European Commission

METIS 3

Study S8

Assessing hydrogen infrastructure needs in a scenario with hydrogen imports and EU production

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ABBREVIATIONS

Abbreviation	Definition
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
EC	European Commission
EV	Electric vehicle
GHG	Greenhouse gas
HP	Heat pump
LHV	Lower heating value
OCGT	Open cycle gas turbine
P2X	Power-to-X
PHS	Pumped hydro storage
PV	Photovoltaics
RoR	Run-of-river
SMR	Steam methane reformation
V2G	Vehicle-to-grid
vRES	Variable Renewable Energy Sources

METIS CONFIGURATION

The configuration of the METIS model used for this study is summarised in the table below.

METIS Configuration	
Version	METIS v3.0 Beta (non-published)
Modules	Energy system integration module
Scenario	METIS 2030 scenario, based on EC's REPowerEU scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

1 EXECUTIVE SUMMARY

Context and objectives

In a context of renewed interest in hydrogen as a means of decarbonising hard-to-abate carbon intensive economic sectors, the European Commission announced the objective of 40 GW electrolyser capacity by 2030 producing up to 5 Mt of renewable hydrogen in its Communication "A hydrogen strategy for a climate-neutral Europe"[1] (2020). Following the Russian invasion into Ukraine, the European Commission's **REPowerEU[2]** plan (2022) further envisages an accelerated uptake of hydrogen, notably in transport and industry sectors, in order to aim for a phase-out of natural gas imports from Russia by 2027, increasing the hydrogen production target to 10 Mt, as well as 10 Mt hydrogen imports, of which 4 Mt will take the form of derivatives.

The present study aims at assessing the needs for pan-European **hydrogen infrastructure** in the **beginning of the 2030s**, adopting the REPowerEU scenario as main framework of the modelling assumptions.

Methodology

To assess hydrogen infrastructure needs, a **multi-energy modelling environment has been designed in the METIS model**, reflecting the operation and coupling of electricity, gas and hydrogen systems with an hourly time resolution over an entire year (2030). The pan-European model (representing all EU Member States plus major neighbouring countries as individual nodes) optimises the capacities of hydrogen storage, production, and cross-border transmission assets. The analysis relies on a central scenario, designed on the basis of the European Commission's REPowerEU scenario as well as three sensitivity analyses.

Key findings

A pan-European hydrogen network allows to produce hydrogen in the economically most favourable sites and transport it to the places of consumption, and to distribute hydrogen imports to where they are most needed.

The first key finding is that the development of a pan-European hydrogen network is cost-efficient and allows to distribute hydrogen, which is found to be mostly produced where low-carbon and cheap electricity is available. In the central scenario, an 83 GW cross-border hydrogen network is developed. The related finding is that under the modelled scenario, the reduction of natural gas demand enables the conversion of a significant part

[1] (European Commission, 2020)
[2] (European Commission, 2022)

of the natural gas transport infrastructure as 48% of hydrogen cross-border capacity comes from the repurposing of methane pipelines. Furthermore, the hydrogen network allows to allocate extra-European hydrogen imports to the countries where they are most needed.

The flexibility brought by the hydrogen ecosystem allows to better make use of low carbon electricity potentials and to accommodate the variability of Renewable Energy Sources.

The analysis shows that the development of a hydrogen infrastructure allowing to operate the hydrogen system in a flexible way is cost-efficient as benefits outweigh investment costs. In particular, it allows electrolysers to benefit from low-carbon and cheap electricity and to provide demand-side flexibility to the power system.

Both long- and short-term hydrogen storage are needed to enable a flexible operation of the hydrogen system.

In total, 24 TWh of hydrogen storage are deployed in the central scenario, which represents 36 GW of injection and withdrawal capacities. Underground storage in salt caverns and above-ground storage in pressurised tanks complement one another: whilst underground storage tackles seasonal storage dynamics, storing large volumes of energy in correlation with periods of high renewable generation, above-ground storage provides short-term flexibility thanks to their high cycling capabilities.

A pan-European hydrogen infrastructure remains cost efficient in a scenario with lower hydrogen demand compared to the REPowerEU scenario.

Hydrogen infrastructure needs are sensitive to the level of hydrogen demand. Yet, even in a scenario with 50% of the hydrogen demand foreseen by REPowerEU, significant investments in hydrogen pipelines appear, at a level of 65% of the pipeline capacities of the central scenario. The hydrogen corridor ranging from the Iberian Peninsula appears as a no-regret corridor as Spain remains the main exporter in this alternative scenario.

2 Introduction

The "METIS study on costs and benefits of a pan-European hydrogen infrastructure"[3] investigated the needs for hydrogen infrastructure in Europe in 2030 under the MIX H2 scenario which reflects the GHG ambition level of the Fit-for-55 Package and the objectives of the EU hydrogen strategy. The study's key finding was that in the scope of the EU hydrogen strategy **it is economically sensible to set up a pan-European hydrogen transport infrastructure by 2030**. Cross-border integration facilitates regional cooperation and contributes to a substantial reduction in hydrogen production cost by reallocating renewable electricity and hydrogen production to the most favourable production sites. A pan-European hydrogen infrastructure further enables a better convergence of hydrogen prices across EU Member States and reduces the overall need for hydrogen production and underground storage capacities, the latter being a scarce resource restricted to selected Member States.

Following the Russian invasion into Ukraine in February 2022, the European Commission developed the **REPowerEU Plan** aiming for a phase-out of natural gas imports from Russia by 2027 and a significant increase of renewable hydrogen demand in industry and transport by 2030 to reduce the dependency on fossil fuels. Compared to the Hydrogen Strategy, the REPowerEU scenario foresees an increase of EU27 renewable hydrogen demand by 15 million tonnes (Mt), reaching **16 Mt of hydrogen and additional 4 Mt of hydrogen derivatives by 2030**. The REPowerEU plan also differs from the Fit-for-55 package on the supply side, as out of the 20 Mt of hydrogen consumed in the EU, imports are planned to reach 6 Mt in the form of hydrogen and 4 Mt hydrogen in the form of derivatives. Furthermore, the REPowerEU plan aims to **accelerate the development of renewable capacities**, aiming for a 45% share of renewables in final energy consumption in 2030 compared to 40% in Fit-for-55, and further reduce final energy consumption by 4.6% compared to Fit-for-55, reaching 768 Mtoe.

The objective of this study is to provide insights into the development of a trans-European hydrogen infrastructure in the beginning of the 2030s under the REPowerEU scenario. In particular, the study focuses on the development of a dedicated cross-border hydrogen network[4] as well as hydrogen storage, and the cost-optimal allocation of RES and electrolyser capacities.

[3] (Artelys, 2021) In the following referred to as METIS 3 study S3.
[4] Only cross-border transmission pipelines are considered, sub-national transmission and distribution hydrogen infrastructure is out of scope.

3 METHODOLOGY AND MAIN ASSUMPTIONS

3.1 THE METIS MODEL

The METIS model is being developed by Artelys and its partners on behalf of the European Commission.[5] METIS is a multi-energy model covering in high granularity (in time and technological detail) the entire European energy system, representing each Member State and relevant neighbouring countries. Each country is represented as a node and all assets of a given country are aggregated by technology type (e.g., wind onshore, lignite power plants, gas storage, electrolysers, etc.).

METIS includes a database with modelling assumptions, datasets and comes with a set of pre-configured scenarios. These scenarios usually rely on the inputs and results from the European Commission's projections of the energy system, for instance with respect to the capacity mix or annual demand of the different energy vectors. Additionally, new scenarios can also be generated via the capacity expansion features of METIS.

If using a predetermined scenario, METIS allows to perform the hourly dispatch simulations (over the duration of an entire year, i.e., 8760 consecutive time-steps per year). The result consists of the hourly utilisation for the different energy vectors of all generation, storage, sector coupling and cross-border capacities, as well as demand side response assets for electricity.

In addition, METIS can jointly optimise the investments in a large number of technologies together with the dispatch optimisation of the hourly demand-supply equilibrium. Both these capabilities (simulation and investment optimisation) have been used in this study. Figure 1 provides an overview of the workflow. The assumptions related to the key input and output data are presented in more detail in the subsequent section.

[5] See the METIS website for further information (methodology, underlying database, realised studies): https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en

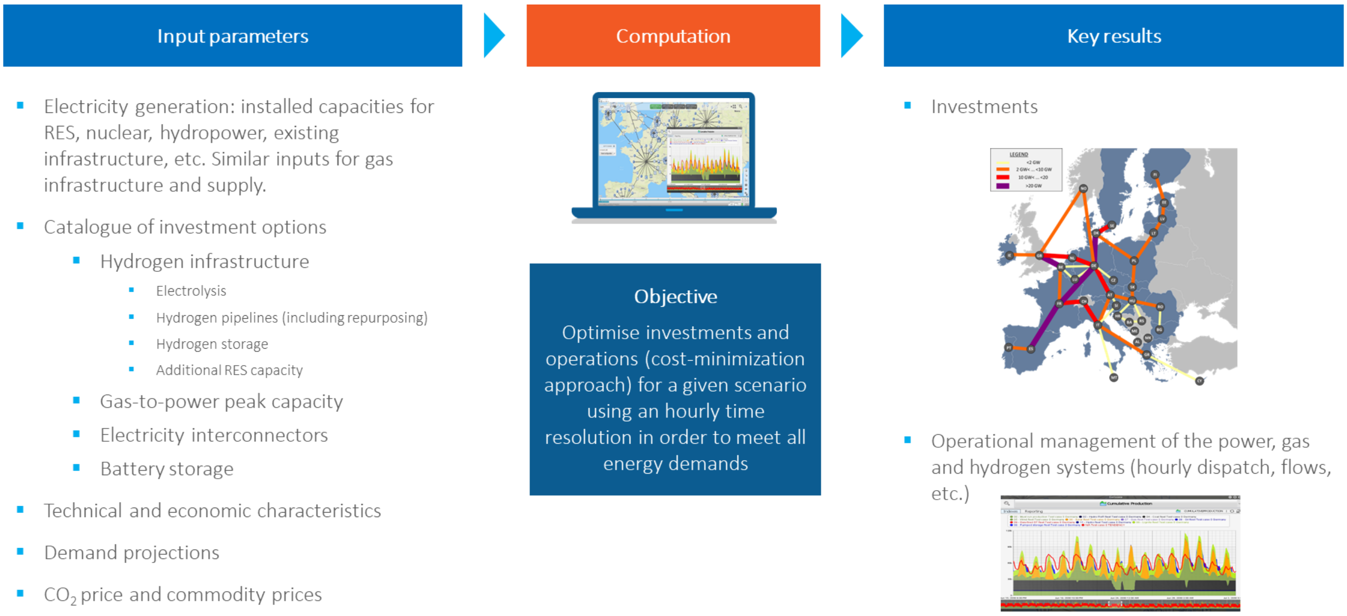

Figure 1: Overview of the general modelling approach

3.2 Modelling the 2030 energy system in METIS

This section provides a general overview of the modelling methodology designed for the purpose of this study.

The optimisation scope of METIS in this study covers hydrogen, electricity, and gas. A hydrogen supply and demand equilibrium are enforced for each hour of the year, similar to electricity and gas. The model represents the European Union, and seven neighbouring countries: Bosnia-Herzegovina, Montenegro, Norway, North Macedonia, Serbia, Switzerland, and the United Kingdom.

Figure 2 provides an overview of all technologies explicitly represented in the METIS model and the interlinkages between the three energy carriers, electricity, gas and hydrogen. Assets are either subject to dispatch optimisation (the model optimises the hourly consumption/production patterns of the considered technology, subject to the techno-economic constraints, based on exogenous capacities) or both capacity and dispatch optimisation (plain circles). In this case, in addition to the optimised operations, the model optimises the level of investments in the technology on the basis of assumptions such as investment costs and potentials.

A single multi-energy optimisation is carried out, with the objective to minimise the total system costs, including both operating costs and capital costs.

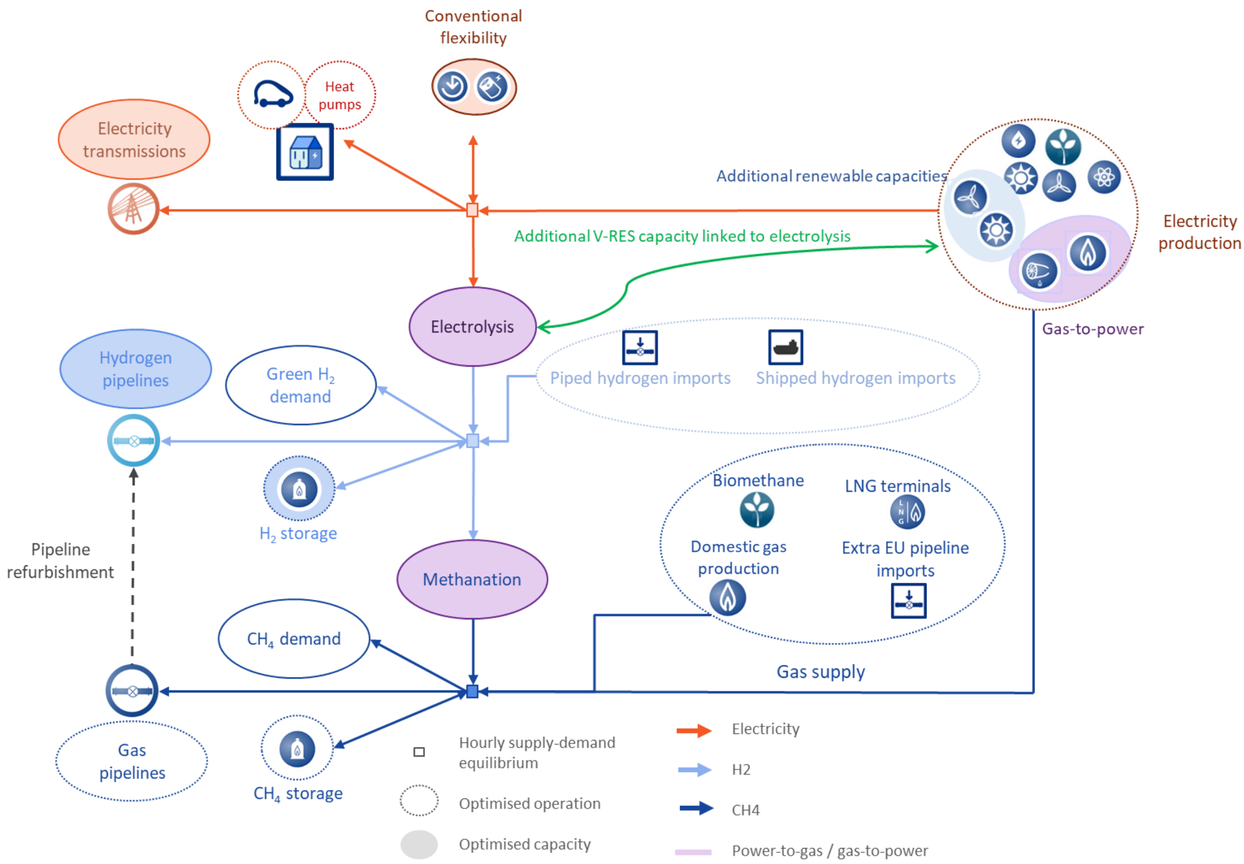

Figure 2: Model of the European energy system in METIS

3.2.1 Modelling the hydrogen system

Hydrogen can be supplied both via electrolysers or via hydrogen imports. Electrolysers are modelled explicitly, linking both the electricity system and hydrogen. Only hydrogen production via electrolysis is reflected in the analysis whereas the conventional production of hydrogen (e.g. via SMR, potentially equipped with CCS, or pyrolysis of natural gas or biomass) is excluded.

The hydrogen infrastructure modelled consists of underground hydrogen storage[6] and above-ground hydrogen storage, as well as cross-border pipelines. For the latter, the model has two options, investing in new hydrogen pipelines or repurposing existing natural gas pipelines[7]. The joint modelling of gas and hydrogen infrastructure allows to reflect the trade-off between repurposing gas infrastructure or using the gas infrastructure for e.g., natural gas, biomethane or synthetic gases.

[6] Only underground hydrogen storage in salt caverns is considered, other geological structures (depleted gas fields, hard rock caverns) are not considered given lower Technology Readiness Levels.

[7] It is only assumed that methane transmission capacities can be repurposed, the model cannot add new capacities for methane.

The electricity consumed by electrolysers is supplied via the market, the model does therefore not strictly constrain electrolysers to be supplied via dedicated renewable capacities, or enforce a temporal correlation between renewable production and electrolysers operation[8]. A constraint ensures that, at Member State level, investment in electrolysers capacities comes with minimum additional investments in renewables capacities: for each Member State, additional wind and solar capacities must exceed 75% of total electrolysis capacity. Electrolysers are also assumed to operate flexibly, allowing them to benefit from low power prices and to provide flexibility services to the power system.

The hydrogen demand is assumed to be non-thermosensitive and is disaggregated at an hourly granularity based on non-thermosensitive gas demand profiles from the METIS database[9].

3.2.2 Modelling the power system

The power system model includes generation technologies, storage, interconnectors, and power demand. The power demand of electric vehicles, heat pumps and electrolysers (which can provide flexibility and whose consumption pattern is determined in the context of the dispatch optimisation) are represented explicitly, while the rest of the electricity demand is based on profiles for thermosensitive and non-thermosensitive end-uses.

The following technologies are subject to capacity optimisation:

- Part of wind and solar capacities can be reallocated compared to the REPowerEU scenario within a limited capacity corridor based on PRIMES capacities for 2030 and 2035[10]
- Cross-border electricity networks can be reinforced compared to existing infrastructure, with limited potentials based on ENTSO-E TYNDP 2020 scenarios and System Needs Study[11]
- Conventional flexibilities are optimised (OCGT, CCGT, lithium-ion batteries)

3.2.3 Modelling the gas system

Gas demand is modelled with a distinction between thermosensitive and non-thermosensitive end uses, it excludes the gas consumption for power generation as capacity and dispatch of gas-fired power plants is optimised endogenously by METIS. Methane can be supplied by pipeline imports, by LNG terminals or by domestic production

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[8] Note however that the cost of CO2 emissions provides an incentive to operate electrolysers in correlation with low-carbon electricity production.

[9] See (Artelys, 2018).

[10] See Annex 9.1

[11] See (Artelys, forthcoming) and (ENTSO-e, 2021)

of natural gas, biomethane (with limited potentials defined by country) or methanation. Gas infrastructures include pipelines, which can be repurposed to transport hydrogen, as well as underground gas storages.

3.3 DEFINITION OF THE CENTRAL SCENARIO AND SENSITIVITIES

The analysis is performed based on a central METIS scenario which is based on European Commission's REPowerEU scenario for the 2030 horizon. Three additional scenarios have been modelled to complete the analysis.

3.3.1 CENTRAL SCENARIO

The main framework assumptions in terms of fuel and CO2 prices, electricity generation capacities, final energy demand are derived from the PRIMES REPowerEU scenario. These variables aligned to the PRIMES scenario are:

- Installed capacities for most of electricity generation technologies
  - Nuclear
  - Hydro
  - Lignite, coal and oil
  - Biomass and waste, geothermal, other renewables
- Final energy demand by energy carrier, decomposed per end-use to properly consider their potential thermosensitivity and flexibility
- Commodity prices
  - Fuel prices (gas, coal, oil)
  - EU-ETS carbon price, at 61 $€_{2015}$/tCO2

These assumptions are complemented with information from public databases, including TYNDP 2020 data for the power system and gas infrastructure:

- Pumped hydro storage capacities
- Existing power transmissions and potentials for additional capacities
- Domestic gas production volumes
- LNG terminals capacities
- Import pipelines and natural gas supply cost curves
- Gas storage and transmission infrastructure

See (Artelys, forthcoming) for further details on the approach for the integration of PRIMES scenarios into METIS.

The following sections describe the main assumptions regarding the hydrogen system that are specific to this study.

3.3.1.1 Hydrogen demand

In the central scenario EU27 hydrogen demand is 536 TWh H2 LHV[12], in line with the REPowerEU scenario. This demand compares to 200 TWh in METIS 3 Study S3, in line with the MIX H2 scenario.

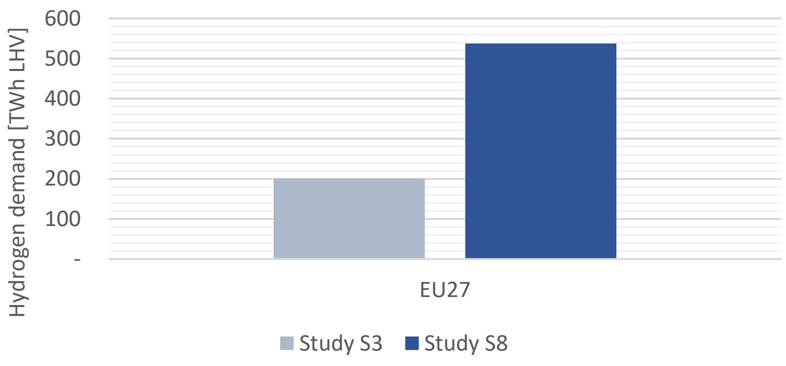

Figure 3: Hydrogen demand for EU 27 under central scenario and study S3 scenario

3.3.1.2 Hydrogen imports potentials

Four hydrogen imports corridors are considered in the modelling. Unlike intra-EU hydrogen pipelines, hydrogen import pipelines are subject to exogenous assumptions based on existing infrastructure and identified import potentials for each corridor:

- Norway to Germany, assuming repurposing of one of the existing offshore gas pipelines (exogenous assumption, approximately 50% of existing natural gas capacity is repurposed to hydrogen)
- Algeria to Italy, assuming repurposing of existing offshore pipeline (exogenous assumption)
- Ukraine to Slovakia, onshore pipeline
- Imports into the Netherlands, via shipping (potentially via liquid hydrogen or cracking ammonia)

For each of these corridors, yearly maximum imports potentials are defined based on hydrogen projects identified by the TYNDP 2022[13] (Figure 3).

[12] The Lower Heat Value (LHV) convention has been used in this study, assuming an energy density of 33,3 kWh/kg H2.
[13] (ENTSOG, 2022)

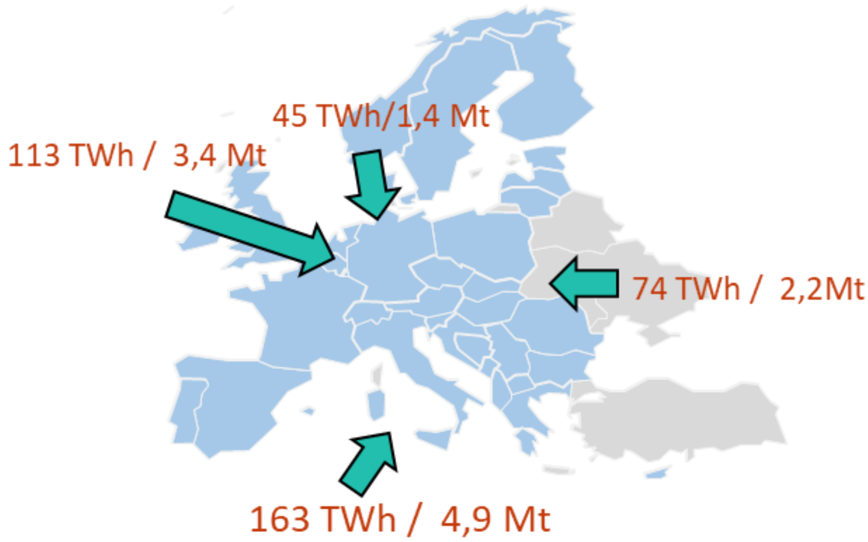

Figure 4: Hydrogen imports potentials under the central scenario [TWh LHV]

The aim of the analysis is not to perform a cost analysis of hydrogen imports but rather to assess where hydrogen imports would be best located in Europe. Therefore, a level of 6 Mt of hydrogen imports is set as a constraint in the modelling exercise, in line with the REPowerEU scenario. The level of hydrogen imports does thus not result from a trade-off between the costs of imported hydrogen and the cost of producing hydrogen domestically. The import corridors are exogenous assumptions, the investment in associated pipelines and import terminals are out of the scope of the analysis.

The model allocates hydrogen imports through these corridors under the constraint that flows through each corridor cannot exceed the corresponding potential, and total hydrogen imports equal 6 Mt. It is assumed that extra-EU hydrogen imports via pipelines are constant over the year whereas shipped imports in the Netherlands can vary across seasons.

The REPowerEU scenario foresees additional imports of 4 Mt hydrogen derivatives (e.g. ammonia or synthetic fuels). As these are to be consumed as such (no conversion back to hydrogen) and do not represent gaseous hydrogen that will transit through a hydrogen transport and storage infrastructure, these additional imports are not represented in the model.

3.3.2 Sensitivity analyses

Two additional scenarios have been modelled to complement the analysis based on the central scenario.

3.3.2.1 Increased CO2 price

In the central scenario, the price of CO_2 emissions is set to 61 €$_{2015}$/t in line with the REPowerEU scenario. This first sensitivity analysis investigates the impact of an increased CO_2 price, at **120 €$_{2015}$/t**.

3.3.2.2 Hydrogen demand

Given the uncertainty regarding the development of the demand for hydrogen, an additional scenario with a reduced level of hydrogen demand is investigated. In this scenario, the hydrogen demand is reduced by 50% compared to the central scenario, reaching 8 Mt H_2. The shares of imports and domestic production are assumed to remain unchanged, i.e., the volume of hydrogen imports is reduced from 6 Mt to 3 Mt.

3.4 SCOPE OF VALIDITY AND LIMITS OF THE MODELLING APPROACH

The modelling approach with the METIS tool presents some limitations to be considered when interpreting results, namely:

- There is a large level of uncertainty regarding hydrogen demand and the uptake of renewables, in particular with respect to allocation between Member States. Different allocations may impact infrastructure needs, depending on the level of colocation between RES and hydrogen. In the present analysis, the cost-optimal distribution is determined, under the given set of assumptions and disregarding other non-economic factors.

- The present study considers 6 Mt hydrogen imports in Europe in line with the REPowerEU scenario. However, the level of uncertainty related to the availability and costs of hydrogen imports remains high. The cost of imported hydrogen and associated infrastructure is not considered in the study as it does not impact the optimisation results.

- Intra-national transport of hydrogen is not modelled explicitly.

- The study focuses on an energy system in 2030 with a hydrogen demand of 16 Mt, therefore it does not capture the additional value a hydrogen infrastructure could have in an energy system with a higher hydrogen demand beyond 2030.

- CAPEX assumptions are subject to high uncertainty as they depend on global market uptake; energy commodity prices and the price for emission allowances are also uncertain.

- The simulations do not include hydraulic modelling to validate the technical feasibility of gas flows (this simplification is a common practice in gas market studies at the European level).

- Defining technical and economical parameters to represent hydrogen storage in METIS requires to adopt a number of assumptions that are homogeneous across countries, e.g. investment cost per kg hydrogen that can be stored, or cycling capacity. In reality, these parameters could vary significantly from site to site. The considered assumptions are not to be seen as exact parameters, but rather as orders of magnitude. These orders of magnitude still allow to compare both underground and above-ground storage technologies.

- The modelling approach does not consider potential additional costs that might result from a flexible operation of electrolysers, such as premature wear, nor ramping constraints. Conversely, it does consider the economic impact of oversizing electrolysers as both investments and operation of the system are optimised.

4 Main findings

4.1 A pan-European hydrogen network allows to produce hydrogen in the most favourable sites and to distribute hydrogen imports to where they are most needed

Hydrogen demand volumes are an exogenous assumption in the model and are derived from the REPowerEU scenario. The main consumers are Germany (117 TWh), France (61 TWh), Spain (53 TWh), the Netherlands (51 TWh), Italy (51 TWh) and Poland (49 TWh). These 6 Member States account for 71% of total hydrogen demand in EU27. The hydrogen production of each country as well as electrolysis capacities on the other hand are results of the optimisation. Figure 5 shows the volumes of hydrogen demand and the volume of hydrogen produced by each Member State.

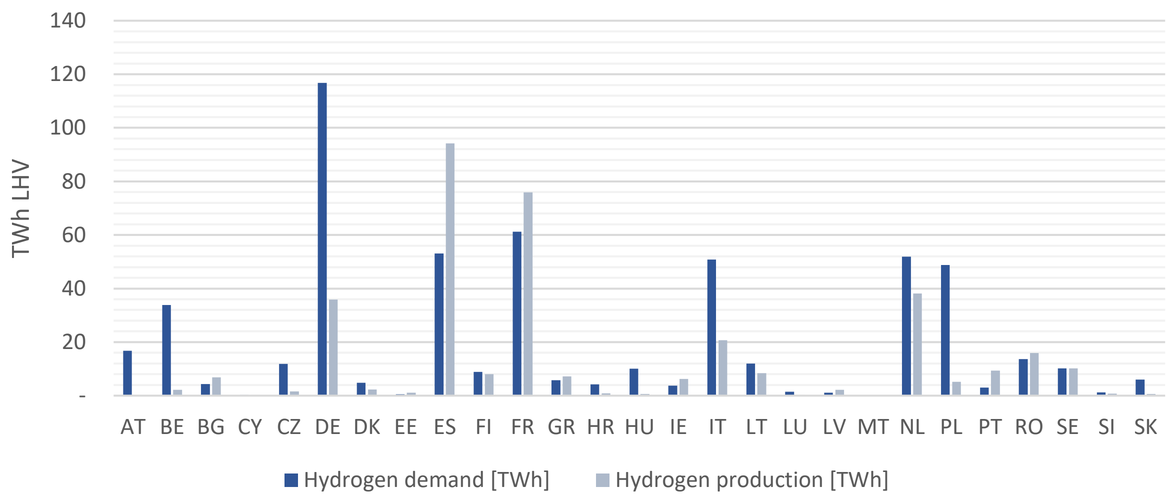

Figure 5: Hydrogen production and demand across EU member states

Three categories of countries can be seen to emerge when comparing the production and demand levels amongst European countries. The first category of countries is net exporters: these countries produce enough hydrogen to meet their domestic demand as well as a surplus for export. This category includes France and Spain which are the main hydrogen exporters and to a lesser extent Portugal, Greece, Bulgaria, and Ireland. A second category of countries includes those which produce a substantial share of their hydrogen demand but require imports to fully meet their demand. These countries notably include the Netherlands, Denmark, and Lithuania. The final category is made up of net importing countries that have little or no hydrogen production, compared to their demand. These countries may have high hydrogen demand and potentially high hydrogen production but supply less than half of their domestic demand, importing the rest. These countries notably include Germany, Poland and Italy and Belgium.

These significant disparities in the levels of hydrogen demand and production translate into hydrogen flows in the European energy system. These flows are mainly driven by the first and last of the categories identified above, namely countries that import or export high volumes of hydrogen.

Figure 6 displays hydrogen imports and exports as well as main hydrogen flows and capacities of the cross-border hydrogen network in the central scenario. The “Net position” background represents the net import/export balance of each country, in terms of hydrogen exports (in blue) or hydrogen imports (in red), while the lines represent net flows between countries (in terms of direction and volume) and aggregated pipeline capacities (pipelines with capacities under 1 GW are not displayed).

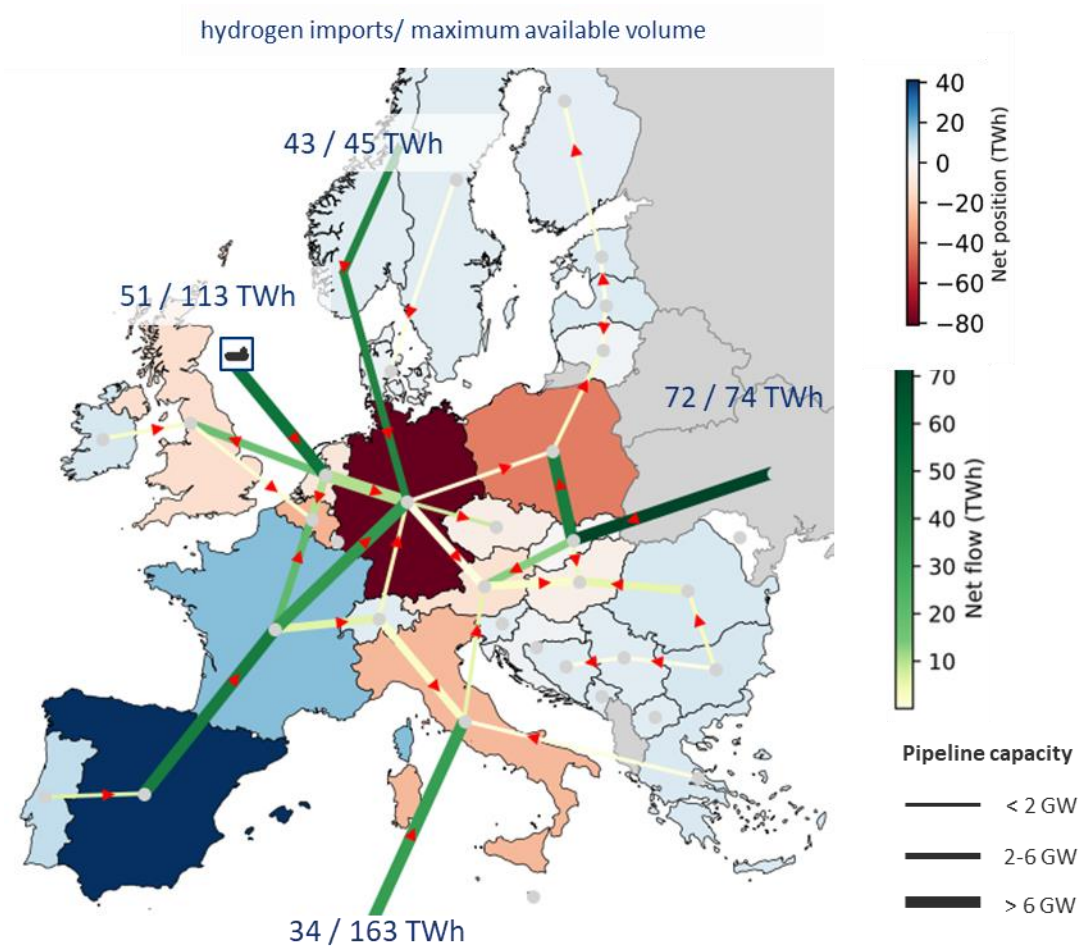

Figure 6: Cross-border hydrogen flows and capacities in the central scenario

Figure 6 illustrates that the main net importing zone is Central Europe, while the main net exporting zone is the Iberian Peninsula associated with France. This regional disparity drives hydrogen flows as pipelines are needed to reallocate both domestic hydrogen production and extra-European hydrogen imports.

Available hydrogen import corridors are not used equally, Ukraine to Slovakia and Norway to Germany corridors are the most used, with respectively 97% and 96% of their potential volume imported, as they are directly connected to Central Europe where hydrogen imports are most needed. A pipeline is installed as an extension of the Ukrainian corridor to reallocate most of the imported hydrogen to Poland which is the main consumer in Eastern Europe. The Algeria to Italy pipeline and the import corridor reaching the Netherlands taken together import a total quantity of hydrogen slightly smaller, but comparable to that transiting through the other two pipelines (85 TWh compared to 115 TWh), but have lower utilisation rates, with respectively 20% and 43% of the available hydrogen volumes imported. As the main potential for domestic hydrogen production is in Western Europe, directly importing hydrogen in Central and Eastern Europe minimises the capacity of the network required to redistribute hydrogen production and imports.

In total, 83 GW of hydrogen cross-border capacities are deployed, almost half of which (47%) come from repurposed natural gas pipelines (Figure 7).

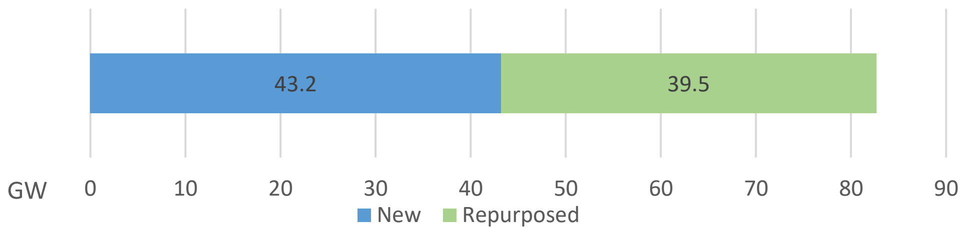

Figure 7: Aggregated cross-border capacity of the pan-European hydrogen network in the central scenario

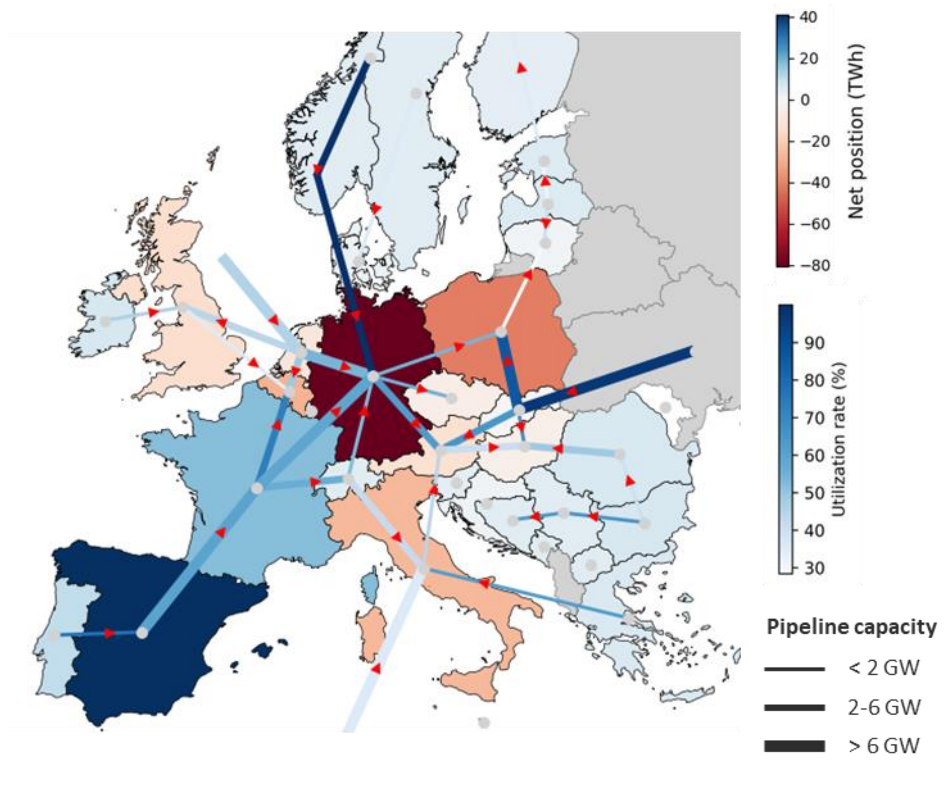

Figure 8: Cross-border hydrogen network capacities and utilisation rates

Figure 8 displays the utilisation rates of the hydrogen network[14]. The red arrow indicated on each pipeline corresponds to the direction of the net flow of that pipeline. The main hydrogen imports corridors showcase high utilisation rates, as well as pipelines that are installed as extensions of these imports corridors, such as the pipelines between Slovakia and Poland or between Germany and Austria. The utilisation rates in the corridor extending from the Iberian Peninsula to Germany and Benelux are of the order of magnitude of 60%. The relatively low load factors of some hydrogen pipelines illustrate a dynamic operation of the hydrogen system, in correlation with VRES power generation. This dynamic operation of the system also translates into bi-directional hydrogen flows that can occur at some borders.

The indicator displayed in Figure 9 analyses the directionality of hydrogen flows at each border. It is calculated by taking the ratio of the flow in the dominant direction to the sum of yearly flows in both directions. A value of 100% thus indicates that hydrogen flows only in one direction while a value of 50% indicates that yearly flows in both directions are equal.

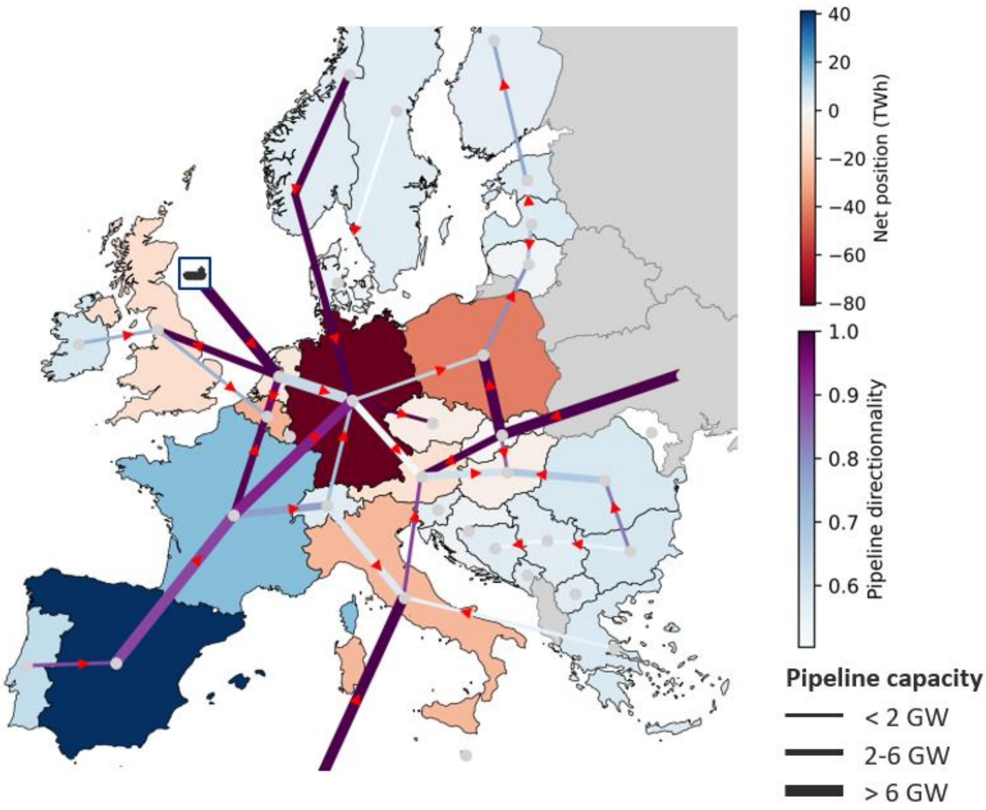

Figure 9 : Directionality of cross-border hydrogen flow in the central scenario

By construction, extra-European hydrogen imports corridors have a value of 100%. The pipelines redistributing hydrogen as extensions of imports corridors also showcase mostly mono-directional flows (see for instance Slovakia to Poland and Austria, Germany to the

[14] When bi-directional flows occur, flows in both directions are accounted for in this indicator.

Czech Republic or the Netherlands to the UK). This also applies to the Iberian Peninsula to Germany corridor.

Bidirectional flows also occur, notably in Central Europe. Such flows can be explained by the sharing of hydrogen storage infrastructure, as not all countries have potentials for underground hydrogen storage. The flows between France and Italy provide an illustration of such dynamics, as the Switzerland-Italy pipeline displays a directionality indicator of 58%. Italy produces part of its hydrogen consumption in order to complement hydrogen imports. Excess hydrogen generation can occur during hours of high-RES availability, the hydrogen production is then stored in France as Italy does not have a potential for underground hydrogen storage[15]. Hydrogen is later reimported from France when needed. Bi-directional flows also illustrate the seasonal dynamics of the hydrogen and power systems, for instance at the Germany-Netherlands border. It is assumed in the model that shipped hydrogen imports can showcase seasonal variations whereas piped imports are assumed to be constant over the year. During summer, a higher solar generation as well as a lower electricity demand for space heating leaving volumes of renewable electricity available for electrolysis result in a higher hydrogen generation in Germany and the Netherlands as more low-carbon electricity is available. As a consequence, a lower level of hydrogen imports is needed during summer months and the Netherlands no longer import hydrogen. Figure 10 displays weekly cross-border hydrogen flows from the Netherlands to Germany (dark blue) and in the opposite direction (light blue). During winter months, the Netherlands import hydrogen, and part of the imported hydrogen is directed to Germany. During summer months, as more domestic production is available, the Netherlands no longer import hydrogen, and the flow between both countries is reversed.

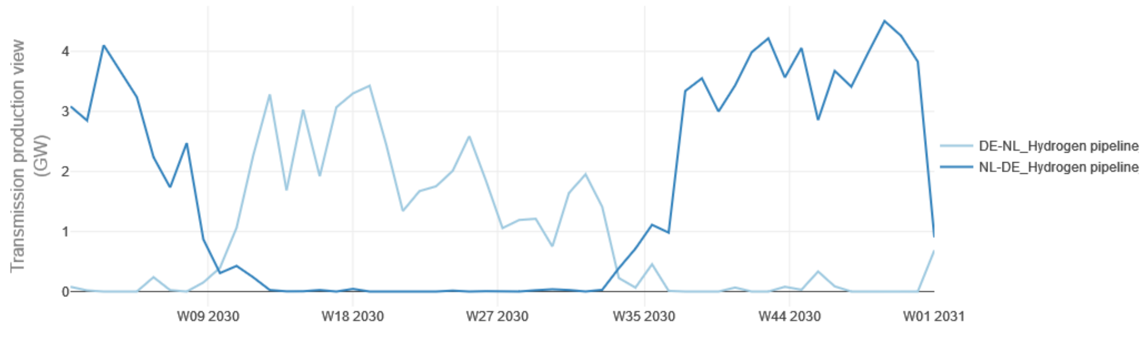

Figure 10: Weekly cross-border hydrogen flows between Germany and the Netherlands

Investments in electrolysis capacities are optimised in METIS. The total installed electrolysis capacity reaches 85 GW H2 LHV (or, equivalently, 127 GW electricity) in the central scenario. The countries where electrolysis develops most strongly are the main

[15]Existing natural gas storage infrastructure in Italy is composed of depleted fields which are assumed to be unavailable for conversion to hydrogen in this study, given the short-term horizon (2030) and lower Technology Readiness Levels for storage of hydrogen in such geological structures.

hydrogen exporters (such as Spain and France) and the main hydrogen consumers (such as Germany, the Netherlands and Italy) as displayed in Figure 11.

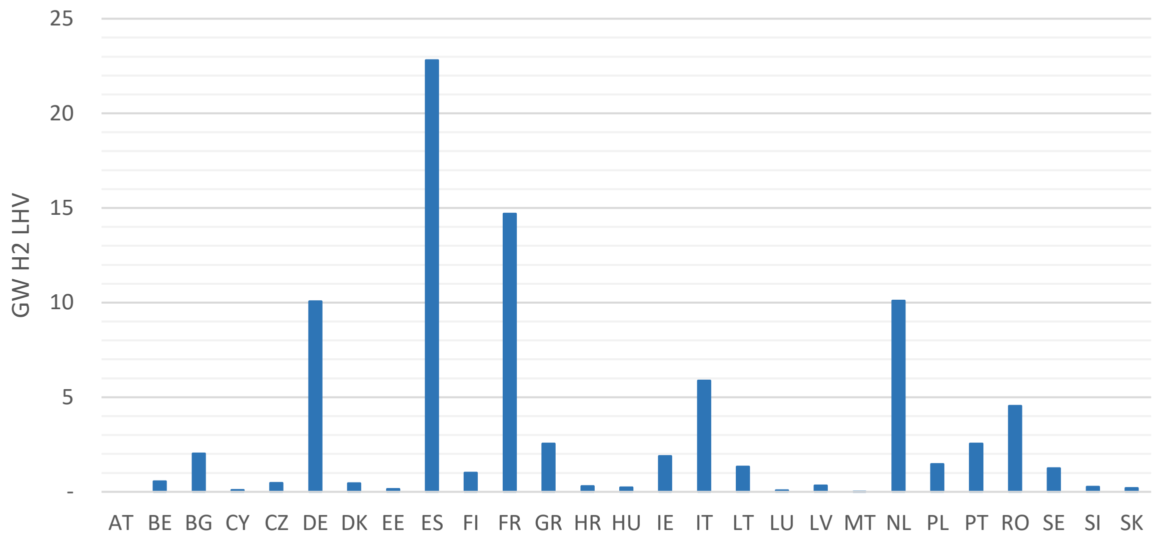

Figure 11: Electrolysis capacities across Member States

4.2 Hydrogen system flexibility allows to benefit from low carbon electricity potentials and accommodate RES variability

Figure 12 displays the distribution of the load factors of electrolysers across Europe (shaded areas correspond to countries with no significant electrolysis capacity or countries that are not modelled). It shows that the capacity-weighted average load factor of electrolysers across all Member States is relatively low (43%) and homogeneous across Europe, which translates the fact that a dynamic operation of the hydrogen system is favourable from a whole system perspective. It is noticeable that a few countries stand out with significantly above-average load factors of electrolysers. These exceptions correspond to countries with large low-carbon and controllable electricity production capacities. Sweden and Finland, with their large hydro and nuclear resources, have load factors of 93% and 91% respectively. The Baltic States also benefit from these low-carbon controllable power generation capacities via imports from Sweden and Finland that account for a significant share of their electricity supply, and thus have higher electrolysers load factors as well. This result is also valid for France, which has a load factor of 59%, thanks in part to its nuclear fleet.

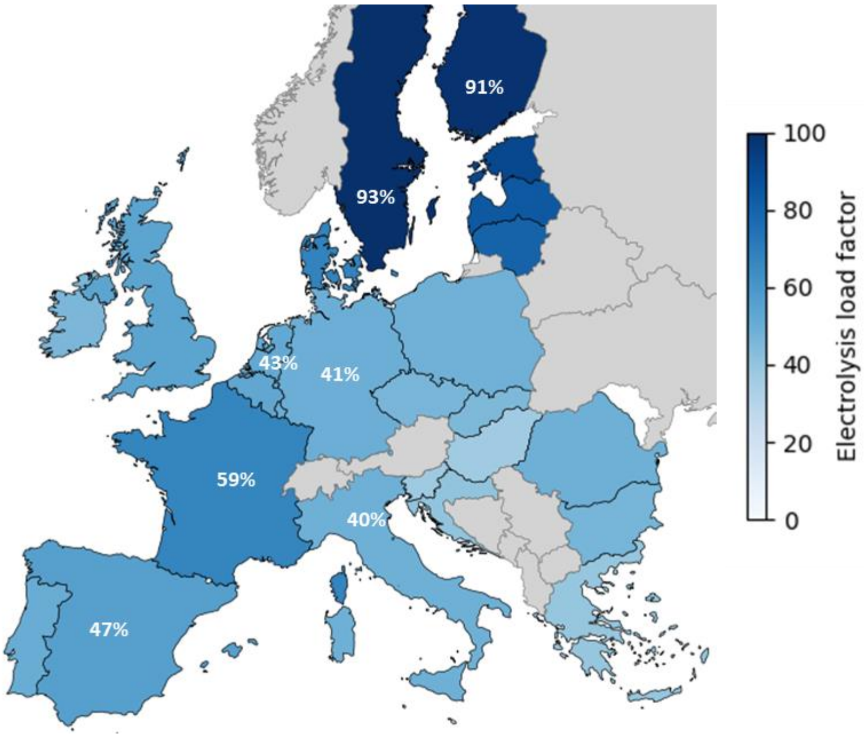

Figure 12: Electrolysers load factor across Europe (central scenario)

This relatively low load factor illustrates the fact that, from a total system cost perspective, it is cost-optimal to oversize electrolysers and to operate them when low-carbon and cheap electricity is available. Figure 13 illustrates this result by comparing the average electricity mix available from the grid (left) to the electricity mix consumed by electrolysers (right)[16] for a selection of Member States. The first observation is that the proportion of low-carbon electricity production increases in the mix consumed by the electrolysers (indicated by the red dash) compared to the average mix. The second is that consumption of non-controllable low-carbon electricity (solar and wind in particular) increases, while consumption of controllable low-carbon electricity (nuclear and hydro) decreases. The flexibility of electrolysers therefore allows to facilitate the integration of renewables and to benefit from periods of high production (daily solar peaks and periods of high wind production in particular). In contrast, hydro resources are preferably used to meet electricity demand during peak hours. The hydrogen produced by electrolysis is therefore preferentially produced during hours of high low-carbon electricity production.

[16] The electricity mix consumed by electrolysers is computed by weighting at each timestep the country's electricity consumption mix by the consumption of electrolysers.

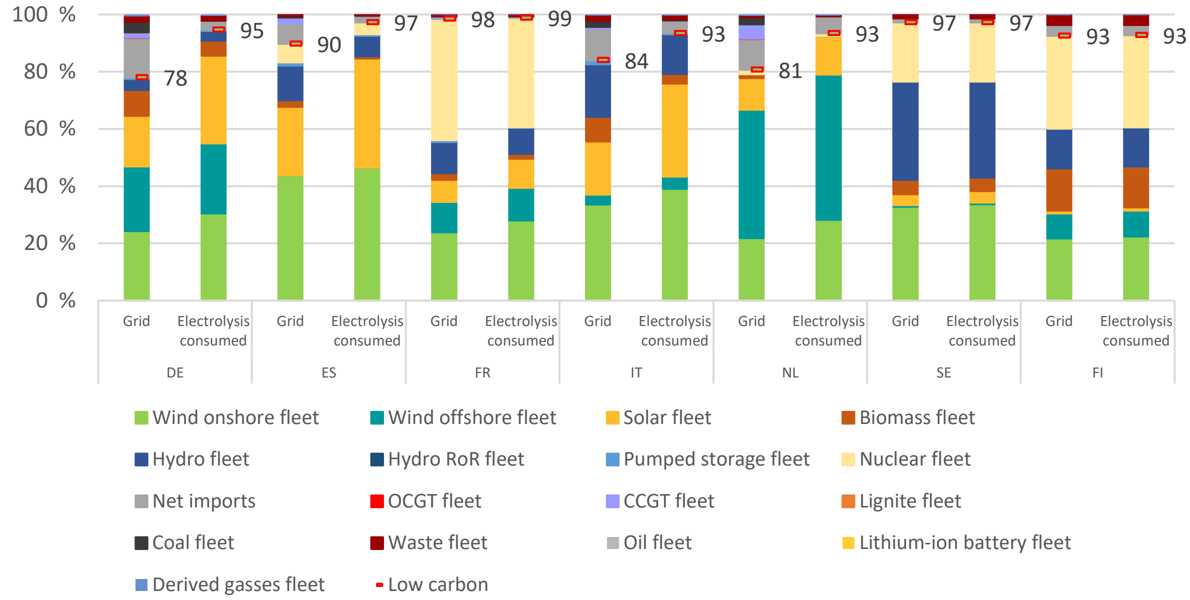

Figure 13 : Comparison of the electricity mix available from the grid and consumed by electrolysers (central scenario)

It is noticeable that despite having similar grid electricity mixes with significant shares of nuclear and hydro capacities, France and Sweeden and Finland present different electrolysers load factors: above 90% in Sweeden and Finland and roughly 60% in France. Different factors can explain this result:

- The share of VRES capacities in the grid mix is slightly higher in France (roughly 43% in France, respectively 38% and 32% is Sweden and Finland), with a higher share of solar capacities. The share of low-carbon dispatchable capacities on the other hand is lower.

- Contrary to France, Sweden and Finland do not showcase potentials for underground storage of hydrogen in salt caverns, which means that storing hydrogen is more expensive[17]. High electrolysers load factors therefore avoid investing in expensive above-ground hydrogen storage capacities.

The correlation between the operations of electrolysers and the periods with low-carbon electricity generation impacts the carbon content of hydrogen produced by electrolysis. Figure 14 shows, for the same countries as above, the average carbon content of electricity available from the grid as well as the average carbon content of hydrogen produced by electrolysis.[18] It is noticeable that despite having different average electricity CO2 contents, all the selected countries produce hydrogen with a low carbon content, thanks to the flexible operation of their electrolysers.

[17] See section 4.3

[18] The average carbon content of hydrogen is computed considering the hourly power generation mix, the consumption of electrolysers, and the yield of electrolysers.

By way of comparison, taking the example of Germany, the average carbon content of electricity available from the grid is approximately 48 kg CO2/MWh. Without the flexibility enabled by the hydrogen infrastructure, i.e. if electrolysers were running in baseload, the average carbon content of hydrogen produced would be 1.6 kg CO2/kgH2[19]. Thanks to the flexibility of electrolysers, the average hydrogen carbon content is 0.06 kg CO2/kgH2, which corresponds to an average electricity carbon content of 1.2 kg CO2/MWh.

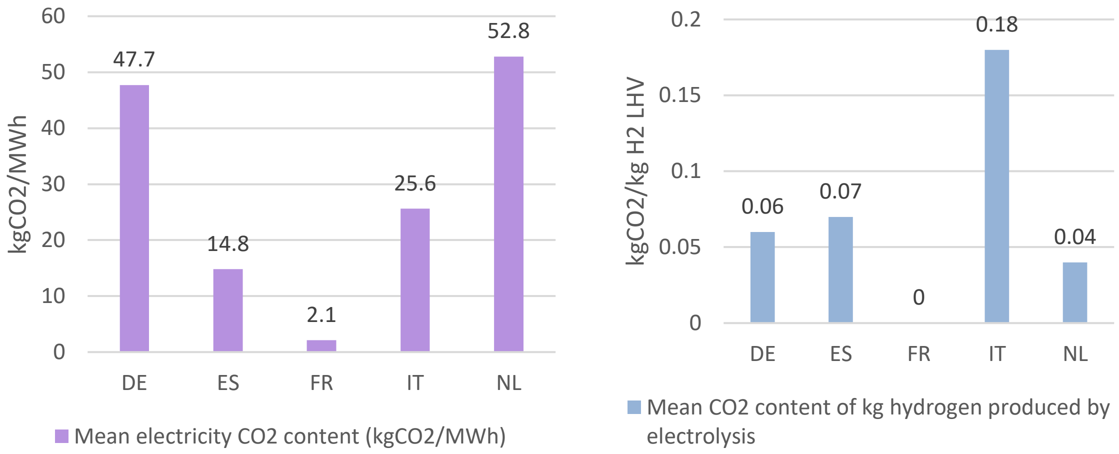

Figure 14 : Average electricity and hydrogen CO2 content across major European hydrogen producers

The graph displayed in Figure 15 presents the link between hydrogen generation and the carbon intensity of Member States' electricity mixes. The x-axis represents the average CO2 content of electricity available from the grid whereas the y-axis represents the share of domestic production in hydrogen demand for each Member State, a value above 100% meaning that the country is net exporter. It shows that overall, the share of domestic hydrogen production tends to decrease when the average electricity carbon content increases. The main hydrogen exporters, namely Spain, France and Portugal all showcase

[19] Considering a yield for electrolysis of 67% and an energy density of 33.3 kWh/kg for H2

low electicity carbon contents. On the contrary, Poland stands out with an above-average electicity carbon content and supplies its hydrogen consumers mostly via imports.

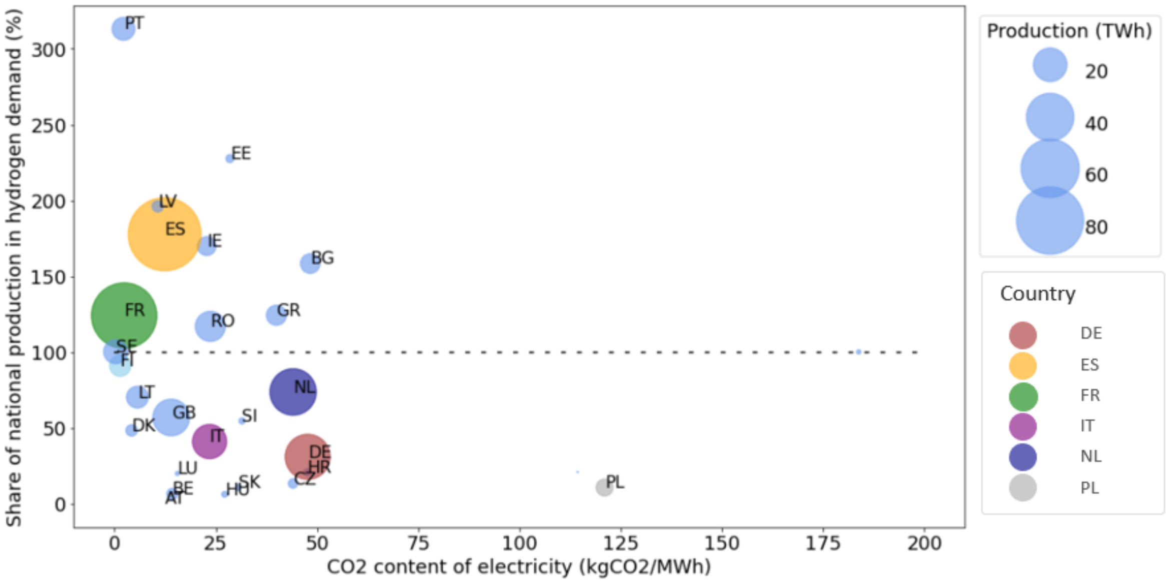

Figure 15 : Correlation between electricity CO2 content, share of national production in domestic demand and hydrogen production

The model can reallocate VRES capacities within a limited capacity corridor based on the REPowerEU scenario. For each Member State and VRES technology, the minimum capacities correspond to capacities from the REPowerEU scenario from which capacities corresponding to the consumption of electrolysers have been subtracted[20]. Additional capacities can then be added endogenously.

In the analysis, electrolysers withdraw the entirety of the electricity they consume from the grid. If the results display a clear link between renewable generation and electrolysers operations, the model does not explicitly constrain electrolysers to operate in correlation with renewable capacities.

The following indicator further investigates the correlation between renewable generation and electrolysers operation, by comparing electrolysers hourly consumption to hourly renewable generation, considering:

- total renewable generation (including hydro),
- total variable renewable generation (excluding hydro, including both pre-existing and added renewable capacities),
- additional renewables generation.

[20] See annex 9.1

	Hydrogen production [TWh]	Exceeding RES generation	Exceeding VRES generation	Exceeding additional VRES generation
DE	36	0%	0%	31%
ES	94	0%	0%	22%
FR	76	0%	1%	12%
IT	21	0%	0%	1%
NL	38	0%	0%	27%

Table 1: Share of hydrogen production in volume produced during hours when electrolysers consumption exceeds renewable generation

Table 1 displays the share of hydrogen production that is produced during hours when the consumption of electrolysers exceeds the different scopes of renewable generation defined above (renewable, VRES, additional VRES). For instance, in Spain, 22% of the hydrogen production in volume is produced during hours during which the generation of added renewable assets cannot meet electrolysers consumption. It appears that, in the selected countries, the consumption of electrolysers only rarely exceeds VRES generation (only 1% of hydrogen production in France). However, when considering only added VRES, a significant share of hydrogen production cannot be covered by added VRES generation on an hourly basis in the optimal solution. A conclusion that can be drawn from this analysis is that constraining an hourly correlation between electrolysers consumption and the generation of added renewable capacities would result in higher total system costs, as it would result in oversizing hydrogen storage and/or renewable capacities.

4.3 Both long- and short-term hydrogen storage are needed to enable flexible operation of the hydrogen system

Both underground hydrogen storage and above-ground storage in pressurised tanks are considered in this study. Underground storage in salt caverns is considered while other types of underground storage assets (aquifers, depleted gas reservoirs, and hard rock caverns) are disregarded due to their lower Technology Readiness Levels for the 2030 time horizon. Table 2 presents the main technical and economic assumptions for hydrogen storage. The METIS model optimises storage and injection/withdrawal capacities jointly, both being linked by the discharge time, which represents the number of hours required to fill/empty the storage at full injection/withdrawal capacity[21]:

$$MaxCapacity_{storage}(MWh) = MaxCapacity_{injection}(MW) \times Discharge\ Time\ (h)$$

The discharge time typically represents the asset cycling capacity, the lower the discharge time, the higher the asset cycling capacity. Hydrogen storage assets injection and withdrawal capacities are assumed to be equal.

	CAPEX (€/kg H2)	Discharge time (h)	CAPEX (€/kW injection capacity)
Salt caverns	27	1000	810
Above-ground storage	535	8	129

Table 2: Main economic and technical assumptions for hydrogen storage[22]

Above-ground storage in pressurised tanks is the most expensive type of hydrogen storage when considering energy storage capacity. However, due to higher cycling capacity, pressurised tanks provide injection/withdrawal capacities at a lower capital cost. The capacity for investment in new salt caverns is limited to a potential derived from (Frontier Economics, Guidehouse, 2021). These potentials represent the availability of salt deposits to build new infrastructures and are relatively high compared to hydrogen demand, ranging from 100 TWh to 9000 TWh. However, the figure might be overestimated as it represents

[21] The METIS model further takes into account the evolution of storage injection and withdrawal capacities depending on the storage level, see (Artelys, forthcoming).

22 Investment costs are derived from (Guidehouse, 2021) for salt caverns and (ENTEC, 2022) for above ground storage. Discharge time is based on existing gas storage for salt caverns and on (ENTSOs, 2022) for above ground storage.

a geological potential and does not consider factors such as social acceptance or potential added costs linked to brine disposure issues.

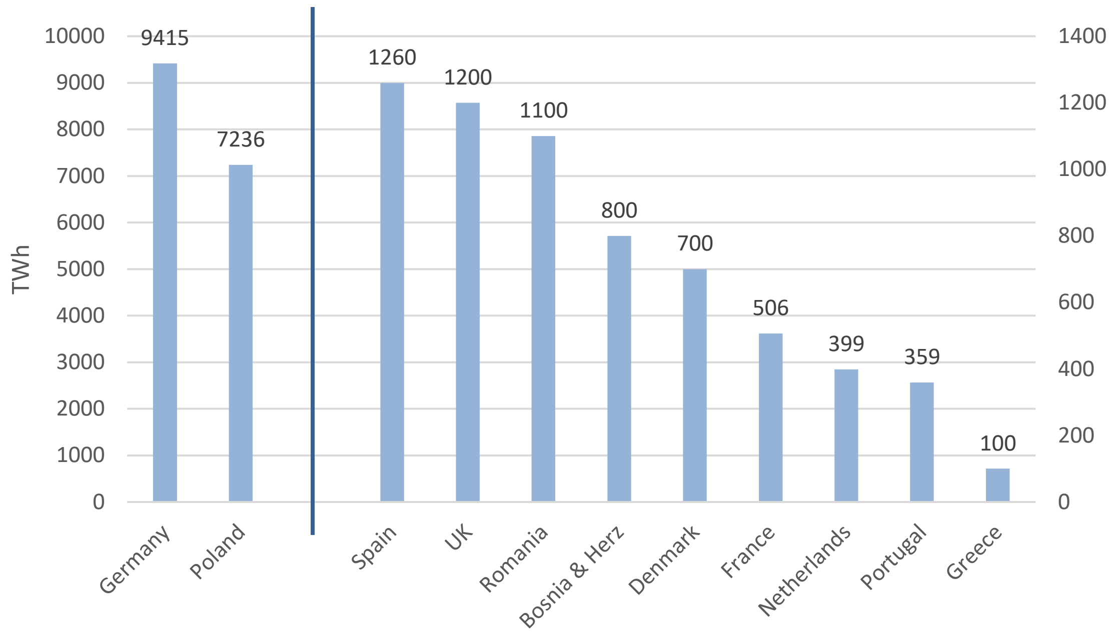

Figure 16: Geological potential for underground hydrogen storage in salt caverns [TW H2]

It is noticeable that underground storage in salt caverns is not available in all countries. In particular, Italy is a major hydrogen consumer but has no salt caverns storage potential, in contrast to other major consumers (such as France, Germany, Poland and Spain)[15].

Figure 17 displays the investments in underground hydrogen storage. The countries installing significant capacities of underground hydrogen storage are both those with suitable geological deposits and those producing large volumes of hydrogen by electrolysis. The main countries installing underground hydrogen storage are France (7.2 TWh), Spain (6.3 TWh) and the Netherlands (6.3 TWh), which together account for 81% of the 24.3 TWh being installed. This volume of hydrogen storage corresponds to a total injection capacity of 24 GW. The total volume of deployed storage is low compared to potentials, as no country exceeds 2% of its potential.

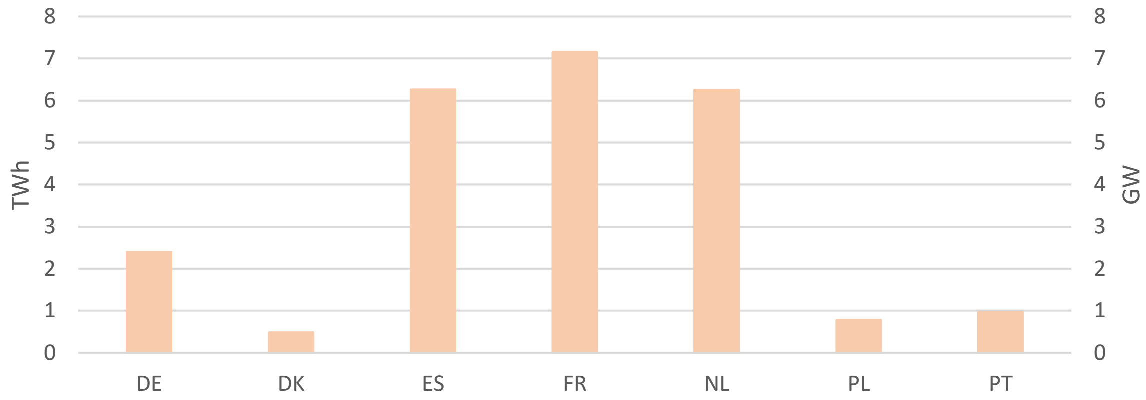

Figure 17: Salt caverns storage (left axis) and injection (right axis) capacities in the central scenario

Above-ground hydrogen storage does not depend on geological factors and is thus assumed to be available in all countries without restrictions. The model results show that this type of storage is preferentially installed in countries with significant solar capacity. In total, 94 GWh (of which 61% in Spain) of above-ground storage are installed. 75% of this capacity is installed in southern countries with significant solar production, namely Spain, Portugal, and Greece. Above-ground storage is also deployed in countries with no salt caverns potentials but significant hydrogen productions, such as Finland or Ireland. The storage volume is negligible when compared to that of underground hydrogen storage (94 GWh vs 24.3 TWh) but corresponds to a total injection capacity of 12 GW, i.e. half that of underground hydrogen storage. Comparing both technologies, above-ground storage is therefore negligible in terms of energy storage, but comparable to underground storage in terms of withdrawal/injection capacities.

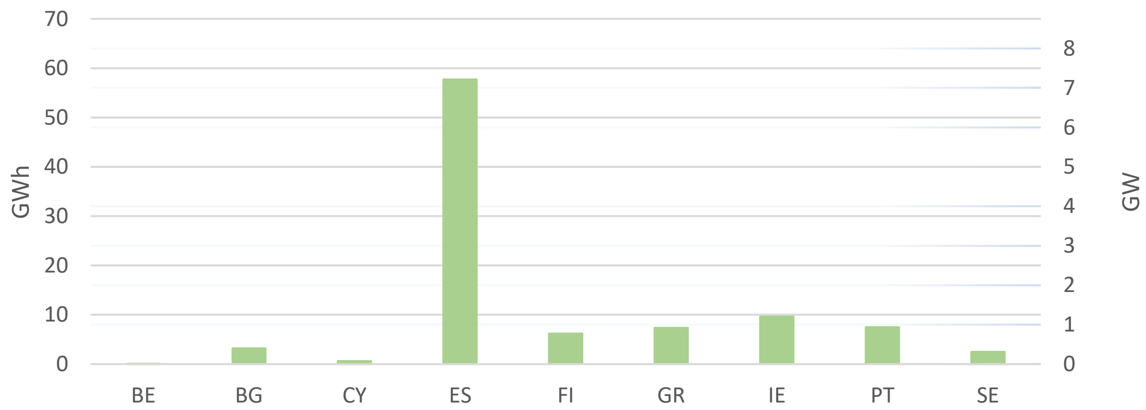

Figure 18: Above ground hydrogen storage, storage (left axis) and injection (right axis) capacities in the central scenario

METIS allows to analyse the hourly operation of all assets, and of storage assets in particular. Figure 19 displays, taking the example of Spain, the dynamics of underground hydrogen storage and the correlation with power generation. It can be seen that the storage level displays **seasonal variations**, and tends to increase during summer. In the displayed example, a period of high wind generation in November correlates with a fast filling of the storage asset.

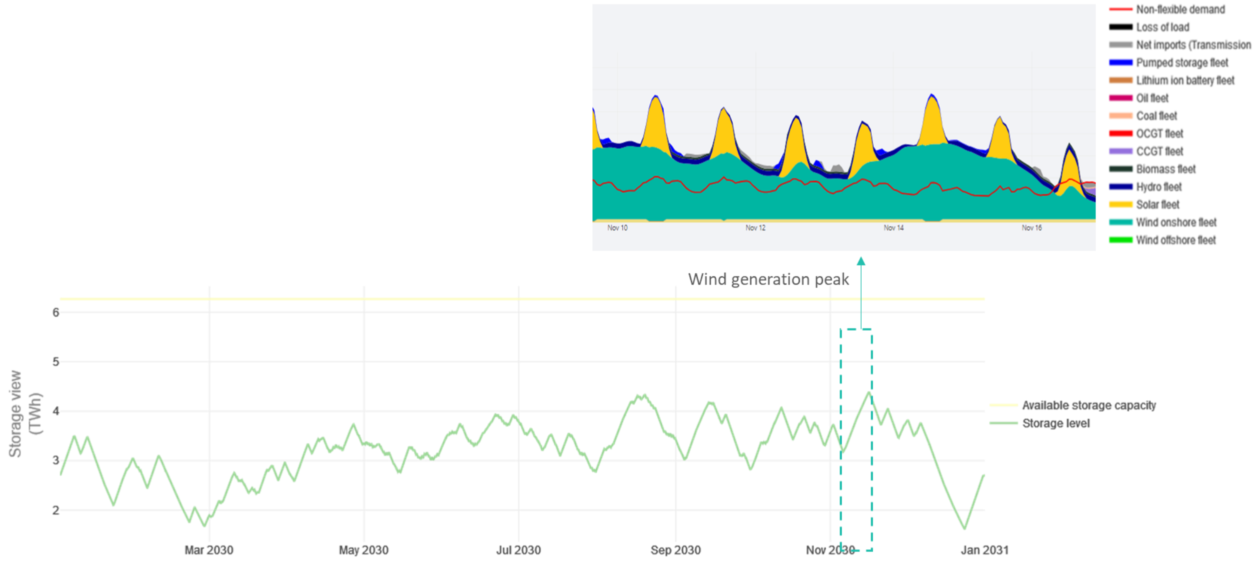

Figure 19: Salt caverns hourly storage level in Spain and dynamics with power generation

Above-ground hydrogen storage, on the other hand, showcases a predominantly **daily storage dynamics**, correlated with solar production. Still taking Spain as an example, Figure 20 shows that during a week in June when solar production is high, above-ground storage adopts daily cycles. The storage is entirely filled during the solar peak at midday and is emptied at the end of the day to meet hydrogen demand.

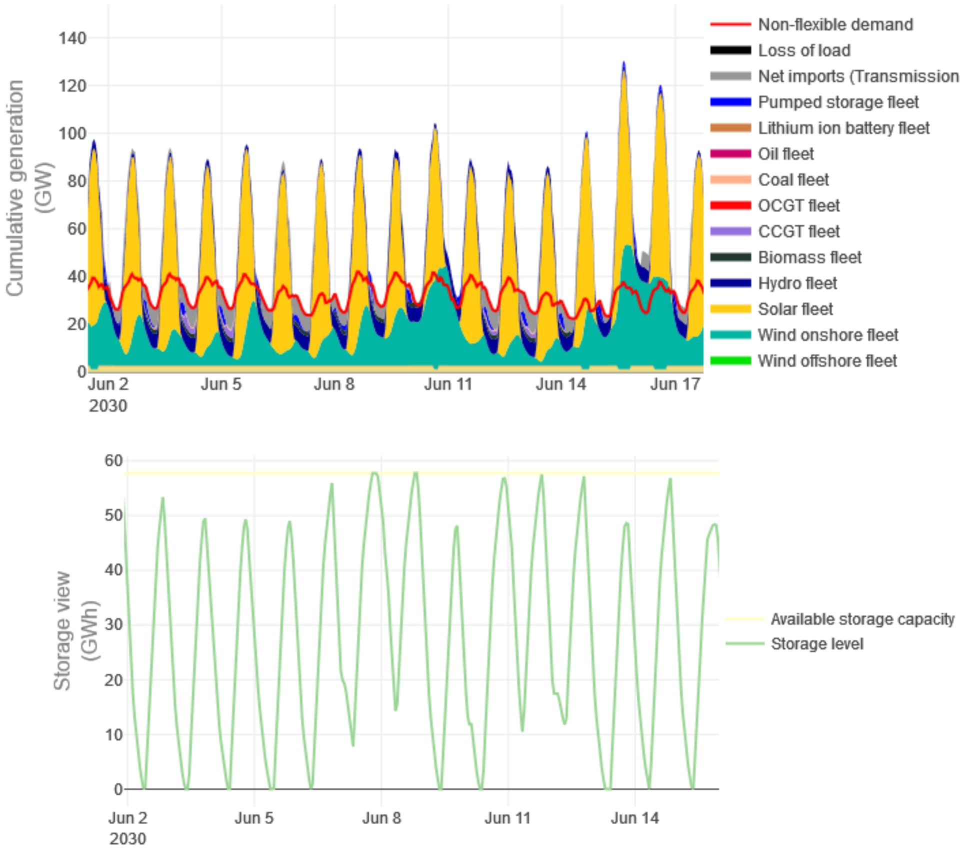

Figure 20: Example of above ground hydrogen storage and power generation dynamics in Spain

Underground storage thus offers long-term storage flexibility for storing energy and then releasing large volumes of hydrogen produced during periods of excess power generation. On the other hand, above-ground hydrogen storage provides high cycling capacities and enables short-term balancing of the energy system.

As a result, underground storage showcases a rather low numbers of annual cycles (i.e. storage asset yearly production compared to storage capacity), of the order of 3 per year, whereas above-ground storage showcases fast cycles (of the order of 250 cycles per year) in correlation with solar energy (Figure 21, Figure 22).

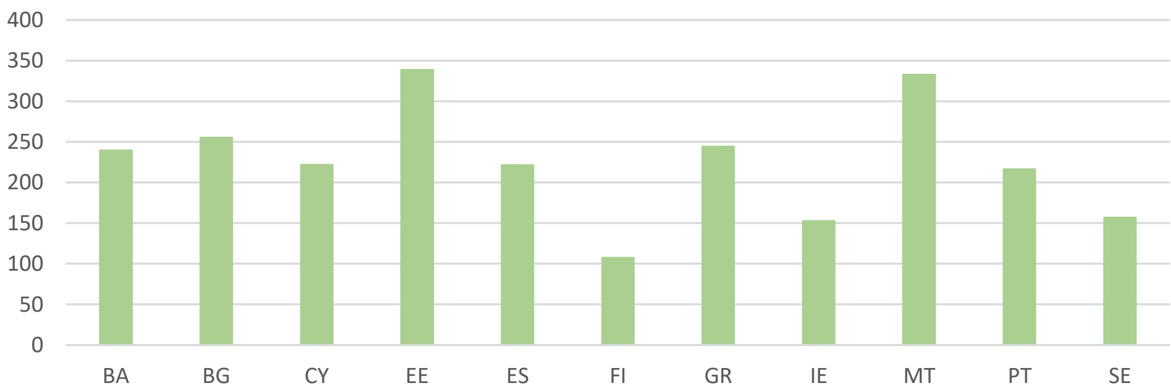

Figure 21: Number of cycles performed by above-ground hydrogen storage

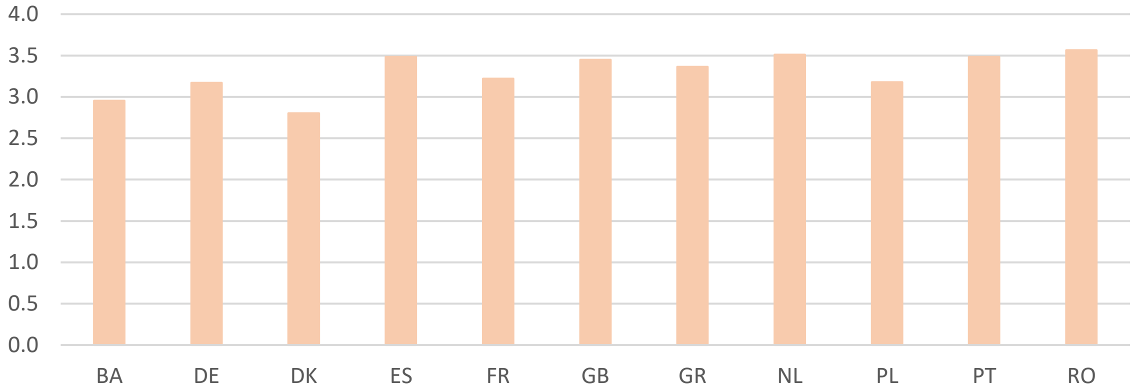

Figure 22: Number of cycles performed by underground hydrogen storage

Considering the total EU 27 hydrogen generation as well as the investment costs in hydrogen infrastructure, the average cost of domestic hydrogen production is computed (Figure 23) [23]. The average cost of hydrogen in the central scenario is approximately 2.9 €/kg. The main cost components are electricity purchase, which accounts for 71% of the cost and electrolysis capacity. The cost of electricity corresponds to an average cost of electricity supplied from the grid of 41 €/MWh. Costs of hydrogen transport and storage infrastructure on the other hand are marginal compared to electricity and electrolysers costs.

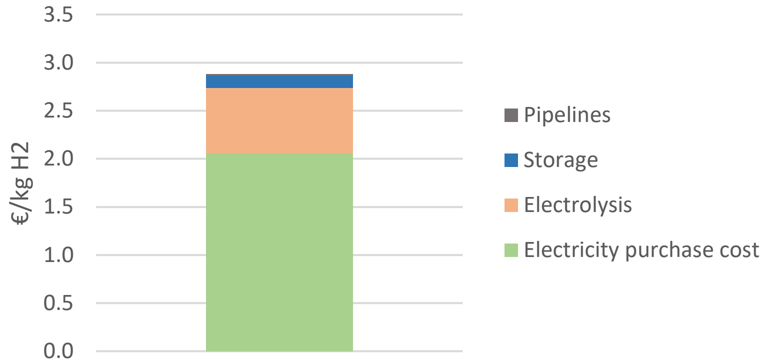

Figure 23: EU 27 Average cost of hydrogen generation[23]

5 INSIGHTS FROM SENSITIVITY ANALYSES

5.1 ADDITIONAL HYDROGEN STORAGE CAPACITIES ALLOW TO INCREASE ELECTROLYSERS FLEXIBILITY AND INTEGRATE ADDITIONAL RENEWABLE CAPACITIES UNDER A HIGHER CARBON PRICE

A first sensitivity analysis investigates the impact of CO2 price, increasing the price of emissions **from 61 €$_{2015}$/t to 120 €$_{2015}$/t**. The increase in CO2 price results in a switch in the power generation merit order, from "coal before gas" to "gas before coal". Most of solids-fired generation is thus replaced by less carbon-intensive gas-fired generation (Figure 23), which results in an overall reduction of CO2 emissions by 11%.

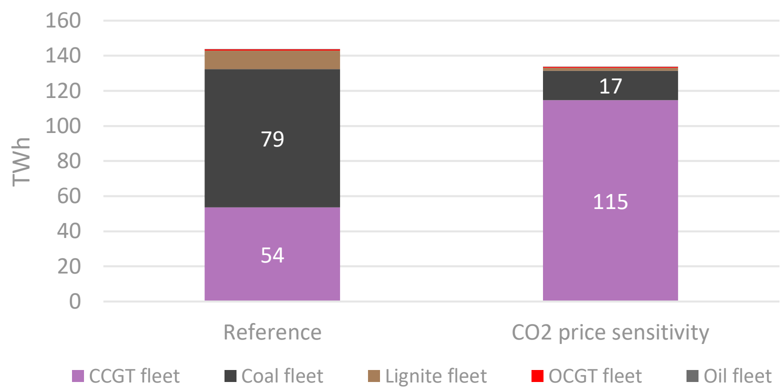

Figure 24: Generation of thermal power plants under central scenario (left) and CO2 price sensitivity (right) [EU27]

[23] To derive this indicator, all hydrogen infrastructure investment costs as well as electricity purchase costs are divided by total hydrogen generation, which represents an average cost of hydrogen from a total system perspective. It is assumed in this indicator that electrolysers supply electricity from the grid, purchased at the hourly market cost of electricity, which is a simplification as in reality electrolysers could also source electricity via e.g., PPAs., which are not represented in the model. The indicator nevertheless gives an order of magnitude for the domestic cost of hydrogen production, as well as the relative importance of the different cost components.

The resulting increase in natural gas use (+105 TWh) impacts the availability of natural gas pipelines for repurposing (Figure 25) as it results in higher natural gas flows (+ 3%). Therefore, part of natural gas pipelines is no longer repurposed (-2 GW), which is compensated by an increased development of new hydrogen pipelines (+ 1 GW). Overall capacity of the pan-European hydrogen network and hydrogen cross-border flows are not significantly impacted by the increased price of CO2.

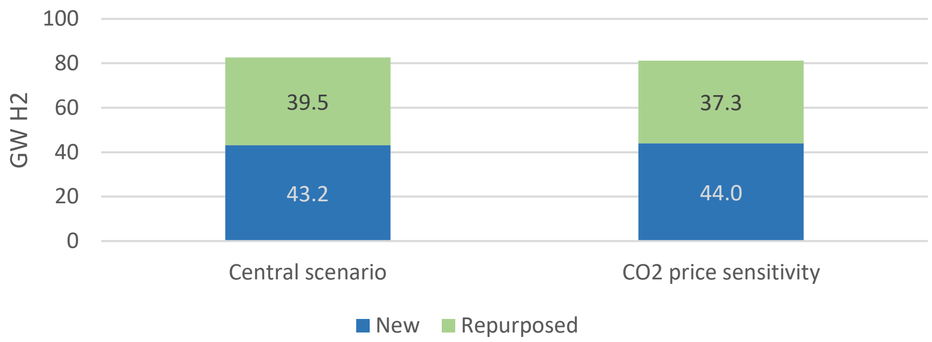

Figure 25: Changes in aggregated hydrogen pipelines capacities under CO2 price sensitivity

In addition to the fuel switch from solids to natural gas, total thermal generation slightly decreases under CO2 price sensitivity, from 144 TWh to 134 TWh (Figure 24). The reduced thermal power generation is compensated by an increased development of VRES capacities, from 1 252 GW to 1 263 GW. In particular, wind onshore capacities in Germany and wind offshore capacities in the Netherlands increase significantly (respectively + 20% and +4%), which is partly compensated by a decrease of solar capacities in France (-19%) as a part of French hydrogen production is reallocated to Germany. Overall wind and solar generation increase by 30 TWh (+ 1.3%).

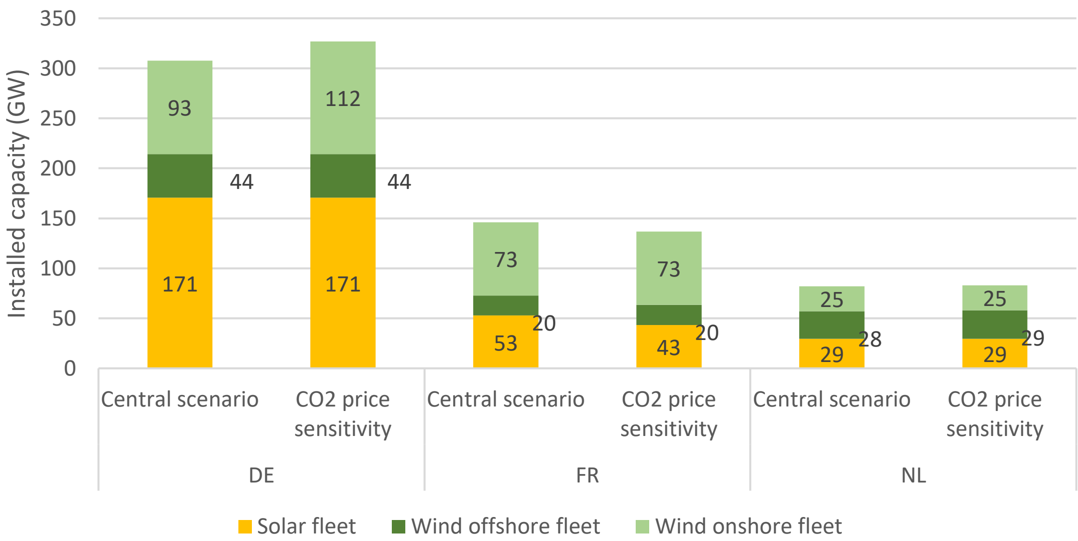

Figure 26: Change in VRES capacities for selected countries

As displayed in Figure 27, total underground hydrogen storage capacities increase by 6 TWh H2 under the high CO2 price sensitivity (+25%). Underground hydrogen storage capacities most notably increase in Germany (+75%) and Poland (+ 80%). Higher underground hydrogen storage capacities allow for a more flexible operation of electrolysers, which enables a decrease of thermal generation and provides flexibility to integrate additional VRES capacities.

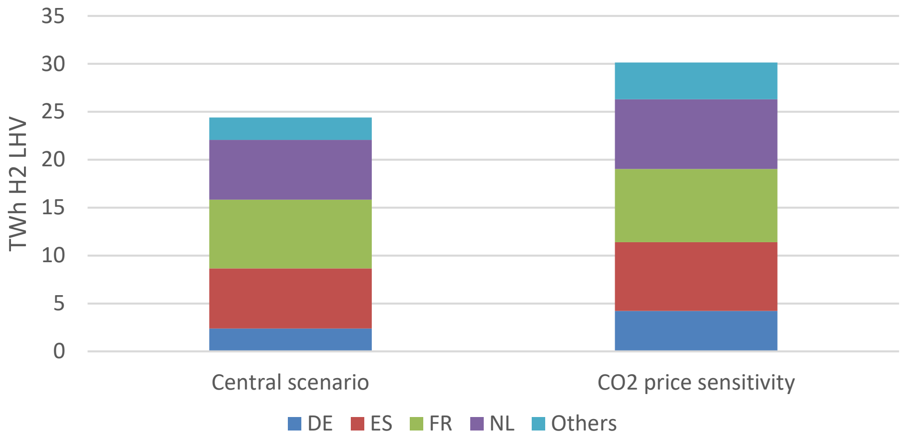

Figure 27: Changes in underground hydrogen storage capacities in CO2 price sensitivity

Figure 28 provides an example of power and hydrogen generation dynamics in Poland during five winter days. Red lines represent the hourly non-flexible demand (that excludes the demand for electrolysers) whereas the different stacked areas represent the generation of each technology. In the central scenario, it can be seen that even though carbon-intensive thermal generation capacities are running, hydrogen storage and import capacities are not sufficient to meet the hydrogen demand. Electrolysers are thus running at the same time as solids-fired capacities, which results in increased CO2 emissions. In the sensitivity analysis, increased hydrogen storage capacities can meet hydrogen demand and electrolysers are no longer running, which results in lower thermal generation during these hours.

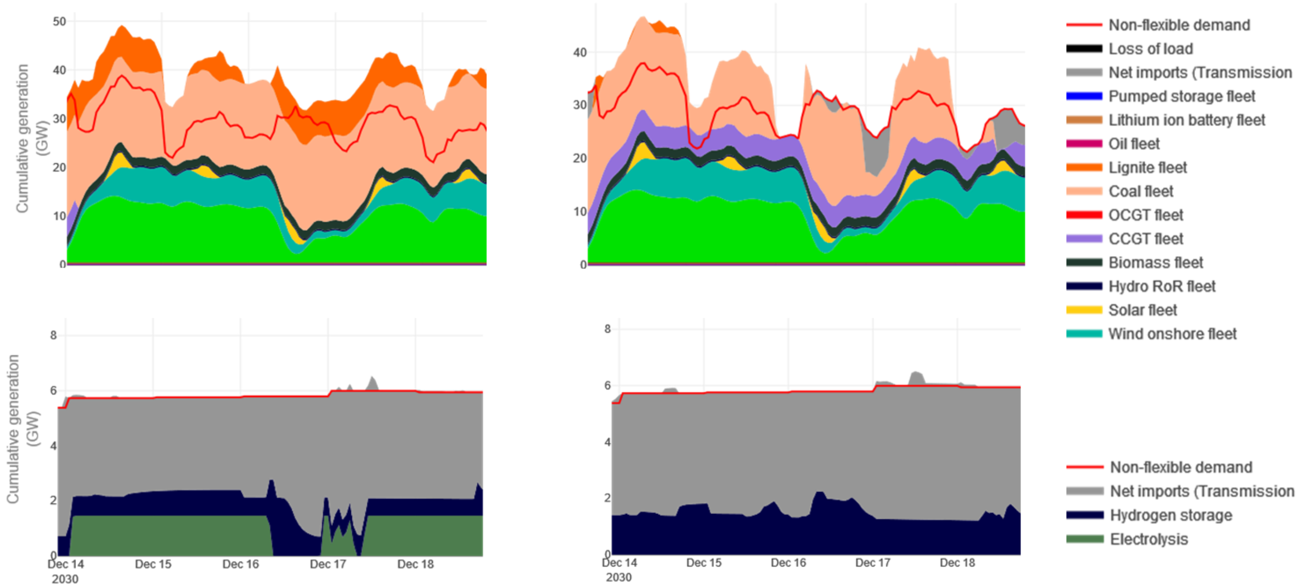

Figure 28: Change in power (top) and hydrogen (bottom) generation in Poland during a winter week: central scenario (left) and sensitivity analysis (right)

Under a higher carbon price, additional hydrogen storage capacities are thus needed to provide flexibility and integrate more renewable capacities in the power generation mix. A more flexible operation of electrolysers allows to reduce the use of thermal power plants whereas the pan-European hydrogen pipeline infrastructure is not significantly impacted.

5.2 A PAN-EUROPEAN HYDROGEN INFRASTRUCTURE REMAINS COST-EFFICIENT IN A SCENARIO WITH A LOWER HYDROGEN DEMAND

As high uncertainty remains regarding the uptake of hydrogen end-uses, notably in the industry and transport sectors, this sensitivity analysis investigates the impacts of a lower hydrogen demand. In this scenario, each Member State's hydrogen demand is reduced by 50% compared to the central scenario, reaching a total of 8 Mt H2. The share of extra-European imports relatively to domestic production is maintained to the same ratio as in the central scenario. Therefore, the total volume of hydrogen imports is reduced as well, from 6 Mt H2 to 3 Mt H2.

Figure 29 represents the share of domestic hydrogen production compared to each Member State's hydrogen demand: a value above 100% indicates that the country is a net exporter whereas a value below 100% indicates net hydrogen imports.

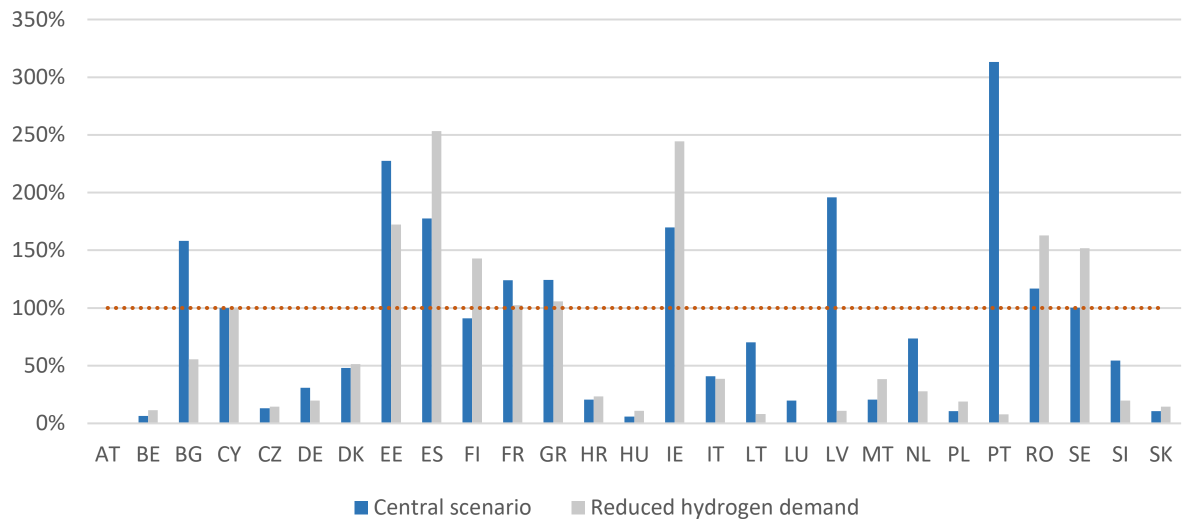

Figure 29: Evolution of share of domestic hydrogen production in national demand

When the total hydrogen demand is lower, different behaviours are seen depending on Member States:

- Some countries that are net exporters in the central scenario reduce their exports, or become net importers. This is for instance the case of France, Portugal, or Bulgaria.
- Some Member States increase their exports or become net exporters. This is the case of Spain, Romania, Sweden, or Finland for instance.
- The main countries importing hydrogen (Germany, Poland, Italy, and Central Europe) remain net importers.

Overall, a wide disparity in the shares of domestic hydrogen production remains when the hydrogen demand is reduced by half, which translates into significant hydrogen flows also materialising in this sensitivity analysis. Figure 30 displays net hydrogen cross-border flows as well as Member States net imports or exports in the reduced hydrogen demand scenario. As in the central scenario, the main hydrogen importers are Germany, Italy, Poland and Central Europe, while the main hydrogen corridor spans from the Iberian Peninsula to Germany. However, France and Portugal no longer contribute to hydrogen flows in this corridor.

Besides, when hydrogen demand is reduced, the allocation of extra-European hydrogen imports is impacted, as the Netherlands become the major entry point of imported hydrogen. Imports through the Ukrainian corridor on the other hand drop to 22 TWh, while flows from Germany to Poland increase to complement Poland’s hydrogen supply.

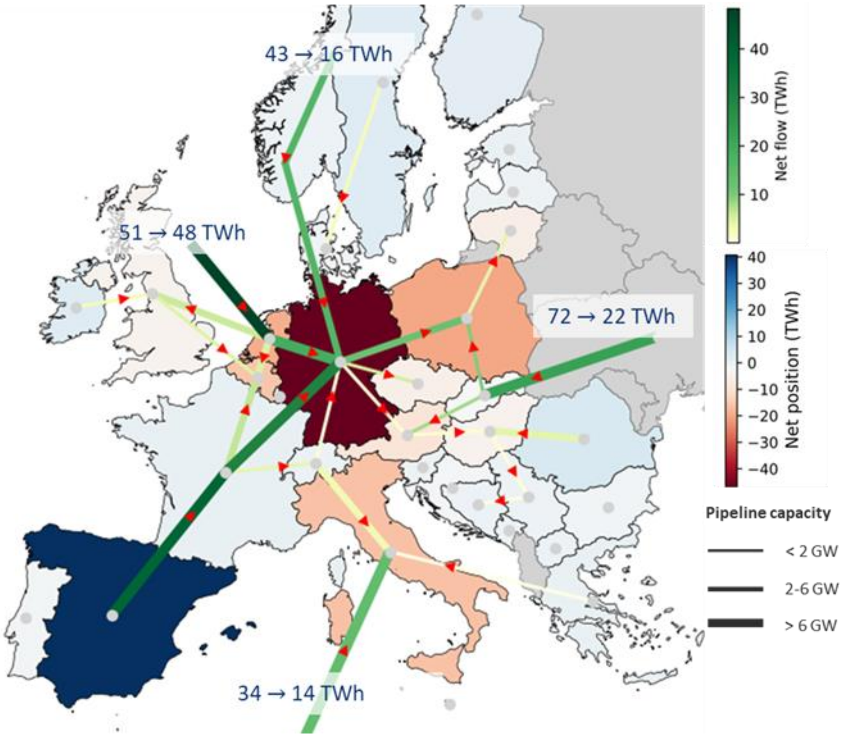

Figure 30: Cross-border hydrogen flows and capacities in the scenario with reduced hydrogen demand

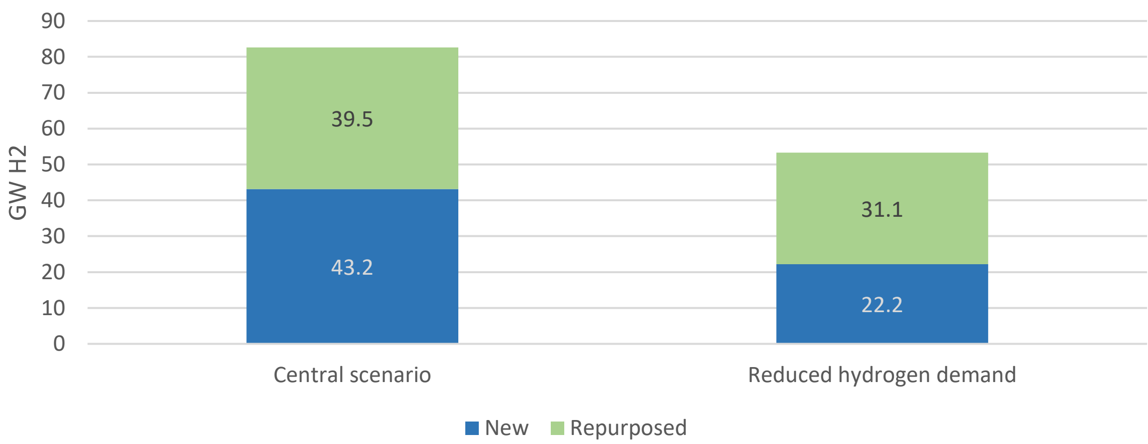

Figure 31: Changes in aggregated hydrogen pipelines capacities under reduced hydrogen demand sensitivity

In the scenario with reduced hydrogen demand, significant cross-border hydrogen flows remain, with a total intra-European hydrogen flow decreasing from 487 TWh H2 to 296 TWh H2 (-39%). As displayed in Figure 31, the aggregated cross-border capacity of the hydrogen network falls by only 35 % (-30 GW) when the demand is reduced by 50%.

The evolution of hydrogen production and storage capacities on the other hand is more closely correlated to the evolution of the hydrogen demand. Underground hydrogen storage capacity falls by 60% while electrolysis capacity falls by 47% (Figure 32). The average load factor of electrolysers is therefore only moderately impacted, decreasing by only four percentage points. The role of Spain as main hydrogen exporter is emphasised, as Spain accounts for 40% of European electrolysis capacity in the sensitivity analysis.

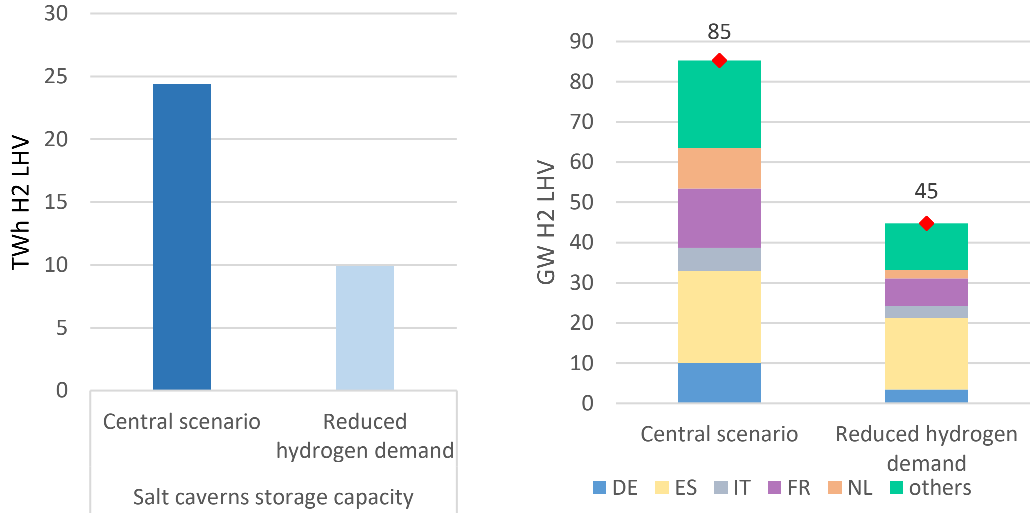

Figure 32: Evolution of EU27 salt caverns storage capacity (left) and electrolysis capacity (right)

The reduction of hydrogen demand translates into a reduction of power consumption of electrolysers by 421 TWh, which impacts the needs for additional VRES capacities. The total VRES capacity added to the baseline capacities[24] decrease from 400 GW in the central scenario to 263 GW in the sensitivity analysis (Figure 33). Solar PV and wind offshore capacities fall respectively by 60% and 44%, whereas wind onshore capacity is reduced by only 17%.

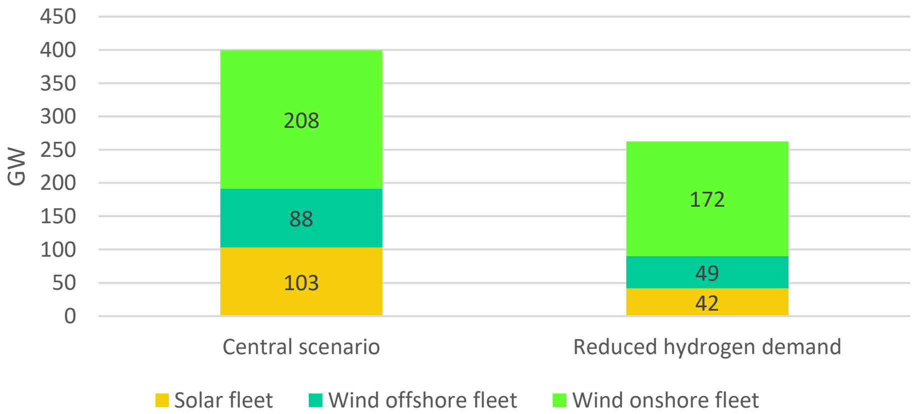

Figure 33: Evolution of added VRES capacities [EU27]

[24]In all scenarios, limited renewable capacities can be added compared to PRIMES 2030 scenario, see 3.2.2 .

Given the strong correlation between solar capacities and above-ground storage needs, the installed capacity of above-ground hydrogen storage falls by 84%, from 95 GWh to 15 GWh due to the strong reduction of solar PV investments shown on the previous figure. The remaining above-ground hydrogen storage capacity is exclusively located in Spain, as both solar capacity and hydrogen production remain high in this Member State.

If hydrogen production and storage infrastructure needs are sensitive to hydrogen demand, a pan-European cross-border hydrogen network remains cost-efficient in a scenario with only 50% of the hydrogen demand foreseen by REPowerEU. The reduced consumption of electrolysers results in a lower need for VRES capacities, wind offshore and solar capacities being the most strongly impacted by the reduction of electricity demand.

6 Conclusions and outlook

Key results and conclusions

To assess the hydrogen infrastructure needs under the REPowerEU 2030 scenario as well as to capture the dynamics of hydrogen system operations and sector coupling, a multi-energy pan-European model has been implemented in METIS.

The study results show that, under the considered modelling assumptions:

- A pan-European hydrogen network is cost-efficient, it allows to produce hydrogen in the most favourable Member States and redistribute it to main consumers.
- From a total system cost perspective, a flexible operational management of the hydrogen system is cost-optimal. The costs of operating hydrogen infrastructure with limited load factors are outweighed by the associated benefits, as the hydrogen system provides flexibility to the power system.
- A flexible operation of electrolysers facilitates the integration of VRES capacities. It allows to preferably produce hydrogen during hours of low electricity prices and carbon intensity.
- Significant capacities of hydrogen storage are required to enable the flexible operation of the hydrogen system. Underground and above-ground storage complement one another, the first storing high volumes of energy with seasonal dynamics, and the latter providing short-term flexibility thanks to high cycling capacities.

These results are to be interpreted within the context of the underlying assumptions and modelling limitations; the key quantitative results are summarised in Table 3.

Hydrogen storage	**Storage capacity**	**Injection capacity**
Underground - EU27	24 TWh	24 GW
Above ground - EU27	95 GWh	12 GW
Electrolysis	**Installed capacity**	**Average load factor**
EU27	85,3 GW	47,5%
Hydrogen pipelines	**Total capacity**	**Share of repurposed pipelines**
Europe	83 GW	48%
Hydrogen production	**Production**	**Imports**
EU 27	355 TWh	233 TWh

Table 3: Main quantitative results of the central scenario

Outlook

The present study focuses on the 2030 horizon. In the scope of the ongoing METIS 3 project, the needs for a hydrogen infrastructure in 2050 have also been investigated, which notably highlights significant hydrogen generation potentials developing in the longer term in other European countries, such as Finland or the Baltic States[25], whereas the Iberian hydrogen corridor appears as the first axis for trading hydrogen to develop on the shorter term.

The METIS model is also subject to continuous development, in the context of the ongoing METIS 3 project. In particular, a study will be conducted using new optimisation capabilities enabling the design of transition pathways, covering several intermediate years, up to 2050.

[25] See for instance (Fraunhofer Institute for Systems and Innovation Research, 2023)

7 Annex

7.1 Corridors for wind and solar capacities

Part of the renewable capacities, including wind and solar can be reallocated compared to the PRIMES 2030 scenario. First, baseline renewable capacities are defined. These capacities are based on the capacities from PRIMES REPowerEU scenario, from which a share of capacities corresponding to the electricity consumption of electrolysers (in the PRIMES scenario) is subtracted. The consumption of electrolysers from the PRIMES scenario is converted to equivalent renewable capacities assuming same load factor and split between technologies as in the PRIMES scenario and subtracted. For each member state, capacities can then be added under the constraint that total capacities cannot exceed the capacities from PRIMES 2035 scenario. Figure 34 describes the obtained capacity corridors for each technology, the capacities are optimized within baseline capacities and maximum capacities.

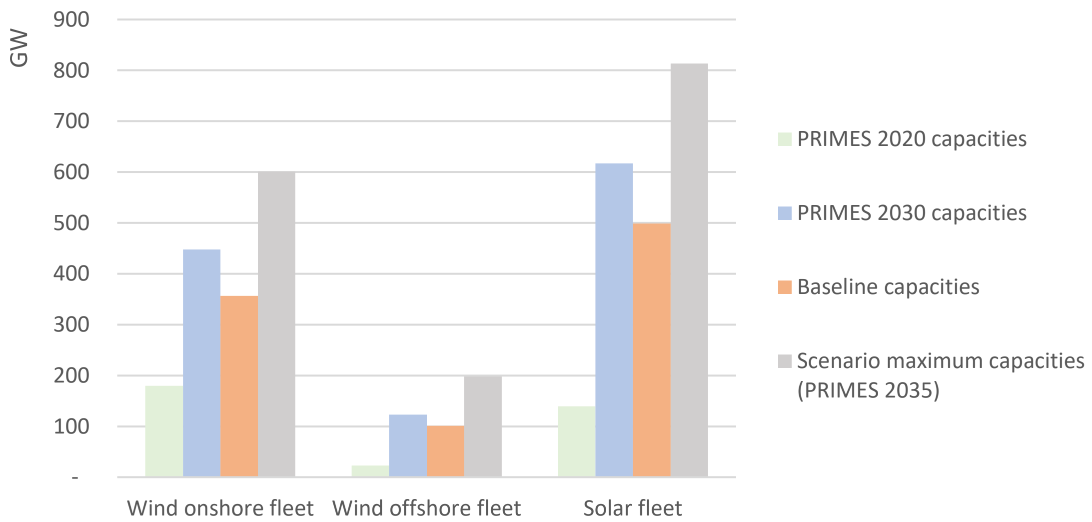

Figure 34: Renewables capacities corridors in the scenario (EU27+UK)

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