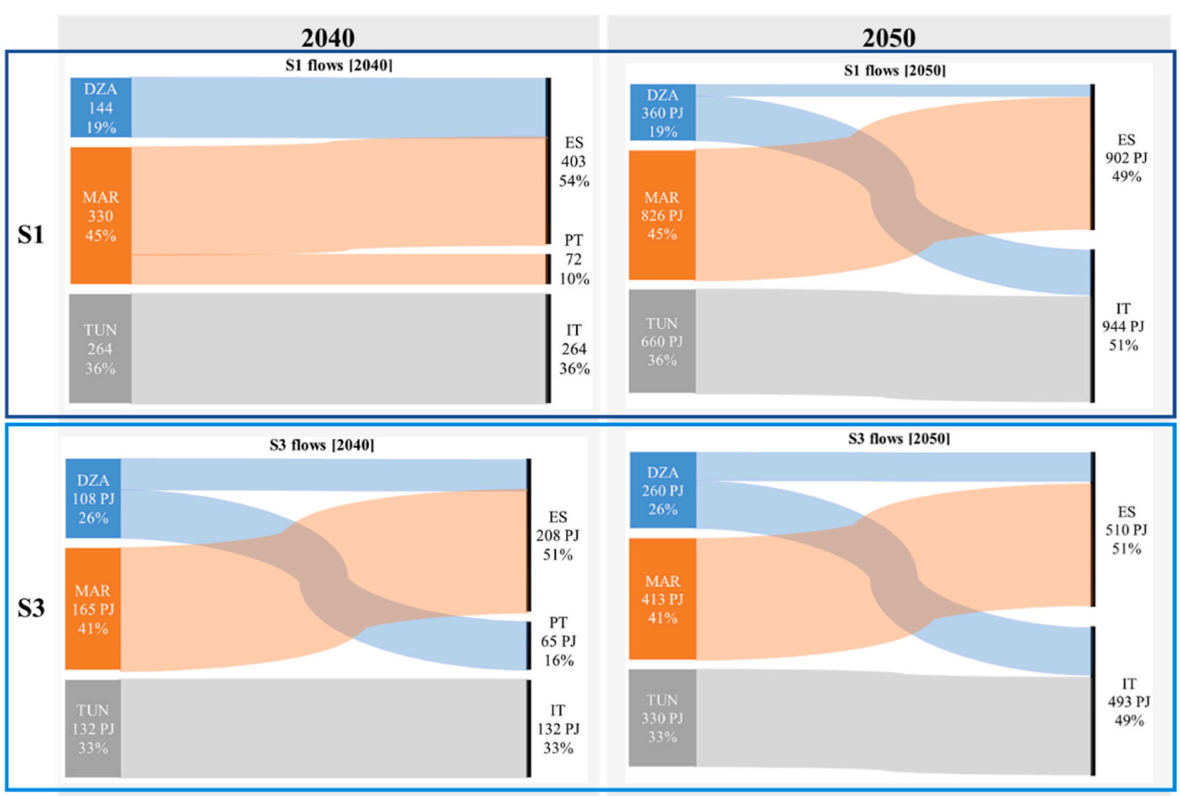

Fig. 7. Trade flows in the form of Sankey diagram for S1 and S3, by 2040 and 2050.

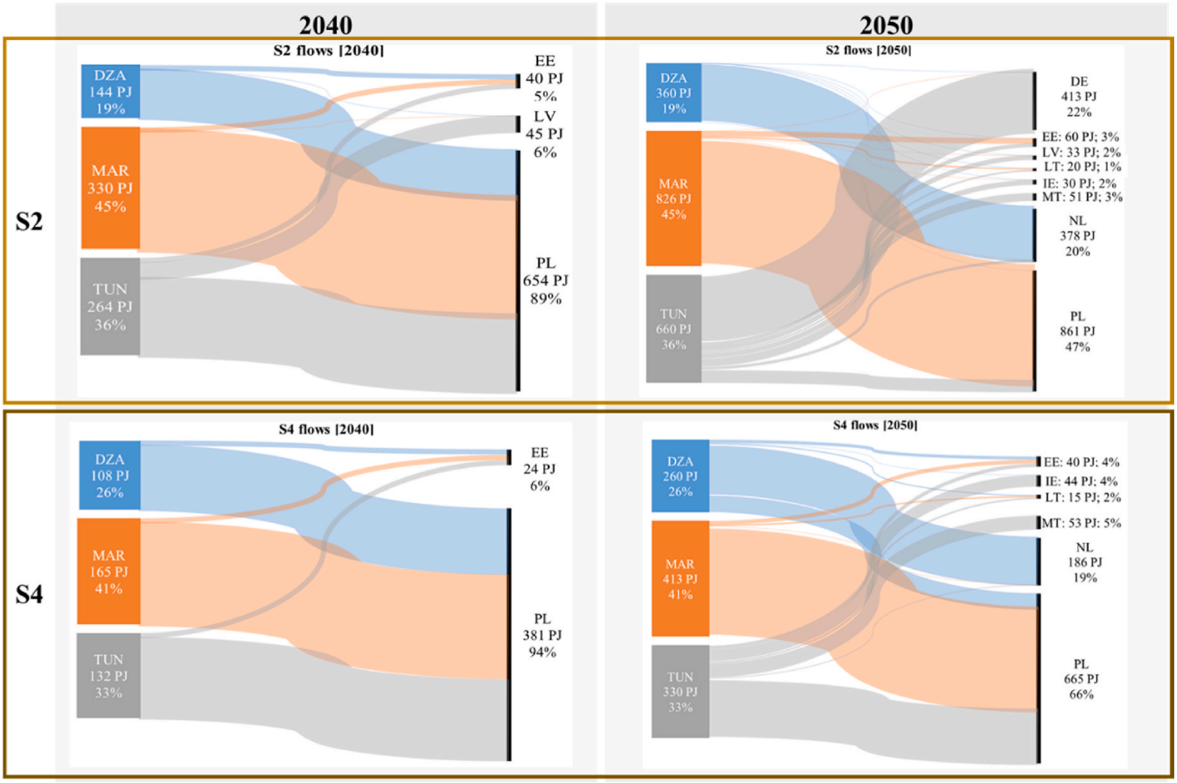

Fig. 8. Trade flows in the form of Sankey diagram for S2 and S4, by 2040 and 2050.

Algeria. The latter imports still in S4 most of the hydrogen coming from Algeria.

Modelling only pipelines as transport options, also [29] confirms the lower domestic production of Europe when higher volumes of hydrogen can be traded from North Africa. Specifically, through scenarios based on different amounts of electricity and hydrogen, Ref. [29] models importable hydrogen volumes ranging from 1750 to 3750 PJ in 2050 by the Maghreb countries, but focusing on the estimation of the costs for the systems and without considering specific routes or flows. Both pipelines and shipping routes are instead modelled through HyPE in Ref. [45]; it is a specific supply chain optimization model of hydrogen, working with a very high spatial and temporal resolution. In this case Europe can benefit of up to 1800 PJ from extra-EU countries – including also other regions than North Africa; this can be due to the high resolution adopted and constraints introduced in the model. With respect to these two studies, the current work is more focused on specific traded amounts and hydrogen flows at country-level and uncertainty on influencing parameters for production and transport costs, making possible the discussion of alternative trajectories for the system.

Table 3
% difference with respect to S0 regarding local production of hydrogen in 2050.

Production by country – delta wrt S0 [2050]	*S1* wrt *S0*	*S2* wrt *S0*	*S3* wrt *S0*	*S4* wrt *S0*
>75%	CZ, DK, SK			
35%–75%	BE, BG		–	
5%–35%	CH, HU			
	EE, LT, LU, LV, PT, RO, UK	NO, PT, RO	BE, BG, LT, LV, UK	BE, BG, PT, RO
−5%–5%	AT, CY, EL, FI, SE			
	NO, MT	IT, LU, UK	DE, EE, LU, NO, PT, MT	DE, IT, LU, NO, UK
−35% to −5%	ES, HR, IS, NL, ***EU***+			
	PL	LT	PL, RO	LT, LV
	DE		FR	
−75% to −35%	IT	LV, PL	IE, IT, SI	PL
	FR		-	
< −75%	-	EE, MT	–	EE, IE, MT, SI
	IE, SI			

4.2. EU + countries involved and impacted by the North African trade

Each of the EU+ countries can locally produce or trade hydrogen within EU+ to satisfy their own demand. Table 3 and Table 4 details different ranges for the delta in percentage of each scenario compared to S0 for each country, respectively for hydrogen production and consumption by EU+ country in 2050. Focusing on the European average, it is found that because of North African imports, the EU+ hydrogen production decreases up to 15% compared to S0 scenario (in S1), while EU + hydrogen consumption increases up to 3% (in S1, S2). This means that EU+ basically exploits the North African hydrogen to produce less hydrogen. However, this additional hydrogen imported is not consumed directly as hydrogen (see section 4.3 for a focus on hydrogen consumption). Despite this, at a country-level there are different reactions to hydrogen trade from North Africa, with varying degrees of sensitivity to the additional amount available (Table 3 and Table 4).

Regarding local hydrogen production, countries like Austria, Greece, Finland and Sweden are not impacted by North African hydrogen in all scenarios (variation in local production of +5%/-5% in all scenarios). Other countries are not impacted only in some of the modelled scenarios, as Germany, UK, Italy or Norway. The countries with national hydrogen production more sensitive to North African trade are Czechia, Denmark, Slovakia, Ireland and some Baltic countries.

In all scenarios, Spain, Italy and the Netherlands decrease their own hydrogen production, while on the consumption side Norway lowers its national hydrogen consumption when North African hydrogen is traded (Table 4). Other considerations concern Austria, that due to the import from North Africa increase the consumption – although the local

Table 4
% difference with respect to S0 regarding local consumption of hydrogen in 2050.

Consumption by country - delta wrt S0 [2050]	*S1* wrt *S0*	*S2* wrt *S0*	*S3* wrt *S0*	*S4* wrt *S0*
>75%	BG			–
35%–75%	AT		–	BG
5%–35%			LV	
	EE, PT, RO		BG, AT	IE, PT, RO, AT
−5%–5%	BE, CH, CY, CZ, DE, DK, EL, ES, FI, FR, HR, HU, IT, LT, LU, MT, NL, PL, SE, SI, SK, UK, ***EU+***			
	IE		EE, IE, NO, PT	NO
−35% to −5%			IS	
	NO	–	RO	EE
−75% to −35%	–	NO		–
< −75%			–	

production is more or less the same –, while countries like Bulgaria and Latvia increase both production and consumption. Trading hydrogen with North Africa can thus impact the intra-EU + hydrogen dynamics.

4.3. Consumption of hydrogen in EU+

Regarding hydrogen consumption and distinguishing between direct and indirect use of hydrogen, already in S0, most hydrogen is consumed by the transport sector. The additional imports from North Africa lead to small differences in terms of overall hydrogen consumption compared to S0. Albeit also small, there are more evident impacts in indirect hydrogen consumption, specifically hydrogen conversion into synfuels and heat (Fig. 9 and Table 5). shows to what extent the scenarios differ in 2050 from the base-case scenario S0 (i.e. without import options); S0 hydrogen consumption is represented by a grey bar and the relative difference to the consumption in the other scenarios is shown as points.

As mentioned, most imported hydrogen is converted into synfuels that are used in the transport sector. Thus, transport is the end-use sector more impacted by the additional trade, and this is also a trend confirmed by other studies [29,37,45]. In Table 5 it is detailed the relative difference of the import scenarios with respect to S0. Not surprisingly, it is evident that the highest differences are related to S1 and S2, which assume the highest importable amounts. Note that hydrogen imports also impact hydrogen consumption via fuel cells, which increases in S1 and S3 while decreasing in S2 and S4. Other impacted sector is the industrial one that consumes hydrogen converted into heat (more than double in S1 and S2 with respect to S0). Focusing on the transport sector, the reduction of the direct use of hydrogen with respect to S0 goes hand in hand with the increase of hydrogen use in transport sector through synfuels, especially in S1 (i.e. trade by pipelines in the optimistic case). It is more cost-effective to consume decarbonised synfuels that use hydrogen directly (Table 5).

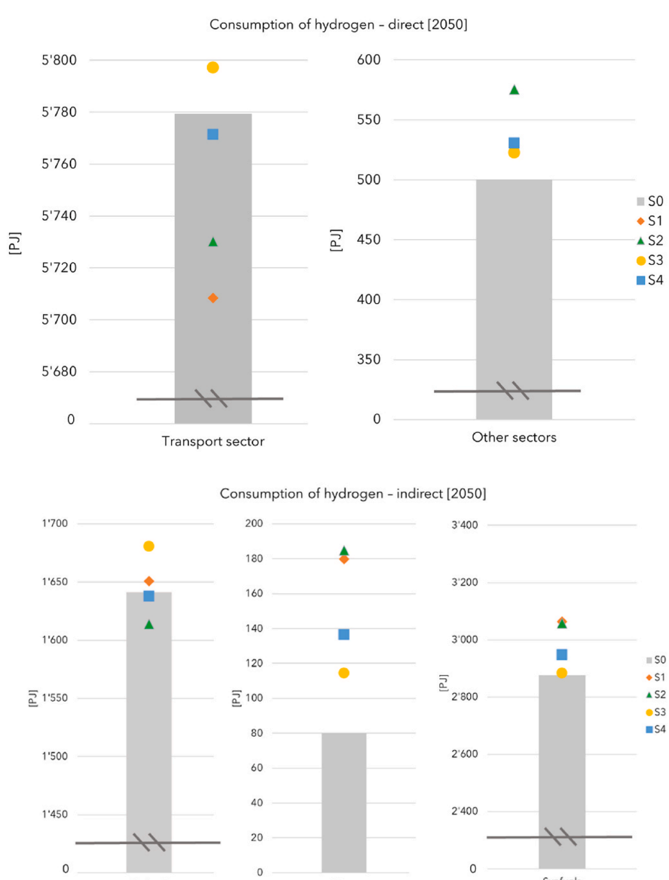

Fig. 9. Consumption of hydrogen for S0 compared to the trade scenarios; year: 2050. a) Direct consumption of hydrogen by sectors; b) conversion of hydrogen into fuels, heat, electricity.

4.4. The effects of trade on mitigation

Considering the decarbonization target, it is crucial to analyse which are the effects in terms of emissions mitigation due to the additional trade of green hydrogen from North Africa to Europe. To this end, it is important to say that, as expected, the scenarios modelling imports from North Africa make EU + decarbonization cheaper. Specifically, it is found that, by 2040, the CO_2 marginal cost with respect to the scenario S0 decreases up to 4% in the optimistic cases – when the imported volumes of hydrogen are higher and cheaper (S1 and S2). By 2050, the decrease in CO_2 marginal cost ranges from −10% – for S3 and S4 – to a huge decrease of −16% for S1 and S2.

4.5. The sensitivity analysis

The sensitivity analysis is performed on hydrogen volumes available for trade and on costs of traded hydrogen, by increasing and decreasing the related values of 50%. By 2050, in terms of traded volumes, it is found that an increase of 50% of hydrogen from North Africa will lead to a reduction in the EU + domestic production between less 4% (for S3 and S4) to less 9% compared to S1 and S2 results in the previous sections. The same percentages are found as a corresponding increase in local production if the amounts of imported hydrogen decrease by 50%. Applying the sensitivity analysis on North African LCOH, a cost decrease of 50% unlocks the import by 2030 also for Algeria and Tunisia in S1 – while in S2 (i.e. by exploiting the shipping option) Algeria and Morocco starts being involved in trade (this not the case for Tunisia). By 2040, only Morocco is still cost competitive when increasing costs by 50% in S3 and S4. In 2050 EU + will import all the North African hydrogen available, even if at higher cost (+50%) in all the scenarios, meaning that EU + will always exploit green hydrogen from North Africa, as a helpful solution to achieve its carbon-neutrality target set.

5. Conclusions

Focusing on decarbonization strategies in the long-term, green hydrogen is identified among the key carbon-neutral solutions to be developed; the more ambitious the targets, the higher the amount of hydrogen required. Nevertheless, there is a series of criticalities to be addressed in order to pave the way for its deployment and to encourage the adoption of new pathways for trade. In this regard, hydrogen could reshape countries' identities and alliances worldwide, enhancing the role of areas with very high availability of resources and space for infrastructure. Thus, this work aims to study the potentialities of green hydrogen trade from North Africa to Europe, to investigate to what extent this additional trade can support the European decarbonization.

Table 5
Relative difference between S0 and the trade scenarios for the H_2 consumption per final sector, through direct use and conversion options; year: 2050.

Sector	H_2 direct use [PJ]				H_2 converted into heat [PJ]				H_2 into synfuels [PJ]			
	S1–S0	S2–S0	S3–S0	S4–S0	S1–S0	S2–S0	S3–S0	S4–S0	S1–S0	S2–S0	S3–S0	S4–S0
Agriculture	0.0	0.0	0.0	0.0	0.3	0.3	0.1	0.2	8.3	7.9	−0.3	3.3
Commercial	0.0	0.0	0.0	0.0	9.1	9.3	3.1	4.9	0.0	0.0	0.0	0.0
Industry	1.7	0.0	0.0	0.0	61.8	65.1	21.3	35.2	28.4	26.9	−1.0	11.2
Residential	23.5	75.2	22.2	30.6	14.3	14.8	5.0	7.9	0.0	0.0	0.0	0.0
Transport	−70.9	−49.1	17.8	−8.0	–	–	–	–	140.5	132.4	2.9	50.7
	H_2 converted into electricity [PJ]											
	S1–S0	S2–S0	S3–S0	S4–S0								
Fuel cell use	9.4	−27.4	39.3	−3.6								

To do this, it is conducted an analysis on specific parameters that, because of their uncertainty, can affect the trade. After studying North African local strategies, the technological status of both production and transport options, and the financial risks in terms of investments and economic viability, different scenarios are modelled, using the JRC-EU TIMES model. Different options for importing hydrogen from Algeria, Morocco and Tunisia are integrated into the JET model with ad-hoc assumptions referred to specific parameters defining five modelled scenarios. S0 refers to the basic scenario case without import; other four scenarios are analysed, distinguishing among transport options (pipeline and shipping), volumes of available hydrogen and the case of market push and strength (i.e. the optimistic case) in contraposition to less favourable conditions (i.e. the pessimistic one). Here the main conclusions of the work are formulated point by point.

- In the short-term (2030) only from Morocco to Spain it is unlocked the possibility to start importing green hydrogen by pipelines.
- From 2040, all available North African hydrogen is imported regardless of its costs.
- By 2050 all the options are definitely cost-effective to achieve EU + decarbonization.
- Hydrogen imports from North Africa into EU + cover around the 16.5% of the EU + hydrogen demand by 2050.
- On the consumption side, the indirect use of hydrogen is the most affected by the additional import.
- Consumption of synfuels in transport and of heat in industry is enhanced because of trade.
- The most impacted countries are Spain and Italy in case of transport by pipeline.
- If the shipping option is available, North African hydrogen becomes cost-effective for other countries like Poland, the Netherlands and Germany.
- The EU + energy system is overall sensitive to green hydrogen imports and to uncertain factors as cost evolution, transport routes and available importable amounts.

As other studies modelling hydrogen to define its role in the decarbonization process [29,37,45,50], this work allows to focus on the European energy system and its requirements and potentials to achieve the carbon-neutrality in the long-term; in addition, it covers all the EU Member States plus United Kingdom, Norway, Switzerland, and Iceland (namely EU+) and is able to detail each country through the role of uncertainties in defining trade flows and potential cross-border relationships.

As future development of the work, it could be of interest to overcome some limitations of the model, for instance including the role of DAC, looking at the interplay of hydrogen and DAC for decarbonization purposes and also it can be of interest to focus on direct hydrogen consumption options for hard-to-abate industry sectors. Moreover, it must be integrated the modelling of off-grid onshore wind plants to supply power to electrolysers. In addition to this, the model can be modified in terms of technological inputs for the electrolysis processes, to better investigate how the technological status and maturity impact on both domestic production in EU+ and production costs in North Africa. Another point concerns specific assumptions to be developed on the EU + hydrogen demand, in order to see how the scenario modelling react in terms of production, consumption and trade to satisfy the demand over a huge range of uncertainty. In any case, this study confirms the key role of hydrogen in the decarbonization process, assessing how hydrogen disposal is crucial also through the exploitation of new routes and alliances and addressing the uncertainty of parameters.

CRediT authorship contribution statement

Maria Cristina Pinto: Conceptualization, Data curation, Methodology, Visualization, Writing – original draft, Writing – review & editing. **Sofia G. Simões:** Conceptualization, Methodology, Supervision, Validation, Writing – review & editing. **Patricía Fortes:** Conceptualization, Methodology, Supervision, Validation, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

This first appendix aims to detail the elaboration of the Levelized Cost of Hydrogen (LCOH), as one of the inputs to the model concerning the definition of the different scenarios. These calculations are the core of another work, specifically focused on suitability and costs up to 2050 for green hydrogen production in North Africa published in 2022 [34]. For the estimation of costs involving different production methods and locations, a focus on different sources is conducted; for the current analysis, the methodology proposed by Nunez-Jimenez and De Blasio [23] is mostly applied, exploiting the equations A1-A4, according to the variables introduced in ***Tab. A1***. Firstly, the Levelized Cost of Electricity from renewable sources ($LCOE_{RE}$) is estimated according to the Eq. (A1), while the investment costs for hydrogen production (aggregated in the $CAPEX_{H2}$ value) and the operational and maintenance costs – evaluated within the $OPEX_{H2}$ variable – are elaborated by the equations Eq. (A2) and Eq. (A3). These three contributions define the overall LCOH, expressed in €/kg_{H2} by the equation Eq. (A4). Matlab and Excel are used to work with the variables detailed by ***Tab. A1***, shown the definition, unit of measure and sources adopted to extract the proper values for the analysis.

$$LCOE_{RE}\left[\frac{€}{kWh}\right] = \frac{I_{RE} + \sum_{t=1}^{T_{RE}} \frac{OM_{RE}}{(1+d)^t}}{\sum_{t=1}^{T_{RE}} \frac{FLH_{RE}}{(1+d)^t}} \tag{Eq. A1}$$

$$CAPEX_{H2}\left[\frac{€}{kg_{H2}}\right] = \frac{LHV_{H2}}{\eta_{H2} * L_{H2}} * I_{H2} \tag{Eq. A2}$$

$$OPEX_{H2}\left[\frac{€}{kg_{H2}}\right] = \frac{LHV_{H2}}{\eta_{H2} * L_{H2}} * \sum\nolimits_{t=1}^{T_{H2}} \frac{OM_{H2}}{(1+d)^t} \tag{Eq. A3}$$

$$LCOH\left[\frac{€}{kg_{H2}}\right] = LCOE_{RE} * \frac{LHV_{H2}}{\eta_{H2}} + CAPEX_{H2} + OPEX_{H2} + f_{H2O} * c_{H2O} \tag{Eq. A4}$$

Tab. A1
The main variables introduced for the elaboration of the LCOH; definition and sources.

Variable	Definition	Unit of measure	Source(s)
I_{RE}	Investment cost for RES technology	[€/kW]	IEA [79]; IRENA [80,81]
T_{RE}	RES plant lifetime	[y]	IEA [79]; IRENA [80,81]
OM_{RE}	Operation and maintenance cost for RES technology	[€/kW]	IEA [79]; self-elaboration
FLH_{RE}	Full Load Hours of co-located RES plant	[h]	Global Solar Atlas [82]; Global Wind Atlas [83]; IEA [79]
η_{H2}	Electrolyser efficiency	[%]	Schmidt et al. [55]; IEA [65]; DEA [66]
I_{H2}	Investment cost for electrolysis plant	[€/kW]	Schmidt et al. [55]; IEA [65]; DEA [66]
OM_{H2}	Operation and maintenance cost for electrolyser technology	[€/kW]	Schmidt et al. [55]; DEA [66]
T_{H2}	Electrolysis plant lifetime	[y]	IEA [65]; DEA [66]
f_{H2O}	Specific water consumption per mass of hydrogen	[m^3_{H2O}/kg_{H2}]	Haider Ali Kan M. et al. [84]; Global Alliance Power Fuels – GEA [85]
c_{H2O}	Desalinated water cost	[€/m^3_{H2O}]	World Bank Group [86]
d	Discount rate/WACC	[%]	IEA [87]; IRENA [21,51,68]

To calculate the contribution of $CAPEX_{H2}$ and $OPEX_{H2}$ to the LCOH, Alkaline (ALK) and Polymer Electrolyte Membrane (or Proton Exchange Membrane, PEM) are considered, as the most used for hydrogen production by electrolysis. In PEM water is introduced at the anode to be split into protons, which go from anode to cathode by membrane to obtain hydrogen, while for ALK water is introduced at the cathode, having that hydrogen is separated from oxygen through a separation unit [88,89]. There is also another option, consisting of Solid Oxide Electrolysers Cell (SOEC), where higher temperatures are reached so that part of the electrical energy is replaced by the thermal one [90]. Concerning this last technological pathway, it is not introduced in these calculations because it is at an earlier stage of development; in Pinto et al. [34] some elaborations are made also for the SOEC case, working on different levels of costs and technological improvements.

Appendix B

This second appendix concerns the JRC-EU-TIMES (JET) model description, to better investigate its main advantages and limitations and how it fits within the scope of the manuscript. In the framework of energy system modelling, bottom-up optimization models are mostly exploited to overcome uncertainties based on modeler's perception in terms of energy system evolution, including detailed specifications for technologies both on supply and demand sides; linear programming algorithms are exploited to minimize the cost of the whole system. Developed by the International Energy Agency (IEA) and Energy Technology Systems Analysis Program (ETSAP) in the framework of energy models used for IEA analyses, the integrated MARKAL-EFOM System (ETSAP-TIMES) model generator allows to perform this kind of system-wide optimization [72,73]. By merging of a techno-engineering approach and an economic approach, it is possible to obtain a least-cost energy system, optimized with respect to specific user's constraints in the medium to long-term time horizon [72,73]. **Eq. B1** shows the formula according to which TIMES selects specific technologies at a certain investment and operation costs, simultaneously deciding also for primary energy supply and trade to finally minimize the whole cost of the system; NPV stands for Net Present Value, ANNCOST is the total annual cost, d is the general discount rate which refers to a specific reference year (REFYR), r is the region and y the set of years involved.

$$NPV[€] = \sum_{r=1}^{R} \sum_{y} \left(1 + d_{r,y}\right)^{REFYR-y} \bullet ANNCOST(r, y) \tag{Eq. B1}$$

In the attempt to summarise the general structure of the model, Fig. B1 shows an overview of inputs and outputs elaborated to satisfy the minimization of the objective function [70,71], detailing also the interactions with other energy models. Specifically, there are exogenous parameters of different types: (i) macroeconomic variables are aligned with the PRIMES EU Reference scenario [91]; (ii) technological parameters are mainly based on [91–93]; (iii) the domestic renewable electricity potential are based on GREEN-X and POLES models and the maximum yearly electricity production provided by RES2020, updated during the REALISEGRID EU projects [70]; (iv) the base year dataset is in line with Eurostat and the Integrated Database on the European Energy Sector (IDEES).

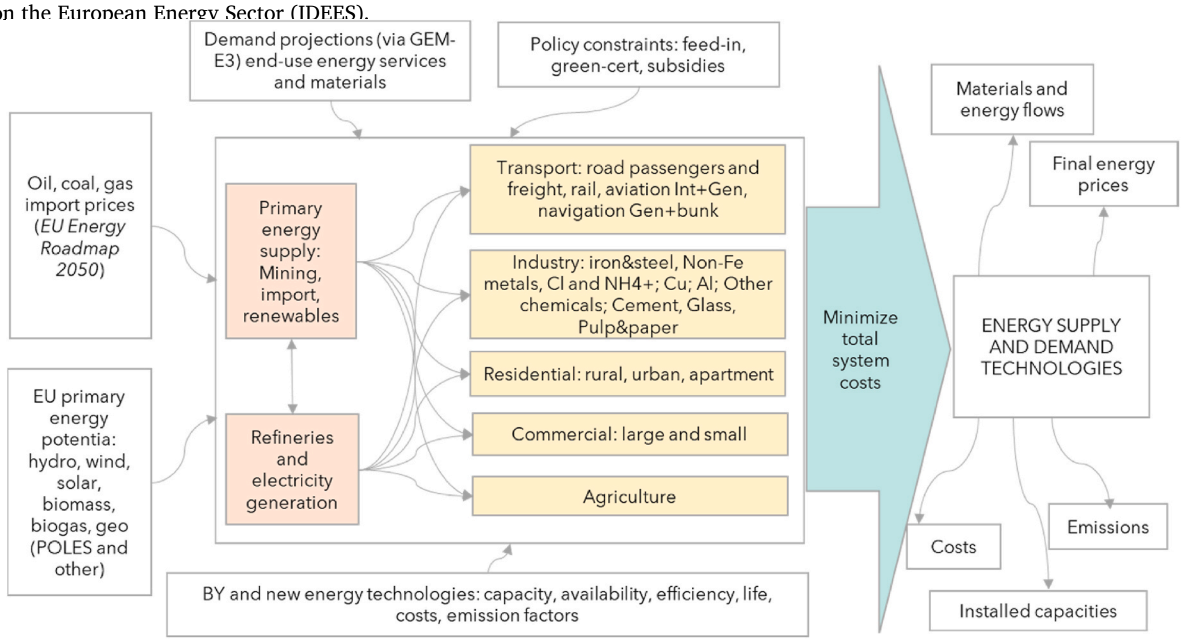

Fig. B1. Overview on the general structure of the JET model, from inputs to outputs [68,69].

This model has been widely used to model EU's energy system decarbonization, including hydrogen economy [37,71,94]. The original spatial coverage included 36 regions, with additional countries to the original EU Member States, so that also energy and emissions trade within Switzerland, Iceland, Norway, Albania, Bosnia and Herzegovina, the Former Yugoslav Republic of Macedonia, Montenegro, and Serbia were included, while the temporal coverage is based on years divided in 12 time-slices (daily average, night, peak demand per season), up to 2050 [70]. Electricity grids consider both import/export processes through existing infrastructures and potential new investments, both within EU+ and outside EU+, reference fossil primary energy import prices into EU are as in the Energy 2050 Roadmap, while the extraction of RES and fossils and conversion in EU+ is modelled endogenously, relying on country-specific resource extraction and conversion costs. Endogenous production of bioenergy is modelled, considering agricultural and forestry products and residues, municipal solid waste through biodegradable fraction, agricultural biogas, landfill gas and sewage sludge; unconventional gas is not modelled. Specifically, TIMES is an energy system model taking into account the energy combustion emissions and industrial processes emissions; the 95% emission reduction was set assuming that LULUCF will be responsible to offset the remaining emissions to reach the EU carbon-neutrality by 2050 [77]. Focusing on hydrogen energy systems in energy modelling, the MARKAL-TIMES energy model family is among the most common used tool [75,76]. To summarise the modelling of the hydrogen value chain within the JET model, Fig. B2 is reported.

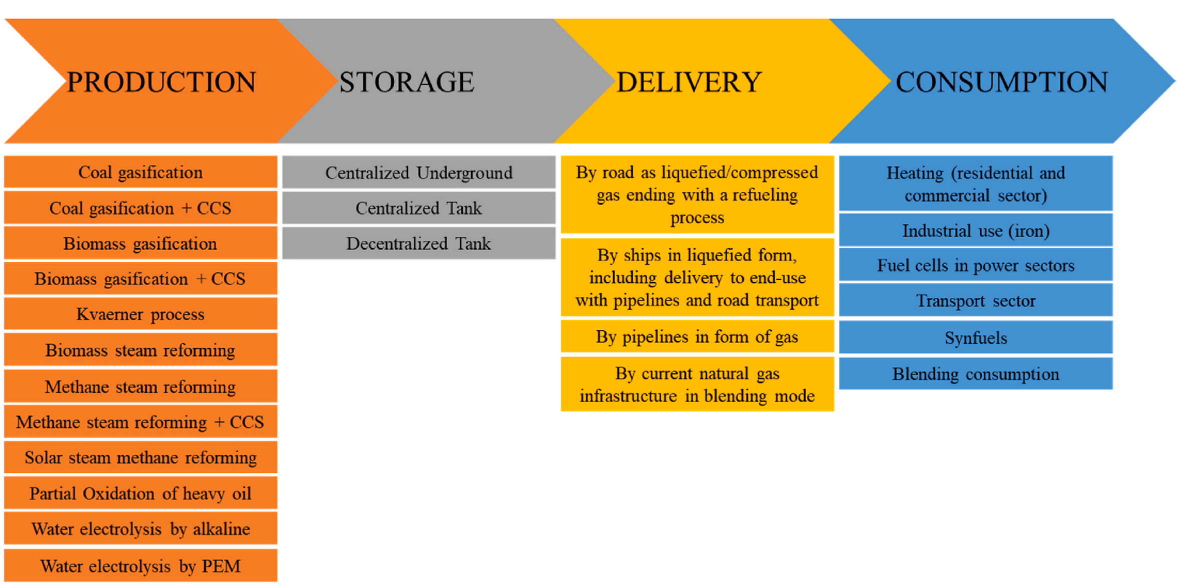

Fig. B2. The structure for hydrogen value chain in JET, adapted from Refs. [72,73].

Looking at the value chain (Fig. B2) and focusing on the modelling of the technologies for production, the following technological pathways are mainly modelled: (i) gasification and pyrolysis – by coal or biomass, (ii) reforming from natural gas, ethanol, biomass or heavy fuel oil, and (iii) electrolysis by Alkaline (ALK) or Proton Exchange Membrane (PEM) electrolysers. Pyrolysis and reforming are among the most developed technologies for production, while for electrolysis processes it is envisioned a huge uptake in the next future with a corresponding decrease of costs and improvements in efficiency. On the consumption side, hydrogen can be exploited in fuel cell buses, cars, and light- and heavy-duty tracks; it is also integrating the possibility to produce electricity by hydrogen through a 100 kW Proton Exchange Membrane Fuel Cell (PEMFC), which increases in performance and decreases in costs up to 2050 [37]. Hydrogen can be also used to produce biofuels, or to enable Carbon Capture and Usage (CCU) technological pathways for kerosene and biodiesel [37].

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