Green hydrogen from North Africa to Europe: impacts and competitiveness through long-term scenario analyses

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ABSTRACT

To achieve the climate-neutrality target by 2050, green hydrogen is gaining importance among the carbon-neutral solutions in the European strategic framework. Specifically, within the adoption of the Fit-for-55 Package and REPowerEU, the European Union aims to boost up hydrogen and its uptake, supporting both domestic production and competitive import options. While assuming a strategic role in the transition context and defining new or consolidated alliances worldwide, clean hydrogen must overcome a series of criticalities in order to be cost-effective and competitive. Beside economic barriers, there are technological challenges, environmental issues, geopolitical factors, lack of infrastructure and other elements making uncertain the hydrogen market and its evolution, specifically in the long-term. Within this context, North African countries can represent an opportunity for Europe to be consistent with the decarbonization target for 2050; this work discusses impacts and competitiveness of green hydrogen trade from North Africa to Europe, exploiting long-term scenario analyses. Aiming to become hydrogen export-oriented countries, Algeria, Morocco, and Tunisia are analyzed with respect to their possibility to produce and transport hydrogen, by pipelines or ships, to Europe. To this end, it is exploited the JRC-EU-TIMES model to build long-term scenarios which allow to trade hydrogen by pipelines or ships, in case of market growth and strength (i.e. optimistic case) or of lower coordination and more criticalities in hydrogen uptake (i.e. pessimistic one). Focusing on the different sources of uncertainty to make hydrogen competitive, these scenario analyses allow to study to what extent green hydrogen trade from North Africa could support the European decarbonization. As a result, it is found that in the short-term (2030) only pipelines in the optimistic case can be chosen as competitive option, while by 2050 in each case green hydrogen from North Africa is imported, regardless the costs. On consumption side, the additional amount is mostly converted into synfuels and heat. At country level, there are different reactions to trade; Italy, Spain, Poland, and the Netherlands are directly involved in trade. In each case, it is assessed that Europe will need clean hydrogen from North Africa as effective contribution to the achievement of the climate-neutrality target.

Keywords: decarbonization, energy scenarios, Green hydrogen, hydrogen trade

1 - INTRODUCTION

To properly follow the guidelines of the European Union (EU), the Italian government is currently focused on the update of its National Energy and Climate Plan (NECP, PNIEC in Italian), whose proposal of update has been submitted to the European Commission in July 2023 [1] and the related final version is expected to be released in July 2024. This implementation will be followed by a review and update of the Italian Long-Term Strategy (LTS) for 2050 [2], [3]. Concerning these main plans and strategies, RSE effectively supports the governance of the national energy system, by developing specific energy scenarios; there are RdS reports addressing the work on the NECP 2019 [4], NECP 2023 [5], and LTS 2020 [2]).

In addition to the NECP and the LTS as key enablers of the transition towards decarbonization, there is also the National Recovery and Resilience Plan (PNRR in Italian) in the framework of the Recovery and Resilience Facility (RFF) [6], to effectively unlock new investments and projects addressing the social and economic damage from the Covid-19 Pandemic [6], [7] and implement the REPowerEU Plan [8].

To this regard, the context of the analysis relies on the study of new efficient and clean technologies that, in parallel with the phase-out of fossil fuels, allow to fight global warming and other energy-related challenges involving traditional energy systems and to accelerate the transition towards a whole decarbonized system [9], [10], [11].

Among the available carbon-neutral solutions, clean hydrogen is getting importance, experiencing an innovation turning point and enhancing its role in the transition process [12], [13], [14], [15]. It is in fact identified as key player of the broader decarbonization framework, to be integrated with the uptake and enhancement of (i) renewable sources, (ii) energy efficiency measures, (iii) electrification, (iv) carbon capture processes [9], [16]. Nevertheless, even if these solutions are well known or ready to be implemented or technologically developed, the transition is not happening fast enough [17], [18], [19], requiring ad-hoc measures and actions to critically address barriers and enhance opportunities of the decarbonization drivers.

As the global hydrogen demand evolves with time and according to different trends, also Europe is encouraging hydrogen development, specifically estimating an increase of the demand by 2050 that is nine times the 2020 level [20]. Looking at the main decisions of the EU within the hydrogen framework, the starting point is the elaboration of the European Hydrogen Strategy released in December 2020 [21], followed by the Fit-for-55 (F55) Package of July 2021 [22], up to the main findings of the REPowerEU presented in May 2022 [8]. Following the commitment of a 55% GHG emissions reduction by 2030 fixed by the F55 Package [22], the REPowerEU acts as a response to the Russia's invasion of Ukraine [8]. While the former addresses many policy areas in the energy transition process [22], the latter is much more focused on pushing hydrogen use in the EU energy system [8]. Looking at the specific renewable hydrogen targets, the value of 5.6 Mt [22] has been replaced by the 20 Mt set in [8]. This represents a significant increase compared to the key objectives of the European Hydrogen Strategy, according to which only the hard-to-abate sectors must be effectively involved in hydrogen use [21]. Specifically, the REPowerEU includes 10 Mt of renewable hydrogen domestically produced and 10 Mt of imported hydrogen from third parties, highlighting the significance of cross-border hydrogen trade, to boost up its development going hand in hand with the achievement of the decarbonization targets.

Within this context, North Africa can emerge as significant hydrogen export leader, increasing its local production and trade perspectives. In other words, it is important to address if and how Europe and North Africa can enhance their cooperations, with respect to the potentialities of the latter in supporting the ambitious transition process and goals towards 2050. To this regard, this work aims to study to what extent the trade of green hydrogen from North Africa – in the form of Algeria, Morocco and Tunisia – can help the EU Member States towards the achievement of the carbon-neutrality goal in the long-term.

To address this topic, different optional long-term scenarios are built, modelling alternative production and transport costs through uncertainty of parameters that can affect cost-effectiveness and competitiveness.
This report is the final step of a study, conducted by RSE in the framework of RdS, which has started with a deliverable to preliminarily assess predisposition and potential of green hydrogen production in North Africa [23], followed by a second work focused on long-term suitability and costs for green hydrogen production and trade in those areas [24]. Within this third report, the concept of competitiveness through scenario analyses is finally developed. It is structured as follows; Chapter 2 reviews the role currently played by clean hydrogen and envisioned for the future, followed by the analysis of the main influencing factors that can affect the effectiveness of production and trade projects because of uncertainty in the long-term. These parameters are at the basis of the elaboration of scenarios to be built and analysed in chapter 3, which details the model setup and update to define the proper scenario analyses, whose outputs are discussed and investigated through a sensitivity analysis.

2 - UPTAKE OF GREEN HYDROGEN BY 2050 THROUGH UNCERTAINTY: INFLUENCING FACTORS FOR COMPETITIVE TRADE

While dealing with hydrogen, and specifically the low-carbon types, it is required to address the significance of different parameters that could enhance or set back its deployment, reinforcing or hindering its role in the transition process, with respect to the long-term options and strategies.
As confirmed by several analyses studying decarbonization strategies, the more ambitious the targets, the higher the penetration of hydrogen [25]; to this regard, the first part of this chapter is devoted to the analysis and comparison of different scenarios and strategies paving the way to hydrogen uptake, with a focus on the European context. On the other side, it is crucial to recognize how different influencing factors and parameters can make effective a hydrogen route with respect to another, exploiting different production and transport options which correspond to alternative solutions for trade among different countries (sub-section 2.2). In addition to this, being undoubted that the main driver is represented by cost assumptions, it is also crucial to understand that hydrogen demand is not only influenced by economic challenges, but also related to environmental issues, political and social dynamics [24], [26].

2.1 Positioning hydrogen in a decarbonized world

By the end of 2022 low-emission hydrogen production covers only the 0.7% of the total hydrogen production [27], with the majority of the demand worldwide satisfied by fossil fuel-based hydrogen, mainly produced through steam methane reforming [28]. In its last Global Hydrogen Review (GHR) published in September 2023 [27], the International Energy Agency (IEA) estimates that around the 80% of hydrogen will be of green type by 2050, i.e. exploiting water electrolysis supplied by renewable energy [27]. The remaining share is assessed as blue type that – differently from the grey one – is coupled with carbon capture and storage (CCS) technologies. To boost the production of these low-carbon hydrogen, there is the need to implement cost-effective pathways for renewable energy production, electrolysers, and storage technologies. In the long-term perspective it is envisioned an uptake of advanced technological applications that now are still at demonstration of prototype phase, e.g. exploiting Solid Oxide Electrolysers (SOEC) as production option [29].
On the consumption side, currently hydrogen is mostly used as a feedstock and produced to be consumed on-site [30]; moreover, even if there is a positive increase in hydrogen demand, it appears to be still concentrated in traditional applications, while requiring to be used in transport, for hydrogen-based fuels, high temperature heating in industry, electricity storage and generation [27].
Figure 2.1 highlights how different targets and constraints will have strong impact on hydrogen uptake; several studies developing long-term scenarios ranging among different hydrogen volumes worldwide, from a minimum of 150 Mt to a maximum of more than 600 Mt by 2050 [31].

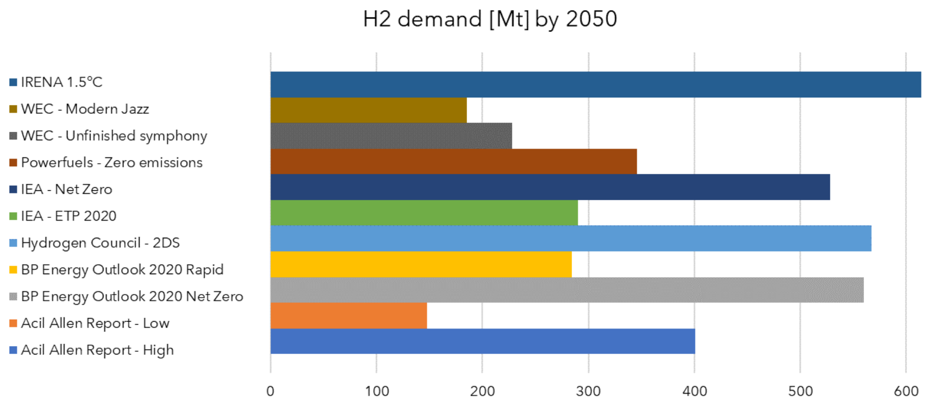

Figure 2.1 – Global long-term hydrogen demand according to different scenarios (updated to 2021), adpated from [31].

While the International Renewable Energy Agency (IRENA) estimates a hydrogen demand increase up to 600 Mt, to make effective the emissions reduction consistent to the pathway of 1.5°C threshold [9], the World Energy Council (WEC) evaluates a demand of 200 Mt by 2050, to make effective the less ambitious target of 2°C as limiting rising temperature [31]. Despite these differences in settings and targets, it is widely recognized the need to overcome key challenges concerning investment costs and infrastructure availability to concretely unlock the hydrogen market by 2040, when it will directly influence a carbon-constrained world [32]. In its 2023 update of the Net Zero Scenario [33], the IEA envisions an average annual growth rate of the demand for low-carbon hydrogen and hydrogen-based fuels of 80% to 2030 and 9% between 2030 and 2050 [33]. It will be required an amount of electricity that is more than half of today's global electricity demand, to basically satisfy the hydrogen requirements of industry and transport, covering the 80% of the total demand by 2050 [33].
Focusing on Europe and according to a review of the main EU long-term analyses [20], it is found that hydrogen usage in end-use sectors will be still negligible in the next decade, while by 2050 it should meet more than the 10% of the final energy demand [20]. To this regard, it is confirmed the role of transport and industry as the two main sectors in which hydrogen will spread and play a crucial role, together with electrification. Specifically, transport will account for a hydrogen share of 27% on average, while concerning industry over the 20% the energy demand will be satisfied by hydrogen supply [20]. It is also estimated that the growing role of renewable hydrogen will contribute significantly to an acceleration in RES integration in Europe [34]. In fact, if the share of RE supply in gross final energy consumption will be pushed up to 80% by 2050, it will mean that around the 95% of the electrolysers will be powered by a direct connection to wind and solar plants [34].
Focusing on the recent updates and improvements within the EU context, the Renewable Energy Directive (RED) III [35], published at the end of October 2023, sets obligations for hydrogen consumption in both transport and industry sectors by 2030, through the definition of the Renewable Fuels of Non-Biological Origin (RFNBOs), as detailed in Figure 2.2.

RED III

"Renewable liquid and gaseous transport fuels of non-biological origin" (RFNBOs) means liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass.

In the industry sector:
- 42% of H_2 used by industry must be RFNBOs by 2030;
- 60% by 2035.

In the transport sector:
- a binding target of 14.5% GHG emissions intensity reduction by 2030 by using renewable energy fuels, or a binding share of at least 29% of renewables within the final consumption of fuels by 2030;
- An aggregate quota of 5.5% of energy in the *transport* sector must be met from advanced biofuels or RFNBOs by 2030; there is an additional sub-sub-target of 1% of RFNBOs in the share of energy supplied to the transport sector in 2030;
- RFNBOs count double towards the fuel supplier obligations;
- RFNBOs used in aviation and shipping are multiplied by 1.5.

Delegated Acts
- Definition of the conditions under which the electricity to produce hydrogen, hydrogen-based fuels or other carriers can be considered fully renewable;
- Elaboration of a methodology for calculating life-cycle GHG emissions for RFNBOs and recycled carbon fuels (RCFs).

Figure 2.2 – Focus on RED III about RFNBOs and related Delegated Acts [35], [36].

Being a key driver of decarbonization for aviation and maritime sectors, ReFuelEU Aviation [37] and FuelEU Maritime [38] provide actions and strategies to enable hydrogen use, as summarised in Figure 2.3. In addition to these two initiatives, the Alternative Fuels Infrastructure Regulation (AFIR), will ensure the exploitation of hydrogen refuelling stations to really unlock the zero-emission vehicles [39] (Figure 2.3).

ReFuelEU Aviation
From a 2% of minimum Sustainable Aviation Fuels (SAFs) by 2025 , to a 20% by 2035 with a sub-quota for synthetic fuels of 5%.
By 2050, a minimum SAFs share within fuel supplied of 70% and a sub-quota of 35% for synthetic fuels.

FuelEU Maritime
Limitation on the annual average carbon intensity of the energy used within the maritime sector from 2025 to 2050: -2% by 2025; -31% by 2040; -80% by 2050.

Alternative Fuels Infrastructure Regulation (AFIR)
- At least one H_2 refueling station (HRS) each 200 km on main roads by 2030;
- One 700 bar refueling point each HRS;
- One HRS in every urban node;
- A mandatory cumulative daily capacity of 1 t of H_2;
- Ad-hoc payment systems at HRS and price transparency.

Figure 2.3 – Details on EU regulations and strategies for hydrogen end-use sectors, adapted from [36].

Besides these technological focus on end-uses, there are the Emissions Trading System (ETS) [40] and Carbon Border Adjustment Mechanism (CBAM) [41], [42], which represent other two main pillars in the decarbonization context. The latter covers cement, iron and steel, aluminium, fertilisers, electricity, and hydrogen; in its first phase (2024 to 2026) it will be applied to the import of products considered carbon-intensive and with significant risk of carbon leakage[1]. From January 2026, the implementation of CBAM will lead to the phasing out of free allowances under the ETS by 2034 [36]. Regarding the ETS, it has been also implemented the ETS II [43], to address with a separate emission trading system also other sectors like buildings and road transport, fixing the goal of a 42% emissions reduction with respect to 2005 levels by 2030 [43].

[1] *Carbon leakage refers to the situation that may occur if, because of costs related to climate policies, businesses relocate the production to other countries with less stringent emission constraints, potentially resulting in a rise of their total emissions. Industries with high energy intensity may face a higher risk of carbon leakage. (https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/free-allocation/carbon-leakage_en)*

Concerning the trade potential, IRENA envisions that a quarter of total hydrogen demand will be traded worldwide by 2050 [9]; Europe is planned to import 50% of the total EU hydrogen demand by 2030 – about 10 Mt of hydrogen by extra-EU area [8]. This means that even if Europe is trying to create a local market of hydrogen production, on the other hand there is the interest and the need to explore other viable solutions for hydrogen deployment, meaning creating or renewed alliances with extra-EU countries.

Nevertheless, in a report released at the end of 2023 by IRENA in collaboration with the World Trade Organization (WTO) [44], it is stressed how hydrogen trade is still currently restricted to a little amount of countries – with United States and the Netherlands identify as the two importing leaders and Canada and Belgium as the major exporters [44]. Moreover, through the analysis of the hydrogen market of 2021, it emerges how the trade of hydrogen derivates is much higher compared to the very small global hydrogen trade experienced up to now (Figure 2.4). Concerning ammonia, in 2021 the top exporting leaders are instead Trinidad and Tobago, Russia, Indonesia, the Kingdom of Saudi Arabia, and Algeria, supplying mostly India, United States, Morocco, and South Korea [44]. The actual landscape of derivates is found as more heterogenous and less regionalized than the green hydrogen one; nevertheless, the uptake of green hydrogen is expected to lead to huge increase in hydrogen market with respect to the current low levels [44].

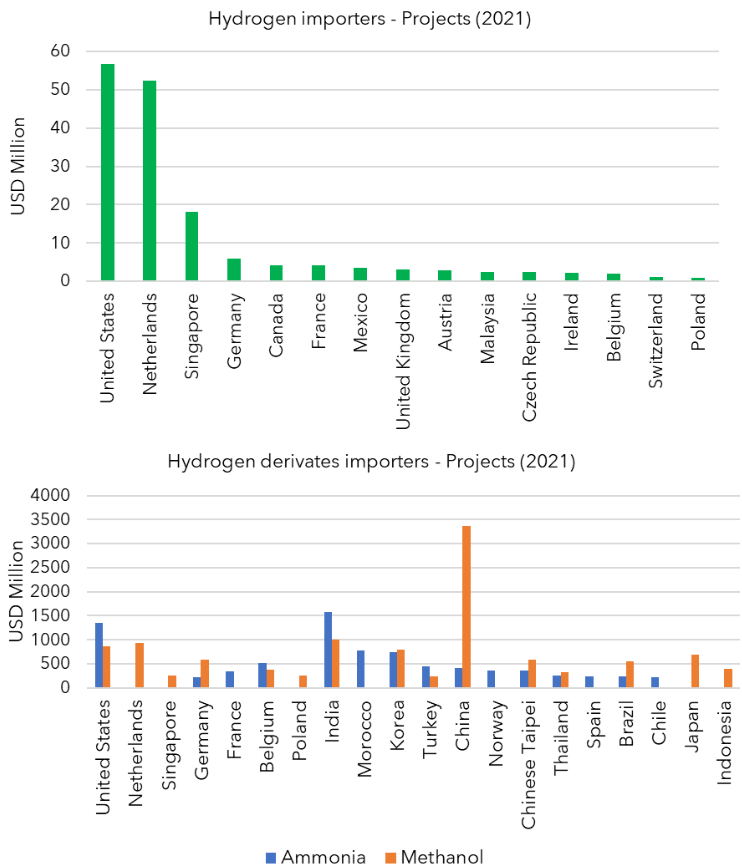

Figure 2.4 – Hydrogen (up) and hydrogen derivatives (down) market according to 2021 projects [44].

If from one side there is an increase in equipment and financial costs – basically due to inflation –, the number of announced clean hydrogen projects is growing fast worldwide, together with the implementation of ad-hoc national strategies and plans supported by governments and private sectors for projects and investments [45], [46]. Scaling up clean hydrogen is the key enabler to

support hydrogen market [27]; from the point of view of the international cooperations, the number of initiatives at different sizes and distances is increasing. With respect to the GHR 2022 [45], the potential of the announced projects is 50% higher according to the updated release [27], expecting a maximum production of 38 Mt of hydrogen by 2030, if all the planned projects will be effectively realized. This is also in line with the increasing number of governments – currently they are 41 – that have already signed a hydrogen strategy [27].
Having set that from 2030 onwards the hydrogen demand is expected to grow strongly and quickly, this will effectively occur only if several barriers like technological maturity, sustainability issues, lack of dedicated infrastructure, and electrification potential will be overcome, addressing still high production and transport costs and also other factors related to geopolitics, trade dependencies, lack of regulation and certifications [26], [31], [45]. Relying on specific availability of resources – water and renewables – this upcoming new hydrogen economy could strongly reshape relationships among countries [26]; in this regard it is crucial to study the uncertainty belonging to the availability of resources and infrastructure, but also the country-specific economic and financial risks, making a country more or less competitive and attractive for hydrogen trade. According to a study analysing land stress and water stress with respect to hydrogen production [47], Southern and Central-East Africa, West Africa, South America, Canada, and Australia are likely to become crucial hydrogen leaders, while for North Africa it is envisioned the problem of water scarcity – even if the related water withdrawal is negligible compared to the one of the other sectors [47]. Other studies stress how Australia could become a hydrogen hub, defined as promising exporters together with Middle East and North Africa [30]. Specifically, Morocco, Norway Chile, Australia, and the United States are emerging as global hydrogen export leaders, while several countries in Europe, Japan, and Korea will become import-oriented countries [48], [49], [50], [51]. With respect to the announced projects for 2030, the major trade links will go from Australia to Europe and from Japan to Korea, or from North America to Asia and Latin America to Europe [27]. On the Mediterranean side, there is a growing interest in creating and renovating trade routes between Europe and North Africa with respect to the development of hydrogen trade. While EU is exploiting potential ways to increase the domestic production [52], [53], [54], on the other side there is a realistic interest in strengthening cooperations with North Africa for hydrogen trade [55]. Currently these countries are experiencing a series of demographic, social, political and economic turning points – that will reshape their identity and role in the whole energy landscape [56]; nevertheless, there are crucial factors making projects unfeasible or creating delay on effective realization, like corruption and authoritarianism, stakeholders fragmentation, ecological externalities, social problems and inflated expectations [57], [58], [59]. Looking for the European hydrogen domestic potential and the optional routes for import, there are several studies modelling specific alternatives and potentials [34], [52], [53], [54], [55], [60]. Concerning the possibility to exploit the already available routes by pipelines, North Africa can enhance its partnership within Europe, specifically through Italy and Spain, which can act as crucial hubs [49]. To this regard, the work of Timmemberg and Kaltschmitt [60] explore the future viability of blending hydrogen in existing pipelines from North Africa to Europe, while Van der Zwaan et al. [55] investigate the potential export of electricity and hydrogen through these existing routes by scenario analyses. Working on scenario analyses based on existing pipelines routes, Van der Zwaan et al. [55] analyse the competitiveness of hydrogen trade through these already available pathways with respect to local production; exploiting the Integrated Assessment Model TIAM-ECN, it is found that North Africa could benefit of significant trade revenues, becoming a major player in the hydrogen game [55]. According to this study, North Africa could become a hydrogen export-oriented area, but considering that there is a real cost-effectiveness when trade amounts are less constrained [55]. By 2050, different studies agree on the definition of alternative routes for trade by pipelines and by ammonia shipping, with the former based on repurposed gas pipelines which are considered more cost-effective than the new ones [61], [62], [63]. Through the modelling of pipelines and shipping of ammonia and liquefied hydrogen, Seck et al. [34] highlight the critical advantage of existing cross-border pipeline infrastructure with

respect to maritime transport, stressing the relevance of infrastructure requirements and availability to boost up hydrogen projects [34]. This study combines three models, i.e. (i) MIRET-EU, which follows the setup of the JRC-EU-TIMES (JET) model, (ii) Integrate Europe, as aggregated energy system model allowing to include technological learning curve, (iii) HyPE, a dedicated model for calculating hydrogen import options for Europe; through scenario analyses assessing different share of renewables, it is found that the higher the RES integration into the energy system, the more effective the unlock of green hydrogen production [34]. Specifically, on the local side [34] argues that it becomes crucial to exploit off-grid solutions to supply electrolysers, while concerning the importing options modelled, i.e. exploiting routes from North Africa, Russia, Ukraine and Middle East, it is estimated that the imported volume can reach up to 10÷15 Mt in 2050 [34].

2.2 Influencing parameters addressing hydrogen routes

In order to model the whole hydrogen value chain, it becomes crucial to consider that there is a huge range of opportunities and criticalities related to the production, transport, storage, and consumption, making an option more affordable than another according to a specific framework and a series of constraints. Among the influencing factors affecting competitiveness there are the availability and cost-effectiveness of renewable electricity, the investment and maintenance costs of the electrolysers, together with the technological maturity and availability, the infrastructure readiness and requirements.

Currently IRENA estimates that in the long-term hydrogen costs could be more than halved due to technological improvement, optimization of the value chain, economies of scale [64]. Figure 2.5 shows the technological maturity and competitiveness associated to production options available for blue and green hydrogen, according to a review carried out by [65], which assesses as green hydrogen production options water splitting from renewables, biological production, biomass gasification and biofuels reforming. As positive signal, the highest level of maturity and competitiveness is estimated to produce blue hydrogen, followed by an encouraging medium status level for electrolysis. This latter production process identifies its most critical barriers in the exploitation of renewable electricity, because of its fluctuations and high capital expenditure [65], and the increasing number of emerging uses in the electricity market [66].

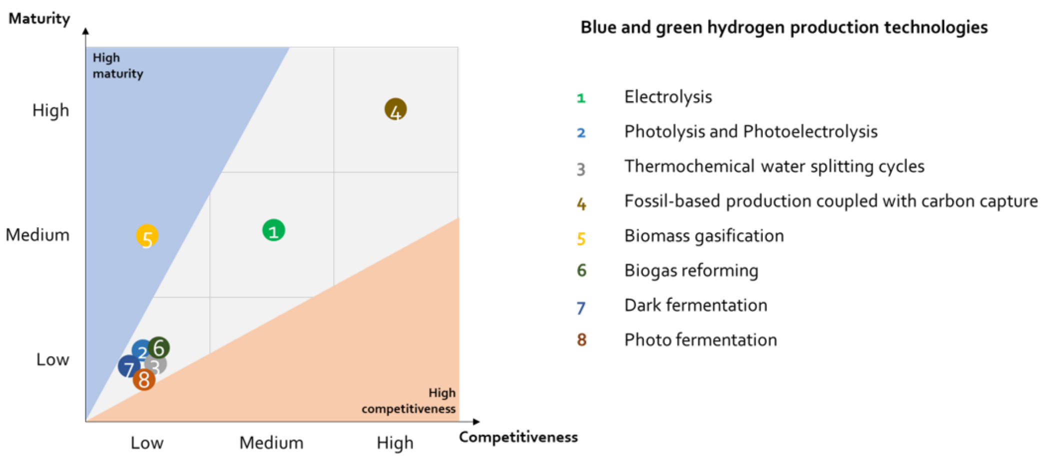

Figure 2.5 – Range of maturity and competitiveness for green hdyrogen production routes (1-3, 5-8) and blue hydrogen production route (4), adapted from [65].

Figure 2.6 focuses on the same aspects – maturity and competitiveness status – but concerning storage and deployment options [65]. As already detailed in [24], the advantages and disadvantages of each option rely on the limitations in technology or infrastructure readiness, availability, or costs. The physical-based storage options are more consolidated than the material-based ones, as highlighted by the status of low maturity and competitiveness of porous materials and metal hydrides, in contraposition to the more consolidated compression or liquefaction processes and absorption via liquid carriers such as ammonia (Figure 2.6).

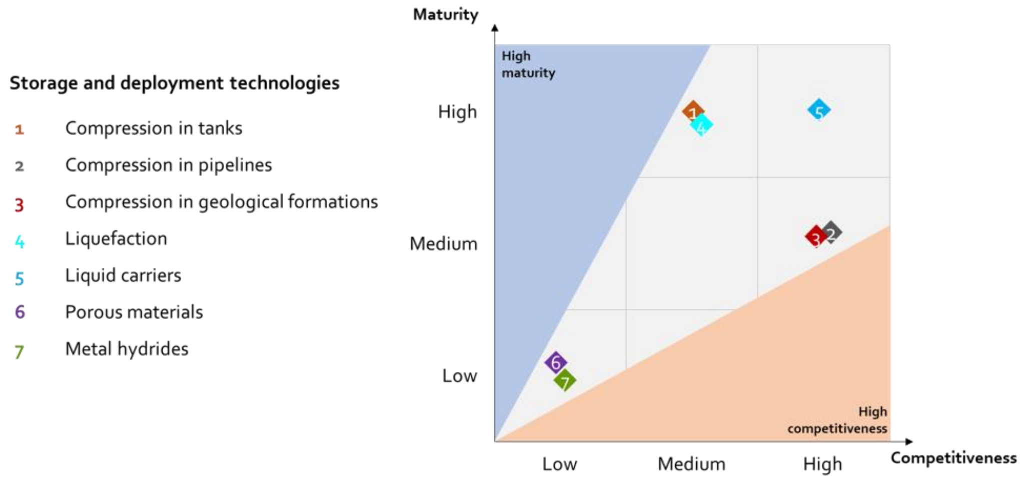

Figure 2.6 – Range of maturity and competitiveness for hydrogen storage and deployment technologies, adapted from [65].

Specifically, all these technical and infrastructure barriers are making green hydrogen still hardly competitive with respect to the fossil-based one for the short-term [65]. Nevertheless, some studies argue the possibility to have a reduction up to 35% of the Levelized Cost of Hydrogen (LCOH) for the green one still by 2030, according to the decrease of photovoltaic costs in parallel to a very high penetration within the distribution network [67]. A competitive threshold corresponds to a Levelized Cost of Electricity (LCOE) not higher than 30 €/MWh according to [68]. Despite the huge impact that renewable costs have on the overall green hydrogen competitiveness, it is also important to address the ranges of uncertainty for electrolysers costs, already analysed in [24], [69]. Being strongly affected by the economies of scale and mass production, it is estimated a reduction of 60% to 70% by 2030 with respect to current costs halving the impact of electrolysers CAPEX in the overall LCOH [33], [66]. Moreover, the improvements in overall performance and efficiencies can make more cost effective the production through electrolysers, i.e. the already commercial Alkaline (ALK) and Proton Exchange Membrane (PEM) electrolysers, and the SOEC at an early stage of development [70].
Another crucial role in making green hydrogen competitive is played by the Weighted Average Cost of Capital (WACC), estimating a lower or higher financial and economic risk associated to a project. Considering that doubling the WACC from 5% to 10% can result in an almost 40% increase for green hydrogen cost [33], it is clear how this parameter can determine the export or import status of a country for green hydrogen trade [49], [61]. It becomes one of the main influencing factors, together with the renewable electricity costs, specifically for the emerging and developing countries, whose uncertainties and instability are reflected in higher WACC compared to more stable economies [33], [51], [64], [67]. Figure 2.7 summarises the main influencing parameters to make cost-effective and competitive green hydrogen, from the short- to the long-term, reporting examples on LCOH variations because of changes in parameters, adapted from [51].

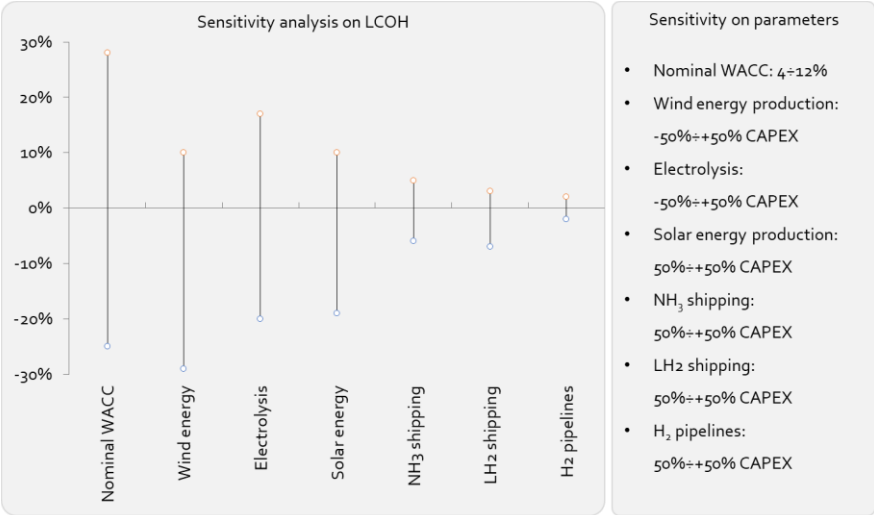

Figure 2.7 – Sensitivity analysis on LCOH according to specific parameters, adapted from [51].

It is confirmed that one of the strongest impacts is given by the WACC and the investment costs for renewable energy production and electrolysers; specifically, also the sensitivity analysis carried out by [67] addresses the relevance of WACC and the volume growth of PV, which strongly impacts the CAPEX of PV by 2050. According to [67], the electricity production has a stronger effect on LCOH than the costs and performances of electrolysers; increasing the CAPEX of the electrolysers by 50% leads to just a 8% increase of the overall LCOH and the same result is obtained working on less amounts of learning rates or Full Load Hours [67]. Working on cost-optimal long-term hydrogen supply and stressing the critical role of capital costs, Brandle et al. [71] estimates around 1 USD/kg as cost for long-term green hydrogen production, if optimistic assumptions in specific regions are verified [71]. In line with this discussion, there is also the increasing key role of inflation with respect to these projects for low-emission hydrogen, because of global impacting "events" like Covid-19 pandemic and the Russian invasion of Ukraine in 2022. As highlighted by IEA, some projects already defined as feasible before mid-2022 have required a review of the specific financial plans, accounting for a cost increase of 50% [27]. Figure 2.8 addresses the main sources of cost inflation according [27], also tailored on the installation of an electrolysers if installed now (2023) with respect to 2021. To this regard, it is also important to consider, particularly in Europe, the relaxation of natural gas prices – 14 USD/MBtu on average in the first months of 2023 [27] – after the high levels reached with the Russian invasion of Ukraine; this is an additional harmful factor for green hydrogen competitiveness [27].

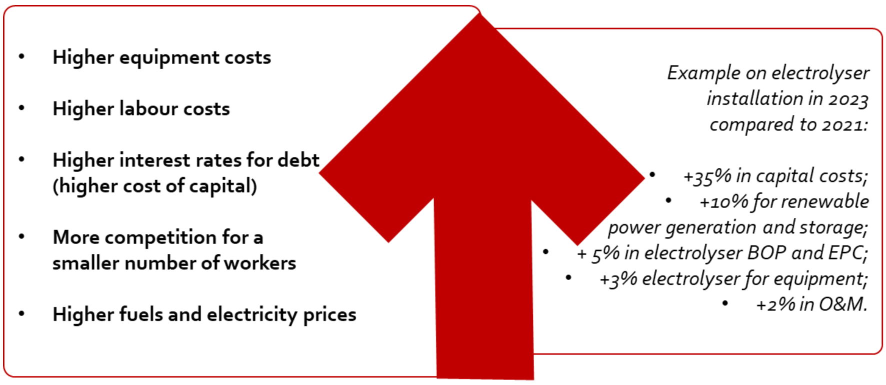

Figure 2.8 – Sources of cost inflation and example on electrolyser installation, adapted from [27].

Also looking at the available hydrogen transport option inflation could play a crucial role. Despite the reduced impacts of transport costs on the overall and the corresponding small effects of uncertainty as reported in Figure 2.7, there are challenges to be addressed for transport infrastructure, specifically if the target year is 2030, as for the European Hydrogen Backbone (EHB) initiative [72]. In fact, in a report published on November 2023, the EHB has updated the assumptions for costs made to estimate the infrastructure development along five different corridors throughout Europe, firstly detailed in [62], [63], [73] and already discussed in a previous report [24]. This update still relies on uncertainty in parameters and assumptions; it is stressed how (i) the European-wide estimation is not able to reflect the heterogeneity of countries in Europe; (ii) there is still a limited collection of empirical data for large-scale hydrogen projects; (iii) materials and labour costs account for 70% to 80% of transmission pipelines and compressor expenditures, making the final costs strongly dependent of a series of different market dynamics [72].

As introduced by these studies and analyses, there are technical factors affecting production and transport costs, but which go hand in hand with country-specific challenges, like energy security, diplomatic relationships already developed, existing infrastructure, stability of the political systems [61]. This framework offers the starting point to effectively model the potential trade of green hydrogen from North Africa to Europe, paying attention to critical parameters that can impact competitiveness and trying to develop optional routes that can account for the uncertainty on evolution of specific factors and routes.

3 - GREEN HYDROGEN IMPORT FROM NORTH AFRICA TO EUROPE: SCENARIO ANALYSES ON ALTERNATIVE ROUTES

To model optional routes for green hydrogen trade from North Africa to Europe, it is exploited an already existing model, the JRC-EU-TIMES (JET) model, building with the TIMES model generator from the Energy Technology Systems Analysis Programme (ETSAP) of the IEA [32], [74], [75].
To this regard, the first sub-section 3.1 details the basic structure of the JET, which has been studied and modified in the framework of a collaboration with the LNEG (National Laboratory of Geology and Energy) and FCT NOVA (School of Science and Technology, NOVA University) in Lisbon.
The second sub-section 3.2 focuses on the assumptions made to build up the optional long-term scenarios for hydrogen trade, to discuss the main outcomes in sub-section 3.3, also commenting outputs from the sensitivity analysis, which is an important step while dealing with uncertainty.

3.1 Focus on model setup: the JRC-EU-TIMES structure

The JET model was developed starting from the Pan European TIMES (PET) model of the RES2020 project, followed up within the REALISEGRID and REACCESS EU research projects [76], [77]. Combining an engineering and an economic approach, a bottom-up linear optimisation problem is solved, to obtain a least-cost energy system which satisfies supply bounds, technical constraints on production and operation of technologies, balance constraints on emissions, timing on investments etc., in the medium to long-term time horizon. 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, average of night, and peak demand seasonally, from 2005 to 2050. Considering both the supply and demand sides, the model covers the following seven sectors: (i) primary energy supply, (ii) electricity generation, (iii) industry, (iv) residential, (v) commercial, (vi) agriculture, (vii) transport. Figure 3.1 summarises the JET model structure, adapted from [74], [75].

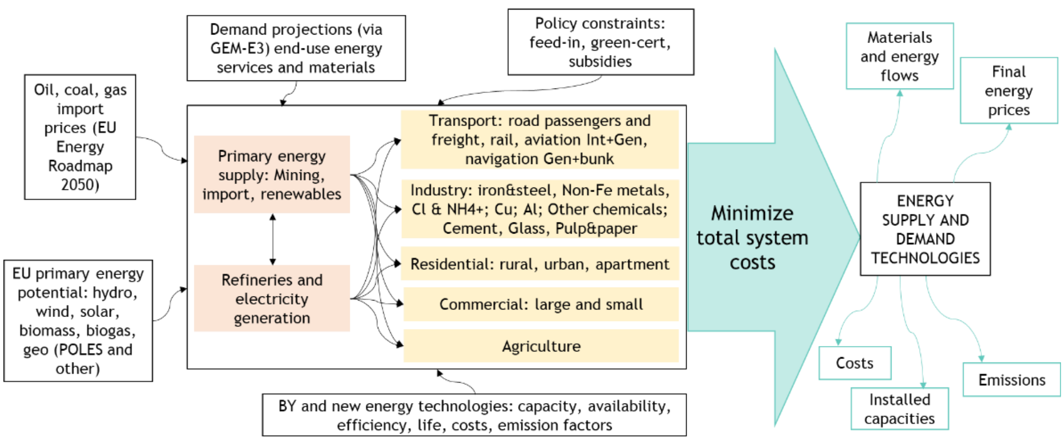

Figure 3.1 – Summary of the JET model structure, adapted from [74], [75].

Concerning the exogeneous useful energy services demand, from 2005 to 2050 it is modelled a decrease only for the residential sector (-12%), as a result of the improvement of building stock;

for the others, it is considered +32% for agriculture, +56% for commercial buildings, +28% for other industries, +24% for passenger mobility, +97% for freight mobility [74]. The reference fossil primary energy import prices into EU are as in the Energy 2050 Roadmap [78], while the extraction and conversion of RES and fossils is modelled endogenously, relying on country-specific resource extraction and conversion costs. Electricity grids consider both import and export processes through existing infrastructures and potential new investments, both within EU+ and outside EU+. 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. The domestic RES electricity potentials up to 2020 are based on the maximum yearly electricity production provided by RES2020, updated during the REALISEGRID EU projects [76], [77].
More details on the model setup and structure can be found in [74], [76], [77].
The import of hydrogen from North Africa was not already modelled in the JET; Figure 3.2 shows the steps followed to integrate the possibility of importing green hydrogen from North Africa in this model. Starting from the definition of variables and assumptions as inputs to the new processes (the first step, detailed in sub-section 3.2), the new scenarios can be modelled (the second step, in sub-section 3.3) and discussed (the third step, in sub-section 3.4).
Specifically, the first step is devoted to the definition of ad-hoc assumptions for scenario analyses on uncertainty in hydrogen trade and competitiveness, i.e. concerning the traded volumes of hydrogen, the alternative ways of production and related costs, the different transport routes, and associated costs. Having set the assumptions, energy scenarios are built to address all the available options and ranging over the different costs and pathways elaborated. Finally, the discussion and comparison of scenarios allow to investigate the role of green hydrogen import from North Africa in the EU decarbonization context, going through uncertainty.

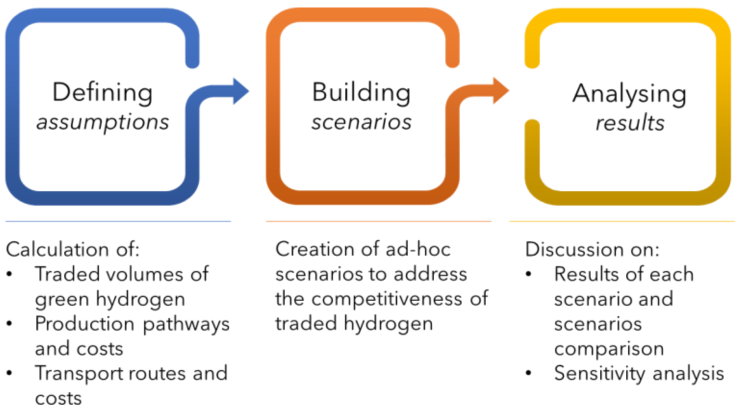

Figure 3.2 – The workflow for scenarios analyses on hydrogen trade on JET model.

3.2 Model update: the elaboration of assumptions

The analysis of the hydrogen technologies through energy system models allows to focus on its interactions and integration within all the other defined technologies. The MARKAL-TIMES energy model family is among the most spread tool for hydrogen energy systems in energy modelling [79], [80]. Figure 3.3 reports how the hydrogen value chain is structured on the JET model, as detailed in [79], [80].

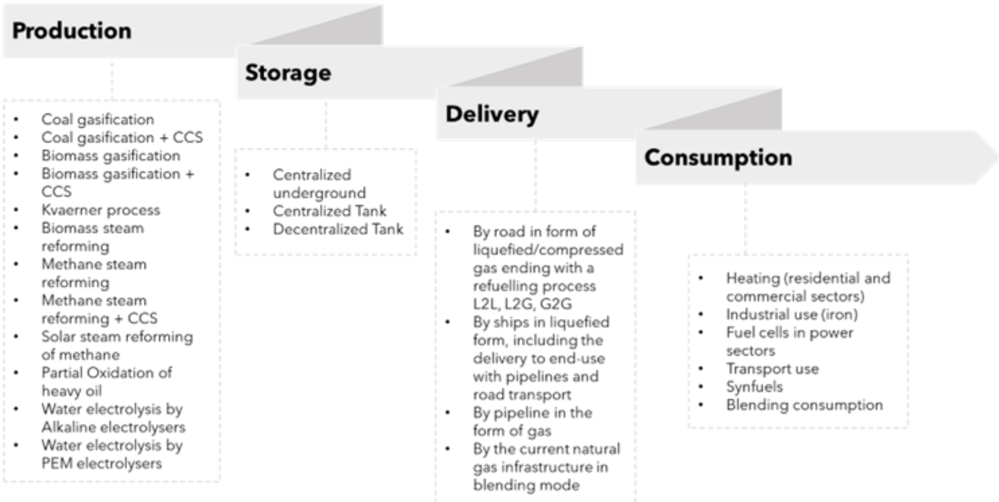

Figure 3.3 – The structure for hydrogen value chain in JET, adapted from [79], [80].

As in was in its original version (Figure 3.3), the hydrogen structure allows to model only internal trade, i.e. among EU+ countries. To this regard, the import from North Africa is added, through six new processes making possible to import hydrogen from Algeria, Morocco and Tunisia, by pipelines or shipping options. These three North African countries are selected as a result of the previous reports addressing the predisposition and suitability of North Africa with respect to green hydrogen production and trade [23], [24]. Moreover, the original model is updated with the possibility to produce green hydrogen also exploiting off-grid PV plants and it is allowed to store green hydrogen by both underground storage and tanks.
To work on available volumes of green hydrogen for trade, it is decided to assess the national strategies and roadmaps of the involved countries, to determine the effective maximum volumes of green hydrogen that can be imported by Europe.
Table 3.1 summarises the documentations and strategies available to support local production and trade in the North African countries in the long-term.

Table 3.1 – Strategies and roadmaps for hydrogen export in Algeria, Morocco, Tunisia.

Country	*Specific targets*	*Strategies/roadmaps*
Algeria	30 to 40 TWh of hydrogen and hydrogen-based fuels to be exported to Europe by 2040.	Government announcement related to the hydrogen roadmap [81]
Morocco	46 to 92 TWh of hydrogen and hydrogen-based fuels to be exported to Europe by 2040; from 115 to 230 TWh of green hydrogen and hydrogen-based fuels to be exported to Europe by 2050.	Green hydrogen roadmap [82], [83]
Tunisia	From 180 to 200 TWh of hydrogen to be exported to Europe by 2050.	Government announcement based on the outputs of the EHB initiative [73], [84]

Among the three analysed countries, Morocco is the first one making huge efforts to define a specific roadmap for hydrogen, since January 2021 [82], [83], also giving a strategic role to hydrogen in its own decarbonization strategy towards 2050 [85] and confirming its potential role as hydrogen leader and export-oriented country.

Algeria is also identified as a key player in the context of the European decarbonization; in March 2023 the Algerian government has announced the release of its hydrogen roadmap, containing the commitment to export to Europe from 30 to 40 TWh of hydrogen and hydrogen-based fuels by 2040 [81].
Focusing on Tunisia, there is a political and social instability still affecting the country; the hydrogen strategy expected to be released on mid-March 2023 is not yet available at the end of 2023 [86]. Nevertheless, the General Director of the Electricity and Energy Transition at the Ministry of Industry, Mines and Energy, Belhassen Chiboub, has stressed the Tunisian purpose of acting as global leader in the upcoming hydrogen market, especially for Europe, making reference to the outputs of the EHB Initiative [73] (Table 3.1).
To work on green hydrogen production costs, the elaborations introduced in the previous deliverable of this project (2022) are exploited as starting point [24]. The LCOH is calculated as input for the new processes modelling the green hydrogen import from North Africa. The costs and efficiency evolutions shown in Figure 3.4 are elaborated started from [87], [88] and exploited to estimate the LCOH for green hydrogen production. Data reported here in figures and tables refer to 2010 currency, in line with the other inputs into the JET files.
The starting year for trade from North Africa is fixed to 2030, while for EU+ the production of hydrogen by water electrolysis is enabled from 2023.

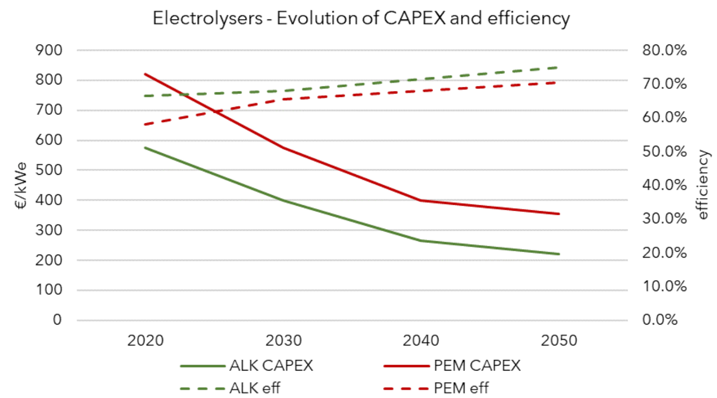

Figure 3.4 – CAPEX and efficiency evolution for ALK and PEM from 2020 to 2050.

On the import options side, to directly calculate the LCOH, the role of financial risks and how this can impact the cost-effectiveness of trade, changing the level of competitiveness of hydrogen, is detailed through the study of the WACCs. As already discussed in chapter 2, this parameter has a strong impact on making a solution more or less competitive [49], [61]. IRENA has recently released a report which refers to the country-specific WACCs for renewable energy projects [89]. Exploiting these values, the LCOH in input to the model is elaborated as country-specific, as a result of the average of two different electrolysers technologies, ALK and PEM electrolysers, supplied by PV plants or wind plants, according to the costs and potentialities of each country and the associated level of risks. Specifically, the costs are differentiated for (i) photovoltaic plants and ALK electrolysers (PV + ALK), (ii) photovoltaic plants and PEM electrolysers (PV + PEM), (iii) wind onshore plants and ALK electrolysers (WO + ALK), wind onshore plants and PEM electrolysers (WO + PEM). To evaluate the case of lower risk it is assigned a WACC of 3% to each North Africa country, while to address much higher risks it is added a 5% to the country-specific WACC elaborated by IRENA [89]. Among the three analysed countries, it is found that the highest risks in renewable projects are associated to Algeria (around 11% of WACC), while Morocco has the lowest one (around 6%) [89].
To summarize, it is assumed that there is the same technological maturity of electrolysers for all the countries (both EU+ and North Africa), meaning to have a fixed CAPEX and efficiency per

technology in each country, evolving over time (Figure 3.4). The differences among countries rely on availability and costs of renewable energy in North Africa, and financial risks in the form of WACC.

As shown by Figure 3.5, the LCOH for green hydrogen produced in Algeria, Morocco and Tunisia is calculated for the four technological combinations available, i.e. PV + ALK, PV + PEM, WO + ALK, WO + PEM. It is reported the evolution of each technological pathway, from 2030 to 2050. As expected, the green hydrogen production costs decrease from 2030 to 2050; Morocco and Algeria show the cheapest ones, 1.23 €/kg$_{H_2}$ (ALK + PV), while the most expensive option is WO + PEM for Algeria (3.77 €/kg$_{H_2}$). Because of the lowest WACC associated to renewable projects among the analyzed countries, Morocco has the lowest production costs also in case of higher risks (i.e., higher WACC), 2.21 €/kg$_{H_2}$ by 2050.

Figure 3.5 – The country-specific LCOH according to the different technologies and risks, for 2030 (up) and 2050 (down).

On the transport side, the different options, i.e. pipelines, shipping by ammonia, liquefied hydrogen or Liquefied Organic Hydrogen Carriers (LOHCs), are already discussed by the authors in [24], focusing on the advantages and disadvantages related to the exploitation of each option, as detailed by IRENA [61]. It is interested to notice how the alternative routes from North Africa to Europe can be developed through both pipelines and shipping, varying countries and distances involved [61]. In fact, even if it is undoubted that for shorter distances pipelines are more affordable than ships, other influencing factors can make the latter more feasible. As stressed in [61], a pipeline as physical connection can last 40 years or more, while a ship can afford an offtake agreement of 10 years and change its target market afterwards [61].

To this regard, it is decided to model both pipelines and ships; for the shipping routes it is decided to focus on the liquefied hydrogen shipping instead of ammonia, although ammonia currently accounts for a higher affordability. This choice relies on the fact that if electricity in the exporting country is abundant and sufficiently cheaper than in the importing one, liquid hydrogen shipping over ammonia can be the best option [61]. To elaborate costs and assumptions associated to transport, the technical reports of IRENA [61] and of the EHB [62], [63] are exploited. Figure 3.6

summarises a pessimistic (PESS) and an optimistic (OPT) cost evolution respectively for onshore pipelines of gaseous hydrogen, offshore pipelines of gaseous hydrogen and liquefied hydrogen shipping; the two cases allows to account for the most and less favourable conditions for transport, as assessed by the cost ranges evaluated by [61], [62], [63]. Concerning pipelines, the values referred to the EHB study which works on the European volumes and capacities [62], [63];an average on new and repurposed pipelines – in terms of CAPEX and OPEX of pipelines and compressors and electricity required by the compressors – is elaborated by EHB taking care of the whole modelling of backbone [62] and exploited for calculations. The estimations on shipping costs start from the assumptions made for very large projects (1.5 Mt/y) by IRENA [61], accounting for the liquefaction, shipping, and regasification steps involved.

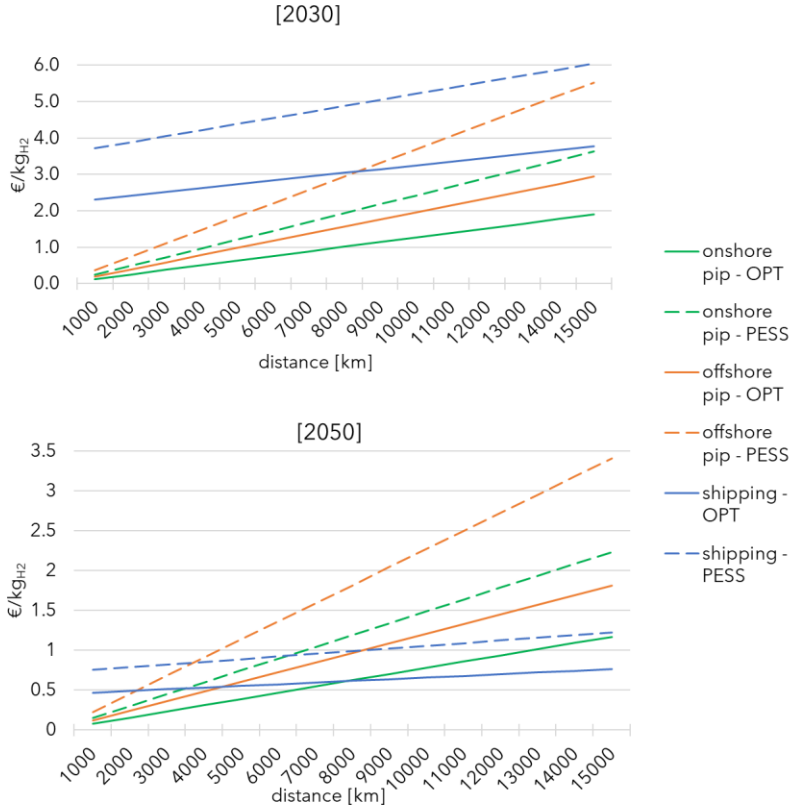

Figure 3.6 – The cost over distance for hydrogen transport options in 2030 (up) and 2050 (down) in pessimistic (PESS) and optimistic (OPT) cost evolution, elaborated starting from [61], [63].

Having introduced and detailed (i) the elaboration of the available green hydrogen volumes starting from Table 3.1, (ii) the estimation of production costs according to Figure 3.4 and Figure 3.5, and (iii) the calculation of transport costs based on Figure 3.6, it is now possible to build ad-hoc energy scenarios to analyse the competitiveness of hydrogen trade from North Africa to Europe. The next sub-section details the identification of these alternative routes in the form of scenarios, working on the ranges of uncertainty for parameters and assumptions.

3.3 Definition of scenarios: modelling of optional routes for trade

In order to study the effect of uncertainty on cost-effectiveness and competitiveness of hydrogen trade, the new processes are introduced (Figure 3.7) to build different energy scenarios (Figure

3.8), following the assumptions and elaborations already discussed. For each process there is a constraint in terms of maximum allowable volume of hydrogen that can be imported by Europe; moreover, an overall cost (production + transport) – tailored on the specific importing country – must be defined.

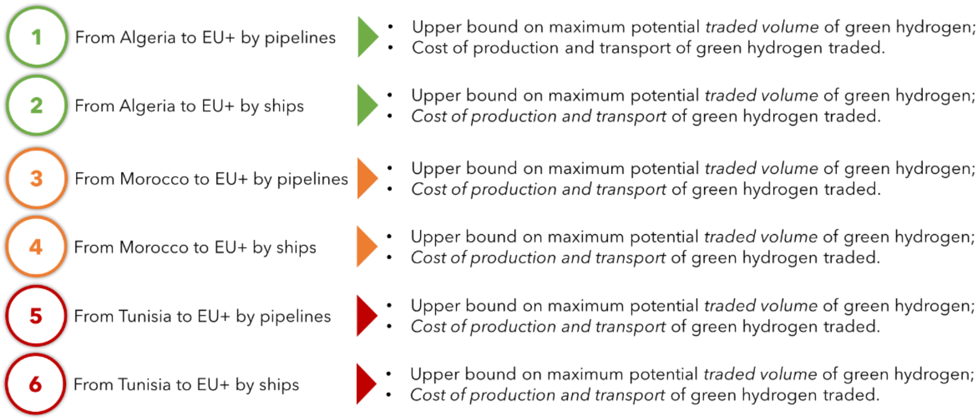

Figure 3.7 – The six processes integrated in JET to model hydrogen import from North Africa.

Scenario S0 has no import options available over the whole time horizon, while from scenario S1 to scenario S4 the work is on (i) different traded hydrogen volumes, (ii) ranges of green hydrogen production costs relying on country-specific potentials and financial risks, (iii) alternative routes and costs for transport of hydrogen (Figure 3.8).

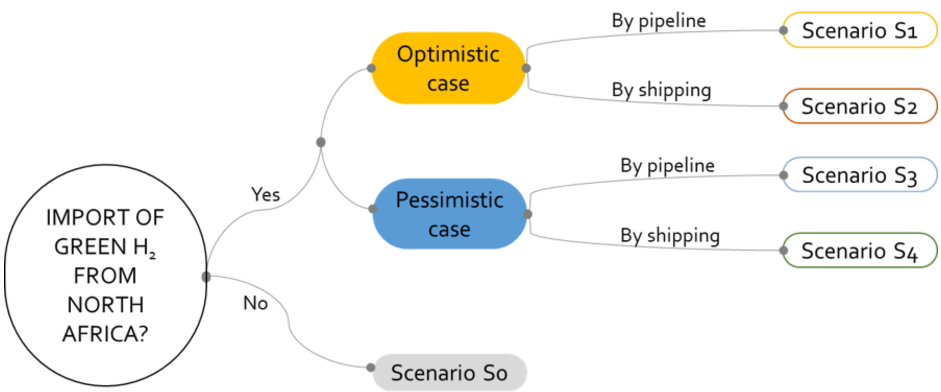

Figure 3.8 – The identification of the alternative scenarios under assessment.

Table 3.2 better details the characterization of scenarios, with "optimistic" accounting 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.

Table 3.2 – The basic assumptions for each scenario analysed.

Scenario name	*Details on assumptions*
S0	No importable hydrogen volumes from North Africa; only local production and trade among EU countries available.
S1	Optimistic (higher) importable volumes from North Africa; optimistic (lower) costs for production in North Africa; transport by pipeline at optimistic (lower) cost to Spain, Italy, Portugal.

Scenario name	*Details on assumptions*
S2	Optimistic (higher) importable volumes from North Africa; optimistic (lower) costs for production; transport by ships at optimistic (lower) cost to each EU country having at least a terminal available.
S3	Pessimistic (lower) importable volumes from North Africa; pessimistic (higher) costs for production in North Africa; transport by pipeline at optimistic (higher) cost to Spain, Italy, Portugal.
S4	Pessimistic (lower) importable volumes from North Africa; pessimistic (higher) costs for production; transport by ships at pessimistic (higher) cost to each EU country having at least a terminal available.

All the scenarios are built under the target of 95% reduction of EU-wide CO_2 energy-related emissions in 2050 with respect to the 1990 levels.
To assign a specific traded volume and cost of green hydrogen to each process, the optimistic and pessimistic cases for volumes, production and transport costs are exploited.
Table 3.3 summarises the specific costs, to be applied to each different trade route.

Table 3.3 – The numerical assumptions for the elaboration on scenarios.

<table>
<tr><th></th><th colspan="2">Traded H_2 volumes [Mt_{H_2}]</th><th colspan="2">Production cost [€/kg_{H_2}]</th><th colspan="2">Transport cost [€/kg_{H_2}]</th></tr>
<tr><td></td><td>2030</td><td>2050</td><td>2030</td><td>2050</td><td>2030</td><td>2050</td></tr>
<tr><td>S0</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>S1</td><td rowspan="2">ALG: 0.30 Mt_{H_2}
MOR: 0.65 Mt_{H_2}
TUN: 0.5 Mt_{H_2}</td><td rowspan="2">ALG: 3.0 Mt_{H_2}
MOR: 6.89 Mt_{H_2}
TUN: 5.5 Mt_{H_2}</td><td rowspan="2">ALG: 2.15 €/kg
MOR: 2.08 €/kg
TUN: 2.28 €/kg</td><td rowspan="2">ALG: 1.49 €/kg
MOR: 1.43 €/kg
TUN: 1.57 €/kg</td><td>On. pip.: 0.13 €/kg/1000km
Off. pip.: 0.20 €/kg/1000km</td><td>On. pip.: 0.08 €/kg/1000km
Off. pip.: 0.12 €/kg/1000km</td></tr>
<tr><td>S2</td><td>LH2 ships:
@1000 km: 2.61 €/kg
@6000 km: 3.19 €/kg</td><td>LH2 ships:
@1000 km: 0.53 €/kg
@6000 km: 0.65 €/kg</td></tr>
<tr><td>S3</td><td rowspan="2">ALG: 0.23 Mt_{H_2}
MOR: 0.31 Mt_{H_2}
TUN: 0.2 Mt_{H_2}</td><td rowspan="2">ALG: 2.25 Mt_{H_2}
MOR: 2.75 Mt_{H_2}
TUN: 2.8 Mt_{H_2}</td><td rowspan="2">ALG: 4.82 €/kg
MOR: 3.70 €/kg
TUN: 4.67 €/kg</td><td rowspan="2">ALG: 3.34 €/kg
MOR: 3.44 €/kg
TUN: 3.24 €/kg</td><td>On. pip.: 0.24 €/kg/1000km
Off. pip.: 0.37 €/kg/1000km</td><td>On. pip.: 0.15 €/kg/1000km
Off. pip.: 0.23 €/kg/1000km</td></tr>
<tr><td>S4</td><td>LH2 ships:
@1000 km: 4.18 €/kg
@6000 km: 5.12 €/kg</td><td>LH2 ships:
@1000 km: 0.85 €/kg
@6000 km: 1.04 €/kg</td></tr>
</table>

Concerning the transport options, the cost for pipelines is elaborated according to the already known distances of the natural gas pipelines, which connect Algeria with Spain, Algeria and Morocco with Portugal and Spain, Algeria and Tunisia with Italy. Table 3.4 reports the overall cost of green hydrogen (production and transport) (i) from Algeria to Italy, Portugal and Spain, (ii) from Morocco to Portugal and Spain, (iii) from Tunisia to Italy, by 2030 and by 2050.

Table 3.4 – The green hydrogen costs for the scenarios S1 and S3 (transport by pipelines, optimistic and pessimistic).

From	*to*	*Green hydrogen cost (production + transport) [€/kg$_{H_2}$]*			
		S1		*S3*	
Country 1	*Country 2*	***2030***	***2050***	***2030***	***2050***
Algeria	Italy	2.30	1.58	5.10	3.51
	Portugal	2.36	1.62	5.16	3.55
	Spain	2.24	1.54	4.98	3.44
Morocco	Portugal	2.18	1.50	3.91	3.37
	Spain	2.12	1.46	3.78	3.29
Tunisia	Italy	2.33	1.61	4.77	3.31

For the liquefied hydrogen shipping three selected terminals in Algeria, Morocco and Tunisia (respectively, Oran, Jorf Lasfar, Sfax) are exploited to calculate the distances to the countries where there is a Liquefied Natural Gas (LNG) terminal at least [90], [91]. Specifically, for the EU+ countries where more than one terminal is under operation or construction or planned, the average distance is exploited to elaborate the final costs; the accounted terminals (status 2022) are extracted from [90], as shown in Figure 3.9 from the European Commission.

Figure 3.9 – The European LNG infrastructure (status 2022), by European Commission [90].

Table 3.5 reports the costs of production and transport for each route modelled for the shipping scenarios, i.e. S2 and S4, exploiting the average distances elaborated for the shipping routes available.

Table 3.5 – The green hydrogen costs for the scenarios S2 and S4 (transport by ships, optimistic and pessimistic).

From	*to*	*Green hydrogen cost (production + transport) [€/kg$_{H_2}$]*			
		S2		*S4*	
Country 1	*Country 2*	***2030***	***2050***	***2030***	***2050***
Algeria	Belgium	4.19	1.78	7.93	3.70
	Croatia	4.15	1.77	7.87	3.69
	Cyprus	4.19	1.78	7.93	3.70
	Estonia	4.42	1.83	8.30	3.78
	Finland	4.42	1.83	8.31	3.78
	France	4.09	1.76	7.77	3.67
	Germany	4.23	1.79	8.00	3.72
	Greece	4.15	1.77	7.87	3.69
	Ireland	4.14	1.77	7.85	3.69
	Italy	3.98	1.74	7.60	3.64
	Latvia	4.41	1.83	8.28	3.77
	Lithuania	4.37	1.82	8.22	3.76
	Malta	4.03	1.75	7.68	3.65
	Netherlands	4.19	1.78	7.94	3.70
	Norway	4.46	1.84	8.37	3.79
	Poland	4.34	1.81	8.18	3.75
	Portugal	3.96	1.74	7.57	3.63
	Spain	3.98	1.74	7.60	3.64
	Sweden	4.32	1.81	8.14	3.74
	UK	4.17	1.78	7.91	3.70
Morocco	Belgium	4.08	1.73	6.88	3.00
	Croatia	4.14	1.74	6.97	3.02
	Cyprus	4.19	1.75	7.04	3.03
	Estonia	4.31	1.77	7.25	3.07
	Finland	4.33	1.78	7.28	3.08
	France	4.02	1.71	6.77	2.98
	Germany	4.13	1.74	6.95	3.01
	Greece	4.15	1.74	6.99	3.02
	Ireland	4.03	1.72	6.80	2.98
	Italy	4.06	1.72	6.84	2.99
	Latvia	4.30	1.77	7.23	3.07
	Lithuania	4.26	1.76	7.17	3.06
	Malta	4.03	1.72	6.80	2.98
	Netherlands	4.09	1.73	6.89	3.00
	Norway	4.36	1.78	7.32	3.09
	Poland	4.24	1.76	7.13	3.05
	Portugal	3.86	1.68	6.52	2.93
	Spain	3.92	1.69	6.62	2.95
	Sweden	4.21	1.75	7.08	3.04
	UK	4.07	1.72	6.85	2.99

From	*to*	*Green hydrogen cost (production + transport) [€/kg$_{H_2}$]*			
		S2		*S4*	
Country 1	*Country 2*	***2030***	***2050***	***2030***	***2050***
Tunisia	Belgium	4.44	1.89	8.02	3.66
	Croatia	4.14	1.83	7.54	3.56
	Cyprus	4.17	1.83	7.59	3.57
	Estonia	4.66	1.93	8.39	3.74
	Finland	4.68	1.94	8.42	3.74
	France	4.30	1.86	7.80	3.62
	Germany	4.48	1.90	8.09	3.67
	Greece	4.15	1.83	7.56	3.57
	Ireland	4.39	1.88	7.94	3.64
	Italy	4.08	1.82	7.44	3.54
	Latvia	4.65	1.93	8.37	3.73
	Lithuania	4.62	1.92	8.31	3.72
	Malta	4.03	1.81	7.36	3.53
	Netherlands	4.44	1.89	8.03	3.66
	Norway	4.71	1.94	8.46	3.75
	Poland	4.59	1.92	8.27	3.71
	Portugal	4.21	1.84	7.66	3.59
	Spain	4.21	1.84	7.65	3.59
	Sweden	4.56	1.91	8.22	3.70
	UK	4.42	1.88	7.99	3.66

3.4 Discussion of results: scenarios outputs and sensitivity analysis

This section aims to show and discuss the main outputs of the modelled scenarios. The following questions are addressed: 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 CO_2 mitigation for EU+?

It is also included a sub-section related to the study of the impact of trade at country-level, followed by a sensitivity analysis.

Starting from 2030 which is the first year of potential import, Figure 3.10 shows the contribution of domestic production and North African trade to the overall European hydrogen demand; different scenarios correspond to different amount of traded hydrogen available and effectively traded.

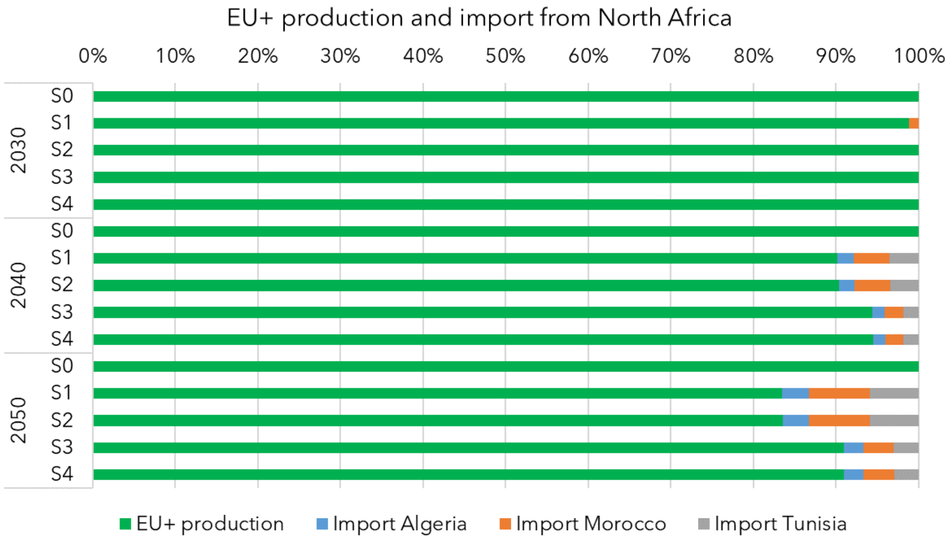

Figure 3.10 – The contribution to the EU+ hydrogen demand of the local production and of the North African import.

In the short-term (2030), green hydrogen from North Africa is not affordable as it is modelled; specifically, only Morocco exports hydrogen into Spain via pipeline in the optimistic case (S1) – around 22% of the hydrogen amount available for trade is imported. From 2040 on, each modelled scenario chooses to import all the hydrogen available for trade, i.e. by pipelines and ships, in both optimistic and pessimistic cases.

Even if EU+ can afford to domestically satisfy most of its hydrogen demand, by both 2040 and 2050 Morocco, Algeria, and Tunisia are identified as key players in the context of the European hydrogen market, supplying it at lower system costs. Despite the higher risks and lower global market coordination modelled through higher costs and fewer amounts, also in the pessimistic cases (in S3 and S4), the additional amount available from North Africa is fully selected by the model and consumed in EU+. In these two scenarios the traded amount covers around 9% of the total demand by 2050, while it is 16.5% the percentage covered in S1 and S2 (i.e., the optimistic cases). In each scenario it is worth mentioning that Morocco is responsible of almost half of this trade. This is in line with the fact that Morocco is the only country among the three analyzed to have a structured hydrogen roadmap, considering exports [82], [83].

To better investigate how transport options affected the trade and which countries are acting like direct importers, Figure 3.11 and Figure 3.12 detail the flows of hydrogen trade from Algeria, Morocco and Tunisia through a Sankey diagram built for each scenario; both 2040 and 2050 are reported.

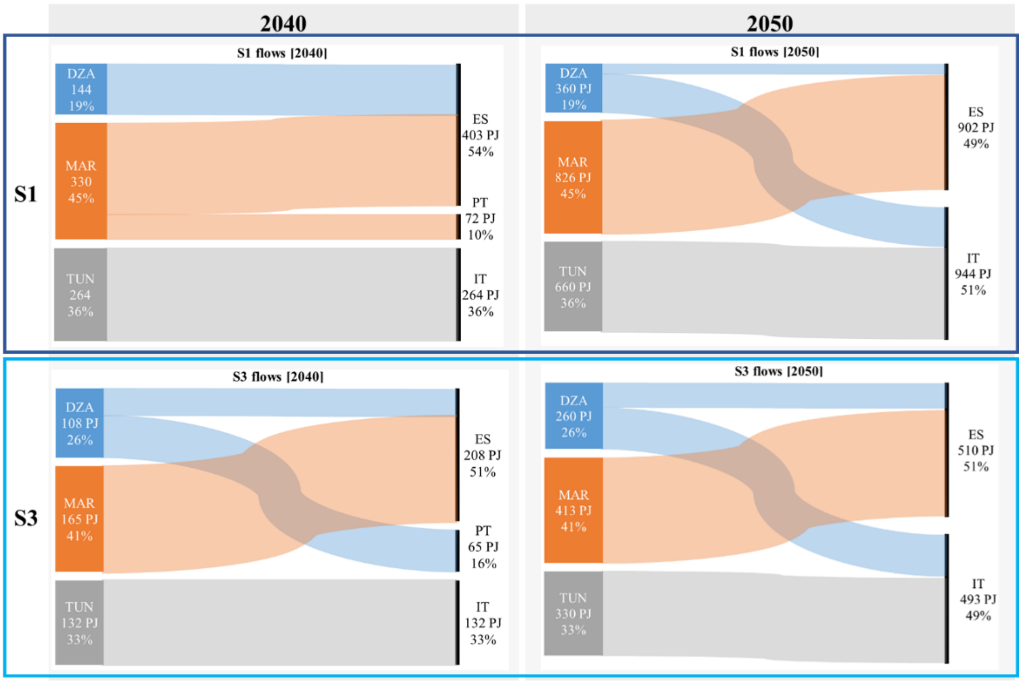

Figure 3.11 – Trade flows in the form of Sankey diagram for S1 and S3, by 2040 and 2050.

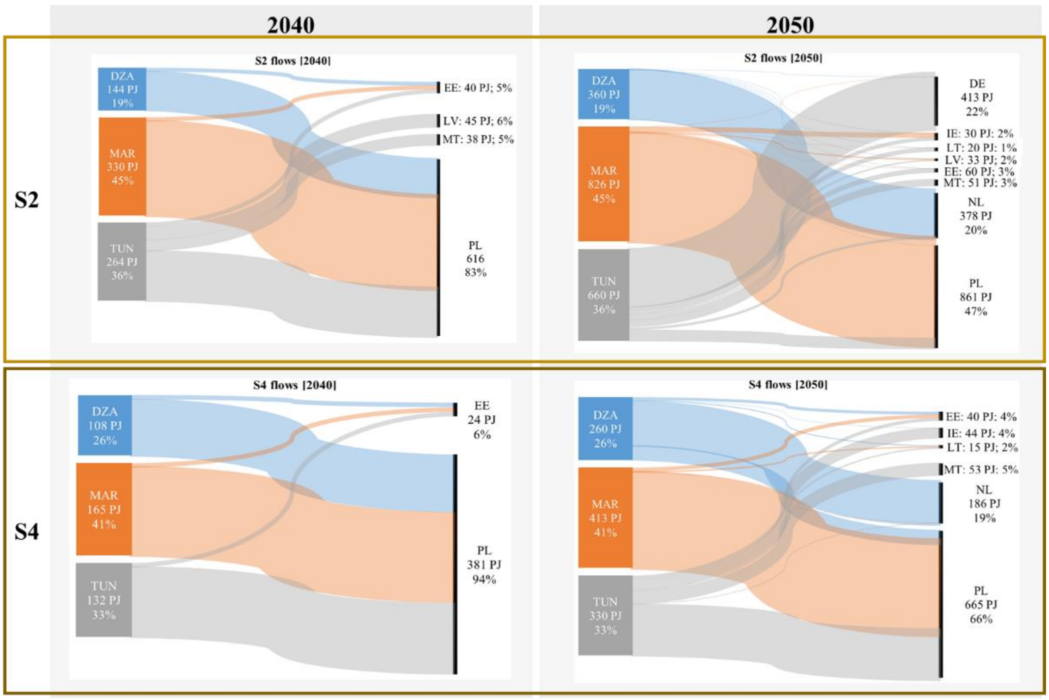

Figure 3.12 – Trade flows in the form of Sankey diagram for S2 and S4, by 2040 and 2050.

Despite pipelines which can become a competitive option by 2030 (Figure 3.10), liquefied hydrogen shipping is exploited directly from 2040. It is interesting to notice that this option is not affordable for Italy, Spain, and Portugal, which import hydrogen only in S1 and S3, i.e., via pipelines. This confirms the competitiveness of shipping only for longer distances, being in S2 and S4 included in trade only the countries which are not linked to North Africa by pipelines. In addition to this, the involvement in trade of different countries while modelling ships highlights

the importance of diversifying the trading routes. In fact, it allows for the selection of different nations that can directly benefit from green hydrogen produced in North Africa.
Concerning the scenarios S1 and S3, which model pipelines (Figure 3.11), Italy and Spain stand out as primary importers, with Portugal playing a marginal role and importing hydrogen only by 2040, mainly from Morocco in S1 and from Algeria in S3.
Looking instead at scenarios S2 and S4 (Figure 3.12), additional countries such as Poland, the Netherlands and Germany have a role in trade. By 2050, also others like Malta, the Baltic nations and Ireland import renewable hydrogen by shipping, even if through small relative volumes. Focusing on the shipping-related results, Poland emerges as the primary importer of the majority of the available North African hydrogen, in both optimistic and pessimistic cases. Moving to 2050, in S2 Germany becomes the major importer from Tunisia, while the Netherlands assumes this role for Algeria. Even in S4, the Netherlands remains the major importer of most hydrogen produced in Algeria. All these findings emphasize the importance of addressing uncertainties related to costs and trade routes within the EU+ hydrogen import from North Africa.
Among the model outputs to be analyzed, it can be of interest to evaluate the deviation by country in terms of production and consumption from scenario S0 (with no import modelled), considering that to meet its hydrogen demand each EU+ country can either domestically produced or trade hydrogen within the other EU+ counties. To this regard, Table 3.6 and Table 3.7, working respectively on production and consumption side, group by row the EU+ countries falling in the same ranges of delta with respect to S0 in 2050. Both tables also include the European average; EU+ undergoes a decrease of around 15% compared to S0 on the production side, especially in S1. Looking at the *consumption*, the delta is much smaller, corresponding to 3% in S2, and 2.3% in S1, with S1 and S2 being the most significant because model the highest traded amounts. These findings highlight how EU+ reduces its own production when the green hydrogen trade from North Africa is allowed, while on the consumption side it is needed to focus on specific sectors, as detailed below. Nevertheless, at country-level there are very different response to this additional trade, having that each country is more or less sensitive to this surplus availability (Table 3.6 and Table 3.7).

Table 3.6 – Delta in % with respect to S0 for local production of hydrogen in 2050.

Production by country – delta wrt S0 [2050]

<table>
<tr><th></th><th>S1 wrt S0</th><th>S2 wrt S0</th><th>S3 wrt S0</th><th>S4 wrt S0</th></tr>
<tr><td>> 75%</td><td colspan="4">CZ, DK, SK</td></tr>
<tr><td>35% to 75%</td><td colspan="2">BE, BG</td><td colspan="2">-</td></tr>
<tr><td rowspan="2">5% to 35%</td><td colspan="4">CH, HU</td></tr>
<tr><td>EE, LT, LU, LV, PT, RO, UK</td><td>NO, PT, RO</td><td>BE, BG, LT, LV, UK</td><td>BE, BG, PT, RO</td></tr>
<tr><td rowspan="2">-5% to 5%</td><td colspan="4">AT, CY, EL, FI, SE</td></tr>
<tr><td>NO, MT</td><td>IT, LU, UK</td><td>DE, EE, LU, NO, PT, MT</td><td>DE, IT, LU, NO, UK</td></tr>
<tr><td rowspan="3">-35% to -5%</td><td colspan="4">ES, HR, IS, NL, EU+</td></tr>
<tr><td>PL</td><td>LT</td><td>PL, RO</td><td>LT, LV</td></tr>
<tr><td colspan="2">DE</td><td colspan="2">FR</td></tr>
<tr><td>-75% to -35%</td><td>FR, IT</td><td>FR, LV, PL</td><td>IE, IT, SI</td><td>PL</td></tr>
<tr><td rowspan="2">< -75%</td><td>-</td><td>EE, MT</td><td rowspan="2">-</td><td rowspan="2">EE, IE, MT, SI</td></tr>
<tr><td colspan="2">IE, SI</td></tr>
</table>

Table 3.7 – Delta in % with respect to S0 for local consumption of hydrogen in 2050.

Consumption by country - delta wrt S0 [2050]

<table>
<tr><th></th><th>S1 wrt S0</th><th>S2 wrt S0</th><th>S3 wrt S0</th><th>S4 wrt S0</th></tr>
<tr><td>> 75%</td><td colspan="2">BG</td><td colspan="2">-</td></tr>
<tr><td>35% to 75%</td><td colspan="2">AT</td><td>-</td><td>BG</td></tr>
<tr><td rowspan="2">5% to 35%</td><td colspan="4">LV</td></tr>
<tr><td colspan="2">EE, PT, RO</td><td>BG, AT</td><td>IE, PT, RO, AT</td></tr>
<tr><td rowspan="2">-5% to 5%</td><td colspan="4">BE, CH, CY, CZ, DE, DK, EL, ES, FI, FR, HR, HU, IT, LT, LU, MT, NL, PL, SE, SI, SK, UK, EU+</td></tr>
<tr><td colspan="2">IE</td><td>EE, IE, NO, PT</td><td>NO</td></tr>
<tr><td rowspan="2">-35% to -5%</td><td colspan="4">IS</td></tr>
<tr><td>NO</td><td>-</td><td>RO</td><td>EE</td></tr>
<tr><td>-75% to -35%</td><td>-</td><td>NO</td><td colspan="2">-</td></tr>
<tr><td>< -75%</td><td colspan="4">-</td></tr>
</table>

Focusing on hydrogen *production* (Table 3.6), Austria, Cyprus, Greece, Finland, and Sweden consistently show no impact from North African trade across the different scenarios, having that the local hydrogen production variations ranging from -5% to 5%. In contrast, countries like Germany, Italy, the United Kingdom, and Norway are affected by the additional available trade only in specific scenarios. Concerning Italy, there is a consistent decrease in production when it is directly involved in trade, i.e. via pipelines in S1 and S3. There are also other such as Czechia, Denmark, Ireland, Slovakia, and some Baltic countries whose production is more sensitive to North African trade, reacting effectively to import in each scenario.

Looking at the deviations with respect to S0 on the *consumption* side (Table 3.7), there are countries like Norway and Ireland which see a decrease in the national consumption, while the majority of the nations are not influenced on their consumption trends. Notably, Austria maintains similar levels of local production but experiences also an increase in consumption due to indirect exploitation of the additional amount from North Africa. On the other hand, countries like Bulgaria experience an increase in both production and consumption.

These outputs emphasize the potential influence of trading hydrogen with North Africa on the dynamics of intra-EU hydrogen interactions; the country-specific behavior in terms of hydrogen balance is analyzed in the sub-section 3.4.1.

In more general terms, the competitiveness of North African hydrogen in supporting the European decarbonization, even if addressing different country-specific behaviors, results in a decrease in local production but without impacting the consumption trends.

Concerning the *consumption* at the EU+ level, the fact that the imported hydrogen from Algeria, Morocco and Tunisia substitute the local production leads to slight variation in the consumption trends. Nevertheless, it is important to investigate which is the role of hydrogen in the consumption sector by 2050; Figure 3.13 highlights the extent to which each scenario differs from the basic one, i.e. without importing options. Specifically, the grey bar corresponds to the amounts of hydrogen consumed in S0, while a specific point with different color and shape represents the relative differences in consumption in the other scenarios modelling imports. Still in S0, most of the hydrogen is consumed directly by the transport sector, as shown in Figure 3.13 (left side), while the "other sectors" include agriculture, commercial, industry, residential.

The most interesting and noticeable results are related to the indirect use of hydrogen, i.e. its conversion into synfuels, heat or electricity (Figure 3.13, right side).

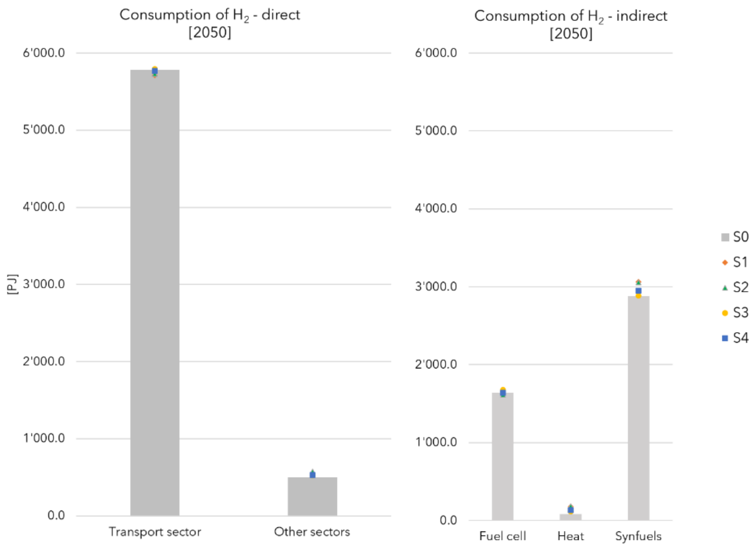

Figure 3.13 – Consumption of hydrogen for S0 compared to the trade scenarios; direct consumption of hydrogen (left) and conversion of hydrogen (right); year: 2050.

As already introduced by Figure 3.13, highlighting the impact of the additional amount of hydrogen on the indirect consumption – primarily in terms of conversion into heat and synfuels – Table 3.8 stresses that the most affected consumption sectors are the transport and the industrial one, according to their indirect use of hydrogen. It is provided a more detailed view on the relative differences in import scenarios compared to S0, and, as expected, the most significant variations involve S1 and S2, which assumes the highest importable amounts. Notably, hydrogen imports also impact hydrogen consumption through fuel cells, showing an increase in S1 and S3 and a decrease in S2 and S4. Focusing on the industrial sector, its consumption is more than doubled in S1 and S2 compared to the S0 absolute value, because of the conversion into heat. For the transport sector, the slight decrease in the direct use of hydrogen with respect to S0 corresponds to a simultaneous increase in the use of hydrogen through synfuels, particularly in S1 (i.e., trade by pipelines in the optimistic case). This shift is attributed to the increase in cost-effectiveness of consuming decarbonized synfuels, despite using hydrogen directly.

Table 3.8 – Relative difference between S0 and the trade scenarios for the hydrogen consumption per sector, through direct use and conversion options; year: 2050.

	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*
AGR	0.0	0.0	0.0	0.0	0.3	0.3	0.1	0.2	8.3	7.8	-0.3	3.3
COM	0.0	0.0	0.0	0.0	9.1	9.4	3.1	5.0	0.0	0.0	0.0	0.0
IND	1.7	0.0	0.0	0.0	61.8	65.1	21.3	35.2	28.4	26.6	-1.0	11.1
RES	23.5	75.2	22.2	30.4	14.3	15.0	5.0	8.1	0.0	0.0	0.0	0.0
TRA	-70.9	-49.1	17.8	-8.0	–	–	–	–	140.5	132.4	2.9	50.8

	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

With respect to the decarbonization target – a 95% reduction of EU-wide CO_2 energy-related emissions in 2050 with respect to the 1990 levels –, the effects on emissions mitigation resulting from the additional trade of green hydrogen from North Africa to Europe are investigated. It is found that because of the green hydrogen import from North Africa the EU+ decarbonization becomes more cost-effective. In fact, by 2040 in the optimistic scenarios (S1 and S2), where the imported amounts are higher and cheaper, it is estimated a decrease of the CO_2 marginal cost up to 4% with respect to S0. This reduction increases by 2050, ranging from 10% (in S3 and S4) to 16% reduction in S1 and S2.

3.4.1 The impact of trade at country level

To better investigate the impact that hydrogen can have on different local economies ranging from one scenario to another, Figure 3.14, Figure 3.15, and Figure 3.16 focus on country-specific hydrogen balances, reporting the delta with respect to the case without import in terms of production, consumption, import from North Africa, import from EU+ and export to EU+ (considering the possibility of intra-EU trade modelled with the same trade matrix of natural gas). For the sake of exemplification, here the countries directly involved in trade and/or having the highest share in hydrogen demand are shown. Specifically, on the model it is found that Germany has the highest share of hydrogen demand in Europe – it covers the 32% of the total in 2050 –, followed by Spain (10%), Poland (8%), France, Italy, and the Netherlands (7%).
Figure 3.14 shows and compares the hydrogen balance in terms of delta with respect to S0 for Spain and Italy. Focusing on S1 and S3, with pipelines modelled, it is found that both countries experience a strong decrease in production but still preserving the same level of consumption of the basic case S0, thanks to the import from Morocco and Algeria for Spain, and Algeria and Tunisia for Italy. Looking at the deviations in the local export, it is interesting to notice that Spain enhances its role as corridor in S1, when higher volumes of hydrogen from North Africa are available, while in S2 and S4 it can afford to produce less hydrogen because the local export is substituted by the North African import from which other countries directly benefit.

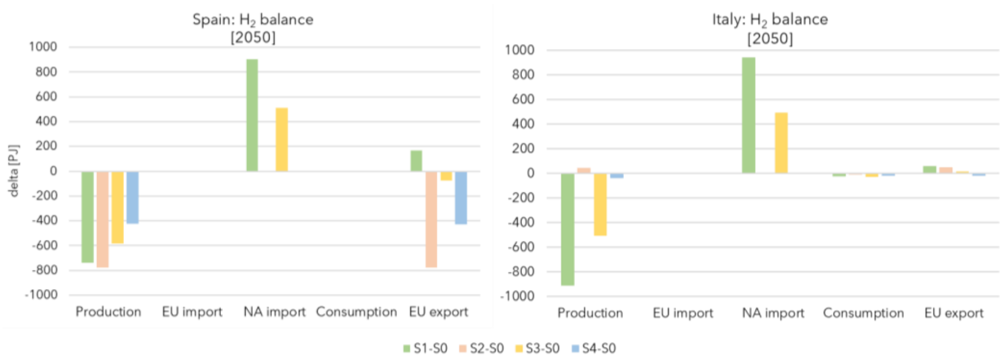

Figure 3.14 – Hydrogen balance in terms of delta with respect to S0 for Spain and Italy; year: 2050.

Looking at Figure 3.15 and focusing on Germany, it is estimated a strong decrease in local import and also in local export while exploiting directly hydrogen from Tunisia, leaving the production trends unchanged and experiencing a slight increase in consumption. France instead, increases the import in S1 thanks to the additional trade from North Africa (i.e. trading hydrogen with Spain), while the local export undergoes a decrease with respect to S0 in each scenario, as it happens on the production side.

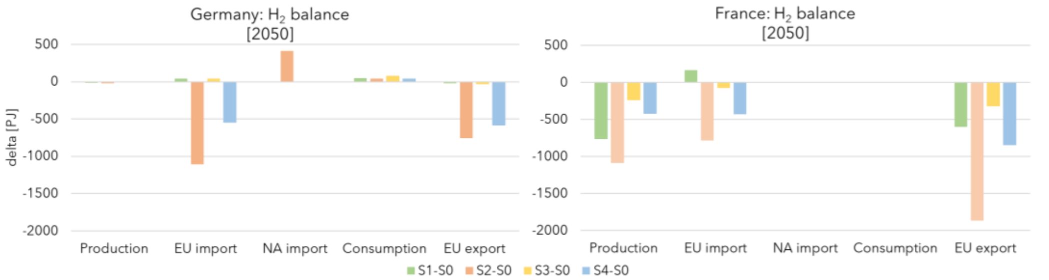

Figure 3.15 – Hydrogen balance in terms of delta with respect to S0 for Germany and France; year: 2050.

The delta in hydrogen balances shown in Figure 3.16 refers to Poland and the Netherlands, as pivotal importers of hydrogen by North Africa in S2 and S4; it is highlighted how the extra-EU volumes replace the EU+ import, while simultaneously maintaining the consumption behavior of these countries unchanged.

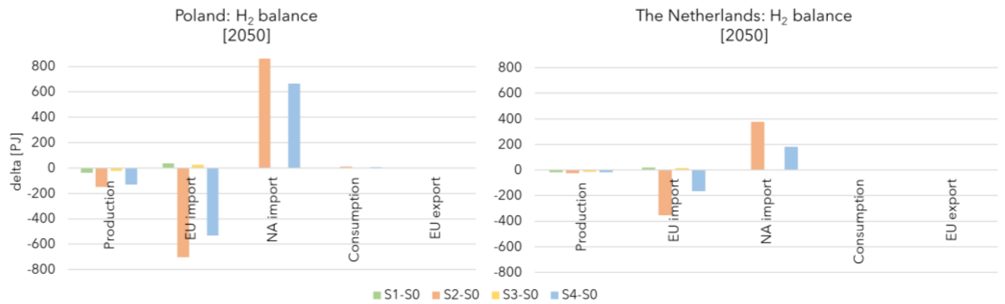

Figure 3.16 – Hydrogen balance in terms of delta with respect to S0 for Poland and the Netherlands; year: 2050.

3.4.2 The sensitivity analysis

In order to effectively tackle the uncertainty of the involved parameters and their dynamicity, it is useful to perform a sensitivity analysis, which analyse the impact of different ranges of hydrogen trade volumes and related costs. Figure 3.17 reports the reasoning behind the identification of 16 different scenarios, working on amounts and costs of the imported hydrogen; for each importing scenario it is applied an increase of 50% on amounts ("_HA") and costs ("_HC") and a 50% reduction on amounts ("_LA") and costs ("_LC").

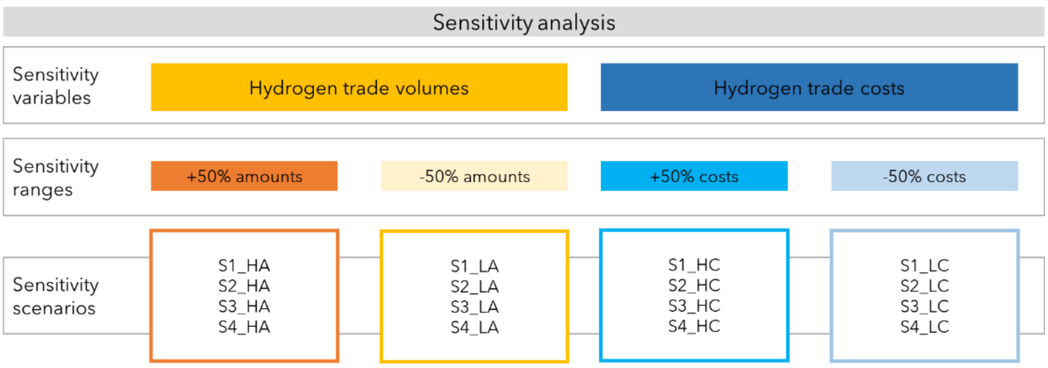

Figure 3.17 – Sensitivity analysis: variables, ranges and scenarios to be analyzed.

By modeling these scenarios for sensitivity purposes (Figure 3.17), it is found that a 50% increase of the imported amount from Morocco, Algeria and Tunisia implies a reduction in local EU+ production of 4% with respect to the basic pessimistic cases; the decrease in domestic production corresponds to a 12% when referring to the basic case of S2 (higher importable amounts at lower costs).
The opposite behavior in the same terms it is found when applying a decrease of 50% in importing volumes, requiring an increase in local production with respect to the one of the basic cases. Concerning consumption, the availability of a higher amount of hydrogen from North Africa will impact mostly the indirect consumption, basically in the form of heat and synfuels.
Applying the sensitivity analysis on the production and transport costs, the reduction of 50% for S1 (S1_LC) means to unlock the option of pipelines by 2030 also from Algeria and Tunisia – while in the basic case only a reduced hydrogen volume from Morocco is traded by 2030 into Spain. This means that unlocking pipelines in the short-term is strongly influenced by uncertainty; it is possible but will require effort to achieve cost-effectiveness, investing more on the repurposed ones and pushing for cost reduction.
The scenario S2_LC, which models the shipping option through a 50% cost reduction, makes possible the related trade routes from Algeria and Morocco by 2030, not from Tunisia.
On the other side, when the costs are increased by 50% in 2040, only Morocco is still competitive in the pessimistic scenarios, i.e. in both S3 and S4.
Focusing on the long-term (2050), as expected EU+ will import all the hydrogen available from North Africa, regardless the costs. In fact, also S3_HC and S4_HC unlock imports by 2050, meaning that in each case EU+ will exploit the amount of green hydrogen available from North Africa to achieve its decarbonization targets.

3.4.3 Limitations and potential development of the work

Concerning the scenario analyses developed and the related outputs, it is useful to consider that there are some limitations in the model setup and the development of the work, allowing to potentially make future analyses on this specific topic.
The main limitations deal with the original model – the JRC-EU-TIMES one – which would require some updated and careful assessments of specific new assumptions and constraints.
Regarding grid modelling, there are strong limitations on the expansion capacity of the power grid. Concerning green hydrogen production, at this stage of the model the off-grid option to produce green hydrogen consists only of PV plants; also off-grid wind plants need to be implemented into the model. Moreover, at this moment the Direct Air Capture (DAC) technologies are neglected and also for future assessment it would be required to integrate a direct hydrogen consumption in industry. Additionally, variations to the model's technological inputs for electrolysis processes could provide insights into the related impacts on EU+ domestic production and North African competitiveness.
In terms of future analyses, it would be of interest to consider various constraints on EU demand to explore how the model reacts when ranging through uncertainties.
In any case, this assessment can be exploited to address the pivotal role of hydrogen in different contexts of analyses and applications, emphasizing and supporting the need for strategic development of new routes and alliances supporting the overall decarbonization target.

4 - CONCLUSIONS

Experiencing a crucial innovation turning point, hydrogen will have a key impact on the achievement of the decarbonization target in the long-term, specifically the green one, produced through water electrolysis supplied by renewable energy. In line with this, the European Union is paving the way to its adoption, pushing for its deployment and supporting alternative trade options, starting from 2030.

In this regard, the aim of the work is to investigate to what extent the import of green hydrogen from North Africa can support the European decarbonization. Set that the more ambitious the targets, the higher the penetration of hydrogen, it is firstly analyzed the evolution of its market worldwide, addressing country-specific roles and strategies for the medium- and long-term.

It is found that there is a general interest to boost up the adoption of low-carbon hydrogen, recognizing its potentialities and strengths; nevertheless, the effectiveness of ad-hoc pathways for production, consumption and trade relies on a series of different parameters affected by uncertainty and influencing its competitiveness. To this regard, these parameters are introduced and analyzed, concerning the cost of renewables and electrolysers, their technological maturity, the country-specific production potentials, and alternative transport routes and costs, each one associated to different financial risks and levels of cross-border coordination. On the other side, the specific role of Morocco, Algeria and Tunisia in the hydrogen development context is investigated, through the focus on local policies and strategies defining the potential volume available for trade.

Within this framework, the TIMES model generator and specifically the JRC-EU-TIMES model is exploited to elaborate ad-hoc scenarios modelling the uncertainty on availability of trade volumes, production costs, transport routes and costs. It is a European-wide partial-equilibrium model with disaggregation at a country level, developed by the JRC in 2013; this study allows to implement the import of green hydrogen from North Africa, working on new processes and related assumptions. After modelling a basic case without import (S0), other four scenarios are introduced to distinguish between transport by pipelines or ships, assuming the case of market push and strength (i.e. the optimistic scenarios) in contraposition to less favourable conditions meaning lower global coordination and higher risk (i.e. the pessimistic scenarios). In this way, S1 and S2 are assumed to model optimistic volumes of hydrogen available for trade and at more affordable costs, respectively through pipelines and ships, while S3 and S4 correspond to lower amounts available at higher costs.

If in the short-term (2030) the only competitive option relies on pipelines from Morocco to Spain in the optimistic case, the main finding concerns the 2050 as target year, when Europe accepts all the green hydrogen from North Africa to achieve carbon-neutrality. Specifically, in 2050 the renewable hydrogen from North Africa covers up to the 16% of the total EU demand, in S1 and S2 (i.e. high volumes available at lower cost). In other words, also in case of pessimistic evolution of the market and higher financial risks, it is allowed to trade hydrogen and not only by pipelines but also exploiting shipping options, exploiting the additional amount from North Africa to decrease the local production and to maintain the same levels of consumption.

Looking at the alternative transport routes, it is found that Spain and Italy are the two countries most exposed to trade by pipelines – with Portugal playing a minor role. In case of ships of liquefied hydrogen, Poland, the Netherlands and some Baltics countries start to directly trade. In addition to this, it is important to notice how each country is sensitive to trade in different ways, also if not directly involved, reacting differently to the additional amount available.

On consumption side, most of the hydrogen is exploited in the transport sector, specifically through its conversion into synfuels; in parallel, also the consumption in industry increases because of the traded amount, concerning its indirect use through conversion into heat.

In addition to this, the sensitivity analysis allows to better understand how costs and amounts could have an impact on the competitiveness of trade; as a result, an increase in the amount up to 50% of hydrogen from North Africa can impact the EU+ domestic production, with a 4% to 12%

reduction. Concerning a 50% decrease of costs, it can be noticed how pipelines would be unlocked by 2030 also from Algeria and Tunisia, while the shipping option will be also available in the short-term but only for Algeria and Morocco in the optimistic scenario.
In each case, it is confirmed the potentiality of green hydrogen from North Africa to accelerate and support the transition to decarbonization, making it more cost effective in the long-term; a crucial aspect is still related to the analysis of sources of uncertainty and risks associated to a growing market like the hydrogen one.

This work was made possible only thanks to Maria Gaeta, as "guiding light" everywhere and anyway. She is the PhD co-supervisor of Maria Cristina Pinto and she made effective this interesting and profitable collaboration in Lisbon with Sofia Simões (LNEG, National Laboratory of Energy and Geology) and Patricia Fortes (FCT NOVA University), supporting from the beginning the definition of the activities and their main goals.

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6 - LIST OF ABBREVIATIONS

Abbreviation	Description
AFIR	Alternative Fuels Infrastructure Regulation
AGR	Agricultural sector
ALG	Algeria
ALK	Alkaline electrolyser
BOP	Balance of Plant
CBAM	Carbon Border Adjustment Mechanism
COM	Commercial sector
EHB	European Hydrogen Backbone
EPC	Engineering, Procurement and Construction
ETS	Emissions Trading System
ETSAP	Energy Technology Systems Analysis Program
FCT NOVA	Faculdade de Ciências e Tecnologia da Universidade NOVA (School of Science and Technology)
G2G	Gas-to-Gas
GHG	Greenhouse Gas Emission
GHR	Global Hydrogen Review
HRS	Hydrogen Refuelling Station
IEA	International Energy Agency
IND	Industrial sector
IRENA	International Renewable Energy Agency
JET	Joint Research Centre European TIMES
L2L	Liquid-to-Liquid
L2G	Liquid-to-Gas
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LNG	Liquefied Natural Gas
LNEG	Laboratório Nacional de Energia e Geologia (National Laboratory of Energy and Geology)
LTS	Long-Term Strategy
LOHC	Liquid Organic Hydrogen Carriers
MOR	Morocco
NECP	National Energy and Climate Plan
NRRP	National Recovery and Resilience Plan

Abbreviation	Description
PEM	Proton Exchange Membrane electrolyser
PET	Pan-European TIMES
PNIEC	Piano Nazionale Integrato Energia e Clima
PNRR	Piano Nazionale di Ripresa e Resilienza
PV	Photovoltaic
RCF	Recycled Carbon Fuels
RdS	Ricerca di Sistema
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RES	Residential sector
RRF	Recovery and Resilience Facility
RFNBO	Renewable Fuels of Non-Biological Origin
RSE	Ricerca Sistema Energetico
SAFs	Sustainable Aviation Fuels
SOEC	Solid Oxide Electrolysis Cell
TRA	Transport sector
TSO	Transmission System Operator
TUN	Tunisia
WACC	Weighted Average Cost of Capital
WEC	World Energy Council
WO	Wind Onshore
WTO	World Trade Organization