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WP2 “Modeling the identified scenarios”

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T2.4 “Modelling the effect of AU Green-H2 production on EU energy system”

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Table of contents

1. Introduction.....	11
1.1 Structure of the Deliverable	11
1.2 Relation to Other Tasks and Deliverables	12
2. Methodology	13
2.1 Modelling approach	13
2.2 Key assumptions regarding AU hydrogen imports.....	14
2.2.1 H2 import potentials from North Africa	14
2.2.2 Available routes for H2 transportation.....	17
2.2.3 H2 transportation cost assumptions	19
2.3 Definition of main AU import scenarios.....	20
2.4 Other key assumptions	21
2.4.1 2050 European power system	21
2.4.2 European H2 demand in 2050	22
2.4.3 H2 imports from non-African countries.....	23
2.4.4 Key investment options in the EU energy system.....	23
3. Key results	26
3.1 The electrolysis capacity in EU27 remains stable when the import volumes from Africa increase, with electrolysers providing more flexibility services.....	26
3.1.1 EU-27 electrolysis capacity.....	26
3.1.2 Hydrogen production by electrolysis in EU-27	27
3.2 The marginal price and carbon content of the H2 produced in Europe decrease when AU import volumes increase	30
3.3 Storage needs in EU-27 increase when imported volumes increase	31
3.4 The complementarity between H2 shipping and offshore pipelines tends to stabilize EU-27 transmission infrastructure needs	35
3.4.1 North African imports tend to consolidate key European H2 supply corridors.....	35
3.4.2 EU-27 transmission needs are mitigated by the presence of H2 shipping.....	36

3.5 The possibility of hydrogen shipping allows total investment costs to remain stable with the increase of imported volumes in scenarios 2 to 4.....	38
4. Conclusion.....	41
5. Annex	43
References	47

Table of figures

Figure 1: Summary of the optimization process	14
Figure 2: Seasonality of hydrogen production in Algeria	16
Figure 3: Seasonality of hydrogen production in Tunisia	16
Figure 4: Seasonality of hydrogen production in Morocco	17
Figure 5: Summary of the pipeline routes considered in the study	18
Figure 6: CAPEX assumptions for pipelines (source: EHB).....	19
Figure 7: Main European hydrogen import terminals in 2050 according to the European Hydrogen Backbone	20
Figure 8: Summary of the North African hydrogen imports scenarios.....	21
Figure 9: Installed power capacities considered in the model for EU27 (GW)	22
Figure 10: Hydrogen demand (TWh) in 2050 for EU27 according to the Distributed Energy scenario from the TYNDP22	23
Figure 11: Assumptions on investment cost for electrolyzers and power flexibilities (source: TYNDP22).....	24
Figure 12: Hydrogen storage costs assumptions (source: Gas for Climate)	25
Figure 13: Assumptions on investment costs for onshore hydrogen pipelines between the European countries (source: EHB).....	25
Figure 14: Total electrolysis capacity (GW) for the EU27 per scenario.....	26
Figure 15: Installed electrolysis capacity (GW) for each country of the EU27	27
Figure 16: Total electrolysis production (TWh LHV) for the EU27 per scenario.....	28
Figure 17: Hydrogen demand and electrolysis production (TWh) by EU27 country	28
Figure 18: Seasonality of hydrogen production by electrolysis in EU27 (in TWh)	29

Figure 19: Average marginal cost for H2 production in each modelling scenario (€/MWh LHV)	30
Figure 20: Average CO2 footprint of hydrogen production for each scenario (kgCO2eq/MWh LHV)	31
Figure 21: Optimization results for the installed storage injection capacity (GW) and working gas volume (TWh) at EU27 level	31
Figure 22: Installed storage injection capacities (GW) per country in the EU27	32
Figure 23: Working gas volumes (TWh) per country in the EU27	33
Figure 24: Average number of storage cycles per year for each scenario	33
Figure 25: Storage KPIs for each storage technology implemented in the model	34
Figure 26: Pipeline investment and national import balances in scenarios 1 and 2	35
Figure 27: Main hydrogen corridors obtained after optimization for the scenarios with high North African hydrogen imports	36
Figure 28: H2 import volumes (TWh) for each transport vector and each scenario	36
Figure 29: Summary of the state of the hydrogen pipelines network across EU27 + UK for each scenario	37
Figure 30: Map of imports and net balances in scenarios 3 and 4	38
Figure 31: Summary of annualized investment costs in hydrogen production, storage and transport in the EU27 (in M€ per year)	39
Figure 32: Installed pipeline capacities in the EU27 + UK in scenario 1 (GW)	43
Figure 33 : Installed pipeline capacities in the EU27 + UK in scenario 2 (GW)	44
Figure 34: Installed pipeline capacities in the EU27 + UK in scenario 3 (GW)	45
Figure 35: Installed pipeline capacities in the EU27 + UK in scenario 4 (GW)	46

List of acronyms used in this deliverable

Acronym	Description
ACSG	Artelys Crystal Super Grid
AU	African Union
EHB	European Hydrogen Backbone
ENTSOs	European Network of Transmission System Operators (for electricity and for gas)
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EU27	European Union
LHV	Lower Heating Value
MTPA	Million tonnes per annum
TYNDP	Ten-Year Network Development Plan



EXECUTIVE SUMMARY

This document is the Deliverable “D2.4 African Imported Green H2 effect on EU energy system”, developed within WP2 of the JUST GREEN-AFRH2ICA project and it presents the work performed by Artelys in the framework of the T2.4 Modelling the effect of AU Green-H2 production on EU energy system

The objective of this study is to assess the impact of AU green H2 import on EU energy system using the Artelys Crystal Super Grid optimization software. The model minimizes the both the operation costs and relevant investment decisions while ensuring an hourly supply-demand equilibrium for the power and hydrogen layers.

The analysis considered four import scenarios with varying hydrogen volumes from North and West African regions, transported through offshore pipelines or via ammonia shipping. Key findings include:

1. **The massive deployment of electrolysis capacities in Europe is no-regret:** Despite increasing hydrogen imports from Africa, needs for electrolysis capacities in the EU27 perimeter remain stable. The availability of additional imported hydrogen facilitates a more flexible operation of the European energy system, allowing electrolyser fleets to concentrate the production within time periods where electricity prices and CO2 emissions are lower. This results in cheaper, less carbon-intensive hydrogen production in the EU-27 perimeter.
2. **Underground hydrogen storage is a pivotal asset for domestic and extra-EU hydrogen valorization:** North African imports increase the overall needs for hydrogen storage capacity in Europe, particularly boosting seasonal storage. This storage is in fact critical to the reduction of domestic hydrogen production costs via electrolysis, which is instrumental in the efficient integration of imported hydrogen volumes.
3. **AU green hydrogen imports are the drivers of structural hydrogen transmission corridors across Europe:** African green hydrogen imports help reinforce key supply routes across Europe, with offshore pipelines remaining the dominant trans-Mediterranean transport method. However, complementary shipping options, however, provide flexibility that stabilizes the needs for investments in transmission infrastructures when import volumes are increased.
4. **The constitution of a Pan-European hydrogen infrastructure therefore appears as no-regret across all scenarios,** notably reducing overall system costs and enhancing the resilience of the coupled power and hydrogen systems.

In conclusion, African green hydrogen imports offer significant benefits to Europe’s energy transition, helping balance infrastructure needs, reduce system costs, and support decarbonization efforts across the power and hydrogen sectors.

1. Introduction

Europe is involved in an ambitious energy transition aimed at achieving carbon neutrality by 2050. In this context, hydrogen is an essential energy vector to decarbonize sectors that are difficult to electrify, such as heavy industry and long-distance transport. To achieve carbon neutrality and reduce dependence on fossil fuels, significant volumes of hydrogen will have to be produced from renewable or low-carbon energy sources. However, domestic production of renewable hydrogen via electrolysis remains limited by the potentials and variability of renewable energy sources. Importing hydrogen is therefore being considered as a strategic way to fulfill ambitious integration levels for green hydrogen in the EU economy. In this context, several African countries are now solidifying their positions as future green hydrogen exporters, in line with their strong potentials for the development of renewable energy resources and the cooperation potentials offered by the repurposing of existing cross-continental gas transmission infrastructures.

In this study, an assessment of the impact of AU green H₂ import on the 2050 European energy system is proposed, using the multi-energy capabilities of the Artelys Crystal Super Grid modelling solution¹ with an integrated power and hydrogen model of the European energy system. The study examines **four AU green H₂ import scenarios**, illustrating different combinations of import volumes, exporting regions and transportation routes for African green hydrogen.

The study notably focuses on the identification of hydrogen infrastructure needs from a Pan-European perspective, with the model being able to invest in a catalogue of hydrogen infrastructures and power flexibilities within the European energy system. Key indicators are computed, including main trade-offs regarding the transportation of hydrogen between Africa and Europe, resulting infrastructure needs within the EU and operational impacts on hydrogen price and CO₂ footprint.

1.1 Structure of the Deliverable

The following structure was chosen for the document:

- Section 3 presents the relation of this study in relation to other tasks and deliverables
- Section 4 describes the methodology of this study, the associated assumptions and the 4 H₂ import scenarios that have been considered
- Section 5 presents the key results
- Section 6 presents the deliverable's conclusions
- Section 7 includes the annex

¹ See <https://www.artelys.com/crystal/super-grid/>

1.2 Relation to Other Tasks and Deliverables

This Deliverable D2.4 is based on Task 2.4 and it provides relevant inputs to T2.5, towards the final goal of WP2: model the identified scenarios and propose sustainable hydrogen value chains for the different scenarios. The outputs of this deliverable will also be used in WP3, which aims to assess the impact of modelled scenarios and to develop the roadmaps to develop the transition to green hydrogen in Africa.

The report has been mostly realized by Artelys with support of UNIGE, JULICH and IRESEN in the identification of scenarios to be analysed and for some data sharing needed by the modelling approach.

Just one reminder for the reader: along the report green hydrogen potential/demand could be presented both in terms of mass or energy value. Please keep in mind that 1 t of H₂ has the energy content value of 33.3 MWh (1 t = 120000 MJ).

The contents of this report have been recently presented in a Webinar organized in October 2024 by JUST GREEN AFRH2ICA project in cooperation with MED-GEM project.

The contents of such webinar are available at the following link: https://med-gem.eu/JGAxMED-GEM_1stWebinar

2. Methodology

2.1 Modelling approach

This section introduces the methodology that was implemented to evaluate the impact of AU green H2 import on the European energy system for the **2050 time horizon**. In particular, we set the focus on both the coupling of the power and hydrogen sectors and the identification of hydrogen infrastructure needs from a Pan-European perspective.

Artelys Crystal Super Grid (ACSG) was used to optimize both the **hourly energy dispatch** at European level and over a full year, as well as **investment decisions within a catalogue of hydrogen infrastructures and power flexibilities**. The modelling covers a **country-level granularity** including the EU-27 perimeter as well as several neighboring countries (the UK, Switzerland, Norway and Western Balkans).

Artelys Crystal Super Grid is a **web-based software solution** dedicated to **modelling multi-energy systems**, from the regional scope to intercontinental contexts. The platform notably allows the modelling of a **vast array of technologies** for **multiple energy vectors**, as well as the optimization of associated dispatch and investment decisions based on a set of techno-economic parameters and environmental constraints. In this study, Artelys Crystal Super Grid was used for the **coupled modelling of the European electricity and hydrogen systems**, with an hourly resolution that fully captures the flexibility services associated with sector coupling – therefore securing an optimal sizing of optimized infrastructure.

As detailed in Figure 1, the modelling runs conducted for 2050 integrate a catalogue of investment options that include hydrogen technologies, including hydrogen storage, hydrogen pipelines, electricity interconnectors and short-term flexibility solutions in the electricity sector (Li-ion batteries, cross-border interconnectors, H2-fired peaker capacities). The assumptions related to the different investment options are presented in section 2.4.4 Key investment options in the EU energy system.

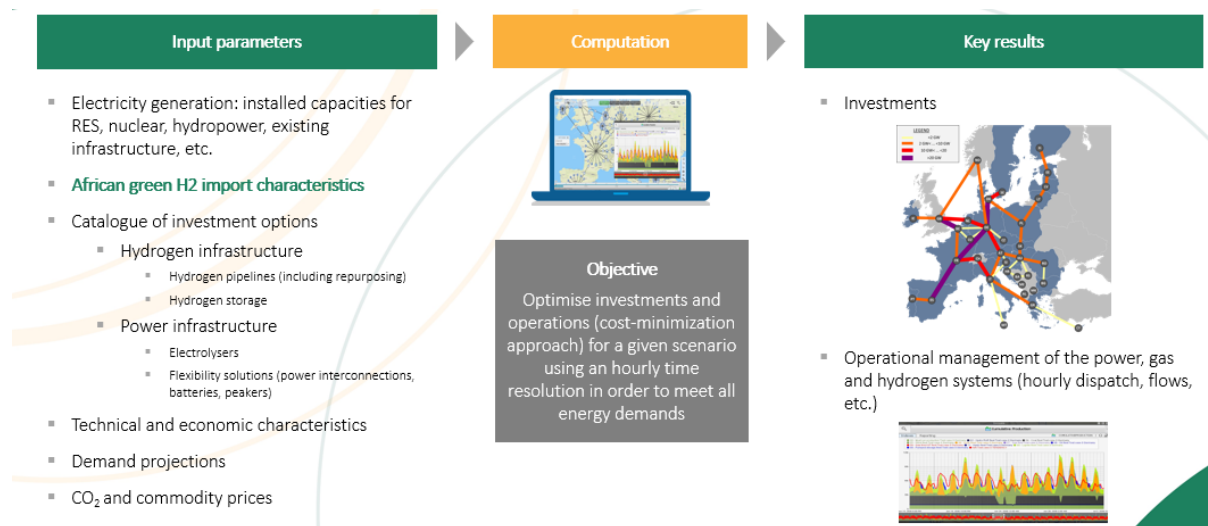


Figure 1: Summary of the optimization process

The main outputs of the model include the levels of investment in all optimized technologies, including hydrogen pipelines, storage and electrolysis capacities, as well as operational outcomes – e.g. hourly dispatch for each energy asset, marginal electricity prices, GHG emission...

For a given scenario including exogenously defined power and hydrogen demands and key techno-economic parameters for power generation, both capacity and dispatch optimisation outcomes are therefore representative of the cost-optimal infrastructure development and operation of the 2050 European energy system.

2.2 Key assumptions regarding AU hydrogen imports

In the model, hydrogen imports from diverse origins are represented through an annual volume or potential, associated with a monthly pattern and combined with a series of options for transportation towards several entry points in the European energy system.

2.2.1 H2 import potentials from North Africa

Several African countries have recently published a roadmap detailing their ambitions regarding green hydrogen exports towards Europe. The scenarios modelled in this study are based on these resources, with a focus on North African countries, which benefits from a relative geographical proximity to European countries and the possibility to exploit Natural Gas Pipelines already connecting their countries to Spain and Italy as infrastructure for H2 export to EU.

According to the 2021 Moroccan roadmap for green hydrogen ([Kingdom of Morocco - Ministry of Energy, Mines and Environment, 2021](#)), Morocco could export **2.7 Mt (81.4 TWh LHV)²** of green hydrogen by 2050 in a pessimistic scenario, and **5.4 Mt (162.8 TWh)** in an optimistic projection. These volumes were both considered in the study.

The 2023 Algerian roadmap for green hydrogen ([République Algérienne Démocrate et Populaire \[People's Democratic Republic of Algeria\], 2023](#)) unveils an objective of producing up to **1.3 Mt (40 TWh)** of green hydrogen specifically for export in 2050, which is considered as an upper bound. These volumes cumulate with 10 TWh of hydrogen production for domestic consumption. To establish a pessimistic export scenario, we consider that Algeria would reach by 2050 their 2040 objective of green hydrogen exports. This represents **1 Mt (33,3 TWh)**.

According to the National Strategy for the development of green hydrogen in Tunisia ([Green H2 Tunisia, 2024](#)), the country is targeting a production of 8.3 Mt (236 TWh) of hydrogen in 2050, including **6.4 Mt (213 TWh)** for exports. This value was considered for the optimistic scenario. Like for Algerian the 2040 export target was considered for the pessimistic scenario, it represents **1.6 Mt (53 TWh)** for Tunisia.

According to the Egyptian roadmap for green hydrogen, Egypt goal is to produce **1 Mt (33 TWh)** of hydrogen for export in 2050 ([Bakr, 2023](#)).

In order to include import potentials that are not limited to North African countries, ambitions from Ghana's Energy Transition and Investment plan ([SEforALL, 2023](#)) were considered, with a goal of **0.64 Mt (21 TWh)** of H2 export in 2060. This was taken as an optimistic value for Ghanaian export in 2050 in this study.

The **seasonality of hydrogen production** in these regions was also considered to secure a dynamic representation of the overall yearly production values previously presented per each country of the contribution of North African imports to the EU green H2 supply. For Algeria, the national roadmap mentions that by 2050, 63% of green hydrogen production will be solar-based and 37% wind-based, also identifying the primary regions for solar and wind production. We therefore processed seasonal generation data for solar panels (CDER [Renewable Energy Development center], 2014) and wind turbines (CDER [Renewable Energy Development Center]) provided by the [Algerian Renewable Energy Development center](#) in order to obtain a monthly generation pattern for hydrogen produced via electrolysis

² 1 kg of hydrogen is considered to represent 33.3 MWh in terms of lower heating value (LHV).

in Algeria. **The same seasonal pattern was applied to the green hydrogen production in Tunisia.**

Seasonal patterns for hydrogen production in Morocco were directly provided by IRESEN in the context of the JUST-GREEN AFRH2ICA project, with a focus on four main regions (see Figure 4).

The seasonality of hydrogen generation in other exporting regions (namely Egypt and Ghana) was not considered, due to the lack of information and the more limited volumes. These export potentials were therefore associated with flat profiles over the full year.

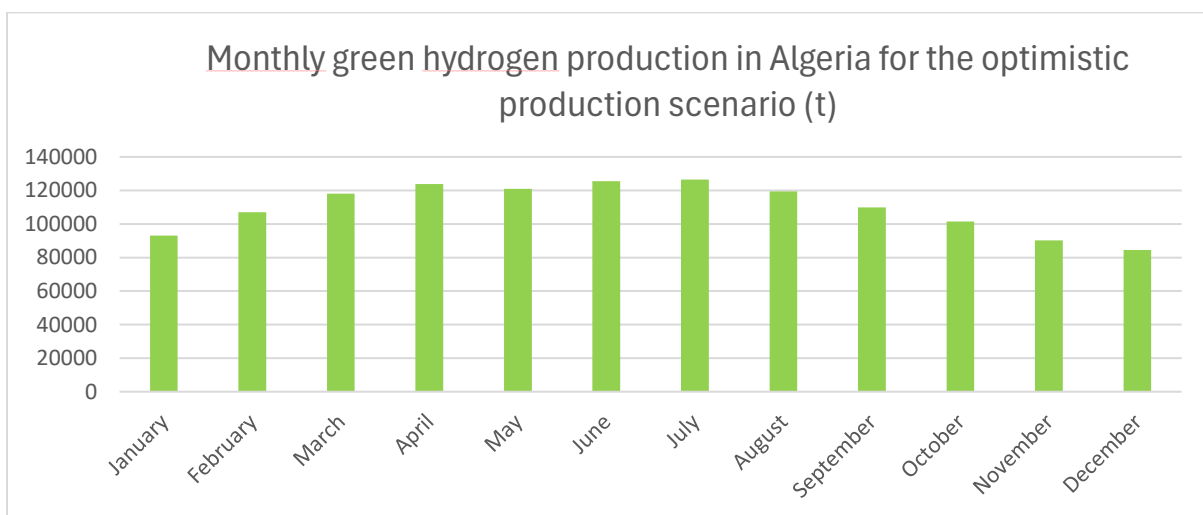


Figure 2: Seasonality of hydrogen production in Algeria

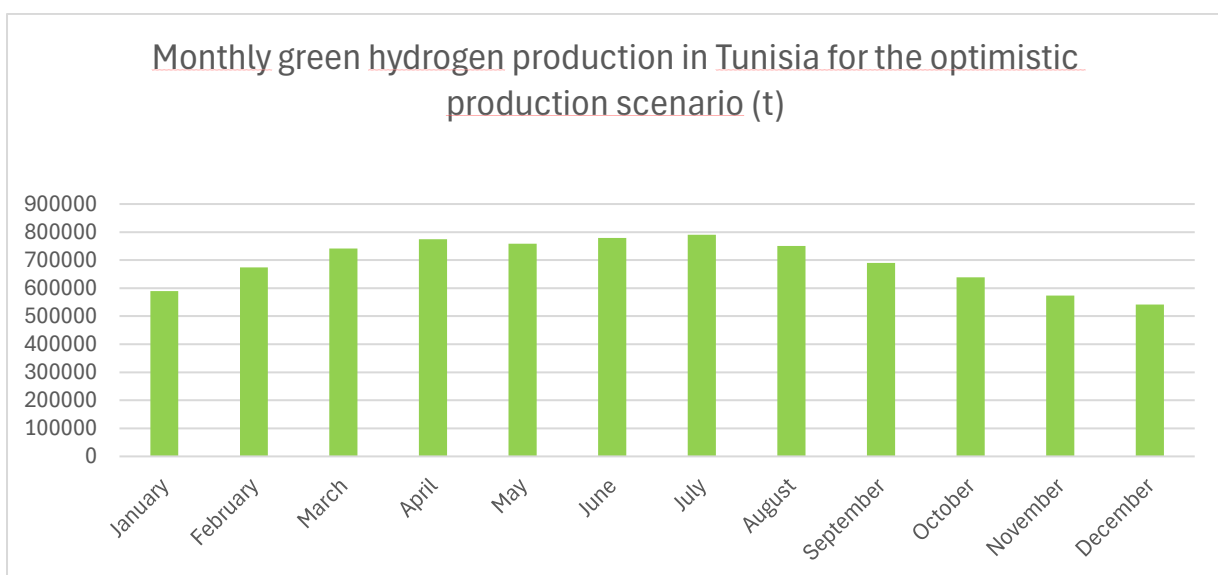


Figure 3: Seasonality of hydrogen production in Tunisia

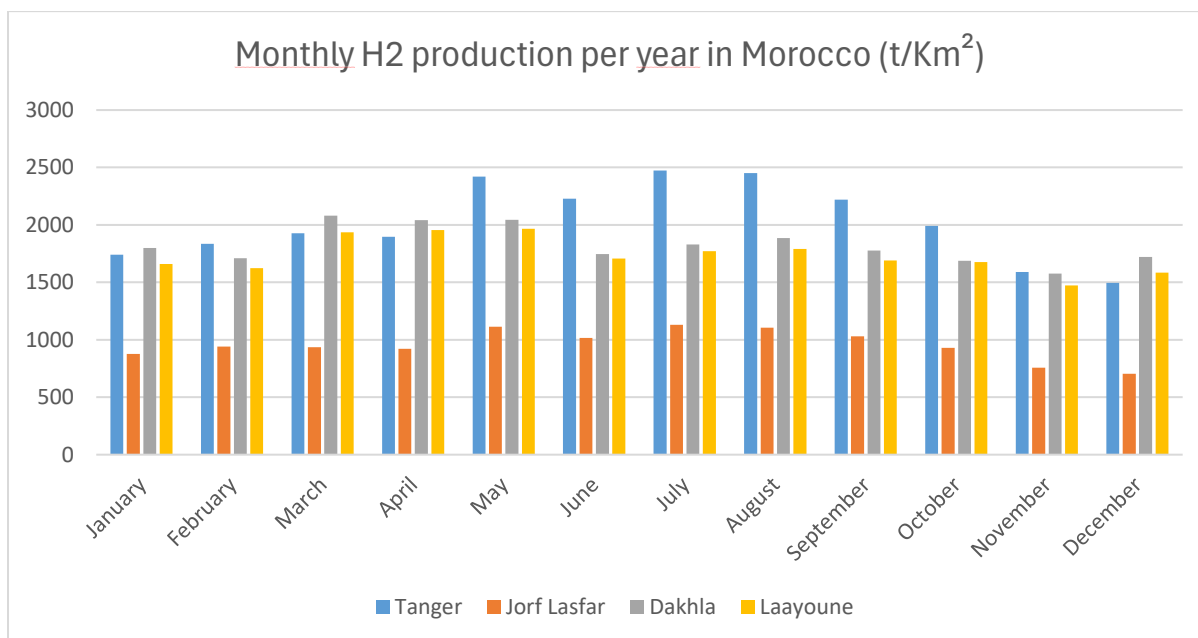


Figure 4: Seasonality of hydrogen production in Morocco

2.2.2 Available routes for H2 transportation

In this study, **two main transport possibilities** are considered:

- Hydrogen transport via pipeline, including both repurposed capacities and newly constructed pipelines.
- Hydrogen transport via shipping, mainly using ammonia.

According to the European Hydrogen Backbone initiative ([European Hydrogen Backbone, 2022](#)), the two main candidates for trans-Mediterranean pipeline (Fig. 5) repurposing are:

- The Transmed pipeline connecting Tunisia and Italy through an offshore pipeline, with an onshore part going through Sicily,
- The Maghreb-Europe Gas (MEG) pipeline, an offshore pipeline connecting Morocco and Spain.

The EHB also provides the repurposing potential associated with these two pipelines, representing 4.7 MTPA for the MEG pipeline and 12.5 MTPA for the Transmed pipeline.

The model is also allowed to invest in newly built pipeline capacities that are assumed to follow the same delineation as the Transmed and MEG projects, which represent a theoretical possibility to reinforce these pipelines.

In scenarios involving imports from Egypt, repurposing potential from the Eastmed pipeline is also considered. The Eastmed pipeline is a project aiming at building a gas pipeline connecting Egypt and Greece. This pipeline could potentially be repurposed to transport hydrogen. This gas pipeline will allegedly have the capacity to carry up to 20 billion cubic meters of gas yearly, and could therefore transport up to **1.8 Mt of hydrogen per year**.

The hydrogen export volumes from Ghana are modelled as an addition to the Moroccan export potentials.



Figure 5: Summary of the pipeline routes considered in the study

2.2.3 H2 transportation cost assumptions

For offshore pipelines

Pipeline investments were represented through a linear capacity optimisation, associated with an annualized CAPEX in euro per megawatt and per year (EUR / MW LHV / year), computed with a 40-year lifetime and a 5% interest rate.

The reference cost assumptions for pipeline repurposing and for new offshore pipeline are therefore based on medium-sized pipelines with a 36-inch diameter, associated with a 4.7 GW capacity (LHV) for newly built pipelines and 3.6 GW LHV for repurposed assets. Latest cost assumptions from the EHB initiative were used ([European Hydrogen Backbone, 2023](#)), considering the cost of the associated compression system and the characteristic length of each offshore project (namely Transmed, MEG and Eastmed).

Parameter		CAPEX costs (M€/km for pipelines and M€/MWe for compressors)
New pipelines	20" onshore pipes	1.80
	36" onshore pipes	3.20
	48" onshore pipes	4.40
	36" offshore pipes	5.44
	48" offshore pipe	7.48
Repurposed pipelines	20" onshore pipes	0.54
	36" onshore pipes	0.64
	48" onshore pipes	0.88
	36" offshore pipes	1.09
	48" offshore pipe	1.50
Compressor station		4.0

Figure 6: CAPEX assumptions for pipelines (source: [EHB](#))

For H2 shipping

According to the EHB ([European Hydrogen Backbone, 2022](#)), **the main ports that could accommodate H2 shipping in Europe in 2050 are in Northern Europe**. Scenarios that consider hydrogen shipping therefore include a transportation route from North African countries to France, the Netherlands, Belgium and Germany.

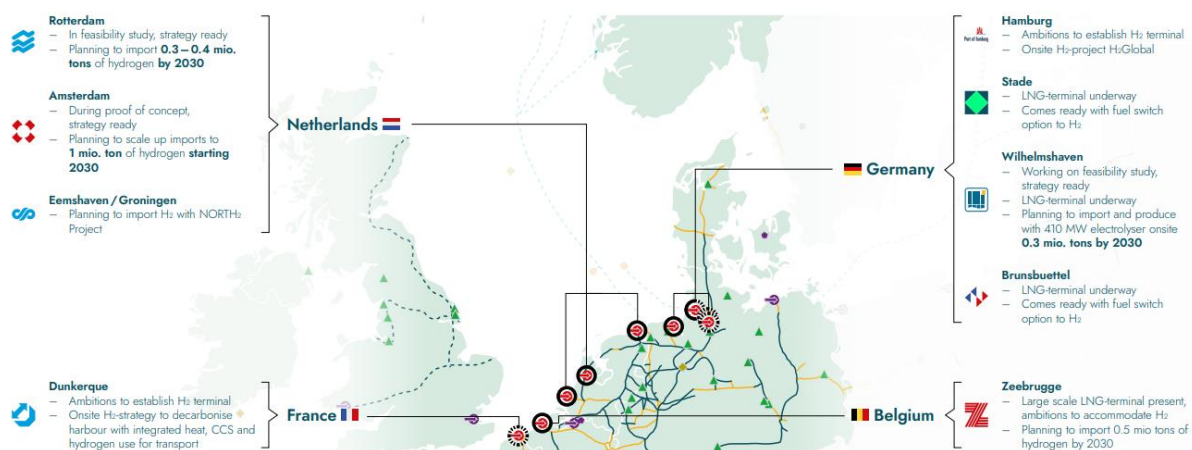


Figure 7: Main European hydrogen import terminals in 2050 according to the [European Hydrogen Backbone](#)

Cost assumptions were based on transportation and conversion processes for ammonia, which appeared as the cheapest and most reliable option given the considered transportation distance ([IRENA, 2022](#)).

In particular, the cost of hydrogen transport via ammonia was taken from a study from JRC ([JRC, 2022](#)): the cost of **1,58 €/kgH₂** that is used in our study corresponds to case A of the JRC study, that considers a characteristic distance of 2500 km and future (2030+) electricity price forecasts.

2.3 Definition of main AU import scenarios

The composition of the main import scenarios in this study is presented in Figure 8, based on different combinations of optimistic and pessimistic import volumes and different transportation options.

In the first two scenarios, the model is only able to use pipelines (new or repurposed) to transport the hydrogen coming from North Africa, whereas in scenarios 3 and 4 the use of shipping is available in the model.

In scenario 1, only pessimistic import volumes from Algeria, Tunisia and Morocco are considered, whereas optimistic volumes are used in all three other scenarios.

In the 4th scenario, additional hydrogen import potentials from Egypt and Ghana are considered.

	Scenario #1	Scenario #2	Scenario #3	Scenario #4
Import volumes				
MA (Morocco)	2.7 Mt (Pessimistic)	5.4 Mt (Optimistic)	5.4 Mt (Optimistic)	5.4 Mt (Optimistic)
DZ (Algeria) + TU (Tunisia)	2.6 Mt (1 + 1,6) (2040 levels) (Pessimistic)	7.7 Mt (1.3 + 6.4) (Optimistic)	7.7 Mt (1.3 + 6.4) (Optimistic)	7.7 Mt (1.3 + 6.4) (Optimistic)
Other regions	No	No	No	1 Mt from EG (Egypt) 0,64 Mt from GH (Ghana)
Total import volume	5.3 Mt	13.1 Mt	13.1 Mt	14.74 Mt
Available transport routes				
Trans-Mediterranean pipelines (H2 vector = gaseous)	Yes	Yes	Yes	Yes
Shipping (H2 vector = ammonia)	No	No	Yes	Yes

Figure 8: Summary of the North African hydrogen imports scenarios

2.4 Other key assumptions

2.4.1 2050 European power system

The main assumptions regarding the state of the European power system in 2050 are taken from the “**Distributed Energy**” scenario from ENTSO’s Ten-Year Network Development Plan 2022 (TYNDP2022). This scenario is the **most ambitious regarding 2050 installed capacities for renewable sources in Europe**. The power generation fleet from this scenario is presented in Figure 9 with the capacity for hydrogen-fired peaking units being reoptimized by the model.

The model is also adjusted with up-to-date assumptions regarding 2050 commodity and ETS (Emissions Trading System) prices: gas and oil prices are respectively set **36 €/MWh** and **63 €/MWh** according to REPowerEU assumptions ([European Commission, 2022](#)). The price of CO₂ (**168 €/tCO₂eq**) is directly taken from TYNDP22 ([ENTSOs, 2022](#)).

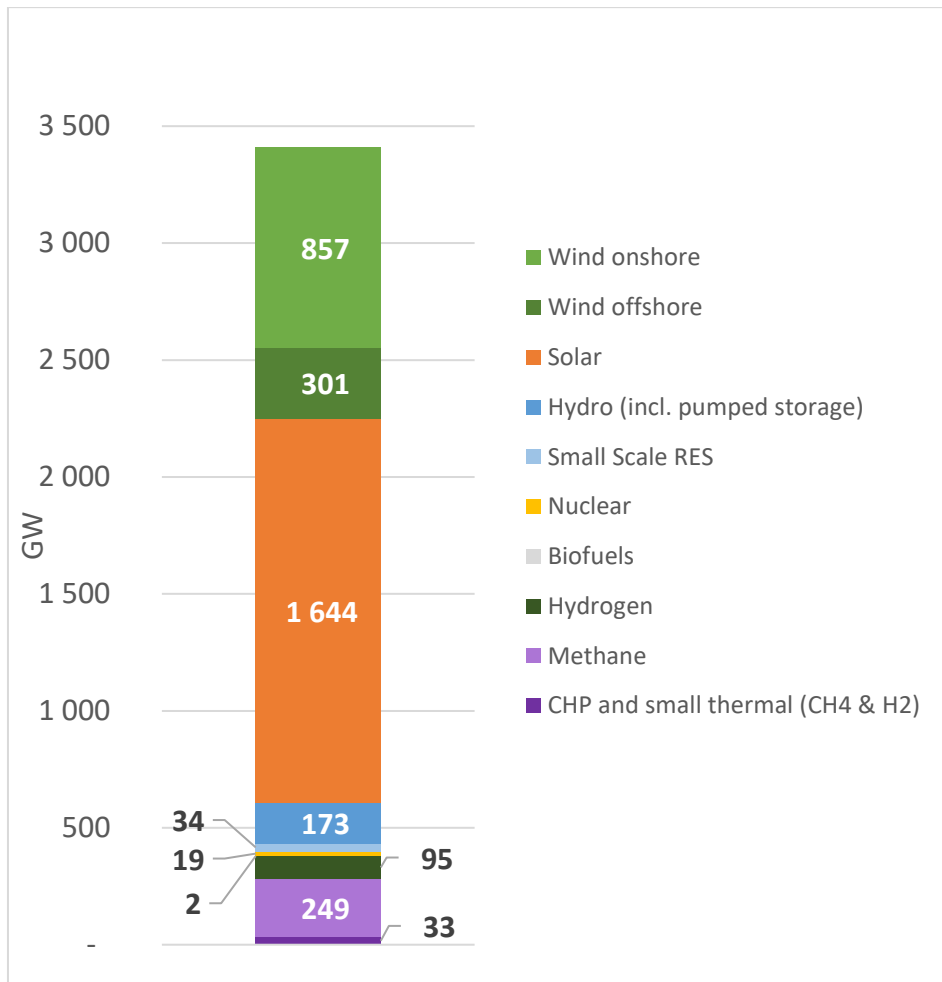


Figure 9: Installed power capacities considered in the model for EU27 (GW)

2.4.2 European H2 demand in 2050

The European H2 demand considered in the model is taken from the Distributed Energy scenario from the TYNDP22 ([ENTSOS, 2022](#)). It features an ambitious level of European hydrogen demand in 2050, with around **61 Mt** in EU-27 (**2032 TWh**). The part of hydrogen used for power generation corresponds to **240 TWh** in the TYNDP, but this part is fully re-optimized by the model. In this study, we therefore obtain a final hydrogen demand of **54 Mt** (**1791 TWh LHV**) in EU-27, which the model may complement by using hydrogen for power generation.

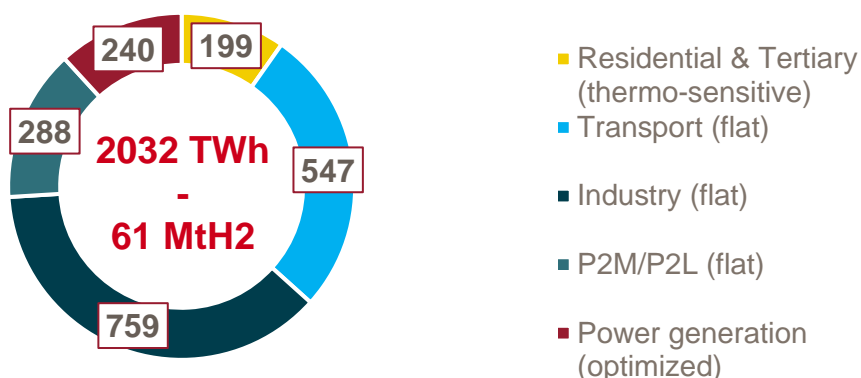


Figure 10: Hydrogen demand (TWh) in 2050 for EU27 according to the Distributed Energy scenario from the [TYNDP22](#)

2.4.3 H2 imports from non-African countries

In the “Distributed Energy” scenario from TYNDP22, extra-EU hydrogen imports are expected to reach **11 MTPA** in 2050. After subtracting the **7.8 MTPA** projected to come from North African countries, it leaves **3.2 Mt of imports from non-African countries**, either as hydrogen shipments to northern Europe or as pipeline transport from Norway or Ukraine. This same value is used in this study for all scenarios and proportionally distributed between the entry points included in the TYNDP22 scenario.

2.4.4 Key investment options in the EU energy system

Investments in **electrolysers and power flexibilities** are optimised by the model according to investments parameters from the “Distributed Energy” scenario ([ENTSOs, 2022](#)), based on an annualization integrating a 5% interest rate. These assumptions are nonetheless taken from the 2022 edition of the TYNDP, but one may note that the recently published 2024 edition of the TYNDP – which was not available at the time of this work – includes more conservative assumptions regarding investment costs for electrolysers in 2050 (325 €/kW). These assumptions are notably consistent with the values of the ASSET database from the EU Reference Scenario 2020³, but may appear quite optimistic compared to currently observed CAPEX, which tend to be superior to 1000 €/kW, as notably mentioned in IEA’s Global Hydrogen Review 2024⁴.

³ [European Commission, ASSET 2020 Database. Technology Assumptions for Energy, 2020.](#)

⁴ [International Energy Agency, Global Hydrogen Review 2024, 2024.](#)

However, both TYNDP reports include a huge decrease in the electrolysis costs expected between 2030 and 2050, with a decrease from 550 €/kW to 325 €/kW (TYNDP24 assumptions). A change in the technology used for electrolyzers is also anticipated, with an expected increase in the share of proton exchange membrane (PEM) electrolyzers. The efficiency of the electrolysis is also expected to increase, from 69 kW H2 LHV / kWe (69%) in 2030 to 74 kW H2 LHV / kWe in 2050 (74%) – which is also rather optimistic based on current project performances.

It is also important to note that investment and production costs for imported hydrogen volumes are not taken into account in the model, including from African regions, as the imported volumes are exogenously imposed to the model. The main focus of this approach is therefore on the impact of AU green H2 imports on hydrogen supply conditions within the European energy system perimeter.

Technology	CAPEX (€/kW)	O&M OPEX (€/kW/yr)	Lifetime (yr)
Electrolysers	270	13,5	25
Li-ion battery (3h)	404	13,1	25
H2-fired OCGT	412	7,4	25
Electricity interconnectors	Border-specific investment candidates based on TYNDP 2022 System Needs study		25

Figure 11: Assumptions on investment cost for electrolysers and power flexibilities (source: [TYNDP22](#))

The model is also allowed to invest in hydrogen infrastructures within the EU-27 + UK perimeter, in the form of cross-border pipeline capacities and underground hydrogen storage, represented at country level.

In particular, the model invests in different types of **storage technologies**, including salt caverns, hard rock caverns and depleted gas field. The obtained capacities are therefore optimised by the model based on cost assumptions presented in a 2023 Guidehouse study ([Gas for Climate, 2023](#)). No maximum storage deployment potentials have been implemented, but storage investment options are consistent with the existence of necessary resources in each European country (e.g. geological opportunities for the deployment of salt caverns).

Technology	Investment costs (€/kWh)	Annual O&M costs (% of invest. cost)	Lifetime (yr)
------------	--------------------------	--------------------------------------	---------------

Salt cavern	0,9	4%	50
Depleted gas field	0,45	4%	50
Hard rock cavern	1,2	4%	50

Figure 12: Hydrogen storage costs assumptions (source: [Gas for Climate](#))

The different storage technologies are distinguished by a discharge time that defines the maximum number of cycles each year and can be interpreted as a ratio between the working volume (GWh) and the injection capacity (GW) of a storage unit. These maximum cycling assumptions are coherent with the previously cited Guidehouse study and correspond to a maximum of 10 cycles a year for salt and lined hard-rock caverns (438h discharge time, i.e. 10 cycles per year) and 4-5 cycles per year for aquifers and depleted gas fields (1000h discharge time, i.e. 4 to 5 cycles per year).

Investment in cross-border pipeline capacities between European countries are modelled similarly to cross-Mediterranean pipeline investments, with a linear capacity optimisation corresponding to the CAPEX of 36-inch diameter pipelines. The calculated annualized CAPEX is computed based on an assumption of a repurposing rate of 50% in 2050, which builds on the assumption made by the [European Hydrogen Backbone](#) that 60% of all pipeline capacities in Europe will come from repurposing in 2040.

Investment costs are also based on the characteristic distance between countries following an approach used in a Gas for Climate study ([Gas for Climate, 2023](#)): the pipeline distance between two countries is determined based on the distance between both geographical centroids and increased by 25% to account for the real-life delineation of onshore pipelines.

Asset	Type	CAPEX (M€/1000 km)	OPEX (%CAPEX)	Lifetime (yr)
Pipeline	New (4,7 GW)	3200	0,90%	40
	Repurposed (3,6 GW)	640		
Compression	New (4,7 GW)	376	1,70%	25
	Repurposed (3,6 GW)	165		

Figure 13: Assumptions on investment costs for onshore hydrogen pipelines between the European countries (source: [EHB](#))

3. Key results

3.1 The electrolysis capacity in EU27 remains stable when the import volumes from Africa increase, with electrolysers providing more flexibility services

3.1.1 EU-27 electrolysis capacity

Between scenario 1 and scenarios 2 and 3, African import volumes increase by around 2.5. This results however in **decrease of only 23 GW** of the EU-27 installed electrolysis capacity which is optimised by the model. The average capacity factor in the pessimistic import scenario (scenario 1) is around **41%** and decreases to around **36%** in the optimistic import scenarios. This shows an increased flexibility in the operation of the European electrolyser fleet, that is able to concentrate domestic hydrogen generation within hours with low electricity prices and GHG emission – also thanks to hydrogen storage.

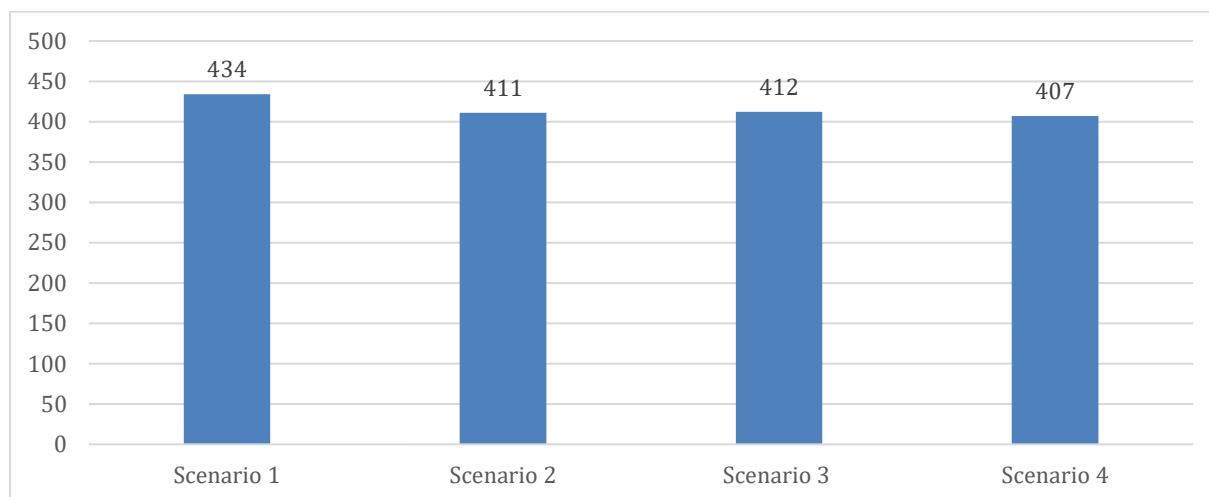


Figure 14: Total electrolysis capacity (GW) for the EU27 per scenario

In particular, the reduction in installed electrolysis capacity needed to fullfill EU Hydrogen demand is **rather evenly distributed** with no country having a significant decrease. In both cases, Spain, Germany and France are the countries with the highest installed capacity.

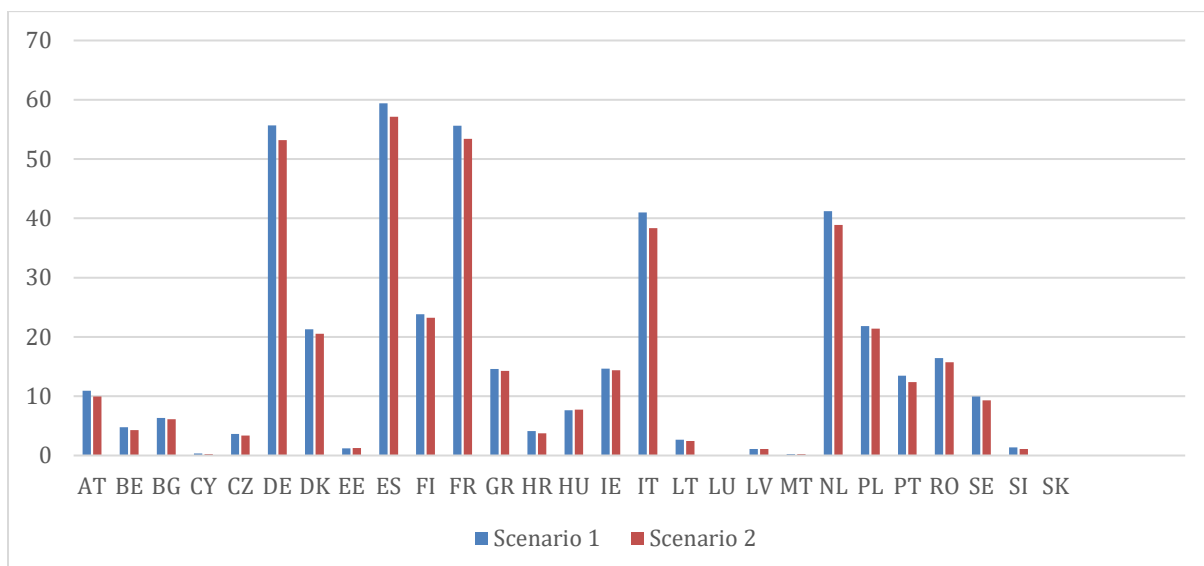


Figure 15: Installed electrolysis capacity (GW) for each country of the EU27

5.1.2 Hydrogen production by electrolysis in EU-27

The hydrogen production by electrolysis decreases by **16%** between the low (scenario 1) and the high imports scenarios (scenarios 2-3), due to an increase of the imported volumes with an unchanged EU-27 hydrogen demand – based on TYNDP 2022 “Distributed Energy” assumptions.

In particular, hydrogen demand is exogenously defined in the model, but the capacities and operation of all hydrogen infrastructures – including electrolysis, cross-border pipelines and storage – are optimised. This means that the net balance of each country is reflective of a cost-optimal development of the Pan-European hydrogen infrastructure, with hydrogen production being notably concentrated in countries where the renewable potential is the most favorable, then transported towards countries with higher demand.

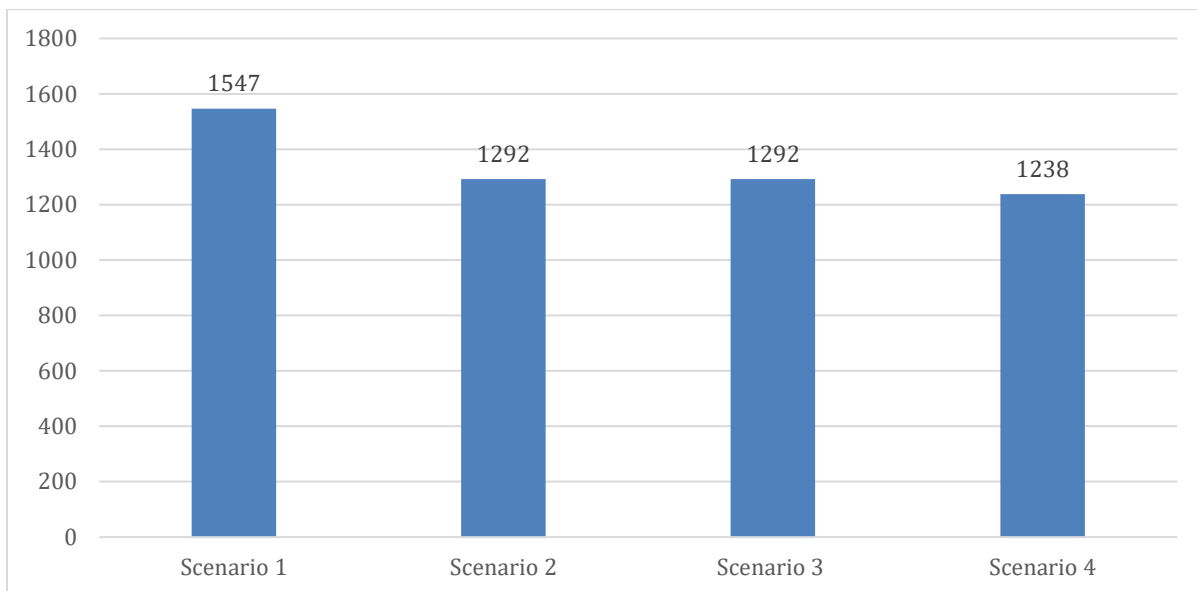


Figure 16: Total electrolysis production (TWh LHV) for the EU27 per scenario

The decrease of the overall EU-27 generation between scenarios 1 and 2 is nonetheless evenly distributed between European countries, as seen Figure 17.

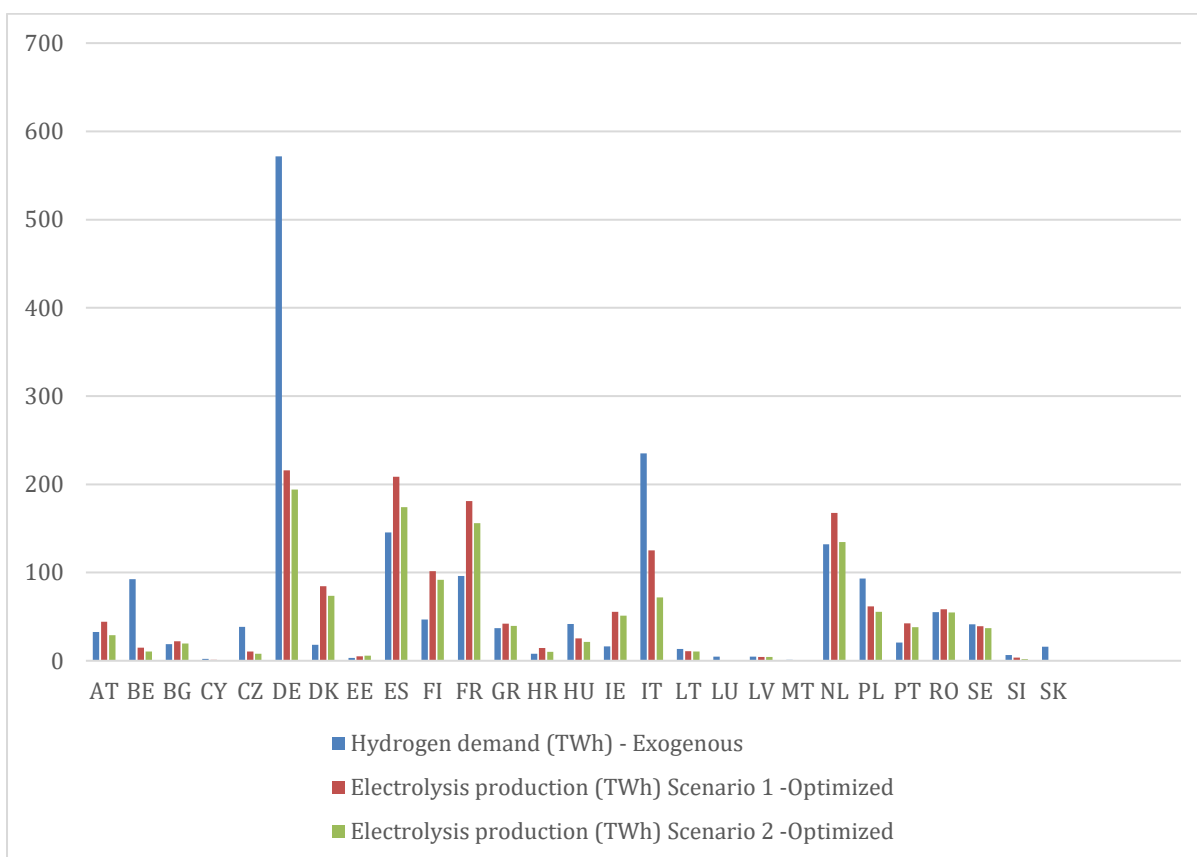


Figure 17: Hydrogen demand and electrolysis production (TWh) by EU27 country

With the seasonality of the hydrogen production in the North African countries being implemented in the model, the seasonality of the electrolysis production (TWh) in EU27 is the following:

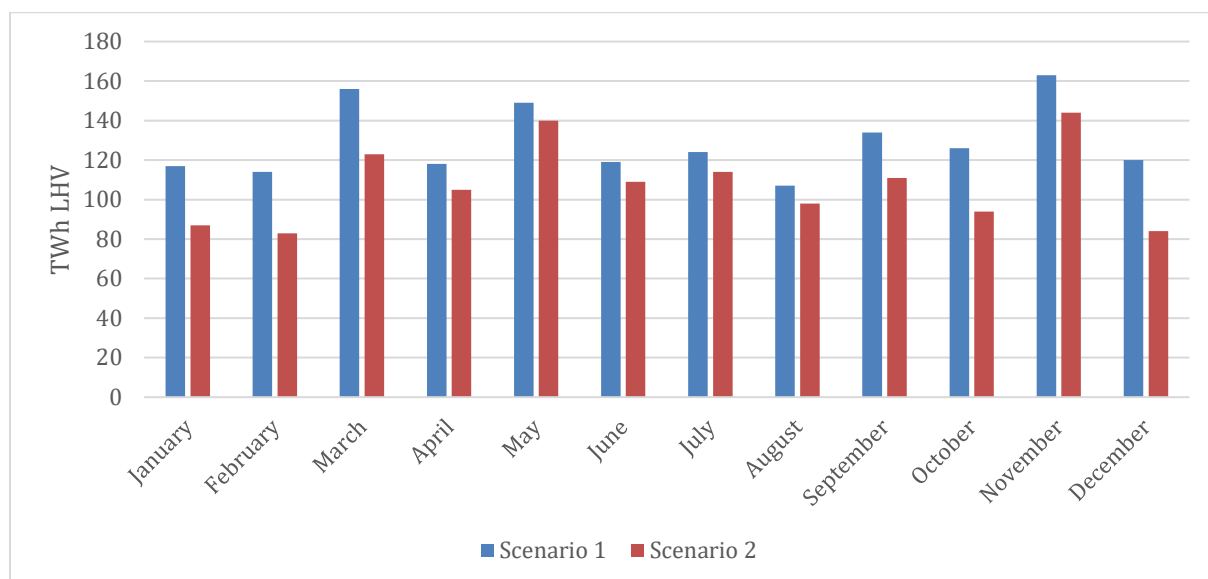


Figure 18: Seasonality of hydrogen production by electrolysis in EU27 (in TWh)

While domestic H₂ production by electrolysis generally decreases between scenarios 1 and 2, the decrease is specifically concentrated **within winter months**, which indicates that the EU-27 supply relies more on the imports and seasonal storage during these periods. A 27% decrease is observed in February, and a 30% decrease in December. Generation nonetheless remains stable during spring and summer months, which illustrates how the development of domestic hydrogen storage helps concentrate hydrogen generation within most favorable periods of the year.

These results highlight the need for European investments in the electrolysis technologies, regardless of the expected extra European imports level. These investments need to be coordinated between the European countries, since a European system with large amounts of electrolysis capacities was chosen by the model regardless of the considered import scenario.

3.2 The marginal price and carbon content of the H2 produced in Europe decrease when AU import volumes increase

As the increase of hydrogen import volumes allows for a more flexible operation of the electrolyzers in EU-27, hydrogen generation becomes more concentrated within time periods with low electricity prices and carbon content. The average marginal cost of domestically produced hydrogen therefore decreases with the imported volumes, as well as the CO2 footprint of H2 produced via electrolysis.

In particular, the decrease of the average marginal cost of H2 is also associated with **significant power generation cost savings** within the European power system thanks to the avoided power generation from fossil fuels. Around **9.9 billion euros per year** are therefore saved in EU-27 between scenarios 1 and 2.

In total, the decrease of H2 CO2 footprint results in **annual emission savings of 33.3 MteqCO2 within the European energy system**, also between scenarios 1 and 2.

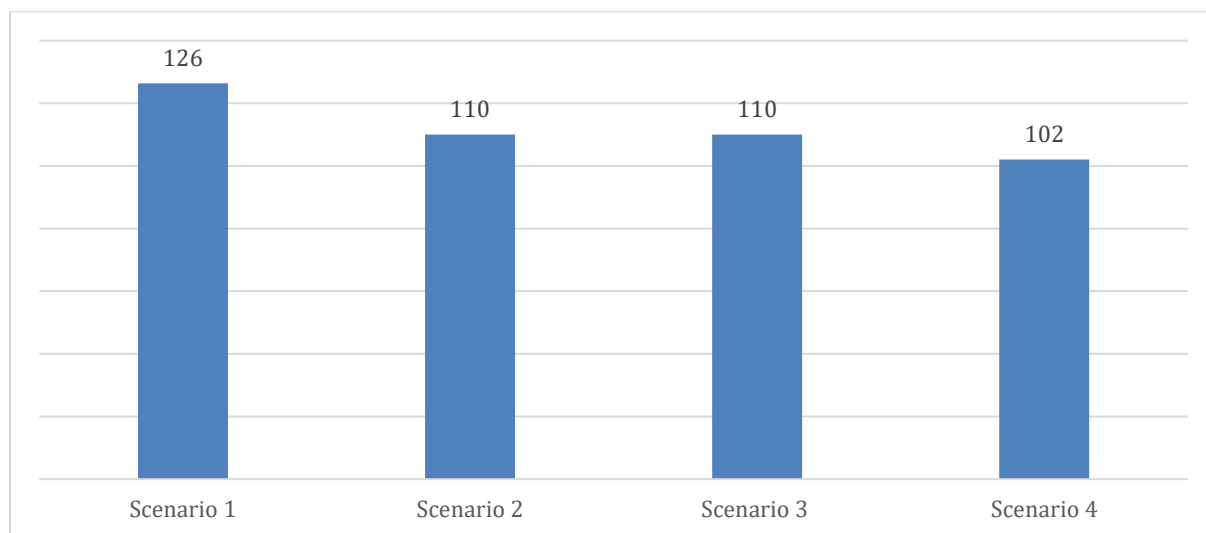


Figure 19: Average marginal cost for H2 production in each modelling scenario (€/MWh LHV)

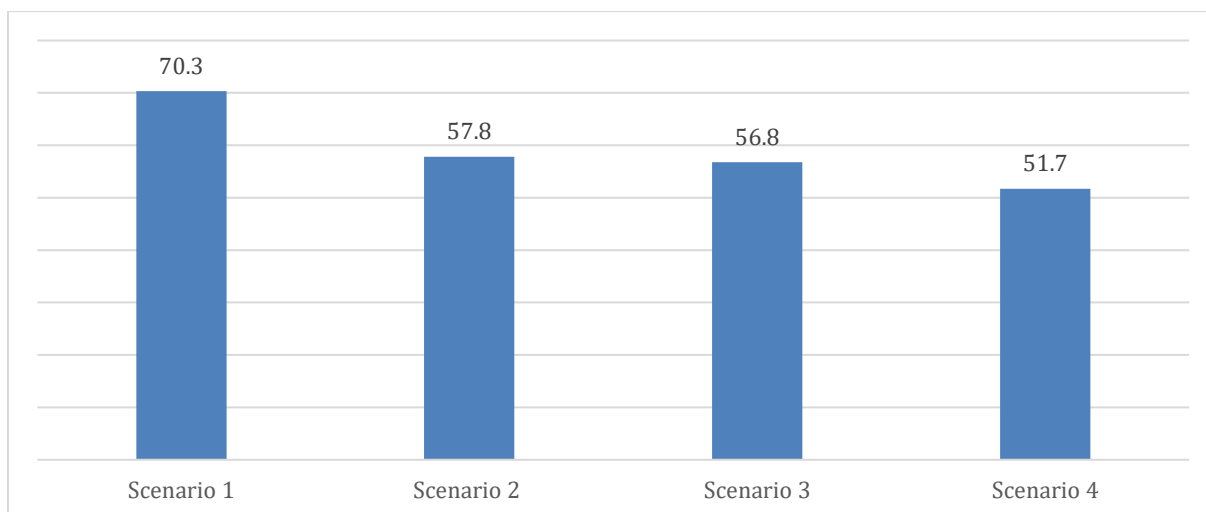


Figure 20: Average CO₂ footprint of hydrogen production for each scenario (kgCO₂eq/MWh LHV)

3.3 Storage needs in EU-27 increase when imported volumes increase

The modelling results show that the need for hydrogen storage in EU27 **increases with the level of hydrogen imports from North Africa**. For example, a **17 GW** increase of the injection capacity is observed between scenarios 1 and 2, which is a **39 TWh (1,2 Mt)** increase in the working gas volume. The total working gas volume for storage in EU-27 goes from **162 TWh (4,9 Mt)** in scenario 1 to **201 TWh (6 Mt)** in scenario 2.

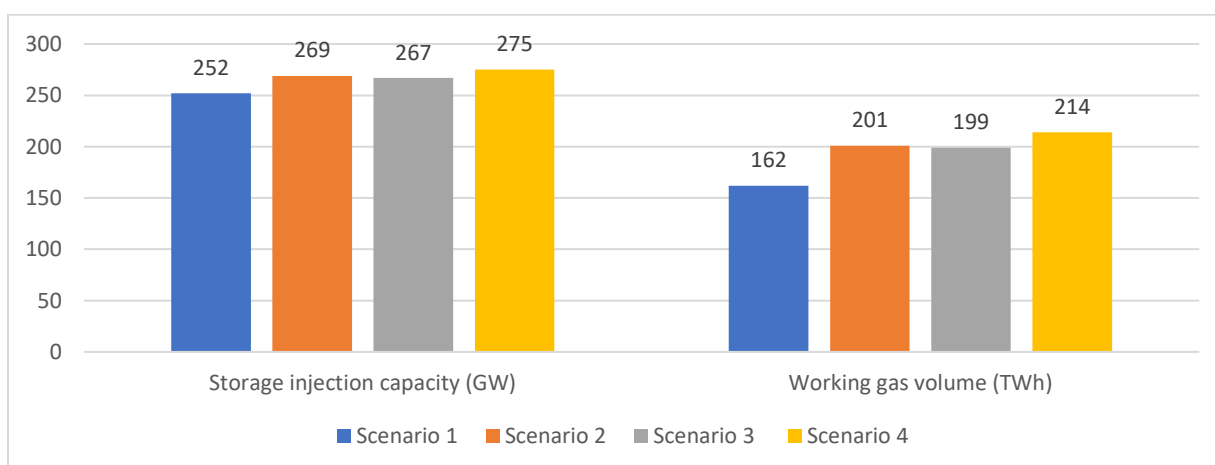


Figure 21: Optimization results for the installed storage injection capacity (GW) and working gas volume (TWh) at EU27 level

Part of this increase can be explained by a need **to mitigate the seasonality of African imports**, which notably explains why storage capacities in Italy significantly increase between scenarios 1 and 2, with an increase of the injection capacity from 28 GW LHV to 37 GW LHV.

Nonetheless, additional investments are also observed and more evenly distributed in other European countries, which illustrates how **opportunities for decreasing the cost of domestic hydrogen production are a structural driver of storage investments**.

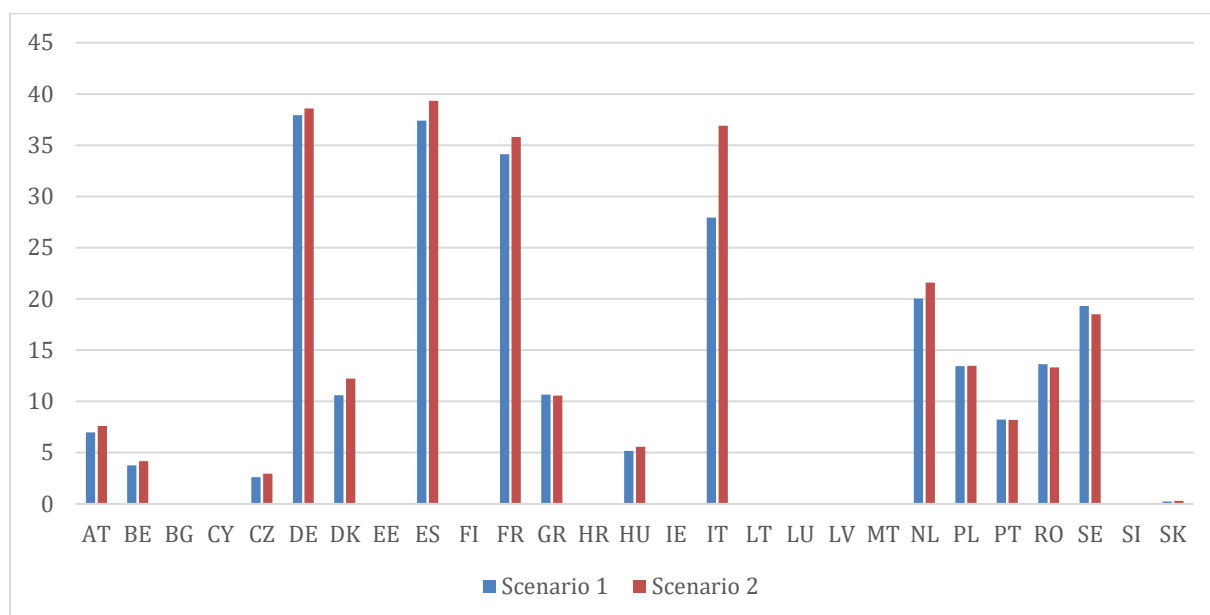


Figure 22: Installed storage injection capacities (GW) per country in the EU27

The **complementarity of different storage technologies** is also fully exploited by the model. For example, Spain has the highest increase in working gas volume from scenario 1 to scenario 2 while the progress of injection capacities is more limited. In this case, additional capacities correspond to salt caverns, while the increase of storage capacities in Italy are associated with depleted gas fields, which is more suitable for seasonal flexibility (i.e. smaller cycling rates, which suggests a compensation of the seasonal variability of imports).

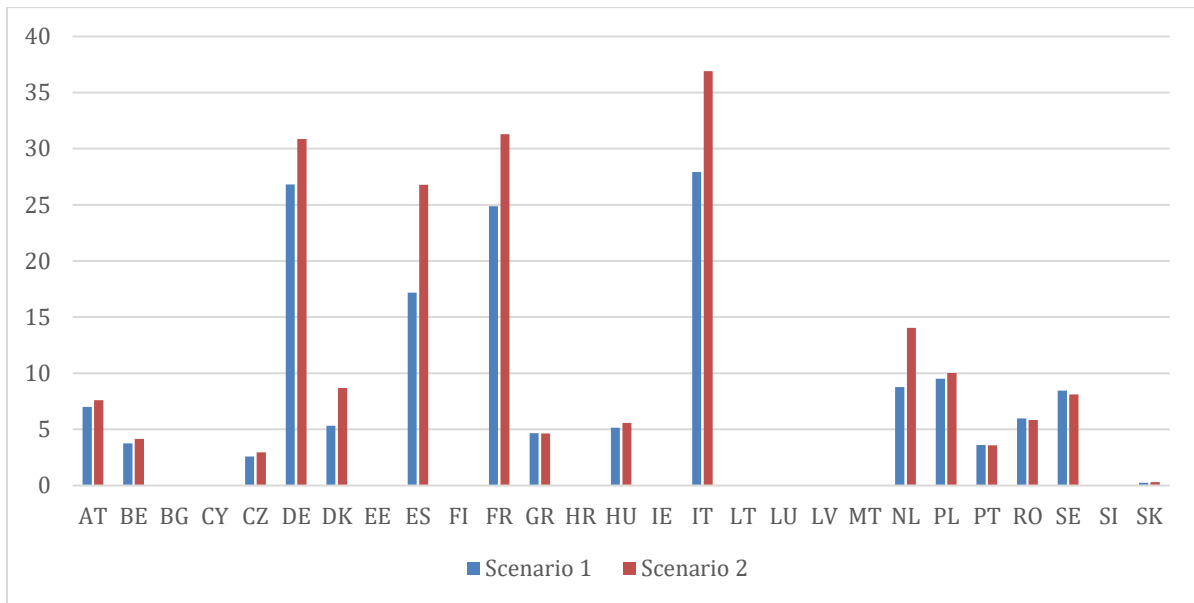


Figure 23: Working gas volumes (TWh) per country in the EU27

As the model optimizes the operation of storage assets, average number of full cycles are also a key output of the model. In particular, it is observed that the increase of imported volumes tends to decrease storage cycling at Pan-European level, from close to 4 cycles in scenario 1 to less than 3 in scenario 4.

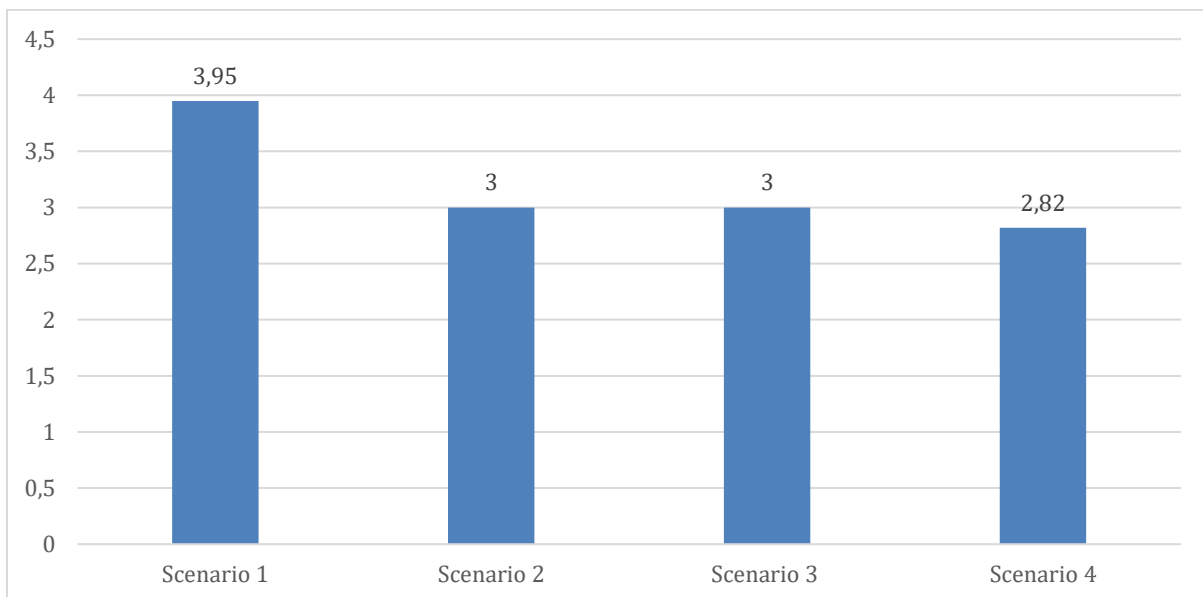
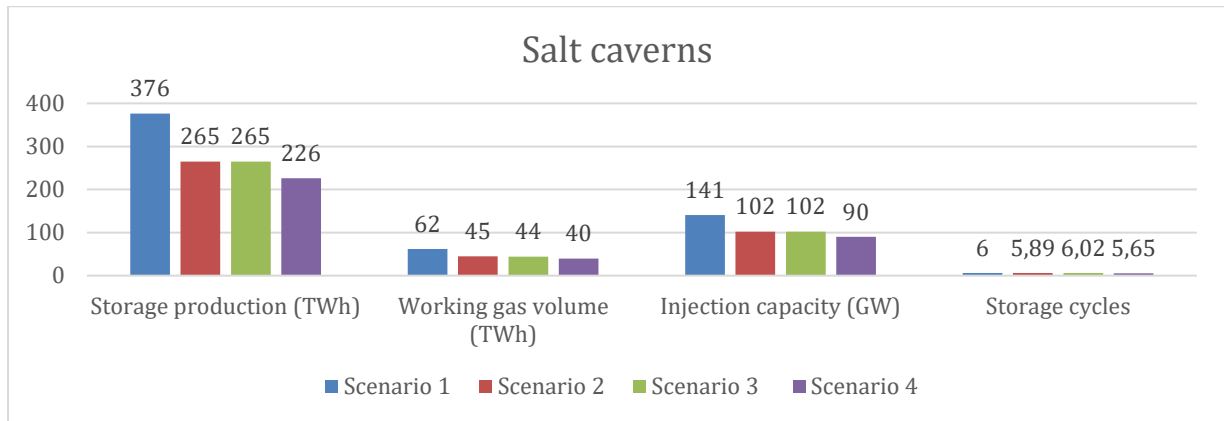


Figure 24: Average number of storage cycles per year for each scenario

As total storage capacities increase in parallel, this illustrates **how seasonal flexibility needs become the main driver of storage investments**, not only because of the seasonality of imports but because seasonal hydrogen storage allows the concentration of hydrogen

production via electrolysis generation within most favorable months of the year (see Figure 18).

This is illustrated by the gradual takeover of “other” types of storage – including both depleted gas fields and aquifers – from scenario 1 to scenario 4, resulting in the predominance of storage technologies with small cycling rates.



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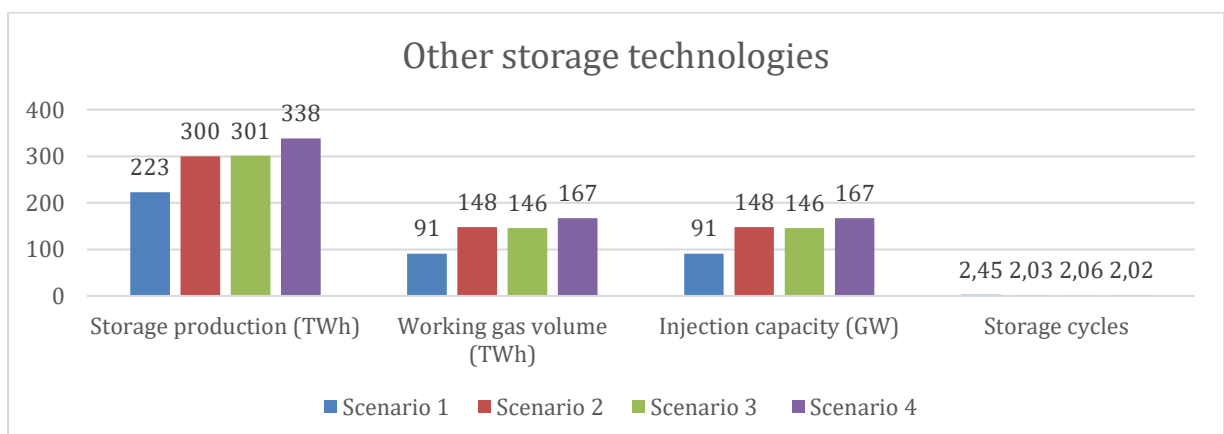
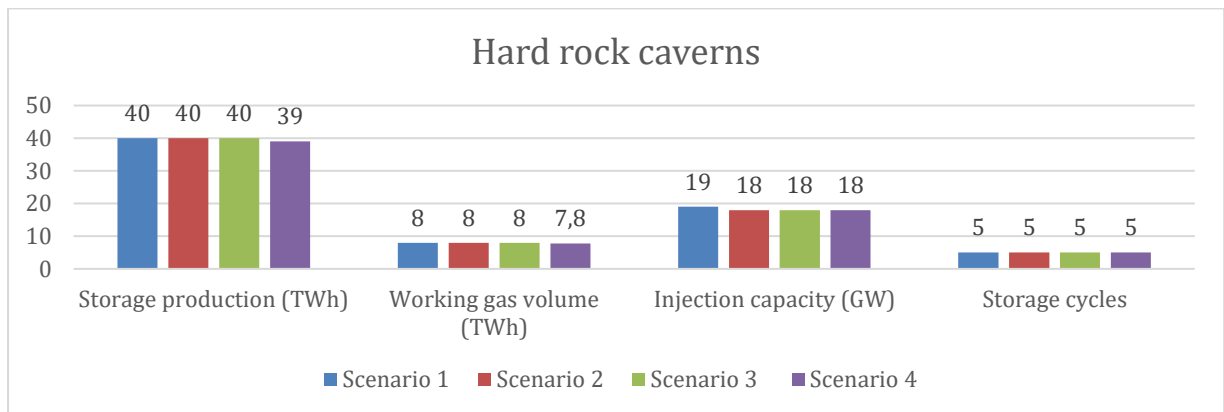


Figure 25: Storage KPIs for each storage technology implemented in the model

3.4 The complementarity between H2 shipping and offshore pipelines tends to stabilize EU-27 transmission infrastructure needs

3.4.1 North African imports tend to consolidate key European H2 supply corridors

The investments in cross-border onshore pipelines increase with imported volumes between scenarios 1 and 2, from 130 to 143 GW in the EU-27 + UK perimeter, with annual flows of **1138 TWh LHV** in scenario 1 and **1254 TWh LHV** in scenario 2.

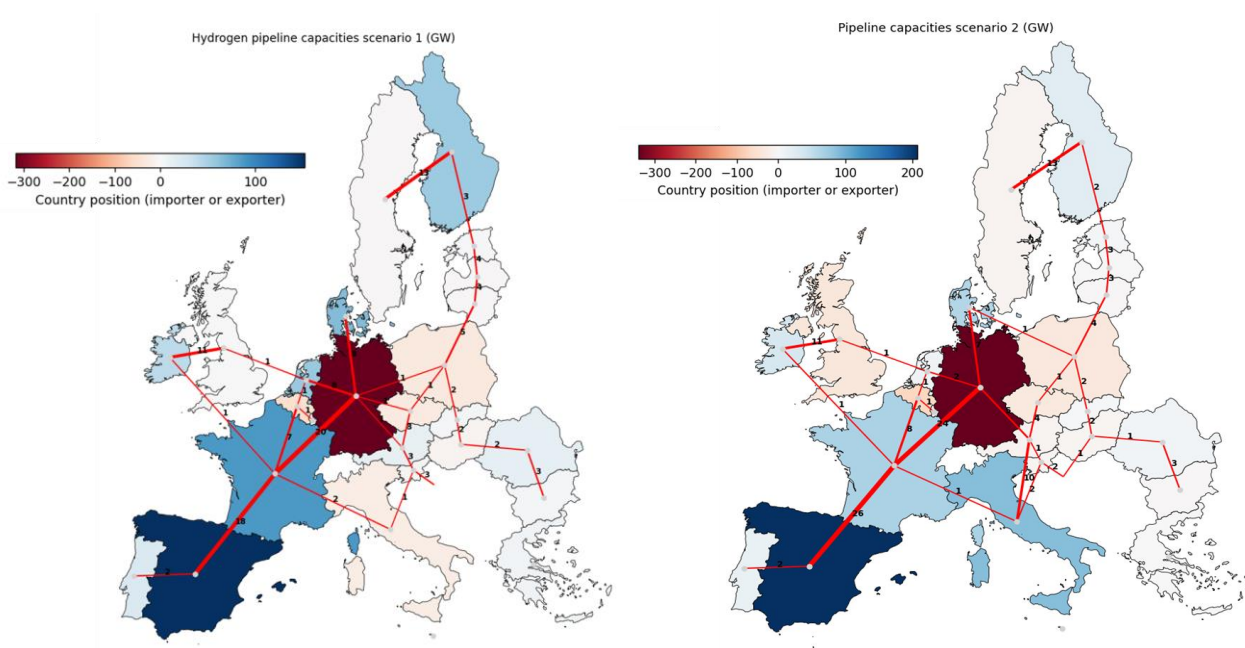


Figure 26: Pipeline investment and national import balances in scenarios 1 and 2

A strong supply corridor is observed in Southwestern Europe in scenario 1, with important volumes being transported from Morocco and Spain towards Germany. As scenario 2 sees a strong increase of imported volumes from Tunisia, a transmission corridor also emerges from Italy to Germany through Central Europe. In particular, Italy evolves from a net importer to a net exporter between scenarios 1 and 2.

The model therefore **confirms the Pan-European H2 supply corridors identified by the EHB initiative** ([European Hydrogen Backbone, 2022](#)), the Italian corridor only appearing if the Tunisian import volumes are sufficient.

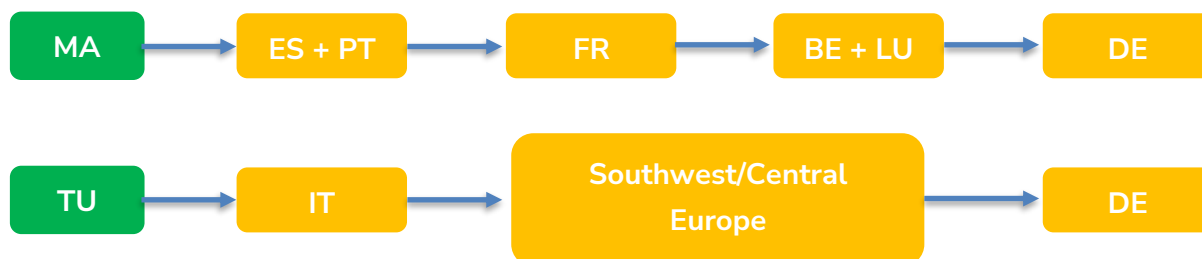


Figure 27: Main hydrogen corridors obtained after optimization for the scenarios with high North African hydrogen imports

3.4.2 EU-27 transmission needs are mitigated by the presence of H2 shipping

In scenarios 3 and 4, the model is allowed to choose between investing in new pipeline capacities and relying on ammonia transportation via shipping. While imported volumes are identical in scenarios 2 and 3, this results in the model prioritizing shipping over the construction of newly-built offshore pipelines for imports in scenario 3, which is also the case in scenario 4.

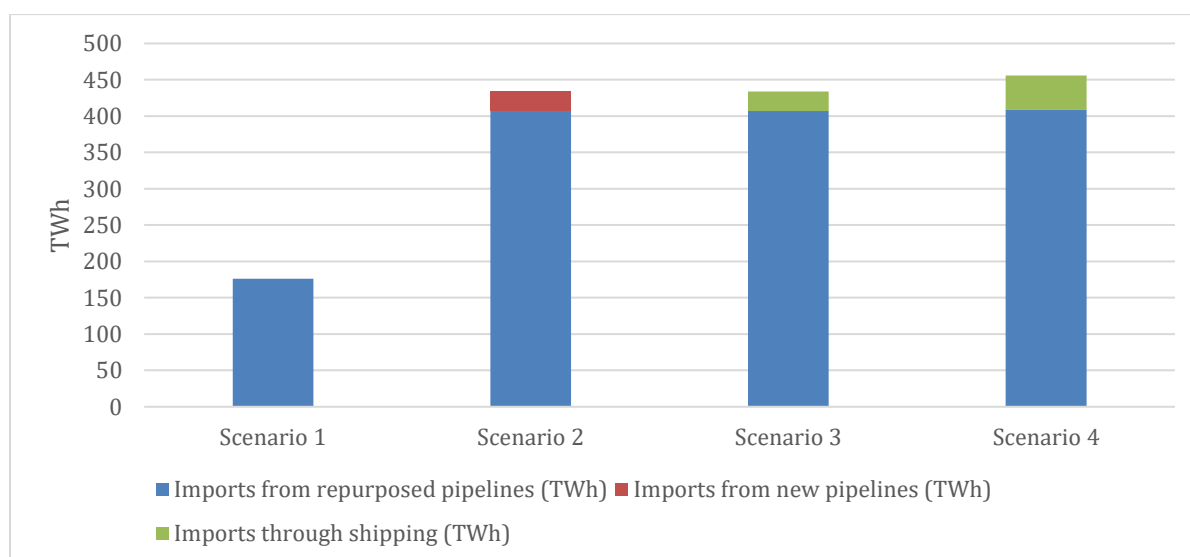


Figure 28: H2 import volumes (TWh) for each transport vector and each scenario

In scenarios 3 and 4, the availability of hydrogen shipping places Germany and the Netherlands as key direct entry points for North African hydrogen imports, which reduces the need for cross-border hydrogen transmission within the European energy system.

This results in a significant decrease of installed pipeline capacities and cross-border flows between scenarios 2 and 3, with investments and flows increasing again between scenarios 3 and 4 but remaining inferior to scenario 2 level – even though imported volumes are more important in scenario 4.

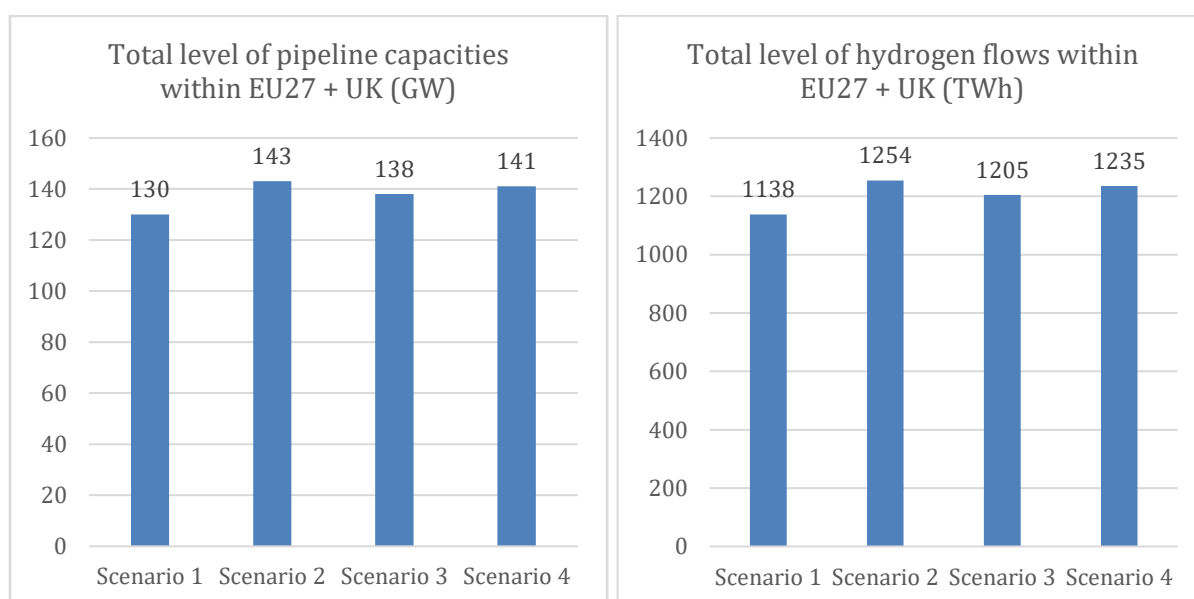


Figure 29: Summary of the state of the hydrogen pipelines network across EU27 + UK for each scenario

In particular, the increase of pipeline capacities between scenarios 3 and 4 is mainly the result of new cross-border capacities between Greece and Bulgaria, Greece becoming a net exporter thanks to the availability of Egyptian hydrogen imports.

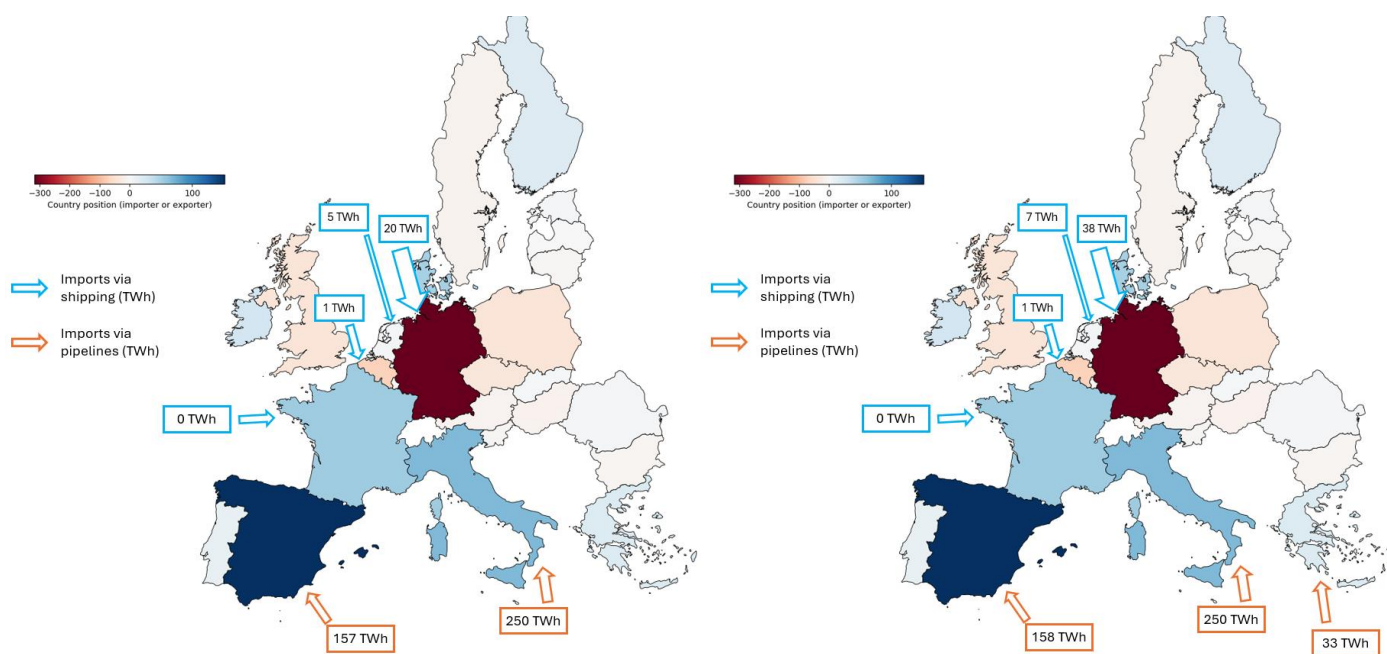


Figure 30: Map of imports and net balances in scenarios 3 and 4

3.5 The possibility of hydrogen shipping allows total investment costs to remain stable with the increase of imported volumes in scenarios 2 to 4.

Investment and operation costs are also an optimisation result from the model. In scenario 1, total hydrogen infrastructure investments represent a total of 29 billion euros per year (annualized costs), which represents slightly less than 0.6 euros per kg of hydrogen consumed in the European energy system.

As shown in Figure 31, total investment costs significantly increase between scenario 1 and 2, with the level of imports from North Africa. This is mostly due to the need for additional transmission and storage capacities, leading in additional investments of 3.8 billion euros per year. This is notably balanced with important operation costs savings achieved within the European energy system – as mentioned in paragraph 5.2.

Once again, the presence of hydrogen shipping as a complement allows for a more limited increase of investment needs, with 2.9 billion euros per year of additional investments between scenarios 1 and 3 and 3.2 billion euros between scenarios 3 and 4.

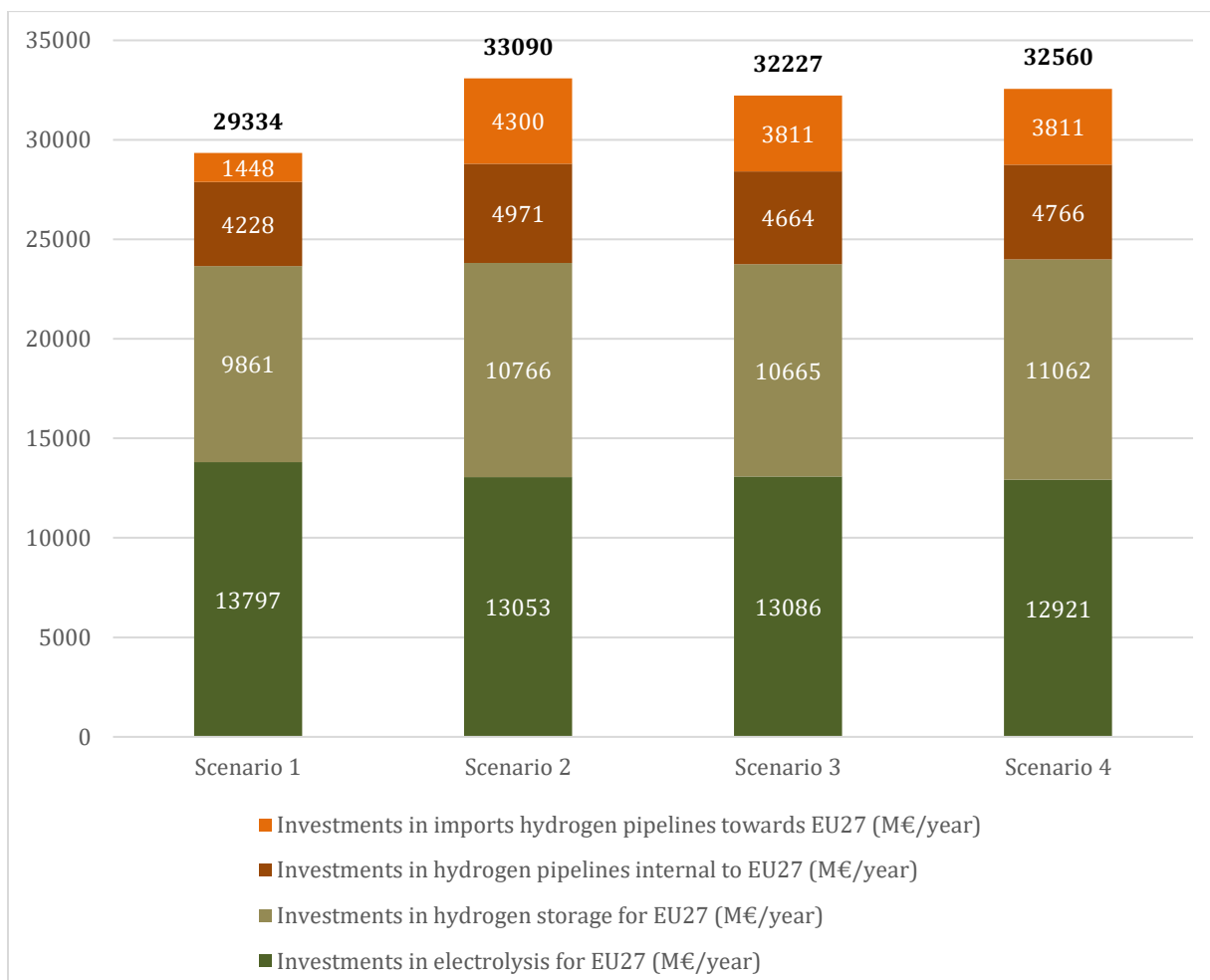


Figure 31: Summary of annualized investment costs in hydrogen production, storage and transport in the EU27 (in M€ per year)



CONCLUSION



Co-funded by
the European Union

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4. Conclusion

The objective of this study is to **assess the impacts of AU green hydrogen imports on the European energy system**. Artelys Crystal Super Grid (ACSG) has been used to model the power and hydrogen layers of the 2050 European energy system, optimizing both the hourly dispatch of all energy technologies and investment options in a catalogue of hydrogen infrastructures and power flexibilities.

Four different imports scenarios are considered, featuring different import volumes from several North and West African regions and different combinations of transport options including new and repurposed offshore pipelines and ammonia shipping.

The study showed that the electrolysis level in EU27 remains quite stable even when imports from Africa increase. Since there is more hydrogen available from import, the power system is less constrained which allows the electrolyzers to become more flexible, concentrating the production more when the electricity prices and CO2 footprints are most favourable. **The hydrogen produced by electrolysis is as a result cheaper and significantly less carbon intensive.**

This shows the need for strong European investments in electrolysis technologies and other hydrogen infrastructures providing flexibility services. In particular, **the constitution of a Pan-European hydrogen infrastructure appears as a no-regret decision** across all scenarios.

The total storage level in the EU27 increases with the North African imports, with **seasonal storage becoming a key driver of flexibility needs** in order to take advantage of most favorable months for domestic electrolytic generation and successfully integrate the imported volumes.

This study also shows that AU green hydrogen imports tend to **consolidate key hydrogen supply corridors across the European energy system**. On the other hand, the complementary between H2 shipping and offshore pipeline tends to **stabilize the transmission infrastructure needs within EU27**. While offshore pipeline transportation remains the main avenue for trans-Mediterranean transportation, the complementary services of hydrogen shipping allows the **total investment costs to remain stable** even with additional imported volumes.

All the results of this report will be a relevant source of information for roadmaps to be setup in WP3, while its results will be cross validated by other WP2 deliverables (e.g. D2.3).

5. Annex

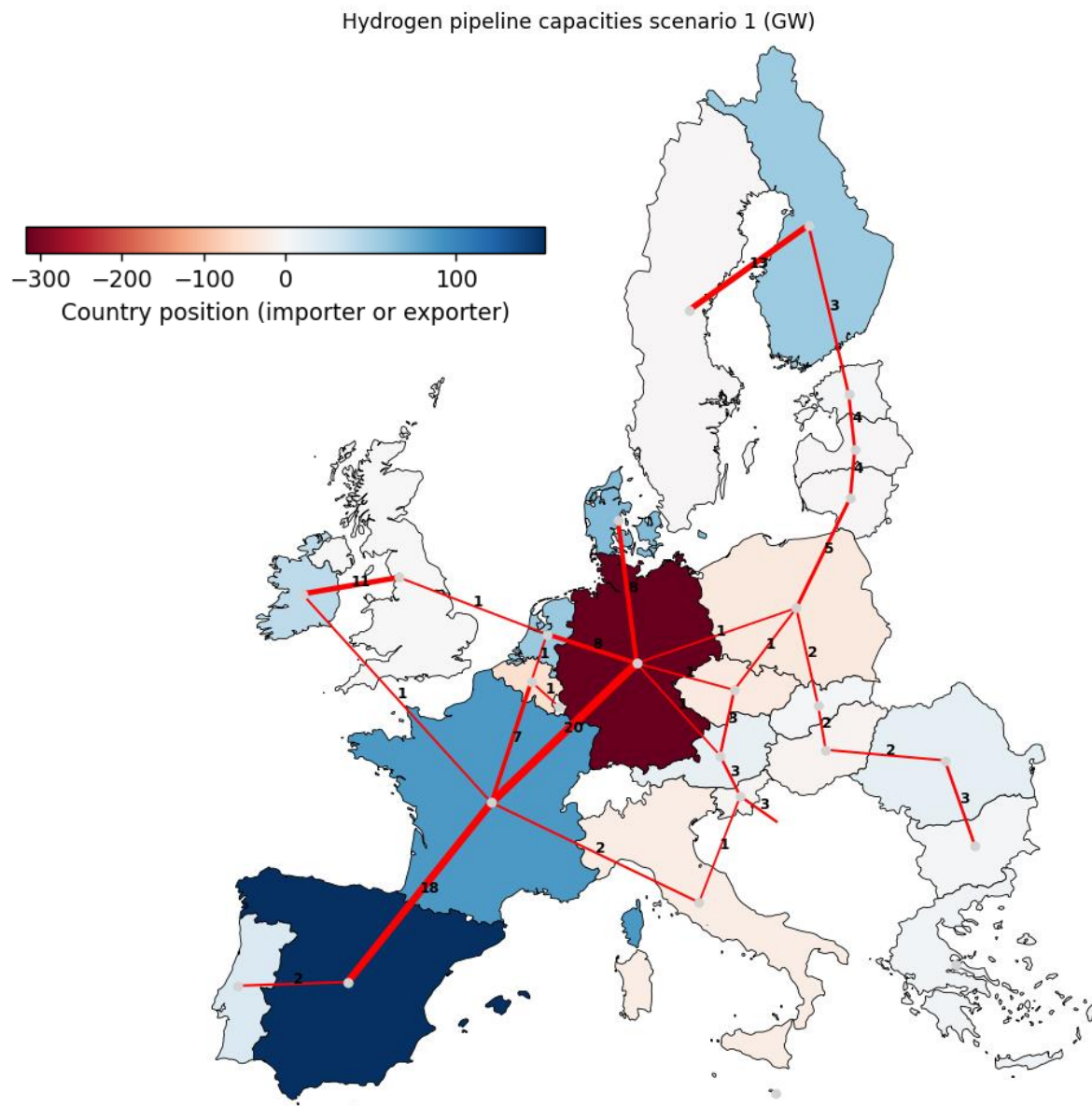


Figure 32: Installed pipeline capacities in the EU27 + UK in scenario 1 (GW)

Pipeline capacities scenario 2 (GW)

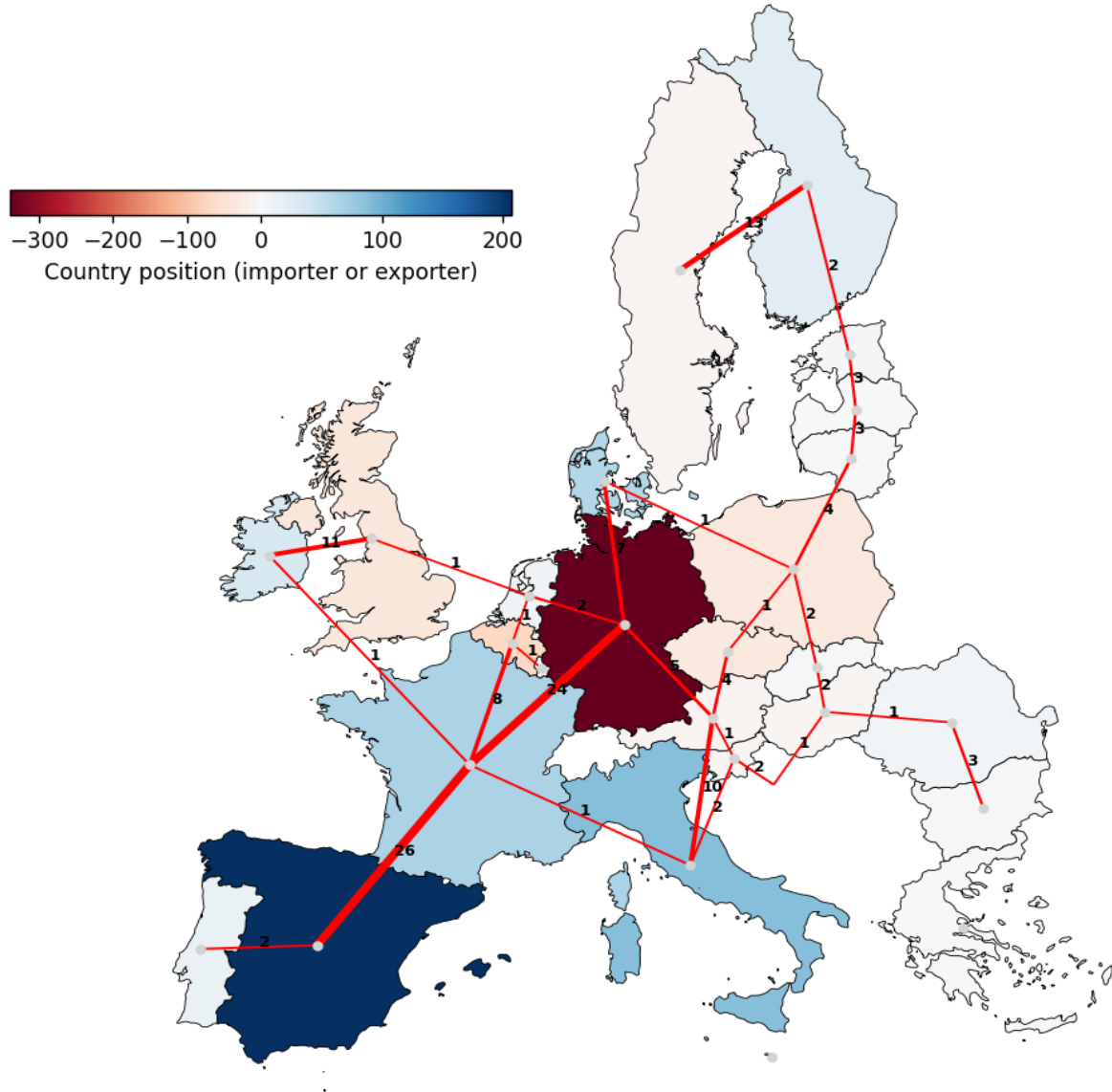


Figure 33 : Installed pipeline capacities in the EU27 + UK in scenario 2 (GW)

Hydrogen pipeline capacities scenario 3 (GW)

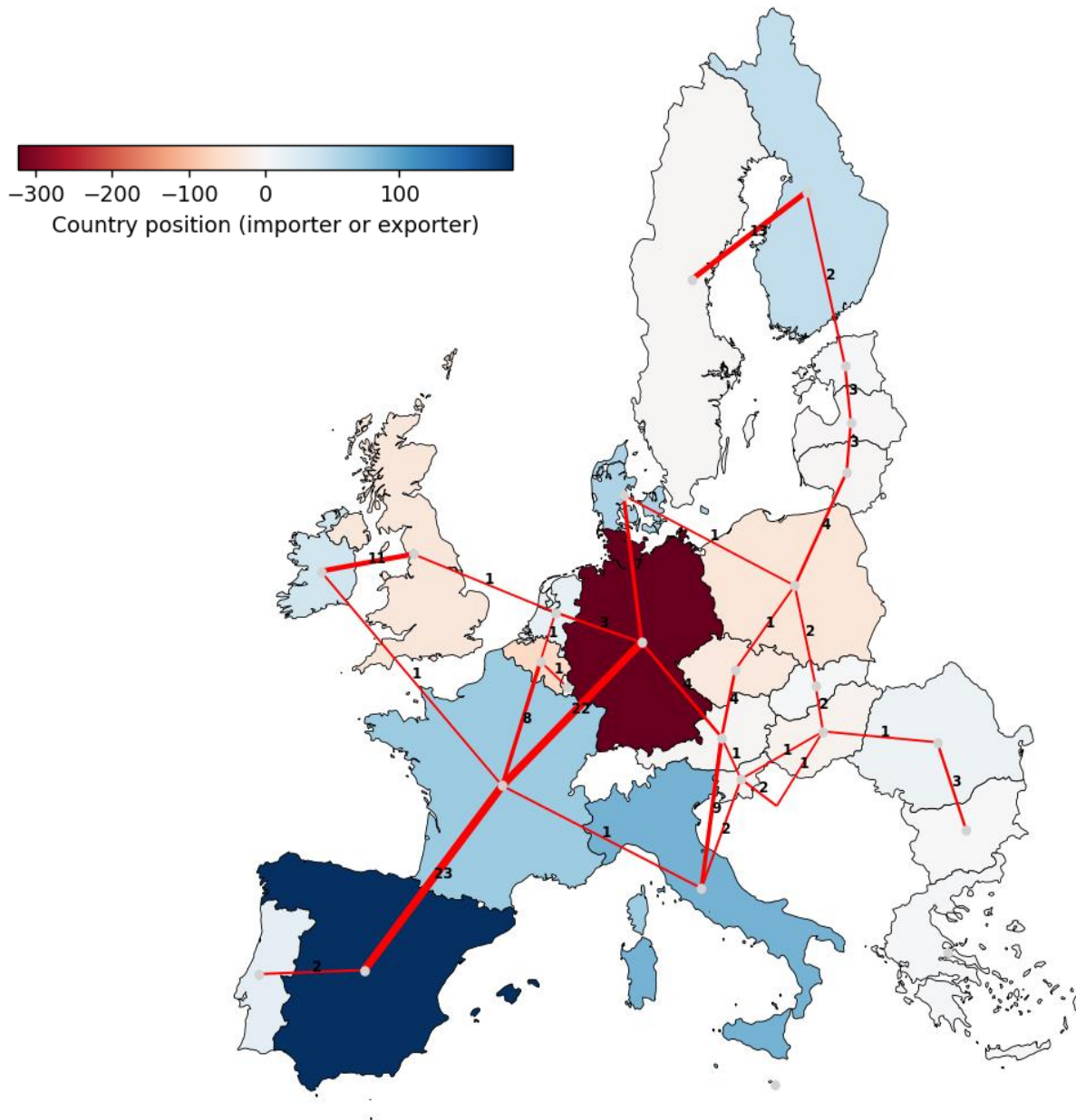


Figure 34: Installed pipeline capacities in the EU27 + UK in scenario 3 (GW)

Pipeline capacities scenario 4 (GW)

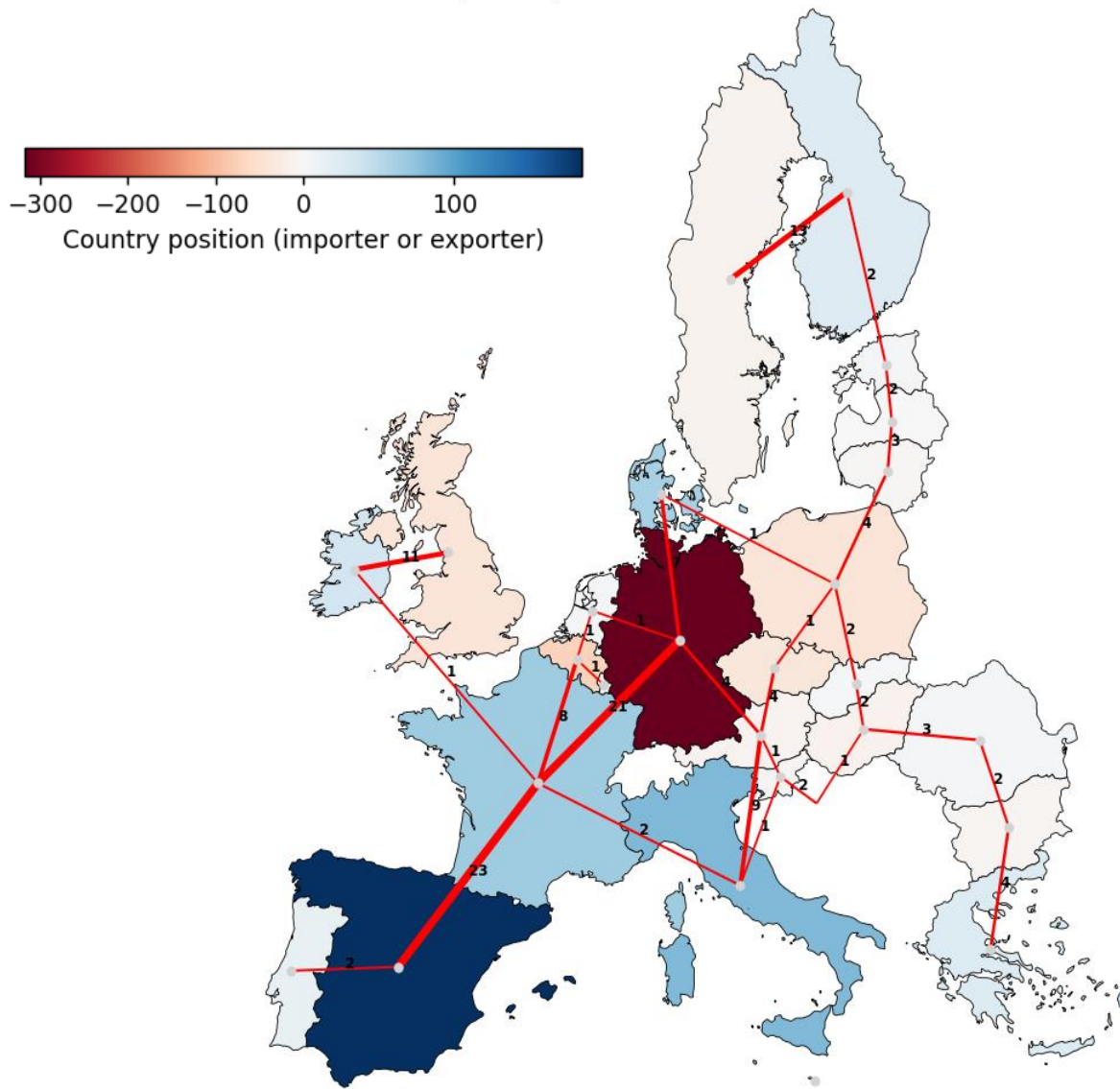


Figure 35: Installed pipeline capacities in the EU27 + UK in scenario 4 (GW)

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