METIS 3 - Study S3

METIS study on costs and benefits of a pan-European hydrogen infrastructure
–
In assistance to the impact assessment for designing a regulatory framework for hydrogen

METIS 3 Studies
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ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

Abbreviation	Definition
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
DSR	Demand side response
EEZ	Exclusive Economic Zone
EHB	European Hydrogen Backbone
H2	Hydrogen
LCOE	Levelised cost of electricity
MS	Member State
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
PPA	Power purchase agreement
PV	Photovoltaic
RES	Renewable energy sources
SMR	Steam methane reforming
vRES	Variable RES

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 MIX H2 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

1 EXECUTIVE SUMMARY

The present study was prepared in **assistance to the impact assessment for designing a regulatory framework for hydrogen** in the context of the revision of the EU Gas Market Directive (2009/73/EC). The analysis has for objective to provide the quantitative evaluation of scenarios and related sensitivities which shall reflect a set of policy options under discussion for the hydrogen framework. The scenarios and sensitivities were jointly elaborated in a pre-phase of the present assessment with Guidehouse and Frontier Economics. A detailed description of the link between the scenarios and policy options is available in the respective report, which is to be understood as a preface for the present analysis. The present analysis provides results via a set of quantitative indicators which complements the more qualitative analysis realised by (Guidehouse & Frontier Economics, forthcoming).

The considered policy options differ in the way they are expected to enable or stimulate cross-border transport of hydrogen (either via new pipelines or repurposed) and trigger the exploitation of least-cost potentials for renewable hydrogen production with the ultimate goal to diminish the overall costs of renewable hydrogen supply (including upstream costs). **Three different scenarios of cross-border capacity deployment** by 2030 are considered to assess the impacts of these packages, considering the green H2 production capacities as outlined in the EU's Hydrogen Strategy. They range from a BAU scenario without any cross-border interconnection, via a scenario relying on the EU hydrogen backbone as indicated by the 2021 Guidehouse report[1], towards a more extended version that allows for the installation of initial cross-border capacities to tap the full potential of regional cooperation benefits when supplying the EU with renewable hydrogen.

In order to capture the hydrogen dynamics, a **multi-energy modelling environment has been designed in the METIS model**, reflecting the investments into and operation of electricity, gas and hydrogen assets with an hourly time resolution over entire year 2030. The pan-European modelling approach (representing all EU MSs plus major neighbouring countries as single nodes) is key to reveal the needs for hydrogen infrastructure. See the dedicated report prepared by (Guidehouse & Frontier Economics, forthcoming) and (Artelys, forthcoming) for further information on scenario design and major modelling assumptions.

The study key finding is that **it is economically pertinent to set up a pan-European hydrogen transport infrastructure by 2030**, under the considered assumptions. 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 sites. The cost-effective exploitation of the EU-wide RES potentials and a concerted European strategy for electrolyser roll-out allow to increase the load factors of electrolysers, thereby avoiding over-dimensioning, paired with least-cost renewable electricity. A pan-European hydrogen grid further triggers a convergence of hydrogen prices across EU Member States and reduces the need for hydrogen storage, which is in any case a scarce resource restricted to selected Member States. Eventually, reallocation combined with the carbon price signal drives down the hydrogen carbon-content.

In the **optimal scenario**, 27 GW of new hydrogen and 44 GW of repurposed cross-border pipeline capacity are commissioned. Storage needs drop from 21 TWh in the BAU scenarios to 18 TWh in the optimal scenario. At the same time, utilisation of electrolysers rises from 42% to 60% at the European level, thus lowering the demand for additional electrolyser capacities by 20% (from 53 to 42 GW). An evenly great reduction may be observed for

[1] (Guidehouse, 2021)

total costs of hydrogen, dropping from 4.22 to 3.30 €/kg in 2030. Hydrogen carbon-content decreases from 0.74 kgCO2/kgH2 to 0.35 kgCO2/kgH2.

The analysis further reveals that **repurposing of existing gas pipelines** represents a cost-efficient option to reduce the need for additional pipelines. **National objectives** for the installation of electrolysers may clearly provide incentives for investments and the development of a national hydrogen economy. However, a coordinated European approach considering national framework conditions (in terms of hydrogen supply potentials, hydrogen demand) and implying a concerted pan-European hydrogen network and production planning approach could significantly reduce the overall system costs. A **joint planning** of electricity, gas and hydrogen production and transmission infrastructure is of utmost importance to ensure a cost-efficient exploitation of the least-cost RES potentials and to avoid over-dimensioned or stranded production assets and cross-border transmission assets. Allowing **electrolysers to market electricity from the grid** may effectively reduce the system costs, yet at the expense of increasing carbon emissions. Maintaining the carbon constraint enables emission reduction at an abatement cost of approximately 27 €/tCO2. **Cost uncertainty** with respect to investments in new and repurposed **pipelines** remains relatively high, yet affects the overall results only to a limited extent. If pipelines turn out to be more expensive than expected, this favours nationally indigenous hydrogen production.

2 INTRODUCTION

In its Communication "A hydrogen strategy for a climate-neutral Europe" (European Commission, 2020a), the European Commission announced the objective of 40 GW of renewable hydrogen electrolyser capacity by 2030 producing up to 5 Mt of renewable hydrogen by 2030. However, the Commission also identified the need to develop a regulatory framework to facilitate the development of dedicated hydrogen infrastructure, provide adequate access to it and enable moving towards competitive and liquid markets for hydrogen to make its objectives materialise. These initiatives are part of a larger reform that the Commission undertakes in the context of the planned recast of the gas directive and regulation.

Artelys has been commissioned to make use of the EU energy system model METIS in order to assess the impacts of different regulatory measures that shall enable or stimulate cross border transport of hydrogen. The qualitative description of the individual measures as well as the conceptual development of the overall assessment framework (with respect to the underlying scenario data, modelling assumptions, selection of sensitivities etc.) was primarily developed by Guidehouse and Frontier Economics in the context of a separate contract. Hence, this study focusses notably on the description of the modelling methodology and the actual modelling results whereas the report from Guidehouse and Frontier Economics (Guidehouse & Frontier Economics, forthcoming) provides the link between the present modelling and assessment of the specific regulatory measures.

The remainder of this report is structured as follows: Chapter 3 provides an overview of the applied modelling methodology. Chapter 4 introduces the different scenarios to be analysed and summarises the major variables subject to optimisation. Chapters 5 and 6 reveal the results of the main scenarios and the sensitivity runs. Major conclusions and a brief evaluation of the limitations of the present analysis are given in Chapter 7.

3 METHODOLOGY IN A NUTSHELL

3.1 THE METIS MODEL

The METIS model is being developed by Artelys and its partners on behalf of the European Commission.[2] 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 single 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.

Based on this information, METIS allows to perform the hourly dispatch simulation (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 national 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 assignment. Figure 3-1 provides an overview of major input and output data which are explained in more detail in the subsequent section.

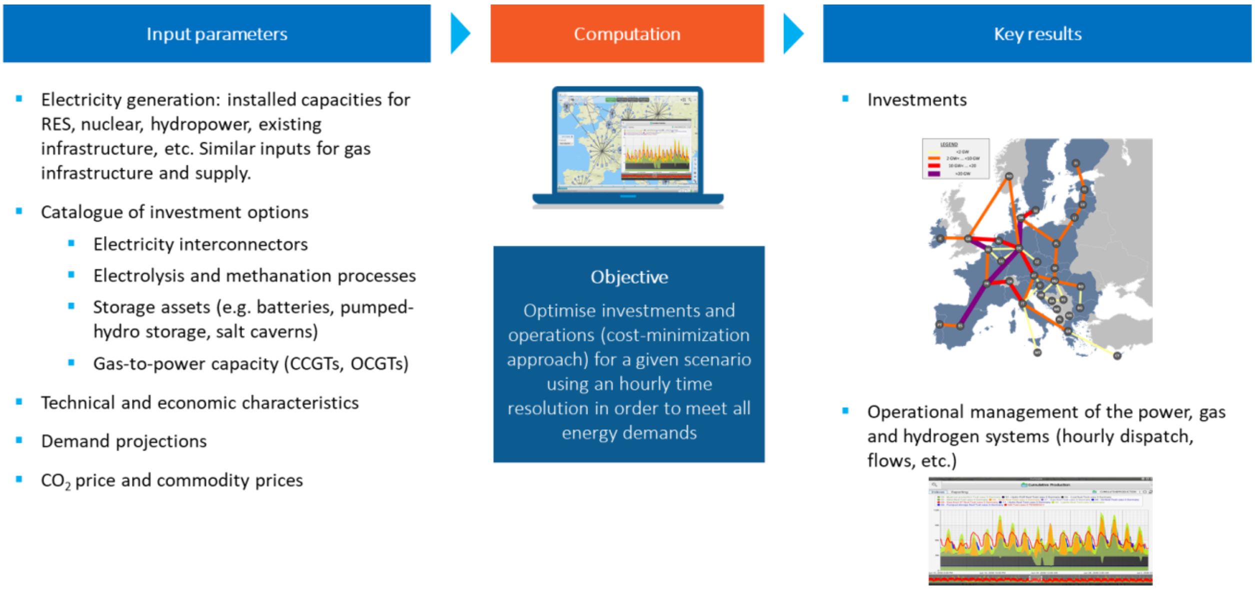

Figure 3-1: Overview of the general modelling approach

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

3.2 MODELLING THE INTEGRATED HYDROGEN SYSTEM

The optimisation scope of METIS in this study covers hydrogen, electricity and gas in order to account for potential benefits of energy system integration. This implies that investments in supply, storage and cross-border transmission capacities are jointly optimised for all three energy carriers, while final energy demand represents an exogenous input.

Hydrogen supply and demand equilibrium is enforced for each hour of the year, similarly to electricity and gas.[3] Hourly profiles are considered for the hydrogen demand, and are built based on gas demand profiles.

Electrolysers are modelled explicitly, linking both the electricity system and hydrogen. It is to be noted that only renewable hydrogen production via electrolysis is reflected in the assessment whereas the conventional production of hydrogen (e.g. via SMR, potentially equipped with CCS) is excluded.[4]

The electricity for electrolysers is supplied both through PPAs, with dedicated vRES generation, and via the market (when sourcing is economically interesting and meets pre-defined carbon-content limits). Electrolysers are assumed to operate flexibly, allowing them to benefit from low power prices and to provide flexibility services to the power system (thereby lowering total system costs).

The hydrogen infrastructure is modelled including hydrogen storages and cross-border capacities. To define the latter, the model has two options, investing in new hydrogen pipelines or repurposing existing gas pipelines. 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.[5]

Figure 3-2 provides an overview of all assets explicitly represented in the METIS model and the interlinkage between the three energy carriers, electricity, gas and hydrogen. Assets are either subject to dispatch optimisation (indicated via a dotted circle), i.e. the model optimises the hourly consumption/production patterns of the considered technology, subject to the techno-economic constraints, while capacities represent an exogenous input. Or assets are subject to capacity and dispatch optimisation (plain circles). In this case, in addition to the optimised operation, the model optimises the level of investments in the given technology.

A single optimisation is carried for all assets. The optimisation has for objective to minimise the total system costs (including operating costs and investments).

The following chapter introduces the major assumptions used in the present assignment.

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[3] Complementary information about the modelling of the power and gas sector is available on the METIS website.

[4] Further information regarding this assumption is available in (Guidehouse & Frontier Economics, forthcoming).

[5] Hydrogen blending is not represented in the modelling as the MIX H2 scenario data assume a role for blending only from 2035 onwards.

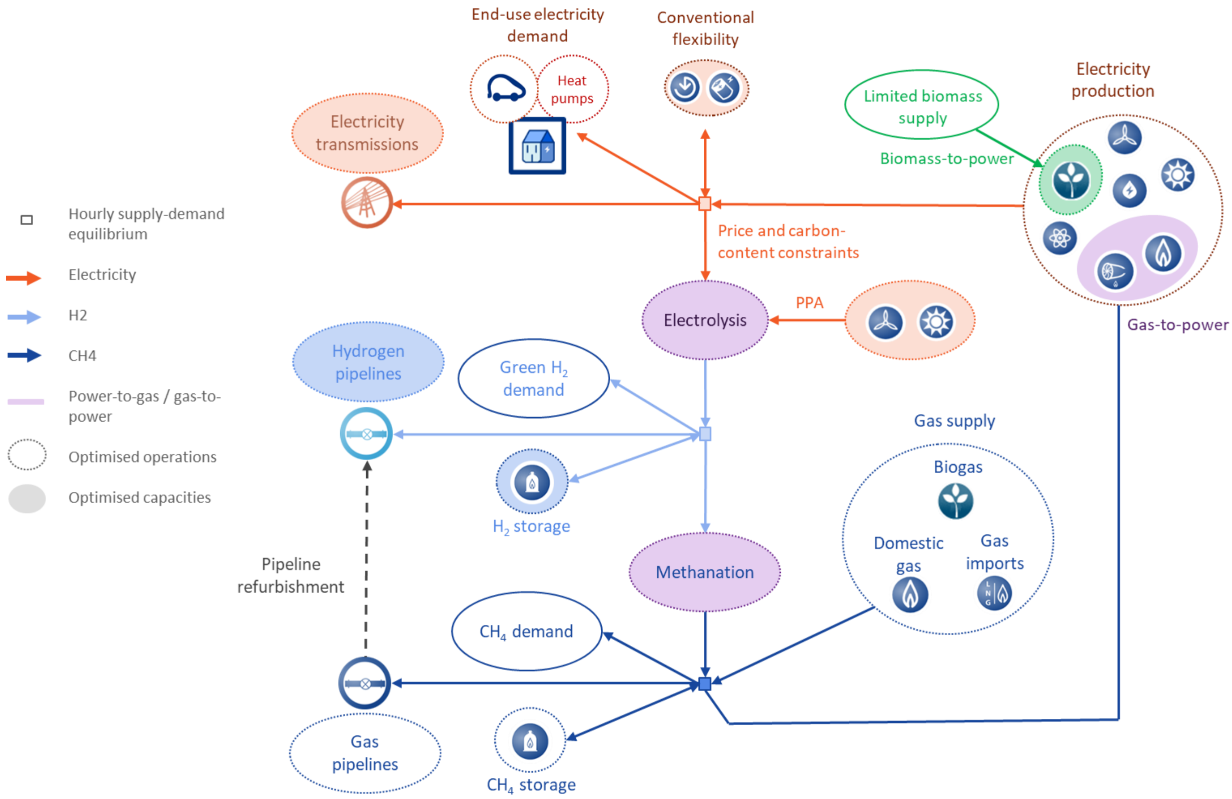

Figure 3-2: Modelling of the EU energy system

4 Definition of the hydrogen infrastructure scenarios

4.1 Definition of the different scenarios for hydrogen cross-border integration in the EU

The regulatory packages defined by (Guidehouse & Frontier Economics, forthcoming) and assessed in this study differ in the way they are expected to enable or stimulate cross-border transport of hydrogen.

Although no direct mapping is possible between a specific network configuration and a specific regulatory package, the report by Guidehouse and Frontier Economics shows that under certain conditions an increased level of regulation may favour the built-out of cross-border hydrogen capacities, thereby facilitating an internal European hydrogen market. The scenarios implemented in METIS are designed to represent different infrastructure build-out scenarios and their related costs and benefits. While costs are primarily related to the built-out of hydrogen infrastructure, benefits may relate to avoided investments in electricity or gas infrastructure (e.g., transmission infrastructure, flexible power generation capacities, more cost-efficient use of renewable potentials) or reduced operational costs.

However, the scenarios analysed do not link explicitly to individual policy packages. Figure 4-1 lists the different policy packages introduced by (Guidehouse & Frontier Economics, forthcoming) and indicates the soft link to the scenarios of the present study, which are indicated in the last line and introduced further below.

	BAU	Option 1	Option 2		Option 3	
		1	2a	2b	3a	3b
Stylised fact used in modelling of impacts						
Cross-border transport capacity	BAU	"A constrained"				"A optimised"

Figure 4-1: Individual policy packages against scenarios implemented into METIS. Source: (Guidehouse & Frontier Economics, forthcoming)

The analysis is carried out for three major scenarios and two scenario variants. Figure 4-2 provides an overview of these scenarios that differ notably in terms of existing minimum cross-border hydrogen capacity in the year 2030:

- The Business-as-usual (BAU) scenario considers the complete absence of cross-border hydrogen capacities. This implies that all renewable hydrogen demand needs to be met domestically.
- The H2-A scenario builds upon the 2030 cross-border hydrogen capacities of the European Hydrogen Backbone (EHB) study (Guidehouse, 2021). They consist of mostly domestic hydrogen infrastructure with cross-border transport only in North-West Europe and Scandinavia. Two scenario variants are considered:
  - H2-A constrained does not allow for a further extension of the cross-border hydrogen capacities
  - H2-A optimised allows for a further extension of the cross-border hydrogen capacities (repurposing or new pipelines) if this is economically reasonable (endogenously determined by the model)
- Scenario H2-B optimised considers that the built-out of cross-border hydrogen capacities is further advanced by 2030 by integrating the 2035 vision of the EHB study. The 2035 map interconnects many additional regions. These capacities represent a minimum built-out which may be further extended by the model.

The first four scenarios – from BAU to H2-A optimised – constitute the core content of the study, while the more extreme H2-B optimised scenario is only assessed in the sensitivity section 6.3.

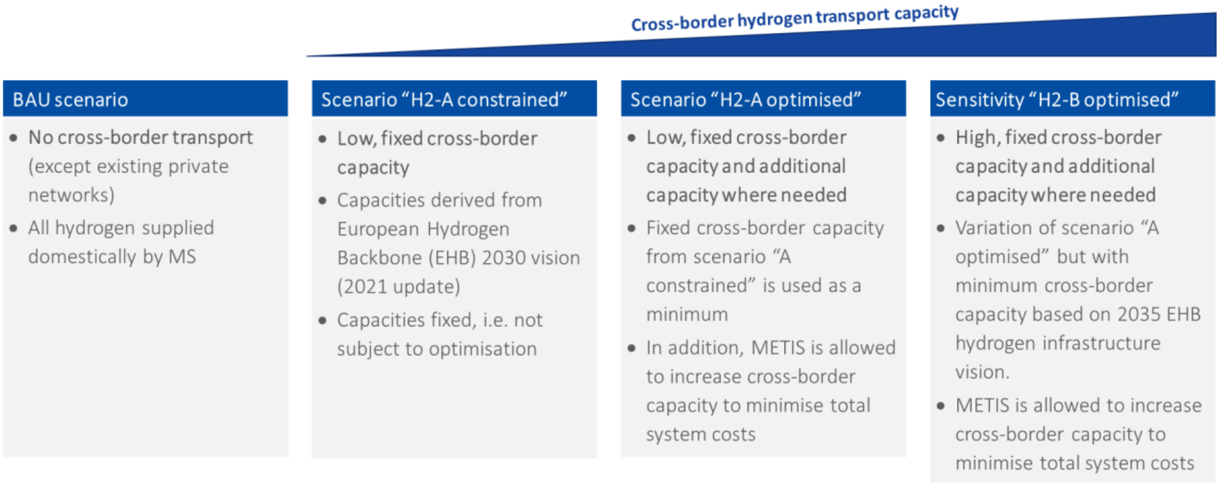

Figure 4-2: Overview of the scenarios implemented in METIS

The main scenarios are complemented by a set of sensitivity assessments, which are introduced in Section 6.1.
For all scenarios, the joint EU-wide capacity and dispatch optimisation is realised in order to determine the least cost EU energy system configuration to cope with the given exogenous final energy demand. Section 4.2 introduces the major framework assumptions considered in the different scenarios, while Chapter 5 provides the results for the main scenarios.

4.2 Creation of the METIS scenario

For the purpose of the impact assessment, the four infrastructure scenarios introduced in Section 4.1 build on a common scenario in the METIS model which integrates all framework data that are not subject to optimisation and common to all infrastructure scenarios. The METIS scenario relies primarily on 2030 data from the European Commission's MIX H2 PRIMES scenario, from which we adopt the main framework assumptions in terms of fuel prices, electricity generation capacities, final energy demand structure. We present below the list of assumptions that have been directly imported from the MIX H2 scenario:

- Installed capacities for electricity generation technologies
    - Solar PV, wind onshore/offshore[6]
    - Nuclear
    - 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
    - Power demand, with a specific distinction of electric vehicles and heat pumps consumption (which can provide flexibility and whose consumption pattern is determined in the context of the dispatch optimisation)

[6] This does not include vRES capacities exclusively dedicated to the production of renewable hydrogen, cf. explanations further below.

- Gas demand, excluding the gas demand for power generation (capacity and dispatch of gas-fuelled power plants is optimised with METIS)
- Hydrogen demand for the industry and transport sector[7], including hydrogen demand to produce e-gas and e-fuels. Non-thermosensitive end-use demand profiles are considered (based on the gas demand profiles)[8]. Additional hydrogen demand for indirect use in other sectors (via e-gas, competing with other gas supply sources) is endogenously modelled.

- Commodity prices
  - Fuel prices (gas, coal, oil)
  - EU-ETS carbon price, at 45.5 €/tCO_2
- Biomethane production is extracted from the MIX H2 scenario.

For more details on the approach the MIX H2 data is integrated into METIS, see the dedicated Technical Note[9].

In addition to the European Union, seven neighbouring countries are modelled to capture their interactions with the EU Member States. These 7 countries are Bosnia-Herzegovina, Montenegro, Norway, North Macedonia, Serbia, Switzerland, and the United Kingdom.

While the UK follows the same modelling process as the EU countries, the remaining 6 countries have their power production capacities and power/gas demand extracted from scenarios developed by the ENTSOs in the context of the elaboration of TYNDP 2018 and TYNDP 2020.

The scenario is completed with TYNDP 2020 data for the gas infrastructure:

- Domestic gas production volumes
- LNG terminals
- Import pipelines and supply cost curves
- Gas storage and transmission infrastructure

On this basis, METIS performs a joint dispatch and capacity optimisation of the European electricity, gas and hydrogen system[10], in order to reflect the synergies between the three energy carriers. The model quantifies the optimal investments in the energy infrastructure and outlines the optimal operation of energy assets under the different infrastructure scenarios in order to minimise overall system costs. It is recalled from Section 3.2 that capacity investments are optimised for the electricity flexibility portfolio (gas-fired plants, storage technologies, interconnectors) and hydrogen infrastructure (electrolysers, storage, interconnectors). Figure 4-3 shows the graphical user interface of METIS containing the imported MIX H2 scenario in the METIS model.

[7] The MIX H2 scenario does not assume any hydrogen consumption in sectors other than industry and transport by 2030.

[8] Given the non-thermosensitivity of hydrogen demand, a single climatic year is simulated in the model.

[9] (Artelys, forthcoming)

[10] For the 27 EU Member States and the 7 non-EU countries.

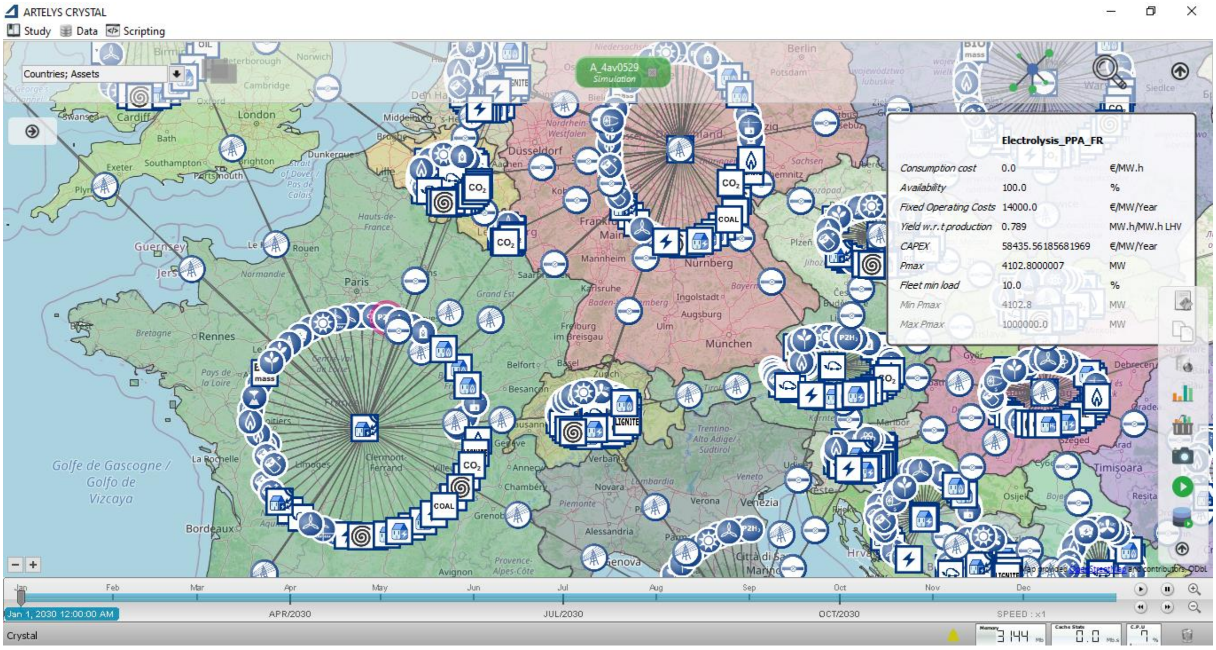

Figure 4-3: Pan-European energy model in METIS, derived from the MIX H2 scenario

For the purpose of an in-depth analysis of the policy options introduced by (Guidehouse & Frontier Economics, forthcoming) for the specific IA, the modelling of electrolyser investment and operation within METIS was further refined:

- Minimum electrolyser capacities are given for selected MS (reflecting 80%[11] of announcements made in national hydrogen strategies)
- To ensure the production of *renewable* hydrogen and to comply with the *additionality principle*[12] for renewable power generation capacities, electrolysers consume electricity from additional vRES capacities for hydrogen generation contracted under a PPA (hereafter called "the PPA"), or from the market subject to carbon-content and price constraints.
- At each timestep, the electrolyser has to exceed a 10%-minimum load to reflect operational constraints. In order to meet this minimum, the electrolyser can source electricity from the market irrespective of the carbon-content or electricity price (see below).
- Investments in dedicated renewable capacities (i.e., the PPA) are optimised, while renewable capacities on the market are fixed as per the MIX H2 scenario for 2030. Investments in the RES capacities under the PPA are optimised from a system cost perspective rather than from the perspective of an electrolyser operator.
- In order to ensure a coherent RES deployment at the Member State level, the total capacity of each vRES technology per MS (including market and dedicated renewables) is bounded by the 2035 national RES capacity from the MIX H2 scenario.
- Total renewable capacities on the PPA side stay within a 75%-125% corridor around the electrolyser capacity, to avoid significant under/over-sizing.

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[11] A sensitivity to this parameter is assessed under Section 6.5

[12] The additionality principle states that the development of renewable hydrogen generation should be covered by additional renewable capacities, adding to the current capacities on the electricity market. See (European Commission, 2021).

There are two constraints when sourcing electricity for the production of renewable hydrogen from the market:

- CO_2 content constraint: sourcing electricity from the market only occurs when the average market CO_2 content is lower than a given threshold (ensuring that hydrogen produced can be defined as *green* as per the Taxonomy).[13]
- Additional constraint on the hourly electricity price: sourcing from the market only occurs when the market electricity price is below a given price threshold.

In both cases, the electrolyser has the possibility to resell the electricity contracted under the PPA to the market, when economically relevant (e.g., when the market features sufficiently high electricity prices that related revenues exceed the opportunity costs from hydrogen production).

See report from (Guidehouse & Frontier Economics, forthcoming) for a more detailed description of the considered constraints and the definition of the specific thresholds. Under the main model runs, both the CO_2 content constraint and the electricity price constraint are applied on market electricity sourcing (except when meeting the minimum load, see above). In order to capture the effect of such constraints on the study results, model runs "-4b" only constrain electricity market sourcing with the electricity price constraint. On the opposite, where relevant, main model runs (with both constraints activated) are labelled as "-4a".

[13] (European Commission, 2021). The threshold value corresponds to 60 kgCO2/MWhe in METIS.

5 RESULTS OF MAIN SCENARIOS

This section reveals the results from the main scenarios, while Section 6 provides insights from a set of sensitivity assessments. The presentation of the results is preceded by a few introductory remarks (Section 5.1) useful to put the sub-sequent results into a larger context and understand the scope and limitations of the present assessment.

5.1 INTRODUCTORY REMARKS

5.1.1 COHERENCE WITH THE RESULTS OF THE IMPACT ASSESSMENT ON GAS

In order to ensure consistency in the overall approach applied to assess the policy options considered by the European Commission in the context of the planned recast of the gas package, a common methodology using METIS has been applied for the Impact Assessments on gas and hydrogen. In particular, the same scenario from the EC – namely the MIX H2 scenario, for 2030 – has been used. Among others, it sets a common framework for the energy demands for all MS of the EU for the different energy carriers.

Yet, the approaches are not exactly the same for the assessments related to the gas and the hydrogen policy options. The IA on gas is based on a model of the gas system, while an integrated model was needed for the IA on hydrogen, to capture the coupling between gas, hydrogen and electricity. Consequently, the METIS modelling for the IA on hydrogen also covers electricity and hydrogen generation technologies. The assumptions on gas infrastructure[14] (pipeline, storage capacities, imports, domestic generation and biomethane injection) are consistent between the two IAs. However, due to the different approaches results may diverge.

5.1.2 RESULTS REPORTING SCOPE

Under the current assessment, the model is allowed to reallocate hydrogen generation capacities in a cost optimal manner. Therefore, the hydrogen demand in the UK may be met by hydrogen produced in the EU27 and vice-versa[15].

Given the scope of the Impact Assessment, the current report covers results for the EU27. When a reorganisation of hydrogen production between the UK and the EU27 occurs, EU27+UK (hence the complete hydrogen perimeter) results are reported in order not to bias results interpretation. In the following sections, an overview of hydrogen production in the EU27 across the different model runs will be provided, to highlight under which scenarios UK-EU27 trade patterns impact the results.

[14] On gas and hydrogen transport cost modelling, it should be noted that gas transport costs are considered via tariffs, and hydrogen transport costs are considered via CAPEX. The rationale behind it is the need to reflect actual gas import flows (as routes depend on tariffs) and to optimise the hydrogen transport infrastructure (for which investments are best reflected by CAPEX). On gas and hydrogen storage cost modelling, CAPEX is the major cost component, and a tariff reflects an additional operational cost (0.7 €/MWh entry-exit fee on average).

[15] No hydrogen demand/production was explicitly modelled in Switzerland and Norway but there could still be local demand and supply.

Limits of the modelling approach

The selected modelling approach with the METIS tool presents some limitations to be considered when interpreting results and using them for the assessment of policy measures, 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.
- Similarly, on the supply side, imports of hydrogen from outside the EU (e.g., from Northern Africa, Russia, Ukraine, via dedicated pipelines or shipped as liquified hydrogen) were not considered. Their integration could reorganise the cross-border flows.
- Blue and grey hydrogen production (via SMR with/without CCS) is not considered in the model. This hydrogen is not expected to be traded (as it is required to meet local hydrogen demand), and not included in METIS modelling of hydrogen flows. Blue and grey hydrogen demand would come on top of the 200 TWh of green hydrogen demand. In large industrialised regions and their surroundings, it may impact cross-border capacity needs, which were not considered in the modelling. See (Guidehouse & Frontier Economics, forthcoming) for further details.
- Intra-national transport of hydrogen is not modelled explicitly.
- The study focuses on 2030 (no pathways investments), therefore it does not capture the additional pipeline value which results from the expected level of hydrogen demand beyond 2030. Conversely, it does capture the reduction in pipeline value that would result from lower hydrogen flows on a specific route.
- CAPEX assumptions are subject to high uncertainty as they depend on global market uptake; energy carrier prices are also uncertain.
- The simulations are carried out with a market model (no hydraulic modelling).

5.2 INFRASTRUCTURE NEEDS ACROSS EUROPE

5.2.1 HYDROGEN CROSS-BORDER CAPACITIES

The H2-BAU scenario considers no cross-border infrastructure for the transport of hydrogen, hence the hydrogen demand must be met domestically. The hydrogen demand is derived from the MIX H2 scenario, and is distributed as displayed in Figure 5-1. The resulting national electrolyser capacities are presented in the next section, 5.2.2. In order to compare the three other scenarios against a case where no cross-border infrastructure is available, H2-BAU will serve as a Baseline in Section 5.

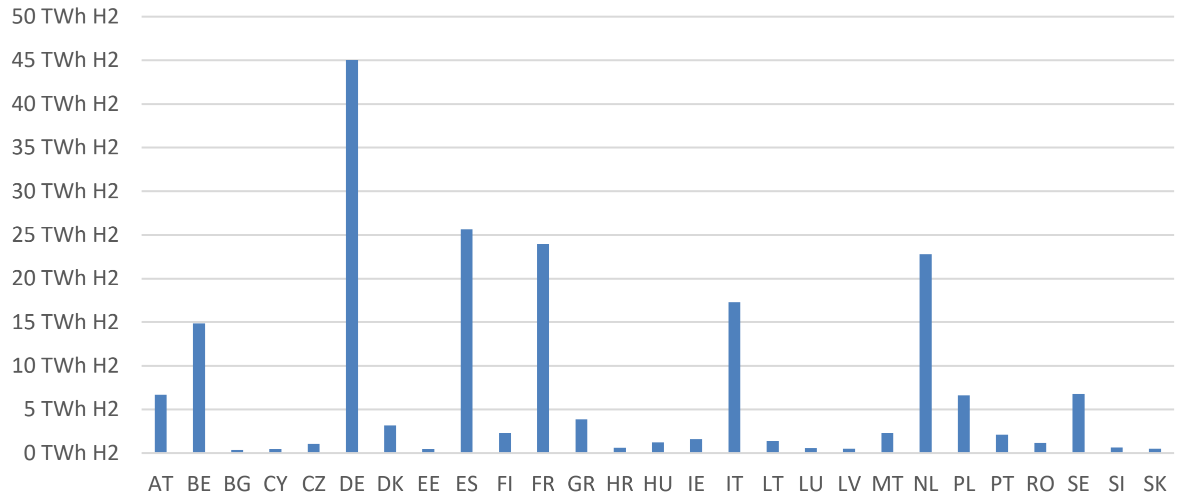

Figure 5-1: Hydrogen demand per Member State

Under scenario H2-A constrained, the cross-border capacities are derived from the EHB 2021 map for 2030[16], and no further investments are allowed. These cross-border capacities are assumed only between FR, BE, NL, DE as well as between SE and FI reaching 29 GW in total. This amount is distributed between FR-BE (4.25 GW H2, repurposed), BE-NL (8.3 GW repurposed, 5 GW new), NL-DE (6.77 GW, repurposed) and SE-FI (5 GW, new). Hence, most countries are not connected to the hydrogen cross-border infrastructure and meet their hydrogen demand with domestic generation of electrolytic hydrogen. The distribution of hydrogen demand across Member States is displayed in Figure 5-2.

Under the H2-A constrained scenario, main exchanges occur between FR as a net exporter and DE as a net-importer. Figure 5-2 shows that the BE-NL pipeline is oversized in this scenario, as it features a utilisation rate between 15% and 50% only.

[16] (Guidehouse, 2021)

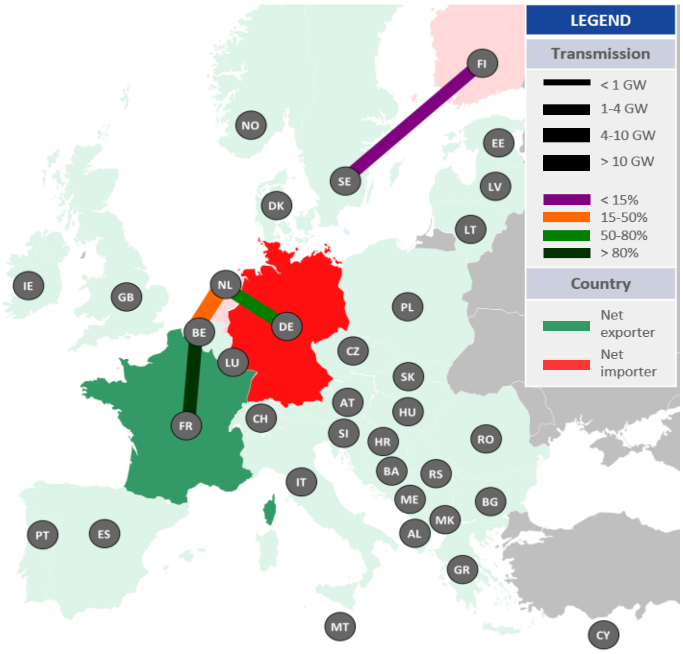

Figure 5-2: Cross-border hydrogen capacities and usage, H2-A constrained scenario (light green countries feature no hydrogen imports; Belgium exports 2.5 TWh of hydrogen)

Scenario H2-A optimised builds upon the same infrastructure map as scenario H2-A constrained, but further investments in cross-border capacities can materialise where they are economically interesting. Under this scenario, additional investments are made all over the EU (plus UK and Switzerland) in order to meet the MIX H2 demand most cost-effectively. Significantly more cross-border capacities are found to be relevant than in the scenario H2-A constrained.

Figure 5-3 shows that a hydrogen backbone is built from Spain to Germany. In addition, the model invests in three other routes: from Greece to Italy, where flows materialise in both directions depending on the electrolyser production patterns and vRES supply mix; from Greece to Romania/Bulgaria, where pipelines have low capacity but high transmission usage; and from Finland to Central Europe via the Baltics. Sweden is the main source of hydrogen in the Nordics and the Baltics under the given assumptions. In scenarios with higher hydrogen demand, Finland and the Baltics could become net exporters, too. In comparison with the scenario H2-A constrained, the BE-NL-DE hydrogen pipeline features a reduced usage, as the direct route between France and Germany is preferred. In total, 43.9 GW of repurposed pipelines and 26.7 GW of new hydrogen pipelines are commissioned (including the capacities from the H2-A constrained scenario) which means more than twice as much capacity than under the H2-A constrained scenario.

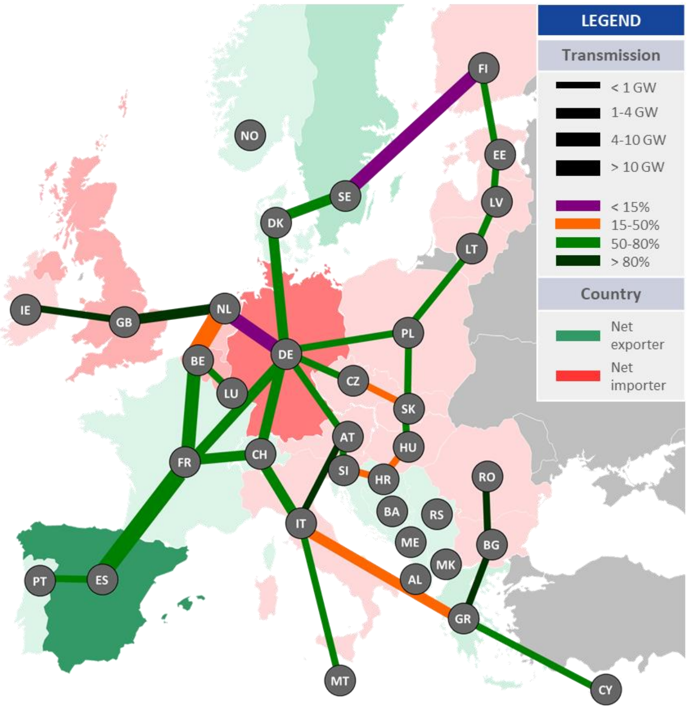

Figure 5-3: Cross-border hydrogen capacities and usage, H2-A optimised scenario

The main hydrogen flows occur on three routes (Figure 5-4): from Spain via France to Germany, Belgium and Great Britain (and ultimately to Ireland); from Greece to Italy and to Eastern Europe; and from Sweden to Germany via Denmark and to the Baltics via Finland. The low infrastructure level over Central Europe is explained by the slight reorganisation of hydrogen production in the region.

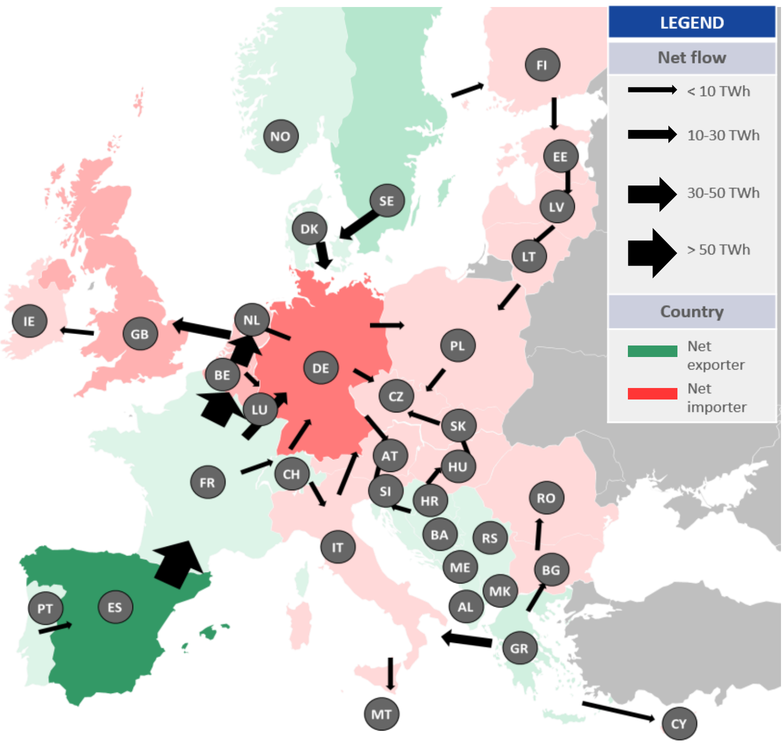

Figure 5-4: Cross-border hydrogen flows, scenario H2-A optimised

Figure 5-5 distinguishes the hydrogen pipelines depending on the type of investment made, namely if a gas pipeline was repurposed or if a new hydrogen pipeline was built. It shows that most hydrogen pipelines are repurposed gas pipelines, except on three routes. Even if new hydrogen pipelines are more expensive than repurposed ones, new pipelines may be preferred because of existing cross-border gas flows or limited gas pipeline capacity. Between FR-ES, IT-GR and DK-DE, the complete cross-border gas capacity is repurposed, and the construction of new hydrogen pipelines is required. Between DE-AT, the gas pipeline is still significantly used (80% utilisation rate, cf. Figure 5-6) and consequently it cannot be repurposed.

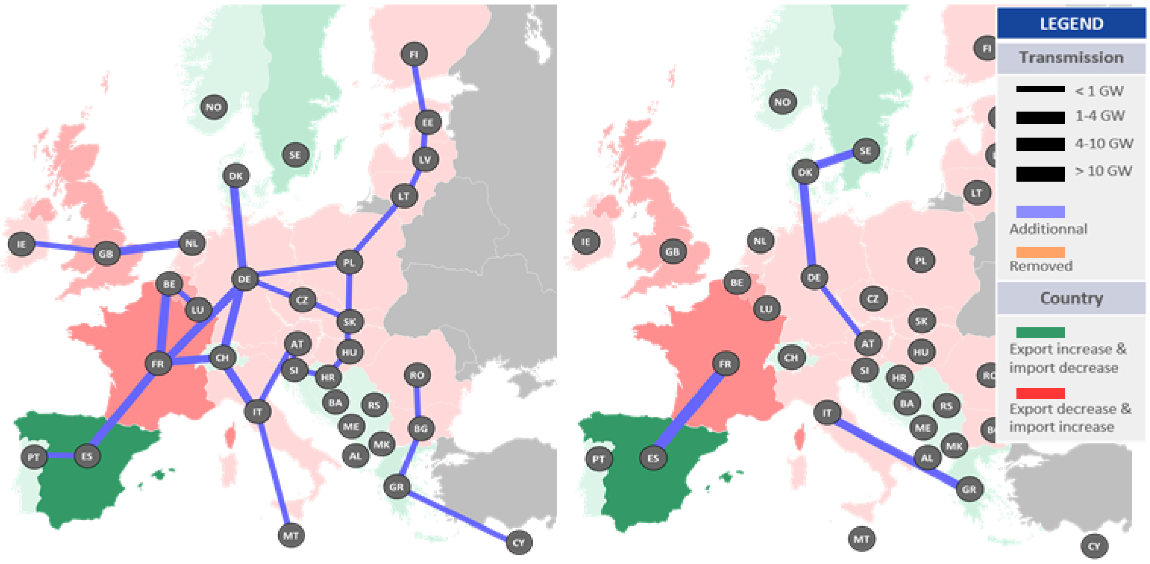

Figure 5-5: H2-A optimised minus H2-A constrained: repurposed pipelines only (left) and new hydrogen pipelines only (right)

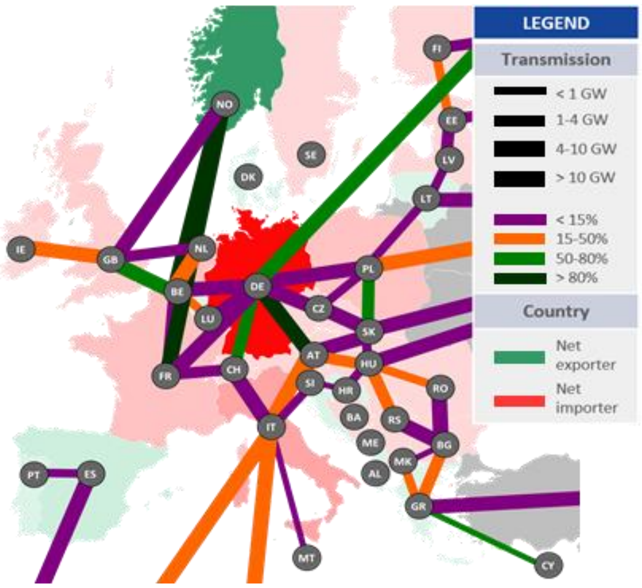

Figure 5-6: Remaining gas capacity under H2-A optimised

5.2.2 ELECTROLYSER CAPACITIES

Investments in electrolyser capacities are optimised across the different scenarios, under the constraint that some countries should feature at least 80% of the installed capacities announced in their national hydrogen strategies. The latter ensures a minimum level of domestic generation in DE, ES, FR, IT, NL and PL.

Import and export patterns identified in Section 5.2.1 are backed by the national electrolyser capacities illustrated in Figure 5-7 and Figure 5-8. ES multiplies its electrolyser capacity by six compared to the minimum level capacity, under an optimised scenario due to significant low-cost RES potentials. Under scenario H2-A constrained, electrolyser capacities in FR increase compared to BAU as FR exports hydrogen to DE and NL. However, under the H2-A optimised scenario, electrolyser capacities in FR as well as in DE, IT, NL and PL drop back to the minimum level derived from the national strategy.

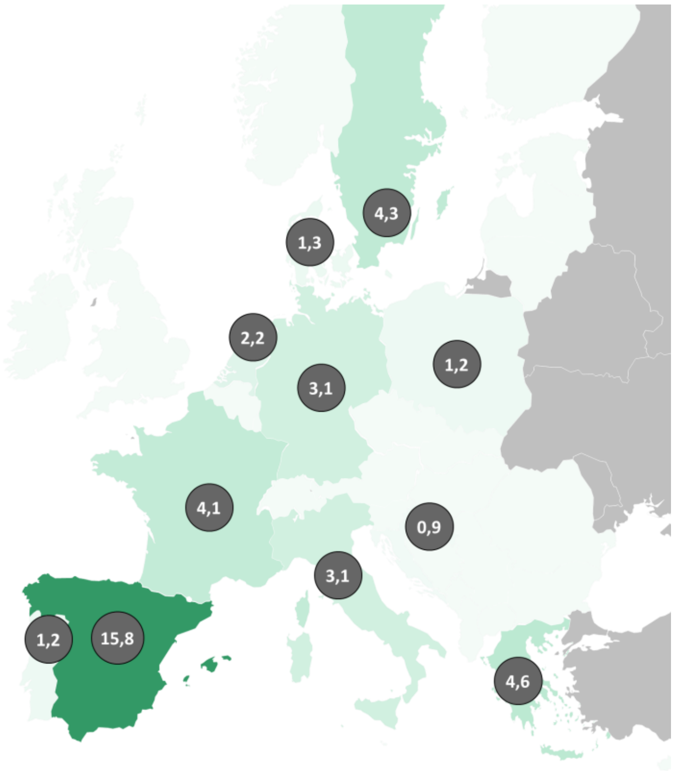

Figure 5-7: Electrolyser capacities per MS, H2-A optimised

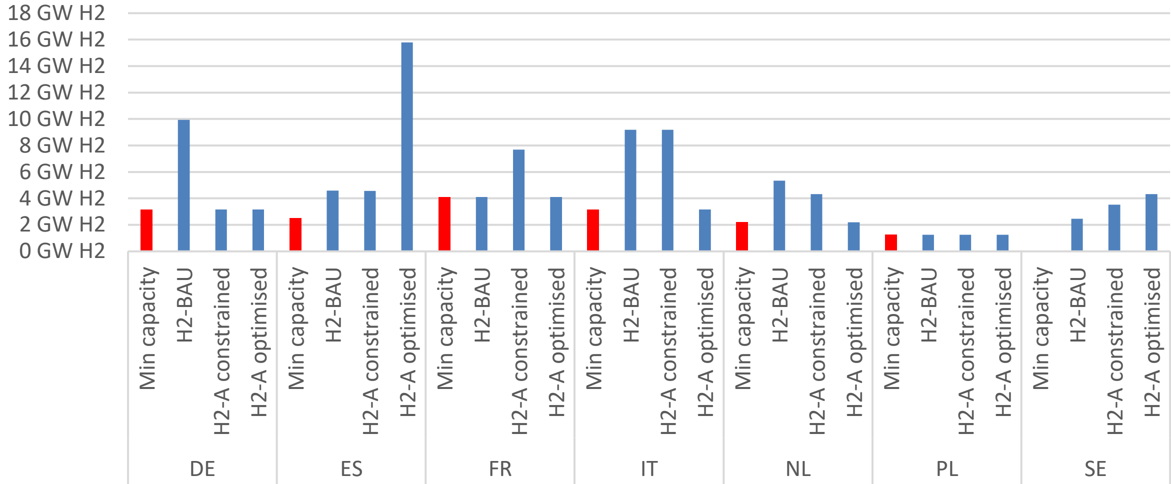

Figure 5-8: Electrolyser capacity in selected EU MSs

The EU-wide capacity-weighted average electrolyser load factor increases from 42% to 60% in the H2-A optimised scenario compared to the H2-BAU scenario as investments are relocated to more favourable locations, which implies also a net reduction in electrolyser capacity from 53 to 42 GW (cf. Figure 5-9).

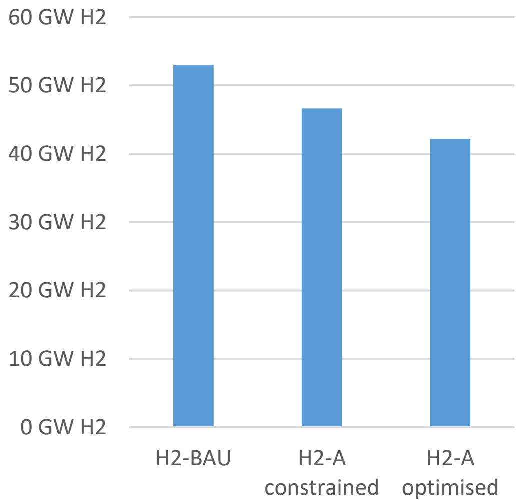

Figure 5-9: Total electrolyser capacity (EU27)

5.2.3 HYDROGEN STORAGE CAPACITIES

In order to ensure a realistic estimate of the investments in hydrogen storage capacities, a maximum potential based on salt cavern availability has been defined[17]. It constrains the spatial distribution across the EU, as most countries do not feature salt cavern potential at all. Therefore, in the scenarios, investments in hydrogen storage capacities only materialise

[17] Based on the estimated technical potential for hydrogen storage in salt caverns in the EU, per MS (storage potential up to 50 km from the shore, excluding repurposing of existing operational salt cavern storages for natural gas). See (Guidehouse & Frontier Economics, forthcoming).

in a few countries, yet without reaching in any scenario or Member State their respective maximum available potential.

Figure 5-10 shows that hydrogen storage is required in all scenarios, either to cope with domestic supply-demand equilibrium (under the BAU scenario, in particular in DE and NL), or with import/export patterns as hydrogen infrastructure connects importing or exporting countries with countries featuring storage (as in FR and ES under the H2-A optimised scenario).

Storage needs are reduced as cross-border connection meets part of the flexibility needs to ensure the supply-demand equilibrium. From 20.8 TWh in the BAU scenario, storage capacity is reduced to 18.3 TWh and 17.9 TWh under the H2-A constrained and H2-A optimised scenarios, respectively. Countries with no potential for hydrogen storage feature loss of load under the BAU scenario (6.2 TWh – BAU – and 2.5 TWh – A-constrained). Loss of load output from the model does not reflect a real security-of-supply issue but rather highly carbon-intensive/expensive electricity consumption, as electrolysers would supply the demand via alternative routes.

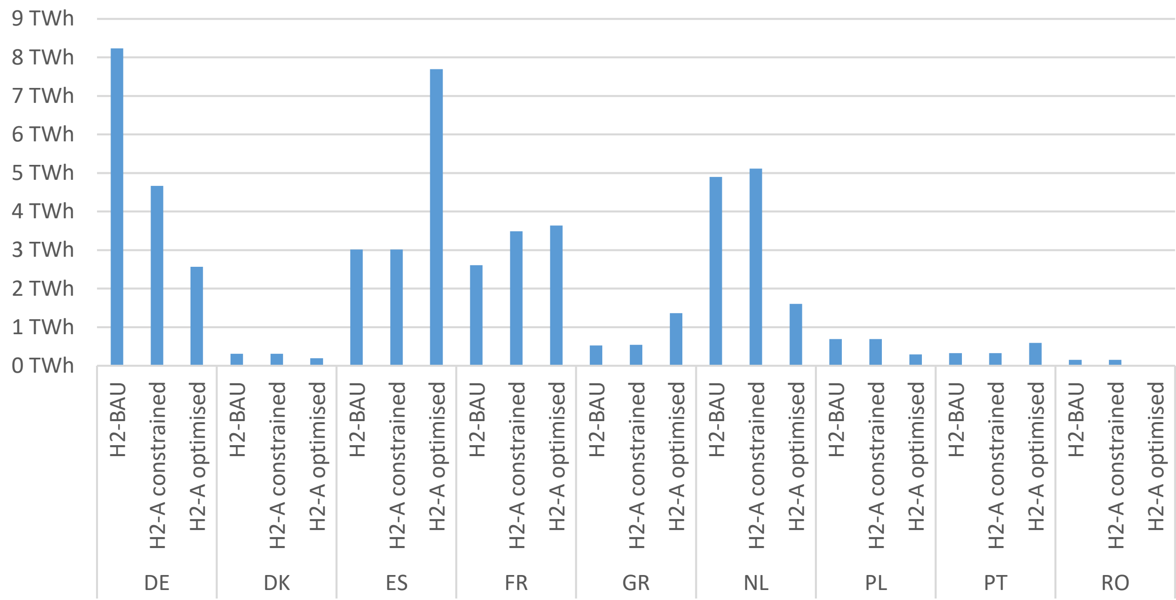

Figure 5-10: Hydrogen storage capacity

5.3 Optimal electrolyser operation

5.3.1 Hourly operation of the hydrogen system

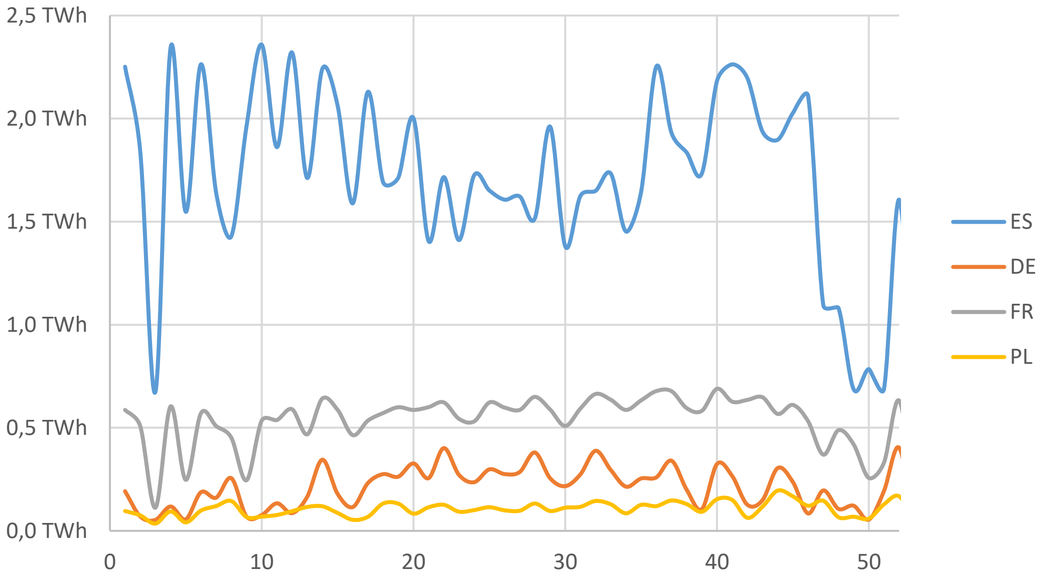

Figure 5-11: Weekly hydrogen production, H2-A optimised

The METIS model runs allow to analyse the dynamics of the hydrogen sector at an hourly granularity, in order to identify the operation patterns and the synergies between the components of this integrated system. Figure 5-11 displays the weekly hydrogen production for some selected Member States. Generation in spring and autumn are higher because of the annual wind generation profile, while it decreases in winter as electricity from the PPA is most useful when resold to the market (as explained in Section 4.2). Figure 5-12 displays the hydrogen supply and demand equilibrium under scenario H2-A optimised, in Germany and France. Hydrogen imports are illustrated via the grey surfaces whereas exports occur when total supply including imports exceeds demand (indicated via the red line). France features both large imports (from Spain) and exports (to Germany), while Germany features large imports only. Storage is used to cope with supply-demand fluctuations both in the domestic and neighbouring markets[18]. The French storage allows to handle both the Spanish production and German demand fluctuations. Eventually, both DE and FR feature a low domestic generation, which is only due to the electrolyser 10%-minimum operation constraint.

[18] The blue area on the graph only shows storage production. When production exceeds demand (the red line), the system may either export hydrogen or recharge the hydrogen storage

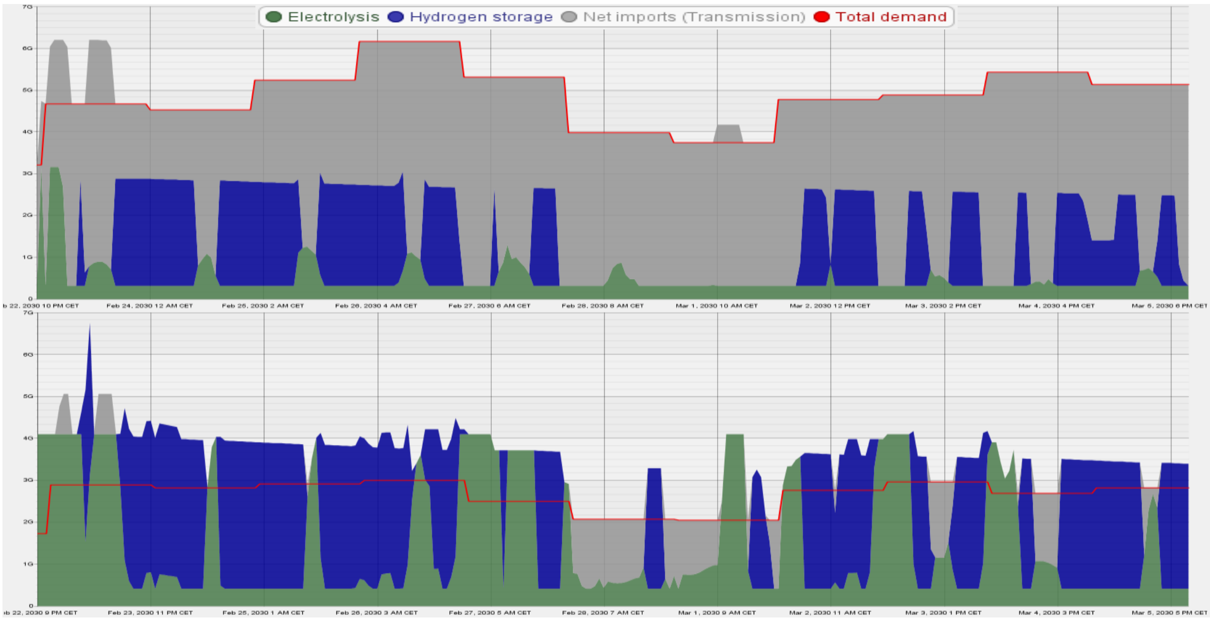

Figure 5-12: Hourly dynamics of the hydrogen supply and demand in Germany (upper part) and France (lower part), February 22th – March 5th

Electricity demand for hydrogen generation can be supplied either through a PPA or sourced from the market (Figure 5-13). In Spain, under scenario H2-A optimised, electricity is partly supplied from the market (grey area, labelled "net imports") and partly from the PPA (onshore wind and a lower share of PV).

The operation constraints previously introduced affect in particular the hourly operation patterns. The 10% minimum load constraint implies a minimum electricity consumption. PPA sourcing competes with supply from the market, and PPA electricity can be sold to the market. Figure 5-13 illustrates this for Spain as an example, where this effect becomes visible at times when electricity supply exceeds electricity consumption of electrolysers, shown as a red line. The electrolyser consumption pattern adapts both to the electricity mix from the market (e.g., high solar-driven production at mid-day hours, reflected on the left of Figure 5-13 by peaky import profiles), and to the renewable mix under the PPA (onshore wind covering a major share of the electricity consumption from electrolysers, visible on the right of Figure 5-13).

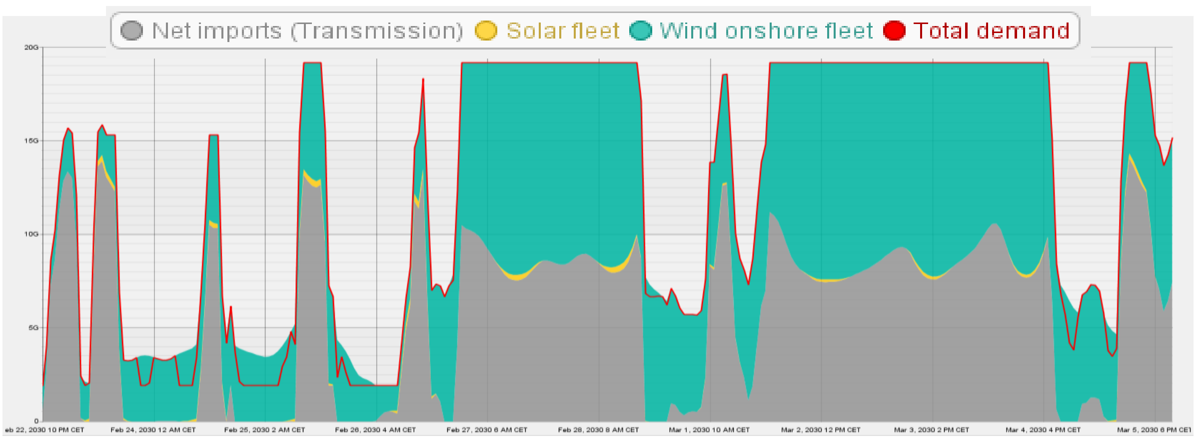

Figure 5-13: Electricity sourcing for hydrogen generation in Spain, February 22th – March 5th

In Poland, hydrogen generation is constrained by market electricity price and carbon-content. The cumulative electricity generation (on the market, see Figure 5-14) displays a major share of gas turbines, and lignite/coal (orange and light orange areas) for peak generation. It translates into limited capability to source from the market due to the carbon-content constraint (cf. Figure 5-15), and favours the development of offshore wind generation on the PPA side, as offshore wind features high load factor, which limits electrolyser oversizing. In contrast, the H2-A optimised-4b sensitivity which does not apply a carbon-content constraint (cf. Figure 5-16) allows for higher market sourcing volumes, and slightly increases the electrolyser load factor.

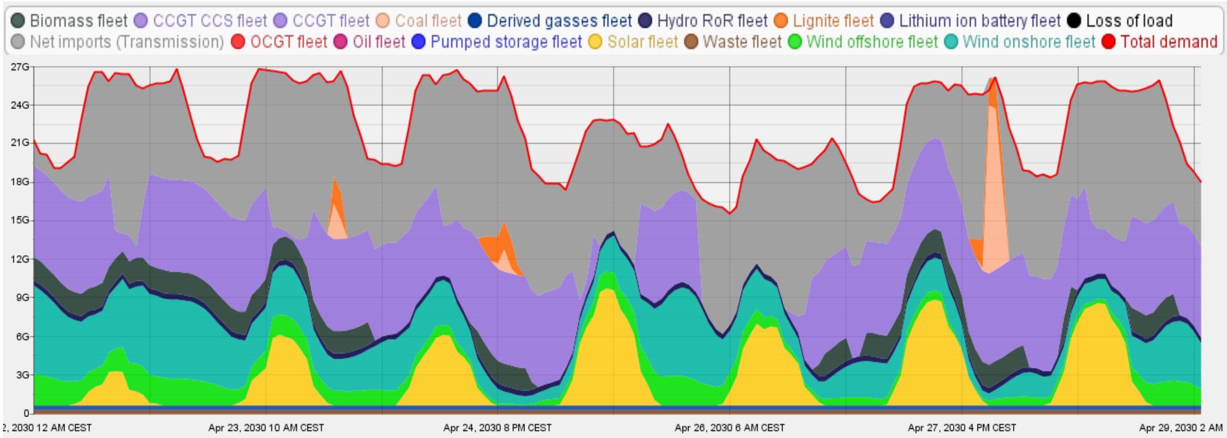

Figure 5-14: Cumulative electricity generation in Poland (market side), April 22th – April 29th

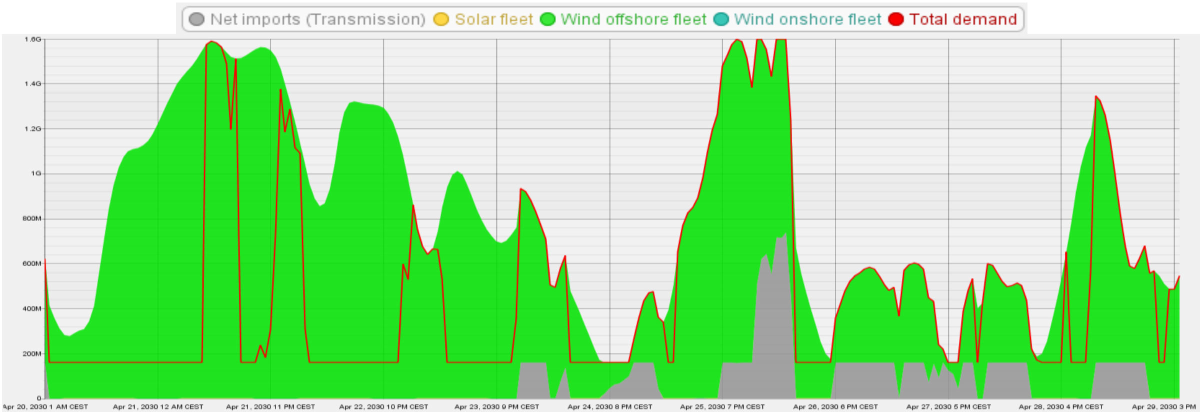

Figure 5-15: Electricity sourcing for hydrogen generation in Poland, H2-A optimised

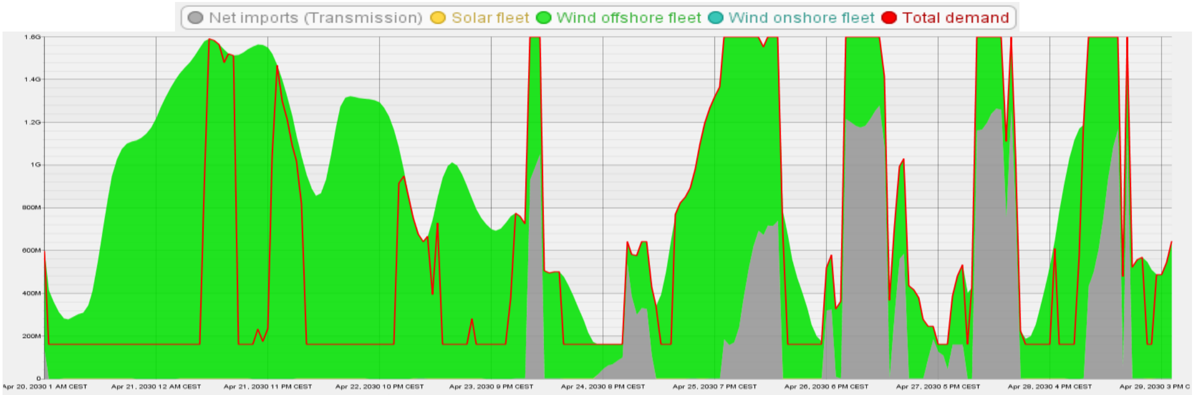

Figure 5-16: Electricity sourcing for hydrogen generation in Poland, H2-A optimised-4b

Comments on storage needs

This study identifies a significant value for storage in terms of flexibility provision[19]. As both the hydrogen demand and the renewable electricity generation feature variable profiles when considered at the hourly resolution, one cannot expect renewable hydrogen generation to meet the demand at every time step.

Therefore, countries that do not feature a hydrogen storage potential (or cannot access one through the cross-border infrastructure) may face some "loss of load" situations (no actual security-of-supply issue), meaning that hydrogen demand could only be met based on the consumption of expensive and carbon-intensive electricity from dispatchable fossil fuels. "Loss of load" reaches 6.2 TWh and 2.5 TWh in the H2-BAU and H2-A constrained scenario respectively (cf. Section 5.2.3), but fully disappears under H2-A optimised thanks to the pan-European hydrogen network.

5.3.2 CO2-CONTENT AND RENEWABLE SHARE INDICATORS

The CO2 content and renewables share are analysed both for the electricity sourced from the market, and for the overall hydrogen production[20]. This section captures and analyses the variations in the two indicators based on the different infrastructure scenarios and electrolyser operation modes. In particular, the impact of the carbon-content constraint on market electricity sourcing is measured.

As displayed in Figure 5-17 and Figure 5-18, market-electricity CO2 content and hydrogen CO2-content vary significantly across Member States, depending on their national power mix and on the share of PPA in hydrogen generation. For instance, Germany has a low PPA share, hence relying mainly on market electricity sourcing for hydrogen production. This market electricity features a carbon-content of approximately 40 kg/MWh, which translates in a similar carbon content for hydrogen generation (carbon-neutral PPA compensates the electrolyser efficiency losses). Yet 75% of its hydrogen is imported, which reduces the carbon-footprint of consumed hydrogen.

In Poland, on the contrary, electricity consumption relies on the PPA, and electricity is not sourced from the market except to meet electrolyser minimum load in hours of no

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[19] In this study, hydrogen storages are considered to be fully flexible on an hourly basis.

[20] Market electricity sourcing indicators are computed based on average market values at the hourly resolution and weighted by the electrolysers' hydrogen production while sourcing from the market:

- Weighted average market CO2 emission factor for electricity used for hydrogen generation. The hourly electricity average carbon content varies depending on the technologies called for dispatch (and the respective CO2 emission factors of the different technologies). When weighted with periods when the electrolyser buys electricity from the market, this provides the average market CO2 emission factor for hydrogen production.
- Weighted average RES-E share for electricity used for hydrogen generation

Hydrogen production indicators are computed based on the overall hydrogen production:

- Hydrogen renewable share
- Hydrogen CO2 emission intensity

renewable power generation[21]. Despite Polish market electricity being highly carbon-intensive (CO_2 content in market electricity reaches 123 kg/MWh – but does not exceed 12 kg/MWh when sourced not to meet the minimum load), hydrogen CO_2 content is limited to 17 kg/MWh_{H2}. As discussed, this is due to the high renewable electricity generation via the PPA.

Removing the electricity CO2-content constraint under "-4b" model runs significantly increases hydrogen CO2-content, as electricity is sourced irrespective of its carbon-content and renewable power via the PPA is only purchased if economically reasonable.

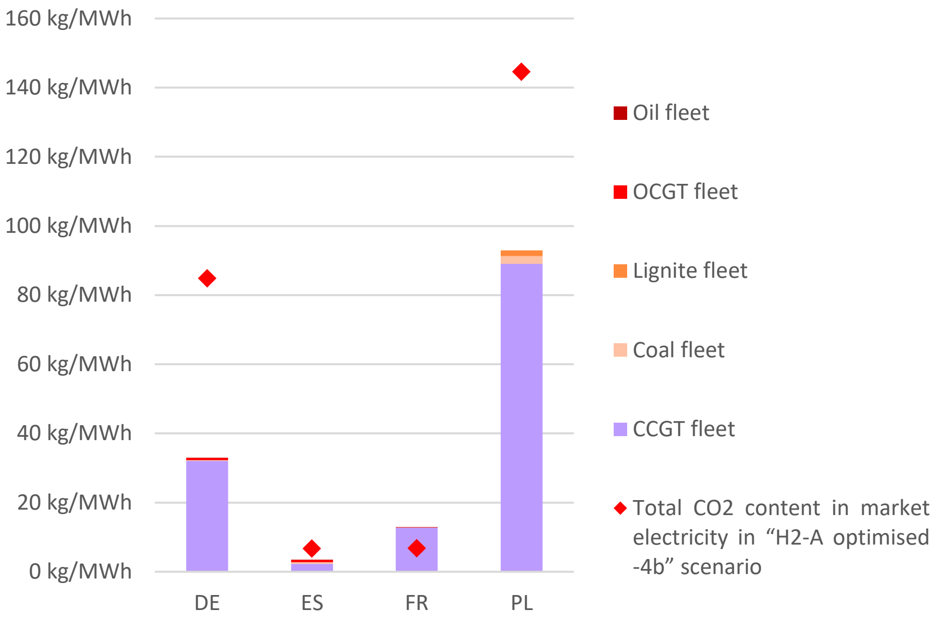

Figure 5-17: H2-A optimised - CO2 content in market electricity

[21] Reminder – the carbon constraint on market sourcing applies in two ways:

- When the electrolyser has to meet the 10%-minimum load, there is no threshold on the market electricity carbon content.
- In any other time, under scenarios "4a", market sourcing is allowed only if the carbon content is lower than 60 kg/MWh. Under "4b", this constraint is removed.

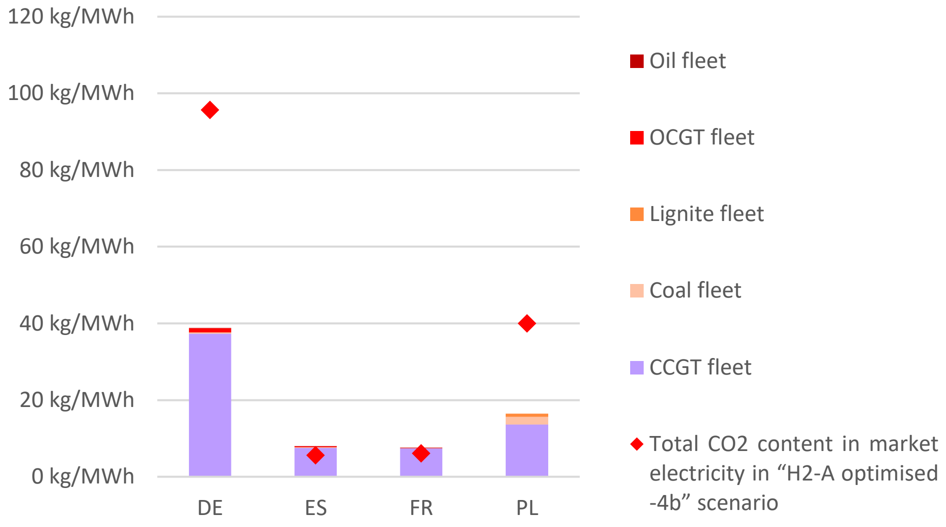

Figure 5-18: H2-A optimised - Hydrogen CO2 content

The hydrogen renewables share varies across Member States. It depends on national mixes (vRES share in market electricity consumption) and electrolyser operation constraints (how much electricity can be effectively sourced from the market). Given the sourcing constraints and economic operation of the electrolyser, as displayed in Figure 5-19, electricity sourced from the market captures a vRES-share higher than the national average. In particular, it favours solar generation, which produces features a relatively peaky profile and correlated with low electricity prices.

Only countries with a large PPA generation resell electricity to the market (IT, GR, PL, see Figure 5-20). In total, 17 TWh are resold to the market under H2-A optimised (against 126 TWh produced by the PPA, and 170 TWh sourced from the market). Electricity is sold either when renewable generation exceeds electrolyser capacity, or when it is economically interesting to sell the electricity rather than to generate hydrogen (e.g., when electricity prices are high). The frequency of such situations varies between countries. In Spain they occur during 900 hours per year (among which, 400 hours higher than 1 GW), in France during 1,000 hours per year (among which, 140 hours higher than 1 GW).

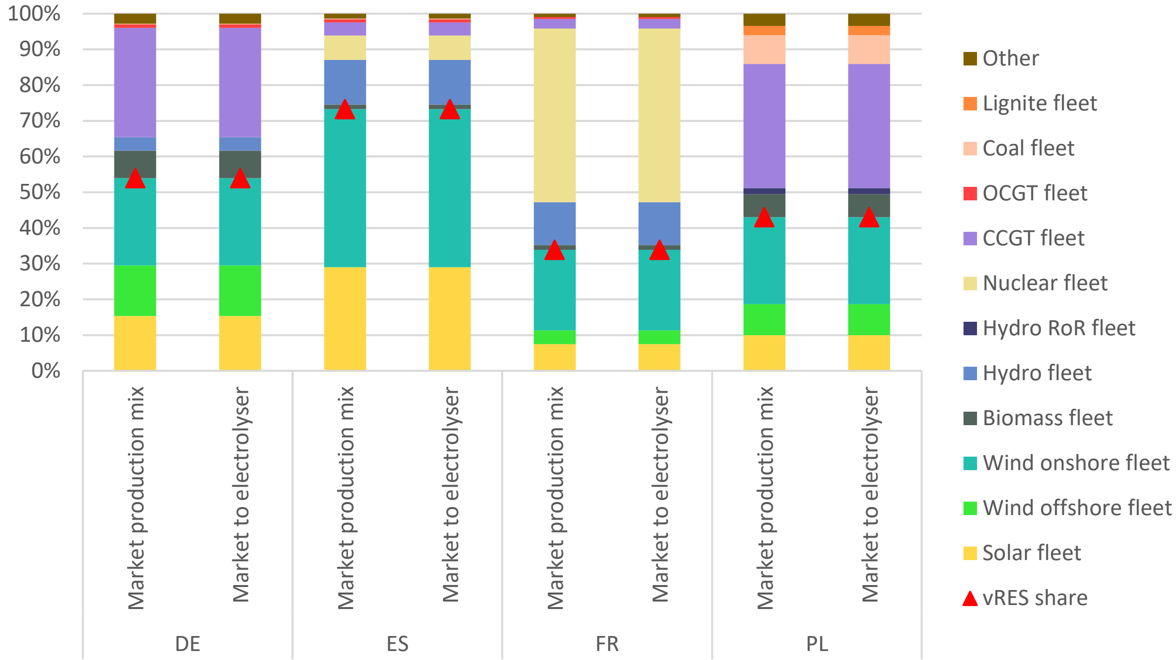

Figure 5-19: H2-A optimised - vRES share (red triangle) and energy mix of the national power systems and of the electricity purchased by electrolysers from the market

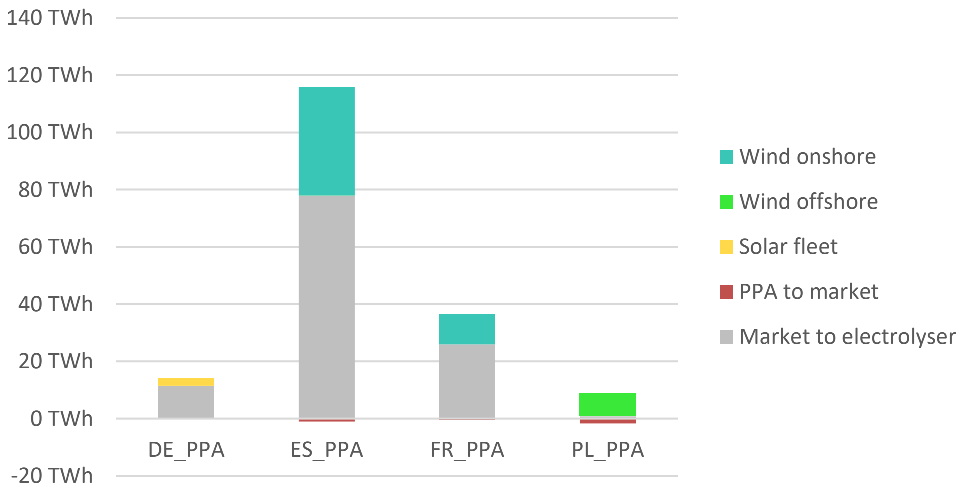

Figure 5-20: H2-A optimised - Market purchases/sales vs. dedicated vRES generation via the PPA

On the PPA side, vRES deployment varies across Member States (see Figure 5-21). Some Member States largely invest in the PPA and reach the upper capacity limit, some stick to the lower limit, and investments are made both in onshore/offshore wind, and solar PV. These investment decisions are driven by several trade-offs[22]:

- Electrolysers relying mostly on market electricity (low electricity market prices, large market surpluses) do not require strong renewable generation on the PPA

[22] As a reminder, investment in vRES capacities on the PPA side is optimised from a system-cost perspective, i.e. considering vRES CAPEX, and within a pre-defined corridor. No additional investments in renewables on the market side can be made (the model sticks to the MIX H2 values).

side. Therefore, the PPA typically involves investments in low-cost renewables in association with low load factors (e.g., solar PV in DE and NL). They often stick to the 75%-minimum vRES capacity with respect to electrolyser capacity[23].

- Electrolysers relying mostly on the PPAs prefer onshore/offshore wind as it features a flatter profile, high load factors (see Figure 5-22) and consequently avoids electrolyser oversizing. Among those countries that prefer wind, some of them invest up to the 125%-maximum vRES capacity (compared to electrolyser capacity). Indeed, flat wind generation profiles combined with 25-50% electrolyser load factors reduce the amount of renewable electricity that is sold to the market, even if the vRES plant is oversized. Generally speaking, countries exploit the vRES corridor to different extent depending on the price at which these surpluses are sold to the market. For instance, as displayed in Figure 5-34, electricity prices are higher in Italy than in France, hence vRES investments are favoured.

Therefore, the vRES mix of national PPAs may differ from the market vRES mix as production profiles and average load factors are additional parameters to consider when investing in the PPA (e.g., to ensure complementary with the price and vRES share pattern of electricity sourced from the market), while sourcing from the market (and the respective vRES mix) is mainly driven by capacity cost-minimisation.

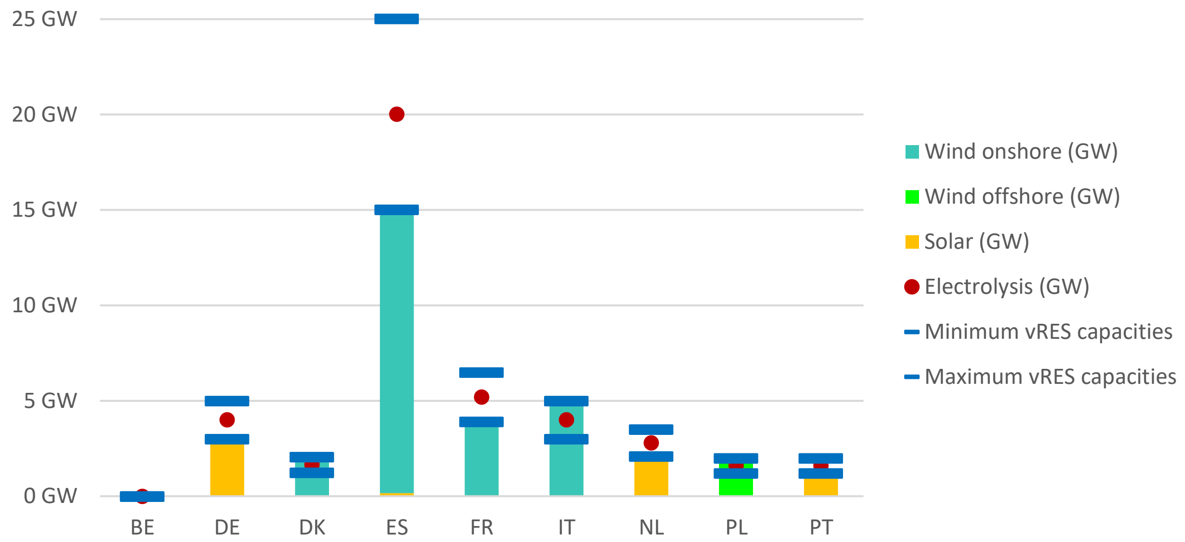

Figure 5-21: H2-A optimised - PPA vRES and Electrolyser installed capacities

[23] vRES capacity on the PPA side would likely be lower if the 75%-constraint was not enforced.

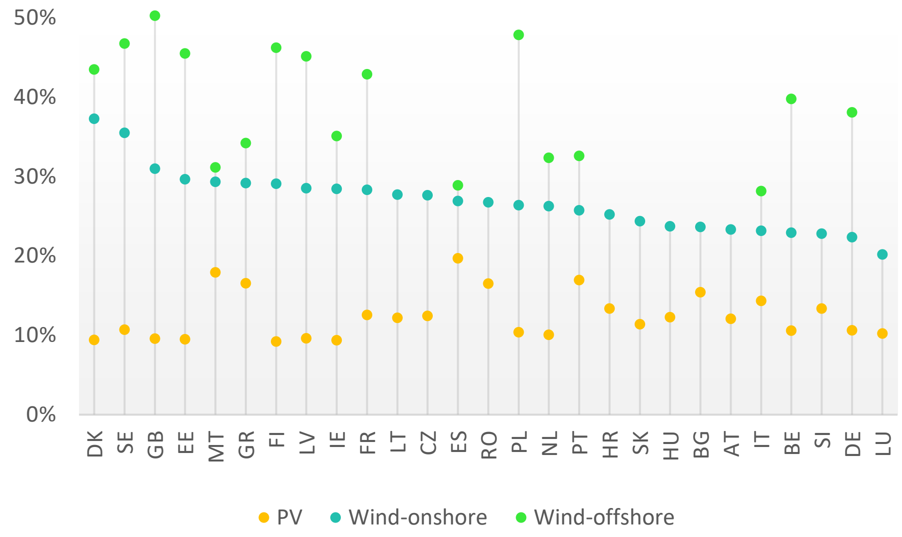

Figure 5-22: vRES load factors as per the MIX H2 scenario

At the EU27 level, up to 57% (170 TWh in H2-A optimised) of electricity consumption for hydrogen generation is sourced from the market (see Figure 5-23). Up to 32 TWh of electricity are resold to the market, under the H2-BAU or H2-A constrained scenarios.

As displayed in Figure 5-24, the hydrogen CO2 content is reduced by half as more cross-border capacities become available (H2-A optimised vs H2-BAU). Most favourable sites (in economic terms) are also those with the lowest CO2-content in hydrogen generation. Removing the carbon-content constraint on market sourcing raises the hydrogen CO2 content by 160% under the BAU scenario, but only 130% under A-optimised: cross-border integration reduces the impact of the electrolyser operation mode on CO2 emissions. Overall, the renewable share of hydrogen production is rather stable, between 70% and 80% (see Figure 5-25).

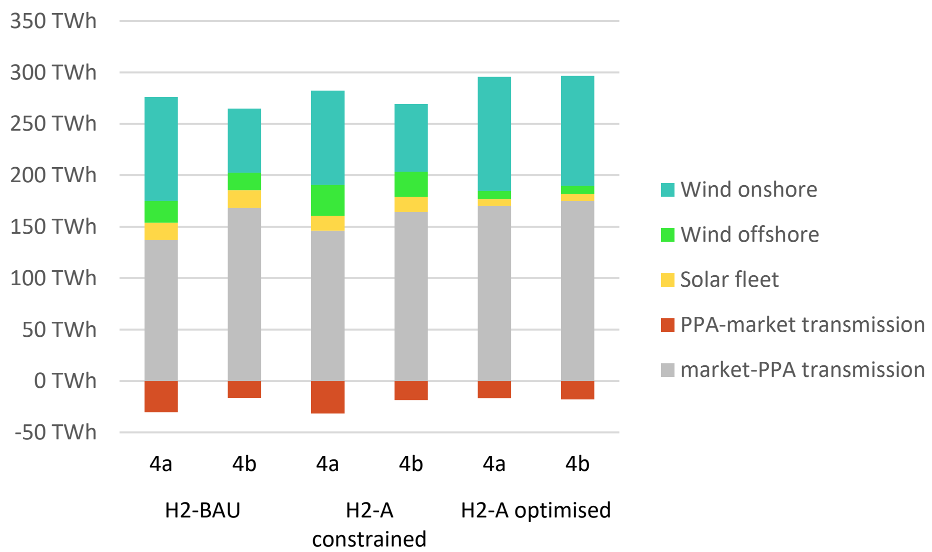

Figure 5-23: Market vs. PPA electricity consumption for hydrogen generation

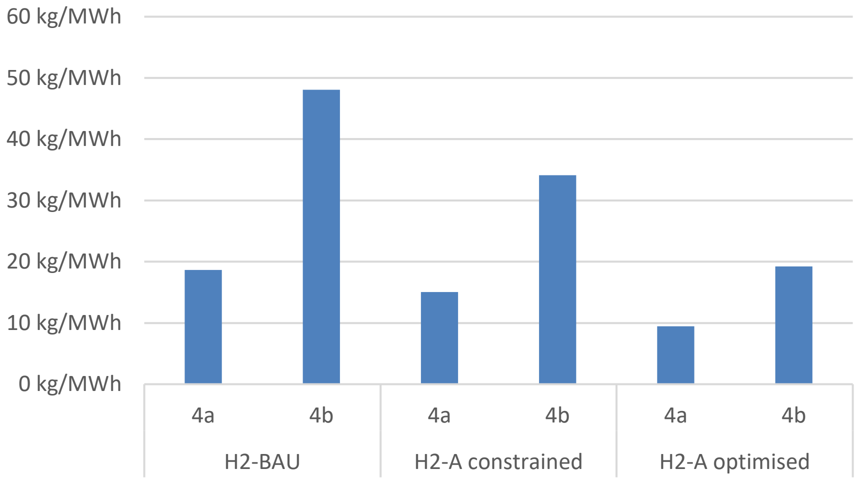

Figure 5-24: Hydrogen CO2 content

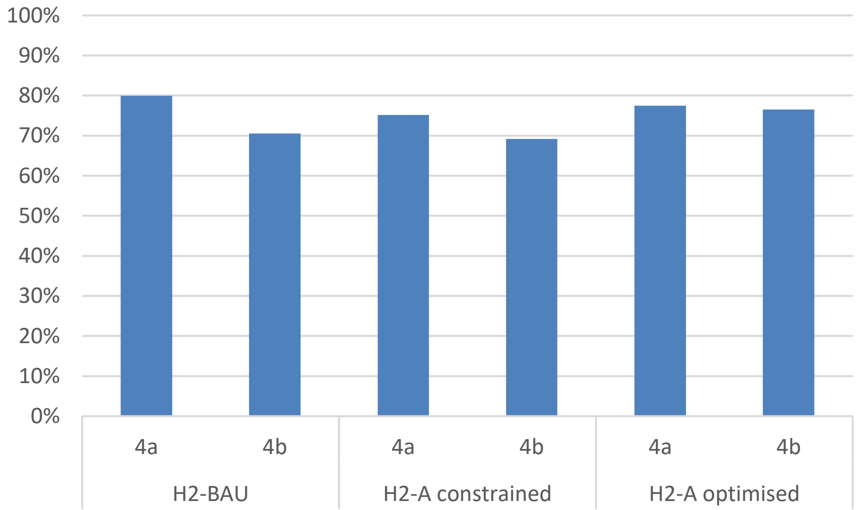

Figure 5-25: Renewables share in hydrogen production

System-wide CO2 emissions exceed the BAU emissions by up to 13 MtCO2 across scenarios (see Figure 5-26, it corresponds to 2.5% of total BAU emissions). System emissions are higher under scenarios "-4b", as the removal of the market electricity carbon-content constraint allows for a share of electricity sourced from the market to be produced by gas turbines (up to 80 TWh of additional gas consumption in gas power plants). As the system gets more integrated, CO2-emissions decrease under "-4b" scenarios, while they increase under "-4a" scenarios, by finally converging. This is partially driven by the quantity of electricity resold from the PPA to the market, which contributes to the reduction of gas consumption and which is higher under H2-BAU and "-4a" scenarios.

As displayed in Figure 5-27, curtailment is reduced by 9% under more integrated scenarios, driven by electrolyser reallocation to countries featuring lower LCOE, but also higher RES-E surpluses. Yet, total curtailment corresponds to 0.6% of total vRES generation (the latter corresponding to around 1750 TWh in the H2-A optimised scenario).

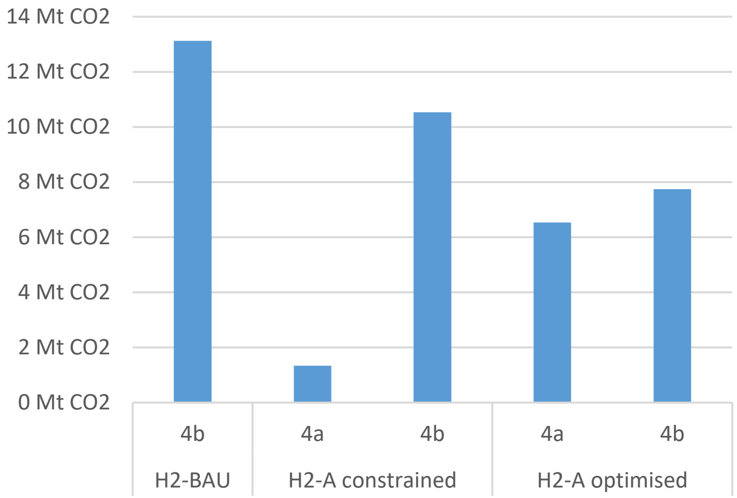

Figure 5-26: CO2 emissions compared to H2-BAU 4a

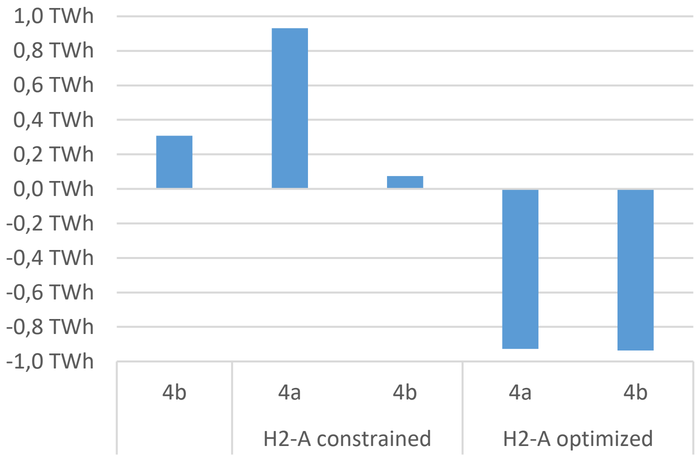

Figure 5-27: Curtailment compared to H2-BAU (11 TWh)

5.3.3 ELECTROLYSER CONTRIBUTION TO FLEXIBILITY NEEDS

In order to assess to what extent electrolysers supply flexibility to the power system, we have adopted the flexibility assessment framework developed in the context of the Mainstreaming RES study[24]. The first step is to assess the flexibility needs of the power system, on different timescales. The second step requires to compute the contribution to flexibility needs, which indicates the role/magnitude of the different technologies to meet the flexibility needs. See Annex 8.3 for the mathematical definition of flexibility needs and the contribution of individual technologies to meet the quantified flexibility needs.

As shown in Figure 5-28, total flexibility needs are stable across the four scenarios – as the final electricity demand remains unchanged. Electrolyser contribution to meet flexibility needs is significant, in particular at daily and weekly timescales, where it covers up to 6% and 7%, respectively, of total needs. It contributes by absorbing vRES surpluses on the market.

[24] (European Commission, 2017)

Yet electrolyser contribution varies across the four scenarios. In particular, as access to the market is facilitated (scenario 4b), hydrogen production relies more heavily on market sourcing, making the latter « follow the hydrogen demand », in particular in countries where no storage is available. It translates in a reduction of electrolyser contribution to flexibility needs. E.g., in scenario H2-BAU-4b (no cross-border capacities thus no mutualisation of hydrogen storages), electrolyser contribution is negative (i.e. the electrolyser load profile increases the flexibility needs).

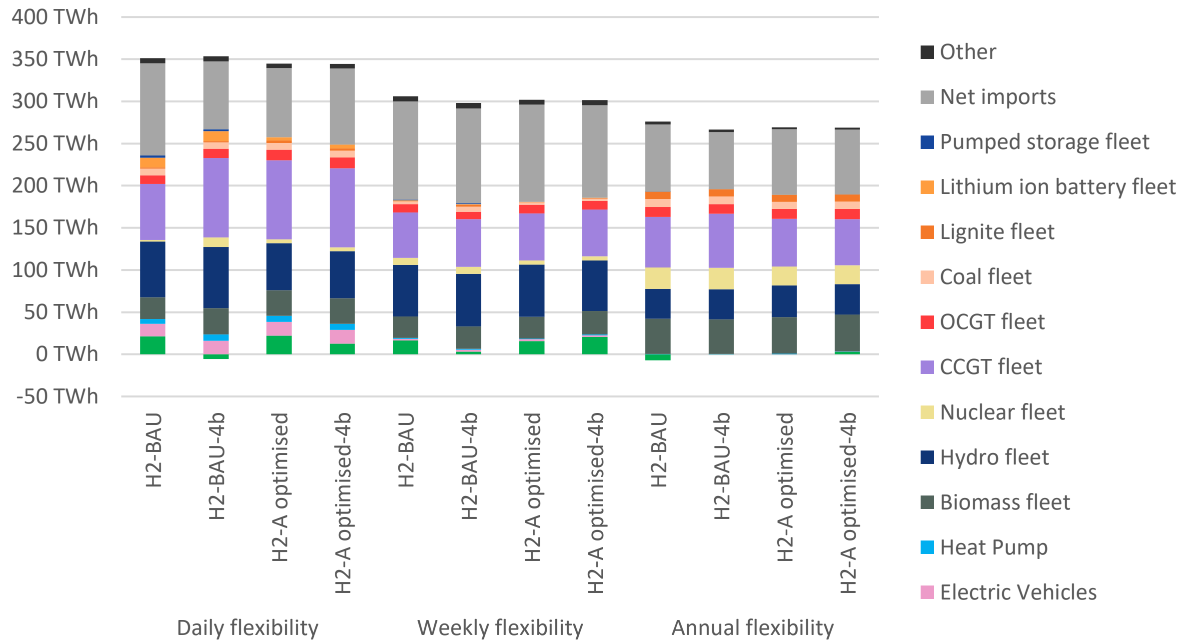

Figure 5-28: Contribution to flexibility needs by technology and scenario

In comparison, the electrolyser contribution is much more significant in the METIS2-S6 study[25] (based on LTS scenario 1.5TECH for 2050), cf. Figure 5-29. Indeed, this 2050 EU energy scenario features higher vRES capacities and a stronger hydrogen demand, as electrolysis is responsible for approximately half of the electricity demand.

[25] (Artelys, 2021)

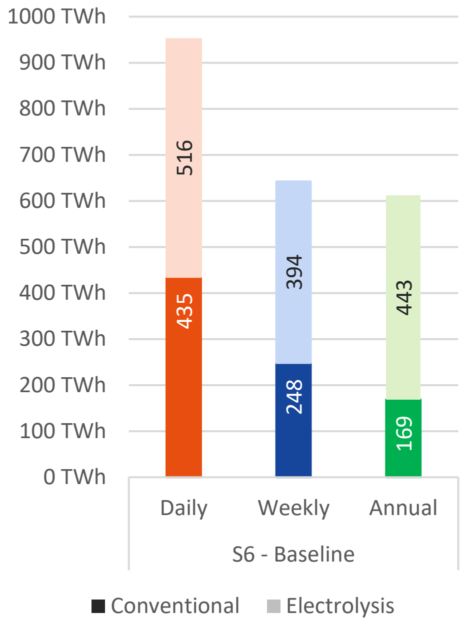

Figure 5-29: Flexibility needs and contribution of the electrolyser assessed in the METIS2-S6 study

5.4 AVERAGE COST OF HYDROGEN

To clearly capture the different cost-components of the hydrogen system, three different types of economic indicators were evaluated.

Total system costs cover all cost components of the system, including natural gas supply, electricity and hydrogen generation. Both variable costs and variations in investment costs between the scenarios are calculated.

Hydrogen cost of delivery covers "first order costs", i.e. capital and operational costs (representing a minor share) for the electrolyser, renewable capacities on the PPA side, and hydrogen infrastructure. Variations in electricity production cost (on the market side, i.e., the electricity price) are excluded from this indicator. This indicator relates to domestic hydrogen production.

The *total hydrogen supply costs* refer to the capital and operational costs of electrolysers, hydrogen interconnection and hydrogen storage capacities (reflected by the hydrogen infrastructure-components of the cost of delivery) plus the hydrogen market price[26]. Given that the determination of the hydrogen price requires an additional round of METIS

[26] The hydrogen market price corresponds to the price which would be obtained after clearing the hydrogen market. Similarly, as for the electricity markets, it represents the variable cost of producing the last (and most expensive), i.e. the marginal unit of hydrogen to meet demand. When summing to the annual average, the hourly hydrogen market price is weighted by the hourly electrolyser production.
Variable costs are largely given by the electricity price that has to be paid by an electrolyser to produce an additional unit of hydrogen. The electricity price relates to the PPA and to the costs related to electricity purchases from the market (or revenues from sales of PPA production to the market). In the following, the hydrogen price is split into these two components, electricity purchase costs and PPA costs.
It is important to note that the hydrogen price reflects the hourly electricity price, and hence, the marginal electricity generation costs of a country, integrating the producer surplus (pay-as-clear). In this regard, it is different from the LCOE, which includes exclusively capital and operational costs.

modelling (considering only variable generation costs, keeping all capacities fixed), the hydrogen prices and thus total hydrogen supply costs were only computed for the major scenarios.

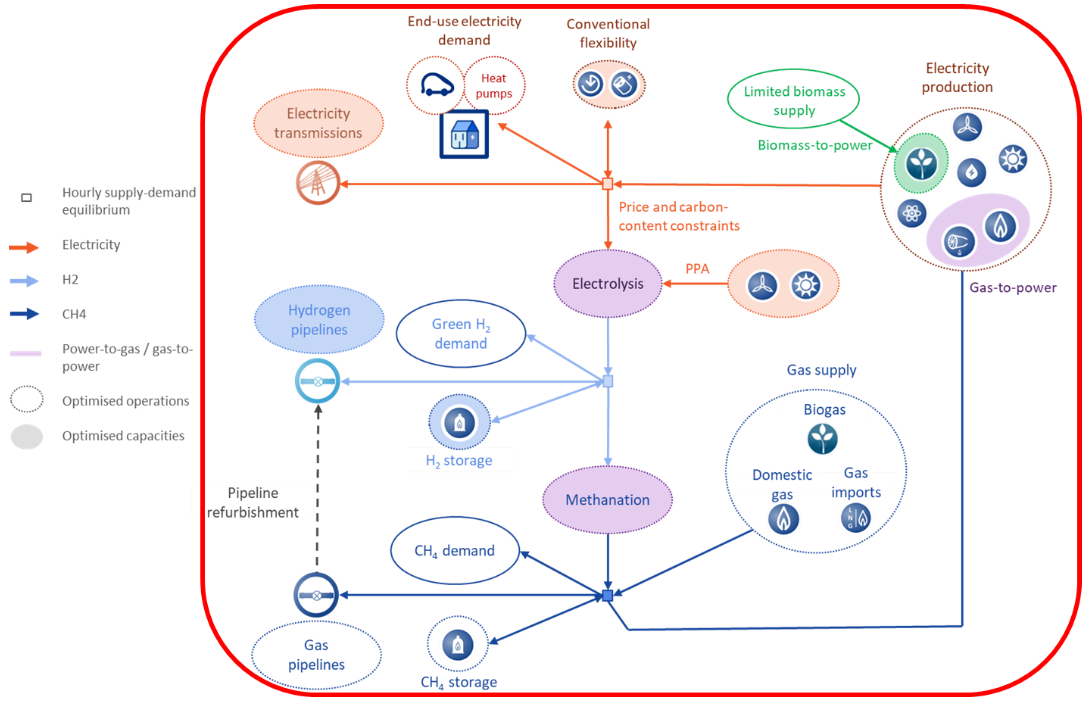

Figure 5-30: Total system costs. Scope of costs indicated by red box: operational and investment costs

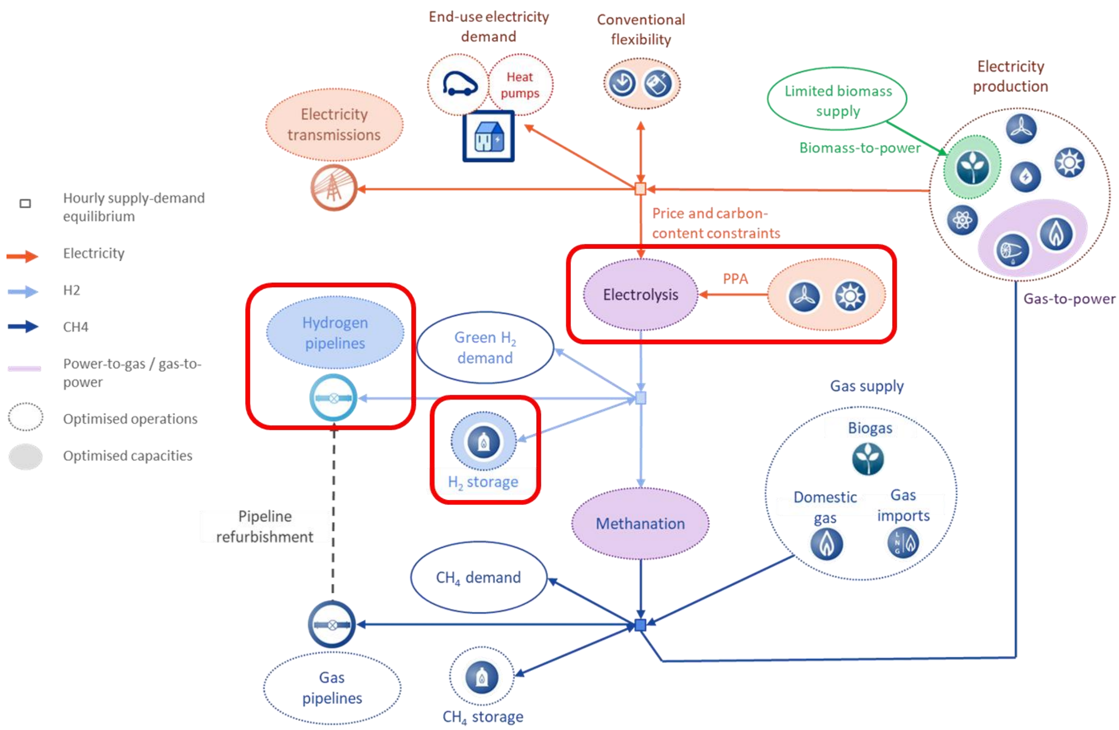

Figure 5-31: Hydrogen cost of delivery. Scope of costs indicated by red boxes: operational and investment costs

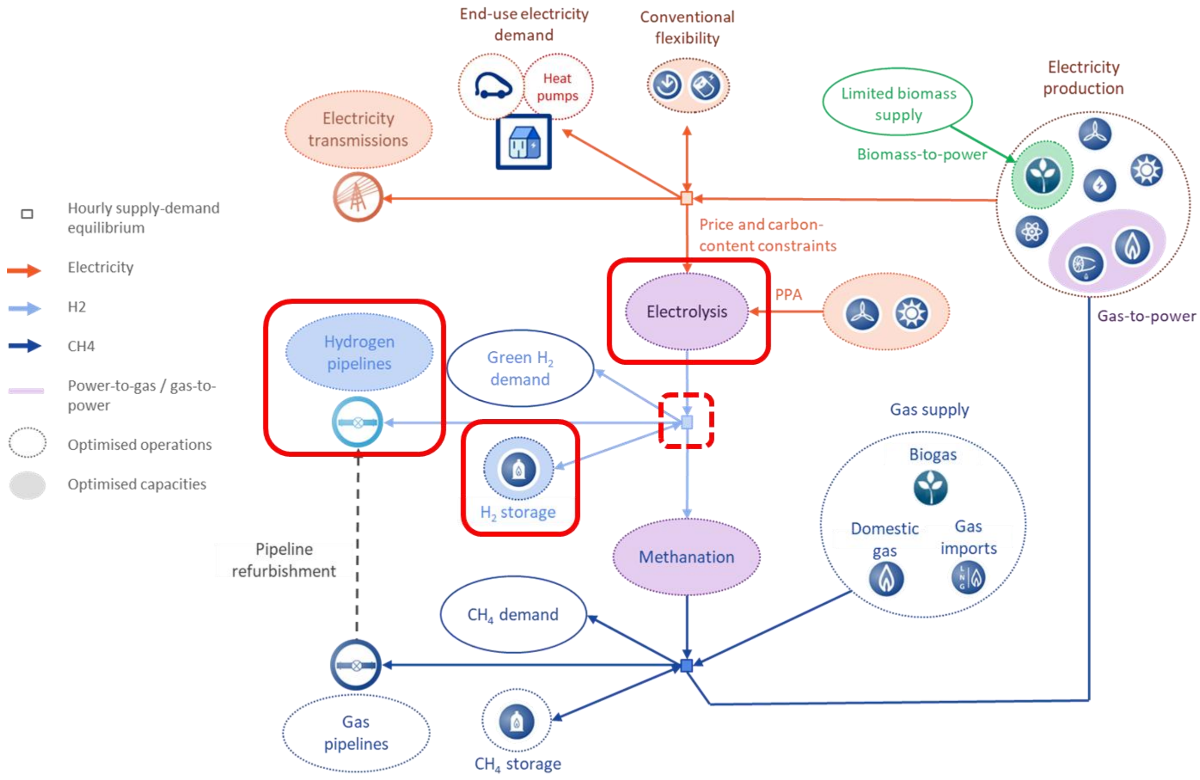

Figure 5-32: Total hydrogen supply costs. Scope of costs indicated by dotted red box: market price – scope of costs indicated by red boxes: operational and investment costs

5.4.1 COST-EFFICIENT ALLOCATION OF HYDROGEN GENERATION ACROSS THE EU

In the H2-A optimised scenario, hydrogen generation is distributed across Europe according to trade-off between production costs and cross-border connection. This is found to translate into important import/export flows. As displayed in Figure 5-33, production is centralised in the most favourable Member States, such as ES, GR and SE while other countries run exclusively on imports. In total, hydrogen demand reaches 200 TWh in the EU27, and 220 TWh in the EU27+UK.

Two cost components drive the reallocation of hydrogen generation capacities between MSs: the hydrogen cost of delivery (which is driven by the PPA price and the electrolyser load factor) and the availability of low-cost and decarbonised electricity on the market[27] (see Figure 5-34). The availability of such supporting factors varies significantly between Member States. Spain is the largest hydrogen producer thanks to its low PPA price and high number of hours featuring low electricity prices on the market. Sweden has a low PPA price, yet reduced benefits from running on market electricity. Poland has both an

[27] When PPA uptake is high (most electricity sourced from the PPA), hydrogen cost of delivery is higher than PPA price (as the cost of delivery includes the electrolyser cost, among others, while the PPA price does not). When PPA uptake is low compared to market sourcing (large amounts of low-cost electricity sourced from the market), the hydrogen costs of delivery may be lower than the PPA price (as in such conditions the PPA price only makes a small share of the cost of delivery).

expensive PPA and reduced market availability, yet the 80% national strategy-based minimum electrolyser capacity triggers domestic hydrogen generation[28].

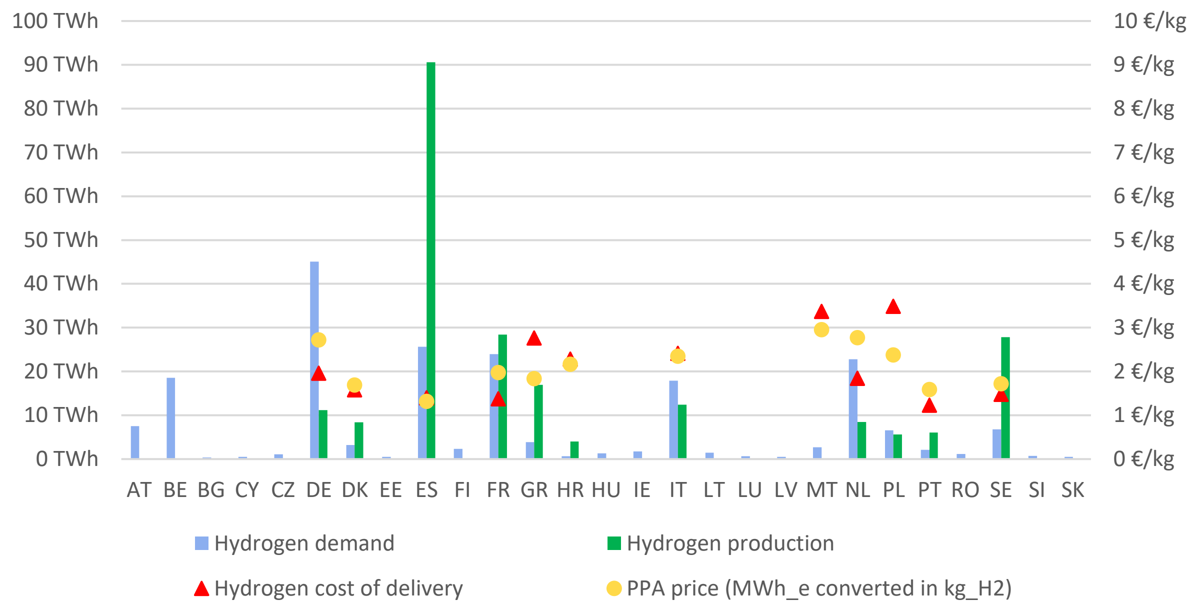

Figure 5-33: Distribution of H2 production and cost of delivery over the EU under H2-A optimised

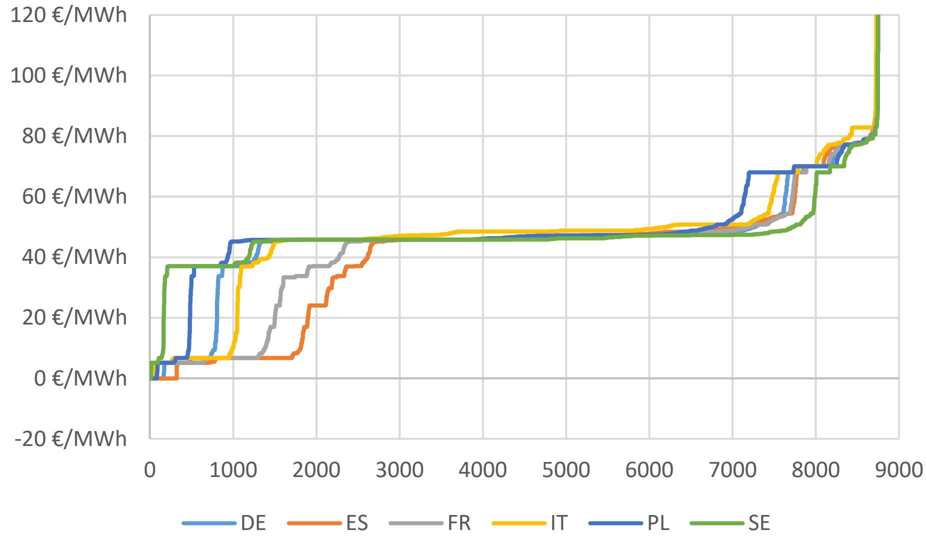

Figure 5-34: H2-A optimised, market electricity price duration curve

Cross-border integration strongly impacts the cost distribution for hydrogen production across Europe: the average and median price (displayed in Figure 5-35) decrease with cross-border integration and production reallocation. Between the H2-BAU and H2-A

[28] A minimum electrolyser capacity is set for DE, NL, PL, ES, FR, IT to ensure coherence with national strategies. Without this constraint, some countries (e.g., FR, which is close to ES) might meet the entire national hydrogen demand via imports (given the large variations in cost of delivery between Member States, it is more cost-efficient to produce at favourable locations and pay increased transport cost). See sensitivities in Section 0.

optimised scenarios, median hydrogen cost of delivery is reduced by 47%. The production-weighted EU average decreases by 27%.

Countries featuring high costs of delivery meet their entire hydrogen demand via imports in the optimised scenarios. This translates into a strong reduction of maximum national cost of delivery in the EU, by 23%. On the other hand, countries featuring low hydrogen costs of delivery satisfy hydrogen demand in other countries under the optimised scenarios, resulting in a 28% increase of their cost of delivery[29]. Overall, there is a convergence of costs across the EU, as the cost variation across MSs is approximately reduced by half.

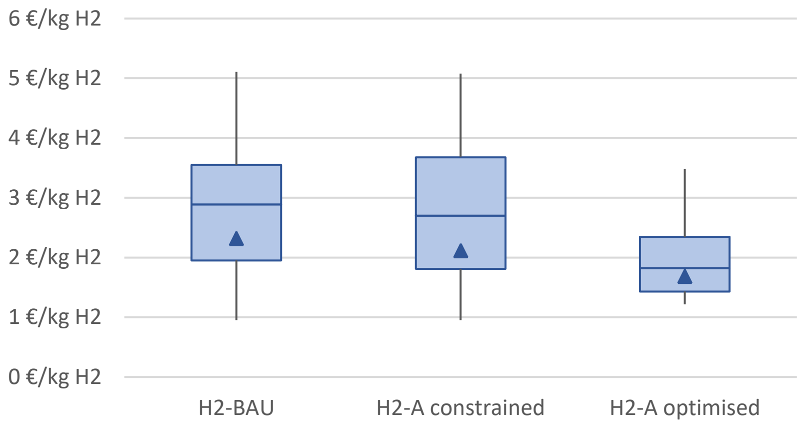

Figure 5-35: Hydrogen cost of delivery distribution across EU27 Member States. The boxplot displays the distribution of production costs across Member States. Minimum and maximum values, along with first quartile, median and third quartile values are shown. EU weighted-average cost of delivery is depicted by the triangle.

5.4.2 HYDROGEN COST STRUCTURE ACROSS SCENARIOS

The largest components of the hydrogen costs of delivery are the electrolyser and renewable/PPA capacities (Figure 5-36). Storage follows third with 11% on average across scenarios. The transport infrastructure (investments in new or repurposed pipelines, covering all cross-border capacities) only accounts for a very limited share of costs in comparison to electrolyser/vRES costs (approx. 3% of total costs in H2-A optimised).

Higher cross-border capacities bring significant cost reductions (Figure 5-37). In particular, they lead to reduced investments in offshore wind (as less-expensive renewable potentials may be exploited), to reduced investments in electrolyser capacities (higher load factors), and to a comparatively little increase in pipeline costs.

[29] Similarly, as for electricity cross-border exchanges, increase in production costs comes along with an increase in social welfare both in the importing and exporting countries.

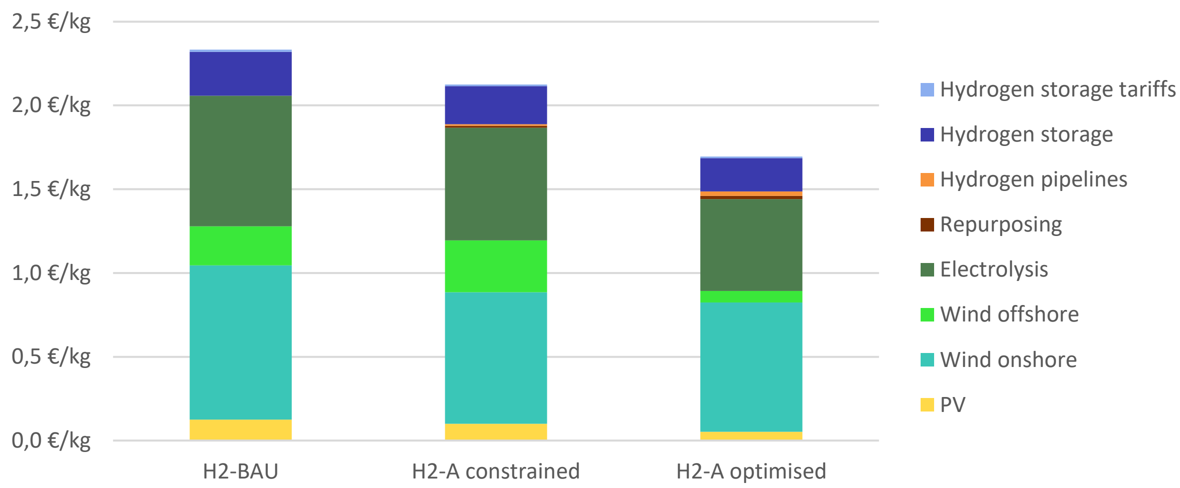

Figure 5-36: Hydrogen costs of delivery

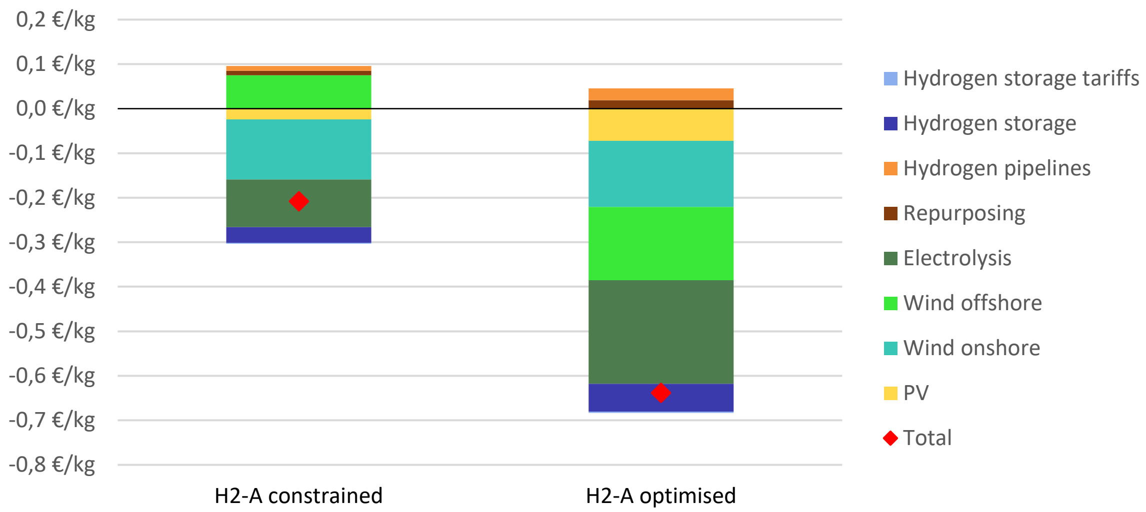

Figure 5-37: Hydrogen costs of delivery compared to H2-BAU

With respect to the total hydrogen supply costs (i.e., including costs related to power purchase from the market), savings under the H2-A constrained and the H2-A optimised scenario are even more important, reaching 22% in the optimised scenario (cf. Figure 5-38). As outlined in Figure 5-39, the optimised pan-European hydrogen network triggers savings in electricity purchase and PPA costs (as electrolysers are preferably located in countries featuring low electricity market prices or low-cost RES-E potentials), in capital costs for electrolysers (due to an enhanced utilisation rate) and storage. The cost increase related to the build-out of the hydrogen network is comparatively marginal.

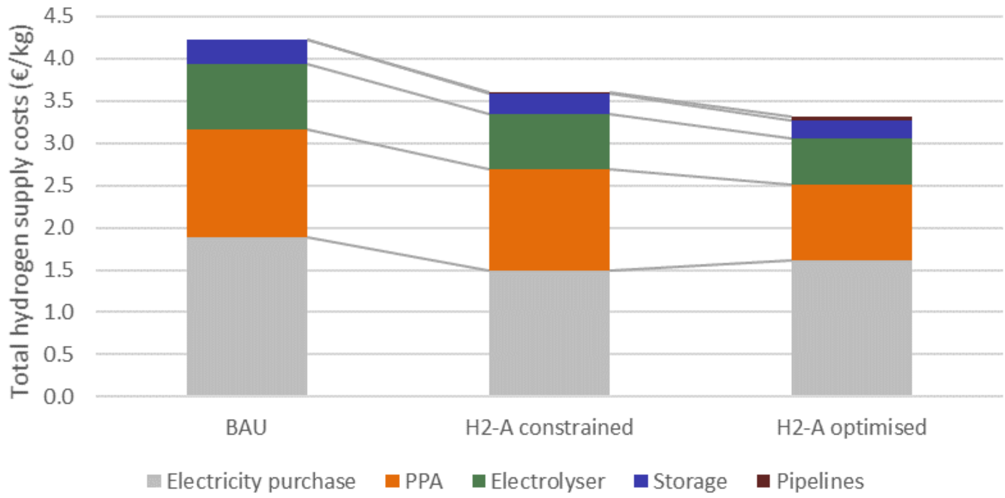

Figure 5-38: Total hydrogen supply costs by scenario

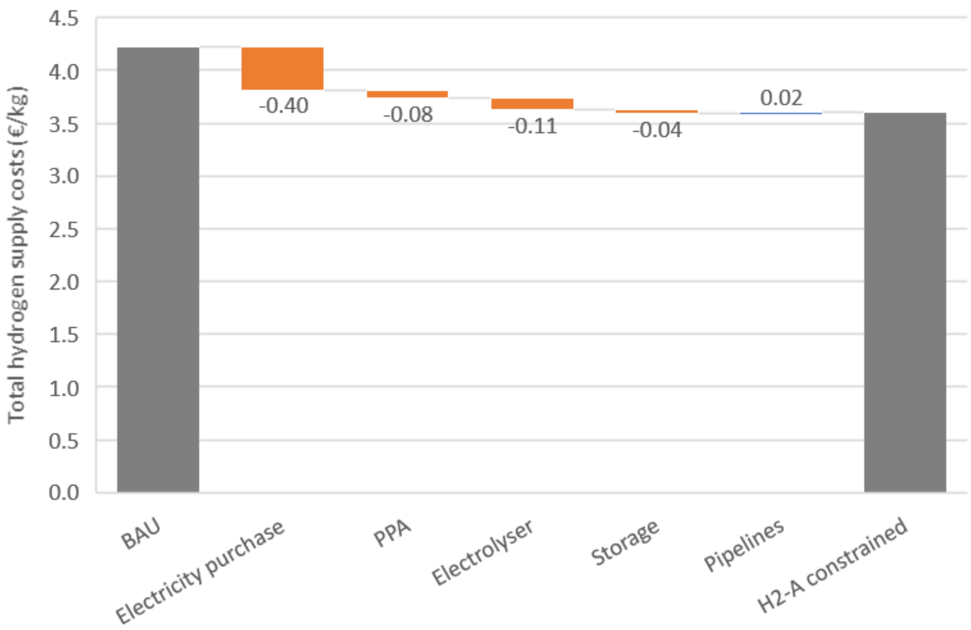

Figure 5-39: Difference in total hydrogen supply costs between BAU and H2-A optimised scenario

Higher cross-border integration reduces the system costs (Figure 5-40). The H2-A optimised scenario reduces the system costs by 1.3 B€ compared to the H2-BAU scenario. Yet, in comparison to the hydrogen costs of delivery, system costs include changes in additional costs related to the entire electricity system: increase in gas consumption and gas turbine capacities, reduced investments in batteries and pumped-storage.

A potential option to further reduce the hydrogen price consists of removing the constraint on the carbon content when purchasing electricity from the market ("-4b"). However, Scenarios "-4b" increase further gas consumption but feature a lower system cost than scenarios "-4a". Yet the gap is narrowed under scenario H2-A optimised. Higher cross-border integration mitigates the impacts of different electrolyser operation modes. This means, the increase in system costs due to the carbon constraint under H2-A optimised compared to the "-4b" (decreasing electricity purchase from the market) divided by the reduction in CO2 emissions (cf. also Figure 5-24) correspond to a “CO2 abatement cost” of 27 €/t.

The UK imports its hydrogen from the EU27 in scenario H2-A optimised, which increases EU27 total system costs with additional electrolyser and vRES capacities. Therefore, when reported on the EU27+UK scope, system cost reduction is even more important.

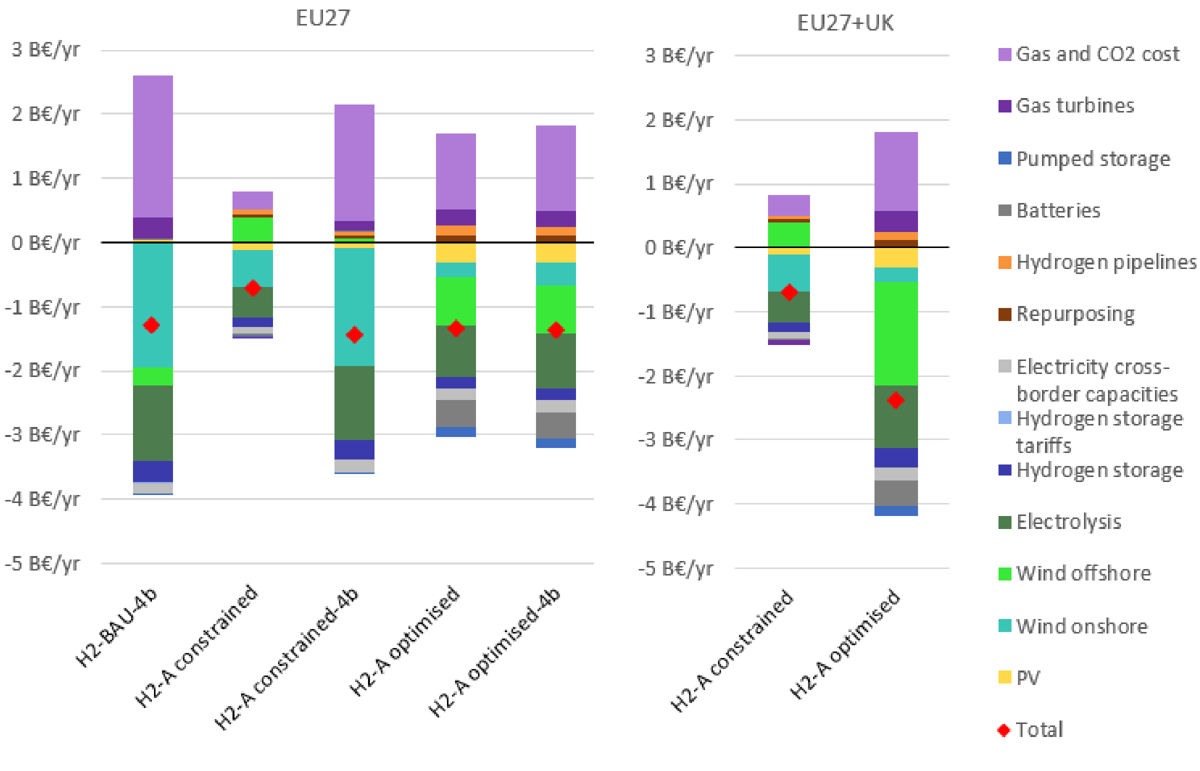

Figure 5-40: Total system costs compared to H2-BAU

5.5 SUMMARY OF THE MAIN SCENARIO RESULTS

This overview summarizes the METIS modelling results and links them to the policy options analysed in the dedicated report prepared by Guidehouse and Frontier Economics[30].

	BAU	Option 1	Option 2		Option 3	
		1	2a	2b	3a	3b
Impacts qualitative assessment (without exemptions)						
Market structure	-	0	0	0/-	++/0	+
Cross-border integration	-	0	0	+	+	++
Administrative costs	+	0	-	-	-	-
Investment incentives/barriers	+	0	0	-/0	-/0	-
Repurposing	+	-	0	0/+	0/+	0
Stylised fact used in modelling of impacts						
Cross-border transport capacity	BAU	"A constrained"				"A optimised"
Impacts – quantitative assessment						
Total energy system cost difference to BAU [EUR billion]	n/a	-0.70				-1.34
Average hydrogen cost of delivery (incl. transmission; EU weighted average) [EUR/kg H_2 (HHV)]	2.3	2.1				1.7
Average renewable share of the hydrogen produced (EU weighted average) [%]	80%	75%				77%
Weighted average market emission factor for electricity used for hydrogen generation (EU weighted average) [kgCO_2eq/MWh e]	26	20				12
Weighted GHG emission intensity of the hydrogen produced (EU weighted average) [kgCO_2eq/MWh H_2 (HHV)]	19	15				9
Ratio of electricity sold and bought by the electrolysers to/from the market versus total electricity sourced [(%) total $Electricity_{sold+bought}$/ total $Electricity_{consumed}$]	55%	57%				60%
Volumes of hydrogen loss of load [TWh H_2 (HHV)]	6.2	2.5				0
Hydrogen interconnection capacity - new [GW]	0	10				27
Hydrogen interconnection capacity - repurposed [GW]	0	19				44
Hydrogen interconnection utilisation (EU weighted average) [%]	n/a	40%				54%
Total electrolyser capacity [GW_{H2}]	56	49				42
Total hydrogen production [TWh H_2 (HHV)]	194	198				220
Impacts – semi-quantitative assessment (in comparison to BAU)						
Impact of transport costs on sectoral distribution	n/a	Differ by sector and depend on subsidy scheme structure				
Impacts of joint versus separate RAB on tariffs	n/a	Impacts H_2 tariffs: likely small c.f. total H_2 costs. Impacts NG tariffs: small.				
Administrative costs [EUR million]	n/a	~5	~10–25			~30–50

Legend	- -	Very low Administrative costs: very high	-	Low Administrative costs: high	0	Neutral / No clear impact	+	High Administrative costs: low	+ +	Very high Administrative costs: very low

The valuation sign is a general indicator and does not indicate a relative comparison to status quo (no regulation); no weighting of assessment criteria has been applied.

30 (Guidehouse & Frontier Economics, forthcoming)

6 SENSITIVITIES

In addition to the assessment of the main scenarios, a set of sensitivities are analysed. They are introduced in Section 6.1, prior to the presentation of the individual results.

6.1 INTRODUCTION OF SENSITIVITIES

In order to capture the system response to the set of input parameters served to the model, sensitivities are performed (cf. Table 6-1), on the following parameters:

- Electrolyser ability to buy electricity from the market can be extended (option "-4b") or disabled ("Electrolyser-PPA"). It is extended when the carbon-content constraint is removed, and disabled when market sourcing is forbidden (except to meet the 10% minimum load).
- Electrolyser minimum capacity per Member States can be reduced to 60% of the announcements in national strategies ("Electrolyser_60%").
- Pipeline CAPEX can evolve within an uncertainty interval. CAPEX can vary simultaneously for new and repurposed pipelines ("Costs-CAPEX-" and "Costs-CAPEX+"), or solely for the repurposed pipeline (which would reduce the cost difference between new and repurposed pipelines, "CAPEX-repurposed+"). The first sensitivity can be used to explore implications of regulatory options that lower transport cost (e.g., cross subsidisation). The second sensitivity aims at covering the full range of uncertainties, including the need for internal hydrogen transport network. The last sensitivity models a situation in which the cost-efficiency of repurposing (against greenfield investments) could be challenged.
- The infrastructure scenario H2-B optimised is also assessed in this section, as a sensitivity (see Section 4.1 for scenario definition)

Table 6-1: Overview of sensitivities

Name	PRIMES scenario	Cross-border scenario	Electrolyser operation	Electrolyser capacity	Pipeline CAPEX (new)	Pipeline CAPEX (repurposed)
H2-BAU	MIX H2	BAU	Option -4a	80% fixed	Normal	Normal
H2-A constrained	MIX H2	A (without optimisation)	Option -4a	80% fixed	Normal	Normal
H2-A optimised	MIX H2	A (with optimisation)	Option -4a	80% fixed	Normal	Normal
H2-BAU-4b	MIX H2	BAU	**Option -4b**	80% fixed	Normal	Normal
H2-A constrained-4b	MIX H2	A (without optimisation)	**Option -4b**	80% fixed	Normal	Normal
H2-A optimised-4b	MIX H2	A (with optimisation)	**Option -4b**	80% fixed	Normal	Normal
H2-B optimised	MIX H2	**B (with optimisation)**	Option -4a	80% fixed	Normal	Normal
H2-B optimised-4b	MIX H2	**B (with optimisation)**	**Option -4b**	80% fixed	Normal	Normal
Electrolyser-PPA	MIX H2	A (with optimisation)	**Option -3**	80% fixed	Normal	Normal
Electrolyser-60%	MIX H2	A (with optimisation)	Option -4a	**60% fixed**	Normal	Normal

Name	PRIMES scenario	Cross-border scenario	Electrolyser operation	Electrolyser capacity	Pipeline CAPEX (new)	Pipeline CAPEX (repurposed)
Electrolyser-60%-4b	MIX H2	A (with optimisation)	**Option -4b**	**60% fixed**	Normal	Normal
Costs-CAPEX-	MIX H2	A (with optimisation)	Option -4a	80% fixed	**-50%**	**-50%**
Costs-CAPEX+	MIX H2	A (with optimisation)	Option -4a	80% fixed	**+400%**	**+400%**
CAPEX-repurposing+	MIX H2	A (with optimisation)	Option -4a	80% fixed	Normal	**+230%**

6.2 EU27 HYDROGEN PRODUCTION ACROSS ALL SENSITIVITIES

When cross-border infrastructure is available, the model has the ability to reallocate hydrogen **generation in a cost optimal manner**. Therefore, the hydrogen demand in the UK may be met by hydrogen produced in the EU27 and/or the UK.

Overall, hydrogen demand in Europe (EU27+UK) reaches 220 TWh in all scenarios, including 20 TWh from the UK. As displayed in Figure 6-1, three configurations are identified with respect to reallocation of UK hydrogen demand:

- Under BAU and A-constrained scenarios, no cross-border infrastructure is available between the UK and EU27. UK hydrogen demand is met domestically.
- When cross-border infrastructure is available, UK hydrogen demand is supplied by the EU27 (220 TWh produced in the EU27)…
- …except under scenarios Electrolyser-PPA and Costs-CAPEX+, where the UK produces and potentially exports hydrogen (only 163 TWh of hydrogen produced in the EU27 under scenario Electrolyser-PPA, with an additional 60 TWh hydrogen production in the UK).

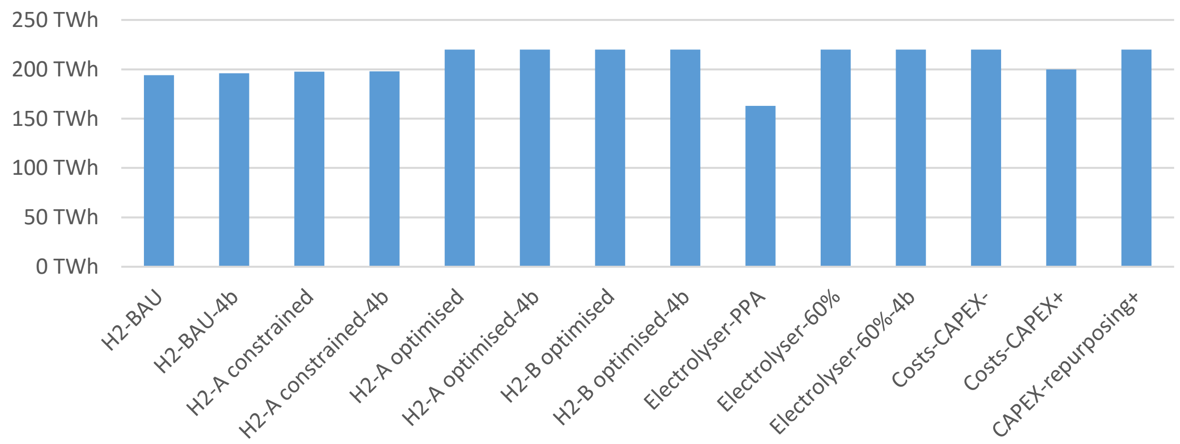

Figure 6-1: Indigenous hydrogen production, EU27

As displayed in Figure 6-2 and Figure 6-3, the parameters which are found to impact the hydrogen cost of delivery and system costs the most are the level of cross-border integration, and the electrolyser operation mode. On level of cross-border integration, Scenario H2-A-optimised allows for a strong cost reduction, while costs increase again under H2-B-optimised (due to the overcapacity of hydrogen pipelines, see Section 6.3). On electrolyser operation mode, costs appear to depend strongly on the level of restriction to sourcing electricity from the market.

All other sensitivities do not feature significant cost variations, and remain close to the scenario they derive from, namely the H2-A optimised scenario.

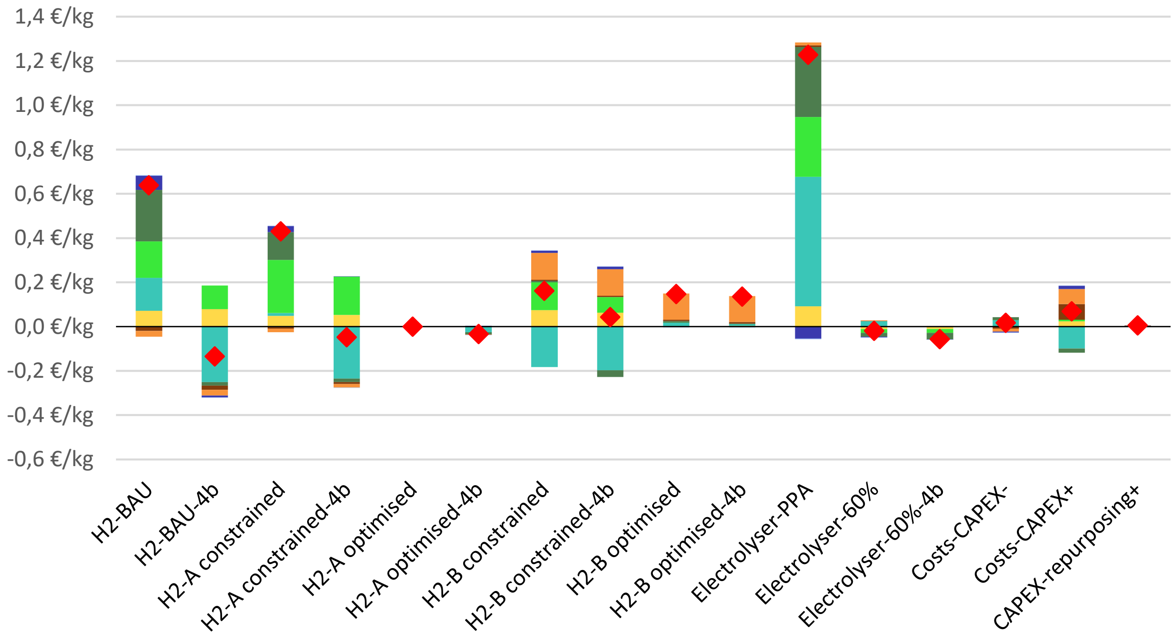

Figure 6-2: Hydrogen cost of delivery compared to H2-A optimised, EU27

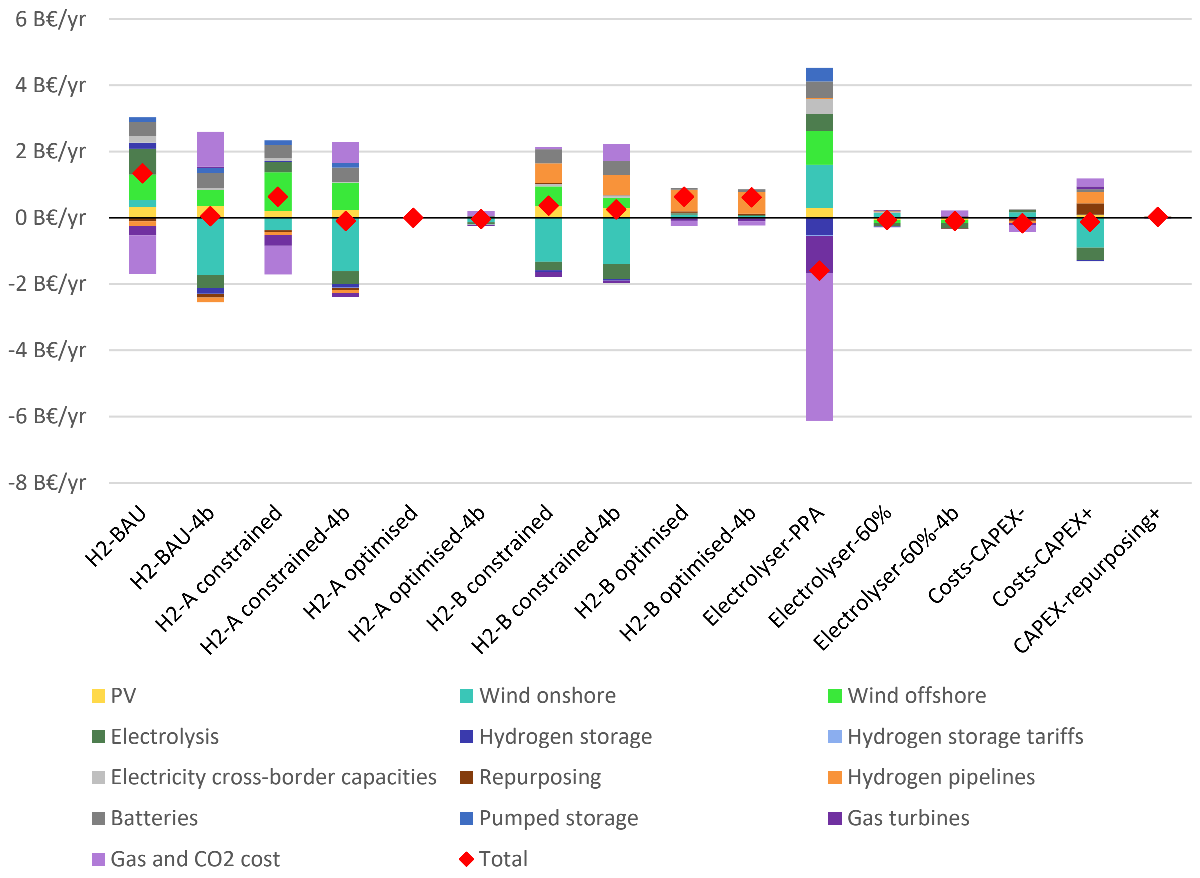

Figure 6-3: Total system costs compared to H2-A optimised, EU27

Differences can be observed between costs reported for the EU27 scope, and costs at the EU27+GB scope (see Figure 6-4 and Figure 6-5). As the UK features a hydrogen demand (as per the MIX H2 scenario) and is included in the modelling scope, it interacts with EU27 system costs (see beginning of the section). In the scenarios BAU and H2-A constrained, the low interconnection level requires the UK to meet its hydrogen demand domestically and no costs are imputed to the EU. However, the UK imports all hydrogen to meet national demand from the EU in H2-A optimised. Eventually, when there is no market availability (Electrolyser-PPA) or high pipeline CAPEX (Costs-CAPEX+), the UK meets a share of its hydrogen demand domestically (or even exports hydrogen). Electrolyser and vRES capacity costs are reallocated between the EU and the UK.

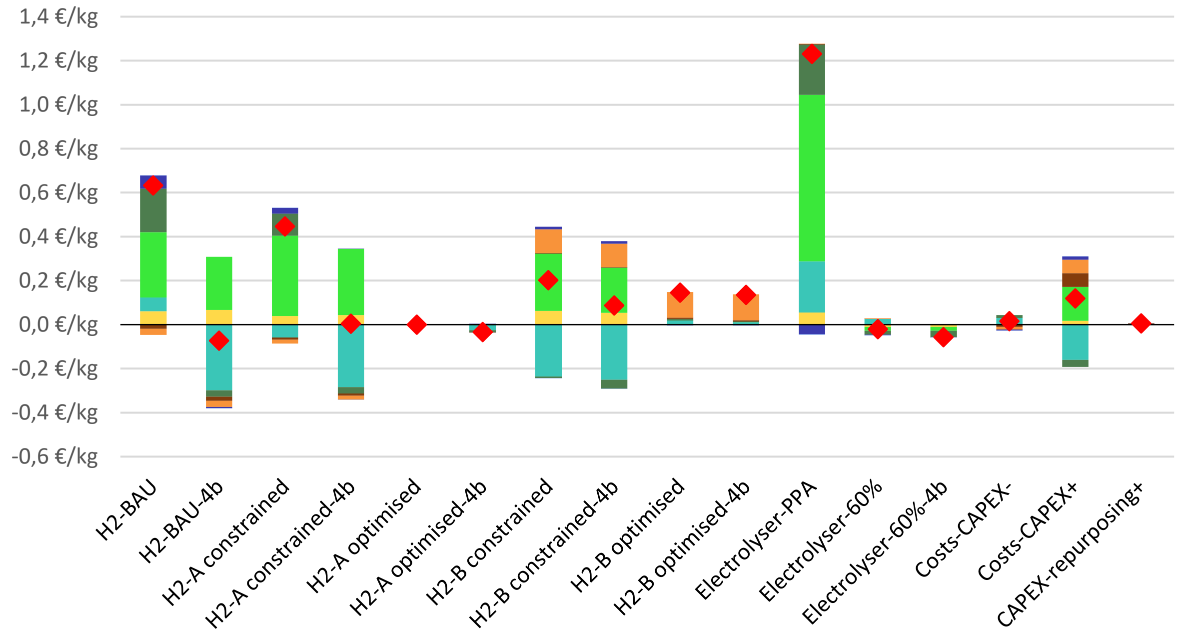

Figure 6-4: Hydrogen cost of delivery compared to H2-A optimised, EU27+UK

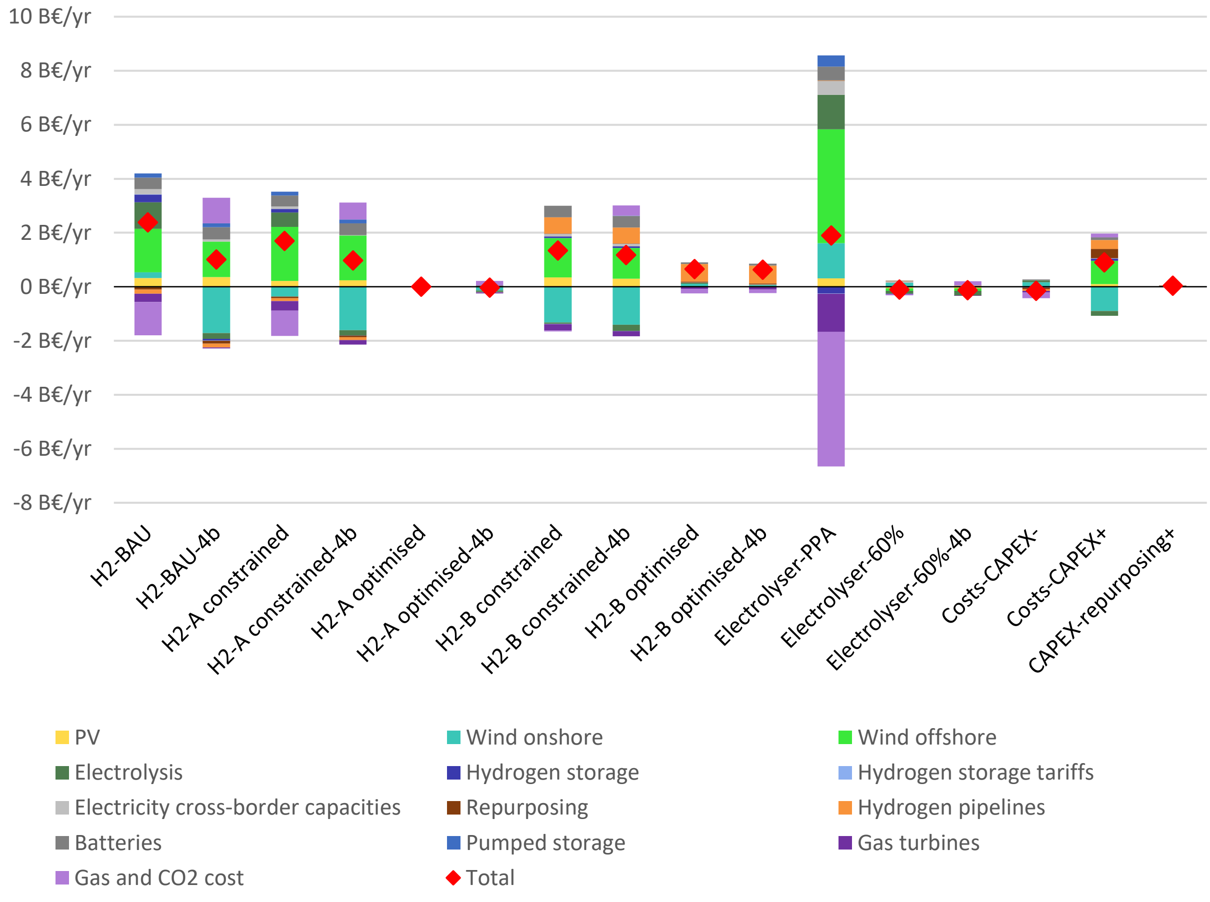

Figure 6-5: System total cost compared to H2-A optimised, EU27+UK

The following sections focus on the individual sensitivities to better capture the dynamics resulting from the variation in assumptions.

6.3 Higher minimum cross-border capacity

Sensitivity H2-B optimised assumes a higher minimum cross-border capacity level[31] compared to H2-A optimised (see Section 4.1 for a more detailed definition of the H2-B optimised scenario). As a result, most pipelines feature a low utilisation rate, especially in central Europe (Figure 6-6). That means that the increased minimum capacities for selected cross-border pipelines lead to an uneconomic over-dimensioning. Still, as displayed in Figure 6-7, additional investments are found to be relevant (18 GW in total, and 17 GW under H2-B optimised-4b), in particular on the FR-ES connection, and in South-Eastern Europe.

Except on the ES-FR-BE connection, where larger cross-border capacities are still economically reasonable under the H2-B optimised sensitivity, no additional investments occur where a minimum infrastructure level is in place.

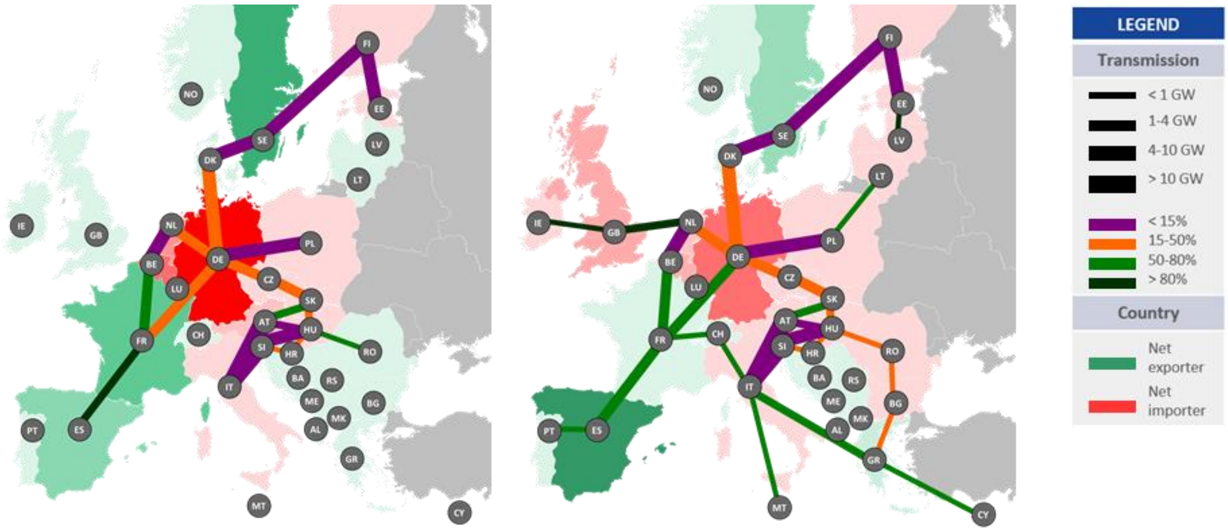

Figure 6-6: Minimum hydrogen cross-border capacity (left) and cross-border capacities optimized (right) under H2-B

[31] Derived from the EHB 2021 map for 2035

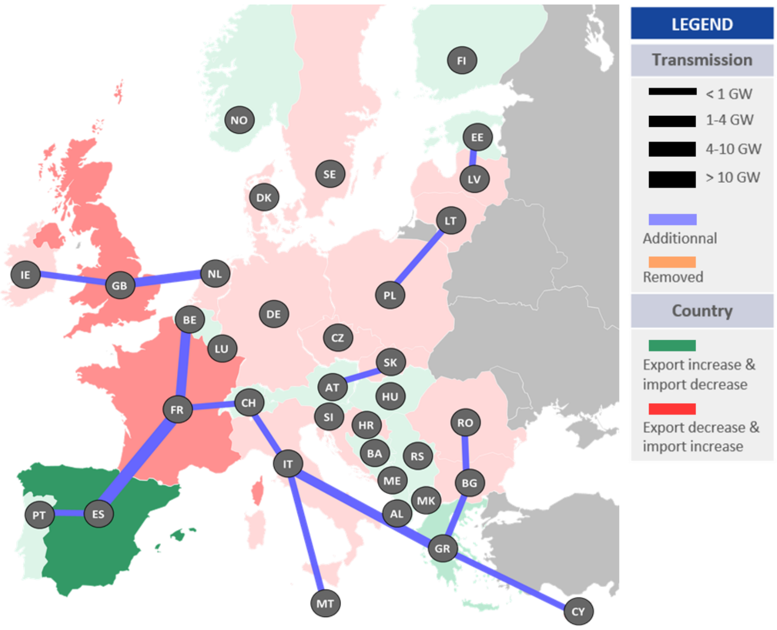

Figure 6-7: Additional investments (H2-B optimised minus minimum capacities)

As the minimum infrastructure under H2-B-optimised is oversized, it translates into additional costs (both cost of delivery and system costs, see Figure 6-8). Installation of new hydrogen pipelines as per the EHB map for 2035 is the first driver of the increase. In comparison, additional repurposed pipelines only account for 3% of the total cost increase. On the system costs perspective, in comparison to H2-A-optimised, this higher minimum cross-border capacity (which facilitates the exploitation of renewable sources and reduces the need for gas-fired power generation) only allows for a slight reduction in gas consumption. It should be noted that this analysis only applies for 2030, therefore it does not capture the additional pipeline value which will result from the likely increase in hydrogen demand beyond 2030.

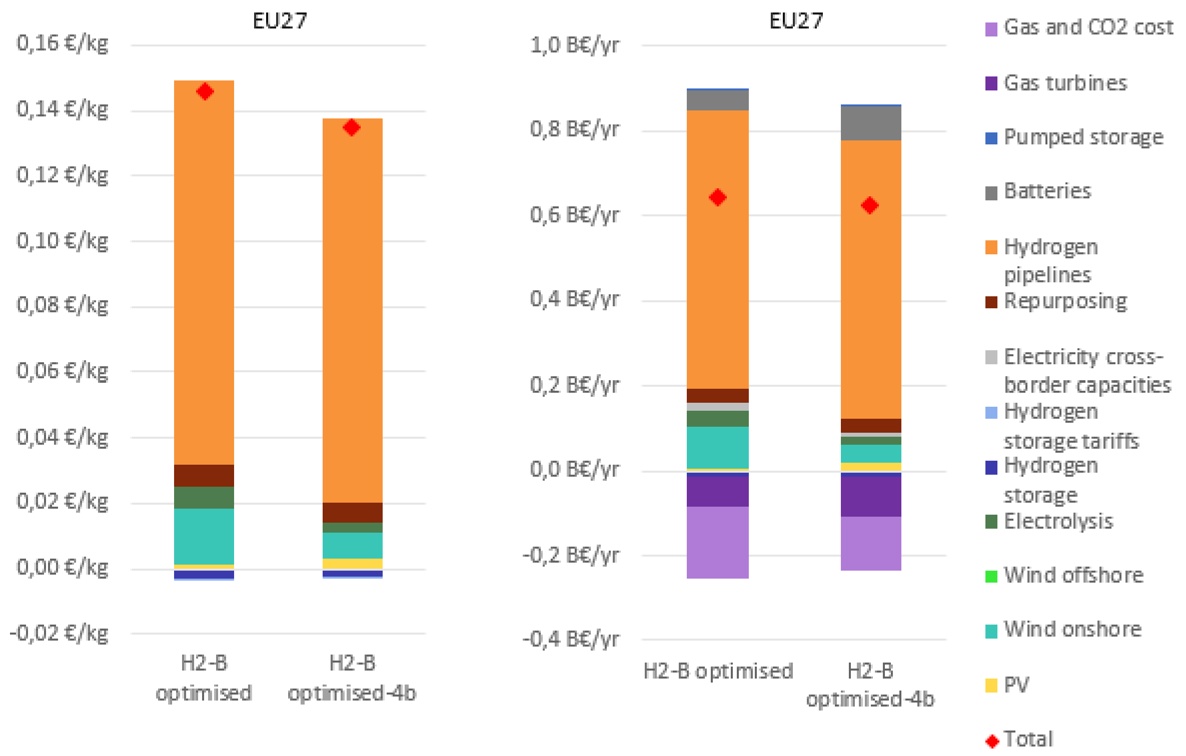

Figure 6-8: Hydrogen cost of delivery (left) and total system cost (right) compared to H2-A optimised, EU27

6.4 Different electrolyser operation modes

In the sensitivity "Electrolyser-PPA", the electrolyser cannot consume electricity from the market (except to meet the 10% minimum load). As displayed in Figure 6-9, the redistribution of capacities materialises as follows[32]: countries which benefited from low market prices in H2-A optimised reduce their electrolyser capacity and increase their PPA capacities (ES, PT), and countries with high wind potentials increase their PPA and electrolyser capacities (PL, RO[33], SE, UK). Where possible, offshore wind is favoured despite its higher cost as it offers higher load factors and more balanced profiles, which facilitates a smaller dimensioning of electrolysers.

Total electrolyser capacity in the EU27 is stable at 49 GW (42 GW in H2-A optimised) but increases by 18 GW at the EU27+UK level (reallocation of electrolysers to domestic supply in the UK). The electrolyser load factor substantially drops, from 60% to 38%, as market sourcing does not provide enough flexibility to mitigate the PPA production profile.

[32] The 80%-national strategy-based minimum electrolyser capacity is maintained and constrains the reallocation.

[33] Apart from Greece, Romania has the highest annual load factor in South East Europe for onshore wind generation.

The limited access to market electricity (40 TWh sourced against 146 TWh) reduces hydrogen carbon-content and increases its renewable share (6.2 kgCO2/MWh and 91%-renewable compared to 9.5 kgCO2/MWh and 77% under H2-A optimised[34]).

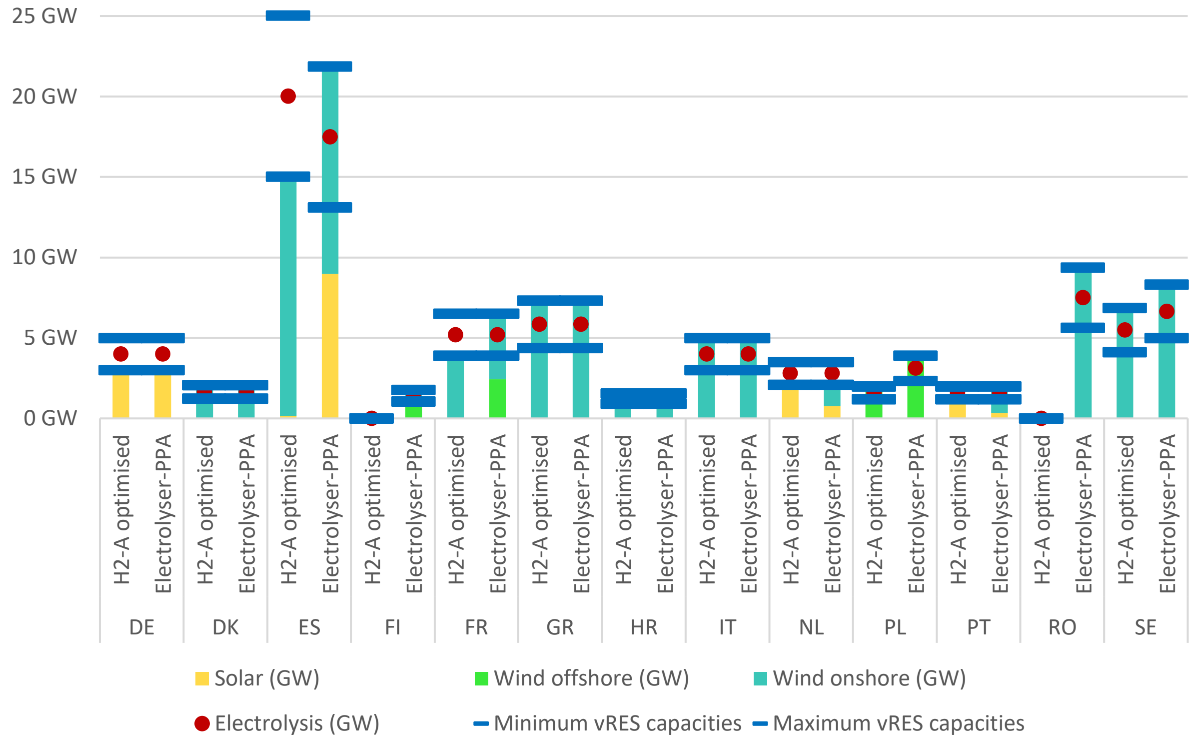

Figure 6-9: PPA and electrolyser capacities. The blue bars account for the corridor enforced between renewable and electrolyser capacities (see 4.2)

On transport infrastructure needs, as displayed in Figure 6-10, the redistribution requires grid reinforcements in countries where hydrogen production is displaced. In total, 15 GW of pipelines are added and 9.2 GW removed.

[34] Electricity is sourced from the market only when needed for the electrolyser minimum load: reduced vRES-share, and the non-renewable share has a higher carbon-content (reduced role of nuclear)

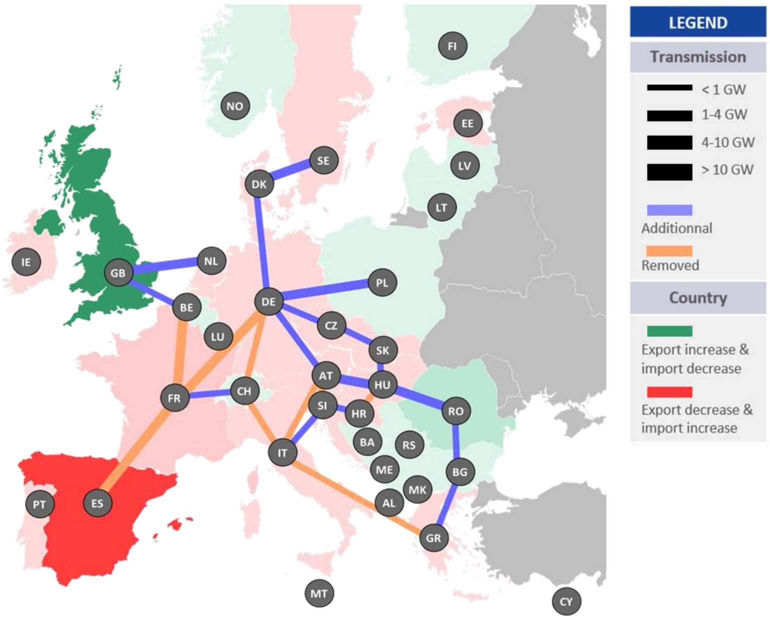

Figure 6-10: Additional investments in hydrogen grid infrastructure under Electrolyser-PPA compared to H2-A optimised

Hydrogen costs of delivery increase substantially, driven by the PPA uptake and the increase in electrolyser and vRES capacities (technologies with higher load factors are favoured), cf. Figure 6-11. However, from a system point of view (Figure 6-12), the cost increase[35] is mitigated by a decrease in gas consumption of 149 TWh (in comparison to H2-A optimised). It is only partially compensated by the increase in PPA electricity resold to the market (25 TWh in the Electrolyser-PPA sensitivity against 16 TWh in H2-A optimised). It highlights the role of gas turbines in producing electricity consumed by electrolysers. Electrolyser-PPA is also the sensitivity with the lowest CO2 emissions, 28 Mt/yr below H2-A optimised (-5.3%).

[35] Note that UK's hydrogen demand is met domestically, contrary to H2-A optimised scenario, consequently reducing EU27 system costs.

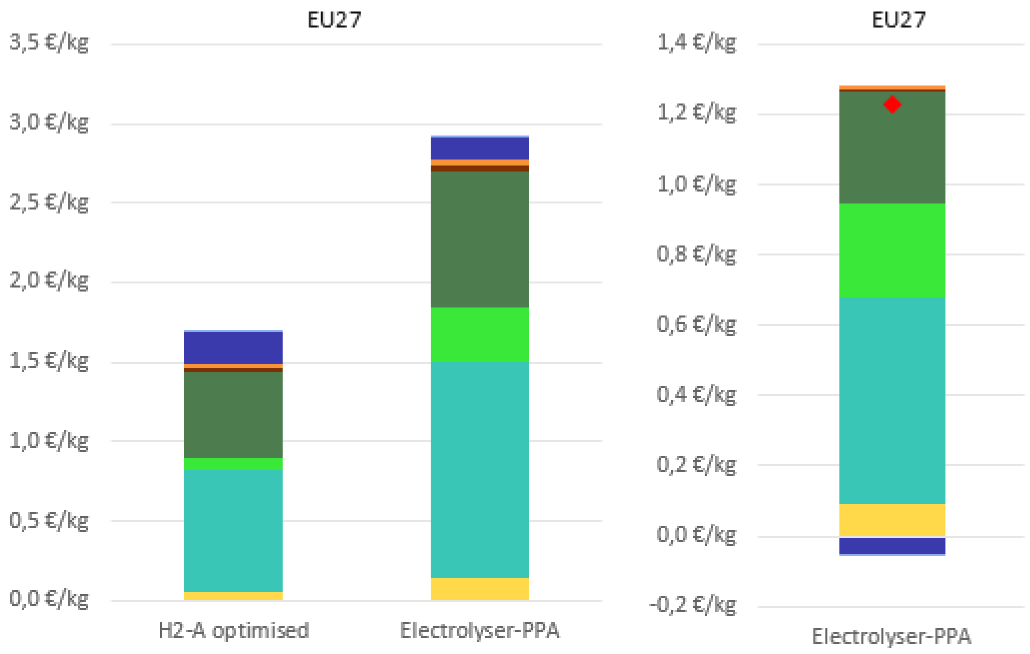

Figure 6-11: Hydrogen cost of delivery (left) and cost difference compared to H2-A optimised (right), EU27

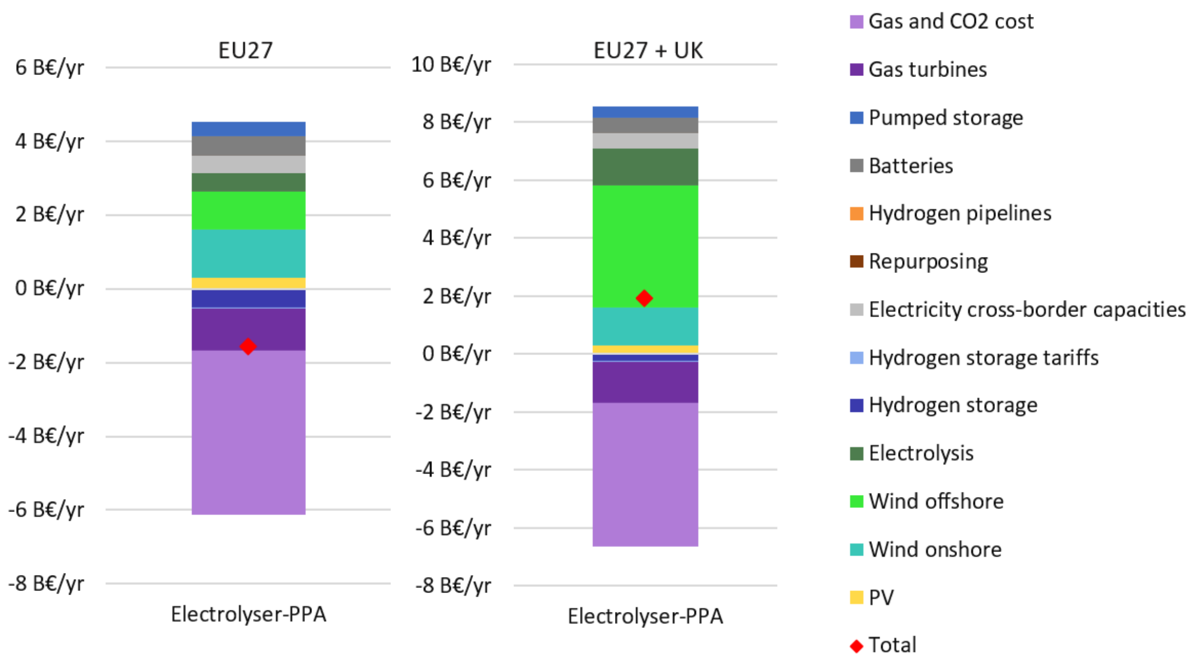

Figure 6-12: Total system costs compared to H2-A optimised, EU27 (left) and EU27+UK (right)

6.5 Lower minimum electrolyser capacity

This sensitivity investigates a compliance with 60% of the minimum capacity for electrolysers in national strategies (instead of 80%).

As displayed in Figure 6-13, a reduced constraint on national hydrogen production allows for a further geographical reallocation to more favourable sites (e.g., ES, SE), at the expense of less suitable sites (e.g., FR, DE). Total electrolyser capacity is reduced by 1.4 GW. However, transmission capacities increase marginally (cf. Figure 6-14): 3.3 GW of pipelines are added, 0.7 GW are avoided compared to H2-A optimised. When allowing sourcing from the market irrespective of the carbon content (option "-4b"), reallocation is less marked, with a stronger role for Germany in hydrogen production. Electrolyser load factors increase. Eventually, total production costs are not significantly reduced (1%).

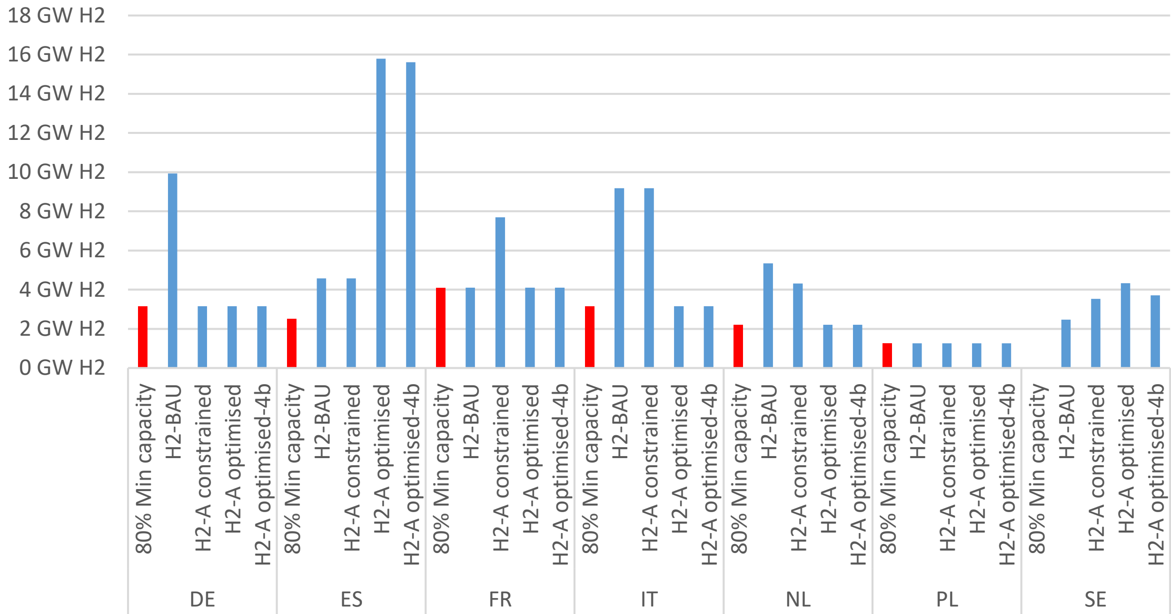

Figure 6-13: Electrolyser capacity in selected countries

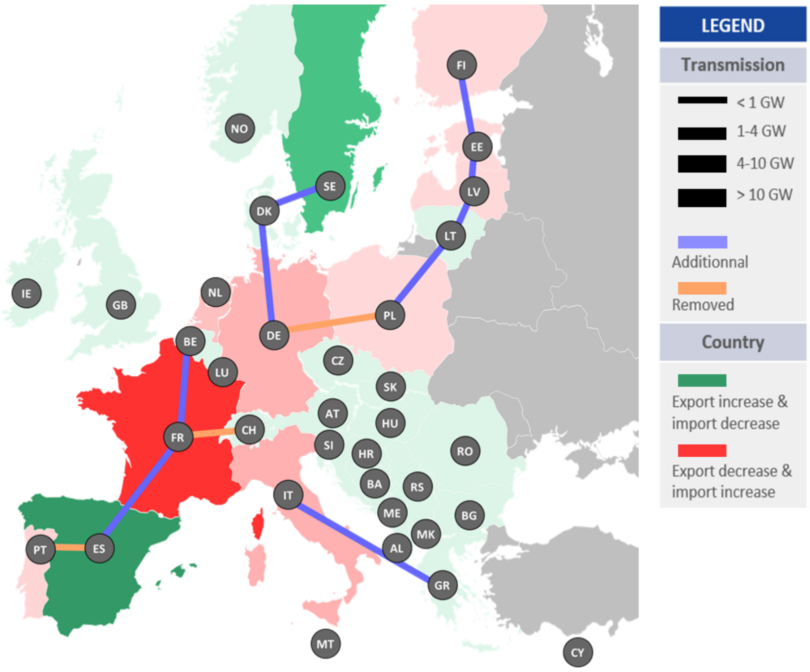

Figure 6-14: Additional hydrogen grid investments in Electrolyser-60% compared to H2-A optimised

6.6 COST OF HYDROGEN CROSS-BORDER INFRASTRUCTURE

The Costs-CAPEX- and Costs-CAPEX+ sensitivities investigate the impact of a -50%/+400% CAPEX variation on new and repurposed pipelines[36].

As displayed in Figure 6-15, when CAPEX is reduced, the hydrogen cross-border capacities slightly increase, by 4.8 GW (+7%). 1.8 GW of repurposed pipelines are removed. Sweden increases its hydrogen production by 4.8 TWh.

When CAPEX is increased, the hydrogen transmission network capacities significantly decrease, by 17.4 GW (-25%). Swedish exports are reduced by 13.3 TWh. With increased pipeline CAPEX, the UK (which imported its hydrogen demand under scenario H2-A optimised) favours a domestic production of hydrogen.

[36] CAPEX for both new and repurposed pipelines derived from the EHB study 2021 update.

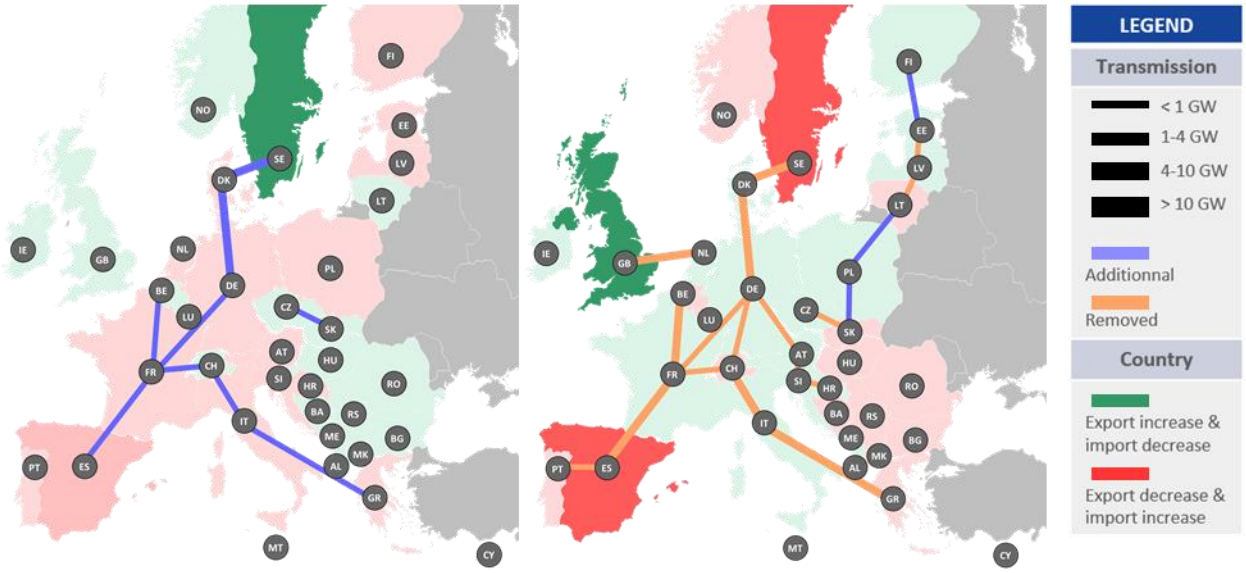

Figure 6-15: Additional investments in Costs-CAPEX- (left) and additional investments in Costs-CAPEX+ (right) compared to H2-A optimised

The CAPEX-repurposing+ sensitivity investigates the impact of a decrease by 50% of the CAPEX gap between new and repurposed pipelines[37].

The hydrogen network capacities slightly decrease, by 0.5 GW. 0.9 GW of repurposed pipelines are removed while 0.4 GW of new hydrogen pipelines are commissioned. Sweden increases its hydrogen production by 0.3 TWh while Spain decreases its production by 0.3 TWh.

Transmission capacity only accounts for 3% of hydrogen cost of delivery (see Figure 5-36). Consequently, the CAPEX convergence between new and repurposed pipelines only marginally modifies the transmission network.

[37] CAPEX for new hydrogen pipelines is left unchanged, only CAPEX for repurposed pipelines is increased. It captures the fact that while the costs for newly built pipelines are relatively certain, there is larger uncertainty on the cost for repurposing natural gas pipelines to hydrogen use.

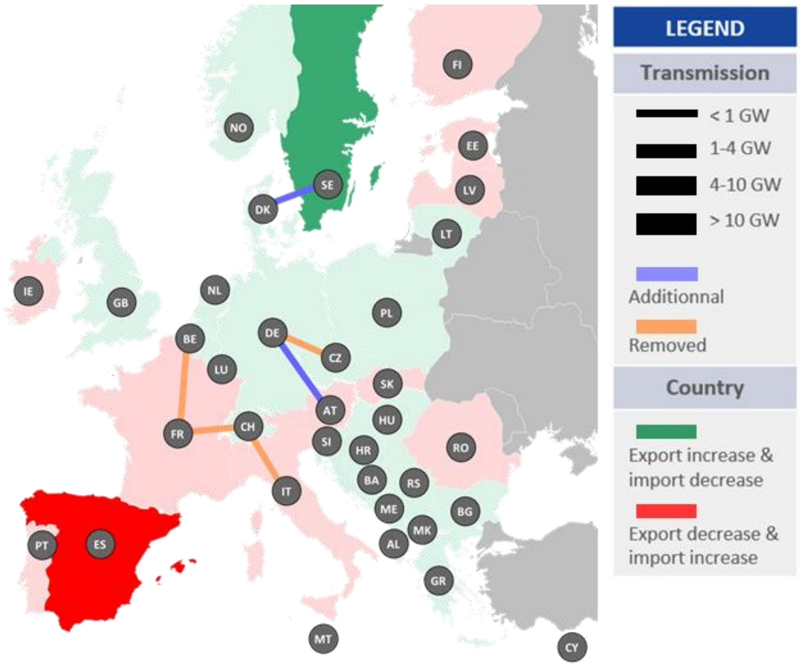

Figure 6-16: Additional investments in CAPEX-repurposing+ compared to H2-A optimised

The change in CAPEX results in limited changes compared to the H2-A optimised scenario, notably because transmission pipeline CAPEX only accounts for 2% of hydrogen costs of delivery (see Figure 6-17). In the Costs-CAPEX- sensitivity, the total system costs decrease by 160 M€ at the EU27 level while Costs-CAPEX+ sensitivity raises the total system costs by 127 M€ (cf. left part of Figure 6-18). The sensitivity on the CAPEX of repurposed pipelines has only a marginal effect on total system costs.

It should be noted that compared to scenario H2-A-optimised, in which UK's hydrogen demand was supplied from the EU27, in this sensitivity the UK meets its hydrogen demand domestically. This results in a decrease of EU27 system costs, and an increase of EU27+UK total system costs in the Costs-CAPEX+ sensitivity (cf. right part of Figure 6-18).

The increase in CAPEX translates into reduced investments in cross-border capacities (-17 GW). As for the BAU and the H2-A-constrained scenarios, in which less cross-border capacity was available, investments in the PPA are displaced from onshore wind to offshore wind generation, driven by higher load factors and flatter profiles.

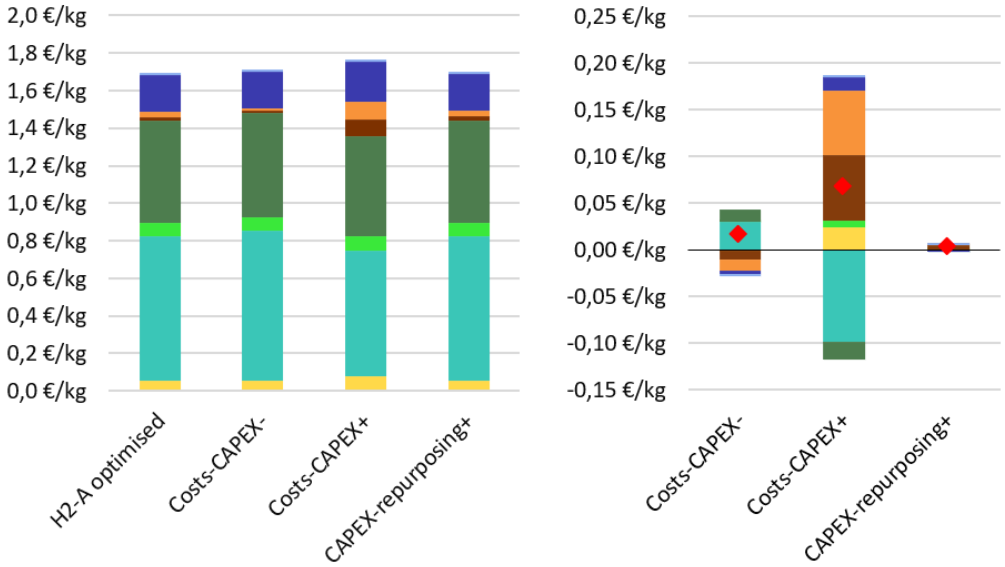

Figure 6-17: Hydrogen cost of delivery (left) and cost compared to H2-A optimised (right)

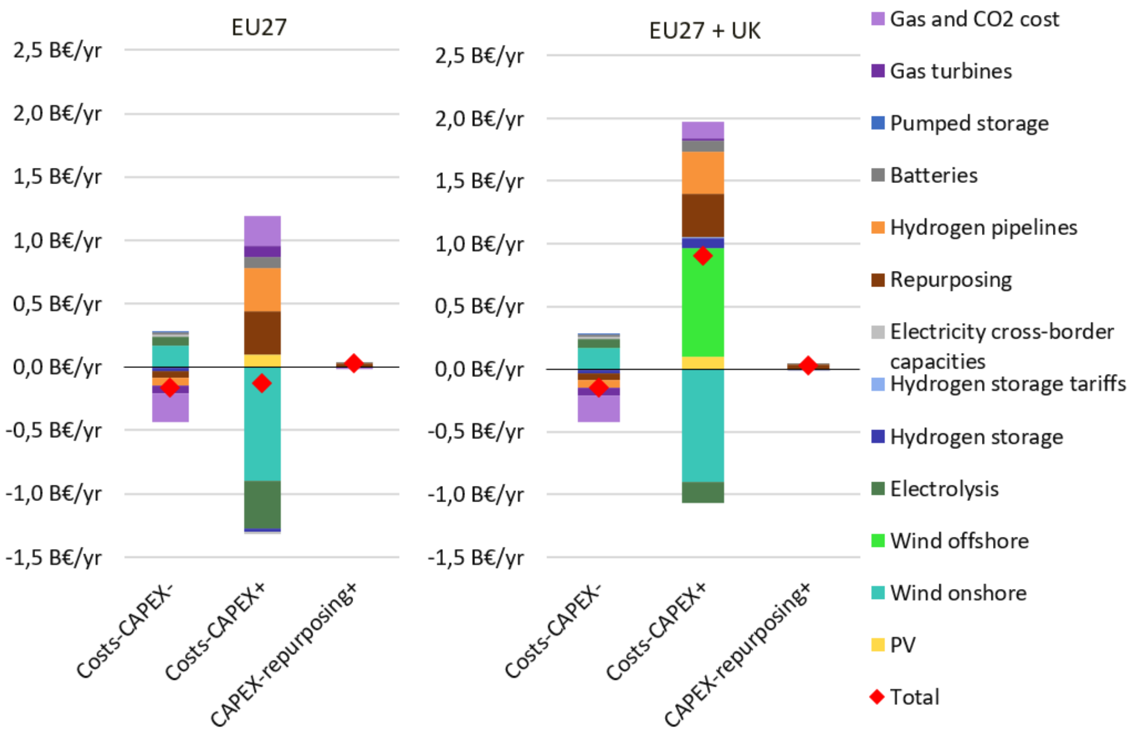

Figure 6-18: Total system costs compared to H2-A optimised, EU27 (left) and EU27+UK (right)

7 CONCLUSIONS AND OUTLOOK

Key results and conclusions

The considered regulatory packages differ in the way they are expected to enable or stimulate cross-border transport of hydrogen (either via new or via repurposed pipelines). Three different scenarios of cross-border capacity deployment by 2030 are considered to assess the impacts of these packages, considering the green hydrogen production capacities outlined in the EU's Hydrogen Strategy.

In order to capture the hydrogen dynamics, a multi-energy scenario has been designed in the METIS model, covering electricity, gas and hydrogen with an hourly time resolution, over one entire year. All MSs and major neighbouring countries (CH, NO, UK and most of the Western Balkan countries) are represented individually. Such an integrated pan-European approach is key to revealing the needs for hydrogen infrastructure.

The study key finding is that it is economically reasonable to set up a pan-European hydrogen transport infrastructure by 2030, under the considered assumptions. Comparing the scenario H2-A optimised to the H2-BAU scenario (featuring no hydrogen cross-border infrastructure), by 2030, **cross-border integration facilitates regional cooperation and contributes to**:

- A substantial reduction in total hydrogen cost by reallocating renewable electricity and hydrogen production to the most favourable sites (costs drop from 4.22 to 3.30 €/kg) – from an EU perspective, the reduction in hydrogen production costs largely offsets the increase in transmission costs;
- A convergence of hydrogen prices across EU Member States;
- Making hydrogen greener and reducing its carbon-content (from 0.74 to 0.35 kgCO2/kgH2);
- Lowering the need for electrolyser (from 53 to 42 GW) and hydrogen storage capacities (21 to 18 TWh), partly by increasing the load factors of electrolysers (from 42% to 60%);
- Reducing the impact of various electrolyser operation modes (with respect to electricity sourcing) on hydrogen production cost, as hydrogen cross-border infrastructure increases overall system flexibility.

The results also show that under the given assumptions:

- **Repurposing of existing gas pipelines** represents a cost-efficient option to reduce the need for additional pipelines, even when representing explicitly the actual gas flows in the model.
- **National objectives** for the installation of electrolysers may clearly provide incentives for investments and the development of a national hydrogen economy but they do not necessarily imply the exploitation of the least cost RES-E and hydrogen potentials (cf. Electrolyser-60% sensitivity compared to the Baseline). A coordinated European approach considering national framework conditions (in terms of hydrogen supply potentials, hydrogen demand) and implying a concerted pan-European network planning approach could significantly reduce the overall system costs.

- A **joint planning** of electricity, gas and hydrogen production and transmission infrastructure is of utmost importance to ensure a cost-efficient exploitation of the least-cost RES potentials and to avoid over-dimensioned or stranded production and cross-border transmission assets. By coupling the modelling of energy transmission and conversion assets showcases how the switch between energy carriers may ensure the optimal utilisation of existing assets and minimize the need for investments in additional infrastructure. The joint planning of gas and hydrogen networks reveals the future need of cross-border gas transmission capacities and the potential availability for repurposing into hydrogen pipelines.

- Allowing **electrolysers to market electricity from the grid** ("-4b" option) may effectively reduce the hydrogen production costs, at the expense of an increasing carbon content.[38] The theoretical thought experiment of linking hydrogen production exclusively to a PPA (Electrolyser-PPA sensitivity), fully decoupled from the market, ensures a fully renewable hydrogen production, yet at an additional cost of about 1.9 B€/yr.

- **Cost uncertainty** with respect to investments in new and repurposed **pipelines** remains relatively high, yet affects the overall results only to a limited extent. If pipelines turn out to be more expensive than expected, this favours nationally indigenous hydrogen production

The quantitative results are summarised in Table 7-1.

[38] Comparing option 4b to option 4a under the H2-A optimised scenario reveals that the carbon constraint under 4a drives down emissions at an increase of system costs which corresponds to an CO2 abatement cost of approximately 27 €/tCO2.

Table 7-1: Overview of modelling results across all scenarios and sensitivities (EU27)

Name	Hydrogen delivered (TWh)	Interconnection capacity (GW H2)		Interconnected region	H2 storage capacity (TWh)	Difference in total system costs compared to H2-BAU (B€)
		Repurposed natural gas	New hydrogen			
H2-BAU	194	0	0	None	20.8	0
H2-A constrained	198	19.3	10.0	FR-BE-NL-DE	18.3	-0.70
H2-A optimised	220	43.9	26.7	EU	17.9	-1.34
H2-BAU-4b	196	0	0	None	15.4	-1.29
H2-A constrained-4b	198	19.3	10.0	FR-BE-NL-DE	16.2	-1.44
H2-A optimised-4b	220	43.8	25.1	EU	18.1	-1.37
H2-B optimised	220	54.4	130.2	EU	17.7	-0.70
H2-B optimised-4b	220	54.1	130.0	EU	17.7	-0.72
Electrolyser-PPA	163	47.5	29.1	EU	9.7	-2.94
Electrolyser-60%	220	43.9	29.3	EU	17.7	-1.41
Electrolyser-60%-4b	220	43.8	27.5	EU	17.9	-1.43
Costs-CAPEX-	220	45.7	29.7	EU	17.5	-1.50
Costs-CAPEX+	200	35.8	17.7	EU	17.5	-1.47
CAPEX-repurposing+	220	43.2	26.9	EU	17.9	-1.31

Results are to be interpreted in the context of the underlying assumptions and with respect to the policy options they are intended to reflect, cf. the report from (Guidehouse & Frontier Economics, forthcoming).

Limitations and outlook

The present analysis applies an advanced approach by simultaneously modelling the electricity, gas and hydrogen system of the entire EU plus major neighbouring countries. The high technological and temporal granularity allow for an in-depth assessment of the hourly dynamics of an increasingly intertwined EU energy system.

Nonetheless, every model represents just an approximation of reality and thus comes with a set of limitations to ensure the right balance between complexity and manageability of the analysis. In this regard the present assessment with the METIS model leaves room for improvement with respect to the uncertainty of major assumptions (future hydrogen demand, evolution of CAPEX, RES potentials and costs) which were not specifically tested by means of parameter variations. Hydrogen demand from the industry sector (potentially restricted to local clusters) in combination with blue (and grey) hydrogen production are excluded from the modelling scope, potentially impacting the synergies (it may either decrease the cost by sharing the infrastructure, or increase the cost of green production as inflexible blue hydrogen production would force the flexibility onto the green hydrogen production). In the same vein, imports of renewable hydrogen were not taken into account as a potential alternative to European green hydrogen production. With respect to the modelling of cross-border interconnections, it needs to be noted that they were analysed considering each country as a single node and thus disregarding infra-national transmission lines and production and storage sites. Further, the modelling of infrastructure builds upon a pure market-based approach, not reflecting any hydraulic or physical behaviour and constraints. Ultimately, energy infrastructure features long asset lifetimes, which implies that the analysis of a single year only reflects a snap shot.

The limitations outlined do not affect or deteriorate the significance of the elaborated results but need to be considered during results' interpretation. In addition, it is important to note that the METIS model is subject to continuous development. In the context of the ongoing METIS 3 project, demand side modelling will be improved by soft-linking METIS to two detailed bottom-up energy demand models. The geographical granularity of the tool will be increased to the NUTS1 level.[39] The optimisation of transition pathways will be enabled, covering several intermediate years in the run up to 2050. Finally, METIS will be complemented by a module to facilitate the realisation of parameter variations in order to evaluate the robustness of results and specific asset behaviours.

[39] In the context of the METIS 2 project, a detailed modelling of electricity transmission and distribution grids was already added, cf. https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en?redir=1.

8 ANNEX

8.1 PRIMES SCENARIO INTEGRATION INTO METIS

The Technical Note[40] contains information on:

- The creation of a MIX H2-based scenario in METIS, deriving from PRIMES data
- The model extensions to create a hydrogen layer

8.2 QUALITATIVE DISCUSSION ON THE UPDATE OF THE MIX H2 SCENARIO

The following analysis has been performed on the MIX H2 scenario delivered by the European Commission to Artelys on 23rd April 2021. The final version of the MIX H2 scenario slightly differs from the latter, among others, the gas demand is 3% lower and total hydrogen demand (EU27) decreases by 2% (from 200 TWh to 197 TWh).

Impacts of the aforementioned changes on the results should remain very marginal, if any. Yet, the hydrogen demand is distributed differently between Member States in the update, in particular from ES-IT to DE-PL-RO. This reallocation will exacerbate the need for hydrogen cross-border infrastructure, as detailed in the following sections.

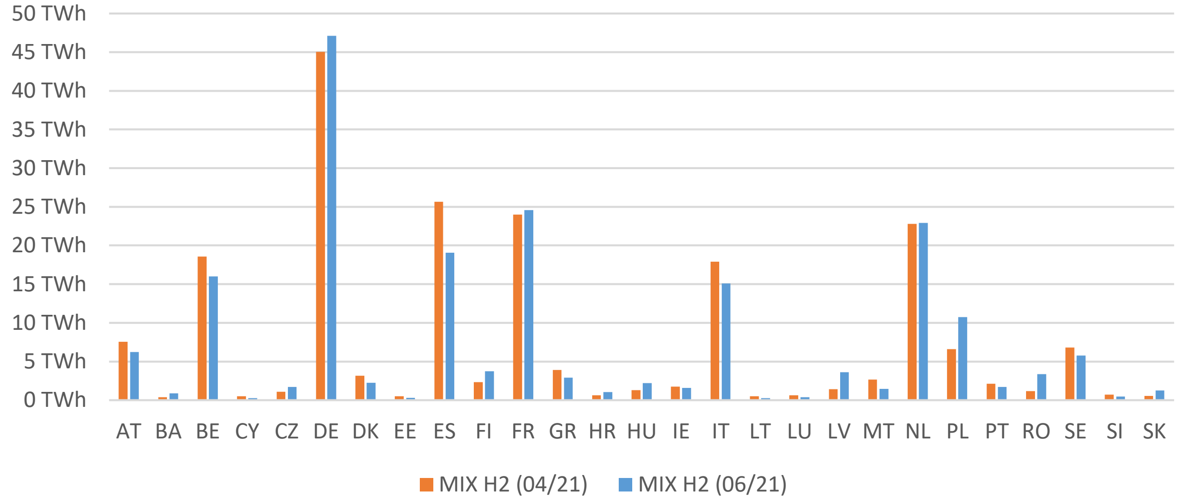

Figure 8-1: Hydrogen demand in 2030 by Member State under the MIX H2 scenario (new and old data)

[40] (Artelys, forthcoming)

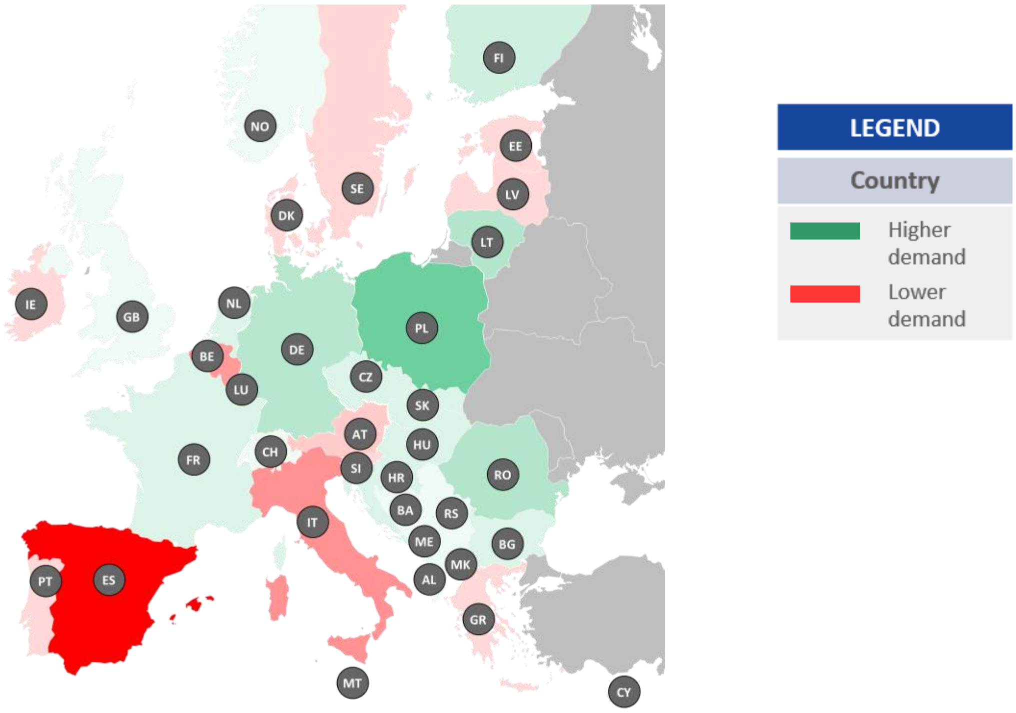

Figure 8-2: Change of hydrogen demand in the MIX H2 scenario (new – old)

8.3 DEFINITION OF FLEXIBILITY NEEDS

In the following we define daily, weekly and seasonal flexibility needs by analysing the dynamics of the residual load on several timescales, so as to take into account all the underlying phenomena that drive the need for flexibility.

Flexibility is defined as the ability of the power system to cope with the variability of the residual load curve at all times. Hence, flexibility needs can be characterised by analysing the residual load curve.

Daily flexibility needs

On a daily basis, if the residual load were to be flat, no flexibility would be required from the dispatchable units. Indeed, in such a situation, the residual demand could be met by baseload units with a constant power output during the whole day. In other words, a flat residual load does not require any flexibility to be provided by dispatchable technologies.

We therefore define the daily flexibility needs of a given day by measuring by how much the residual load differs from a flat residual load. The daily flexibility needs computed in this report are obtained by applying the following procedure:

1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand

2. Compute the daily average of the residual load (365 values per year)

3. Sum the result obtained over the 365 days. The result is expressed as a volume of energy per year (TWh per year).

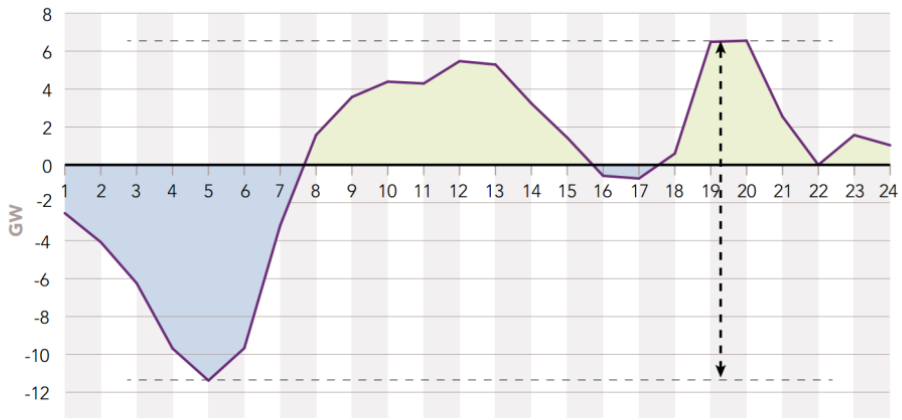

Figure 8-3: Illustration of daily flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given day).

Weekly flexibility needs

The same reasoning is applied to evaluate the weekly flexibility needs. However, in order not to re-capture the daily phenomena that are already taken into account by the daily flexibility needs indicator, we recommend adopting the following procedure:

1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand with a daily resolution
2. Compute the weekly average of the residual load (52 values per year)
3. For each week of the year, compute the difference between the residual load (with a daily resolution) and its weekly average (the light green area). The result is expressed as a volume of energy per week (TWh per week).
4. Sum the result obtained over 52 weeks. The result is expressed as a volume of energy per year (TWh per year).

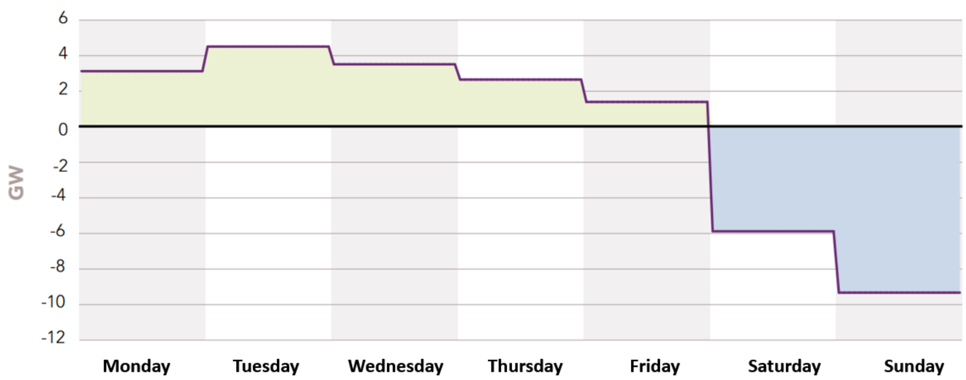

Figure 8-4: Illustration of weekly flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given week).

Seasonal flexibility needs

Finally, the seasonal flexibility needs are assessed in a similar way:

1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand with a monthly time resolution
2. Compute the annual average of the residual load
3. Compute the difference between the residual load (with a monthly time resolution) and its annual average. The result is expressed as a volume of energy per year (TWh per year).

Definition of the contribution to the provision of flexibility needs

The provision of flexibility of a given technology is calculated by comparing the flexibility needs based on the residual load (as explained in the previous section) to residual flexibility needs. The latter are based on the residual load minus the technology generation profile.

Figure 8-5 illustrates the computation of the provision of flexibility by a given technology:

1. Step A – Compute the daily flexibility needs based on the *residual load*
2. Step B – Compute the residual daily flexibility needs based on the *residual load – technology X generation profile*

The difference between the two quantities is the contribution of technology X in the provision of flexibility. The contribution of each technology is then computed by iteratively removing all technologies to the residual load.

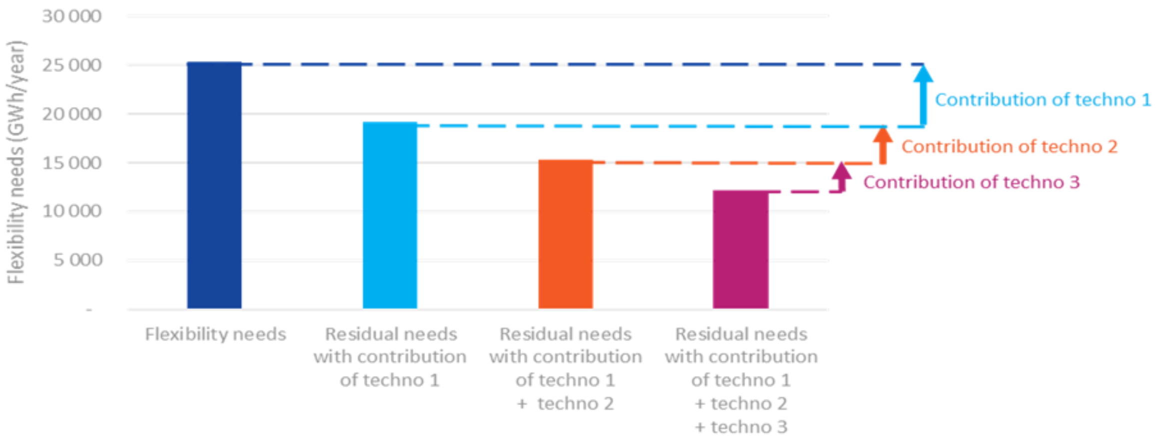

Figure 8-5: Methodology to assess the contribution of a technology to flexibility needs

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