H2FUTURE
Green Hydrogen

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Roll-out perspectives of green ammonia and the impact of renewable hydrogen on the electricity system

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Executive summary

This report is part of the deliverables of work package 9 of the H2FUTURE project and focuses on the transition of fossil fuel-based ammonia production to green ammonia in Europe. The report consists of two parts. The first part aims to provide insight into the challenges for the transition to green ammonia in Europe, and the status and current developments regarding the transition. The second part focuses on the impact of large-scale electrification of hydrogen production on the electricity system in Europe. As electrification of hydrogen production will not take place in isolation, but is part of a larger trend of electrifying sectors, a deep decarbonisation scenario for the whole European energy system, including the ammonia industry, has been taken as a basis of the impact study.

At least 100 MW per month up to 2050 for full transition to green ammonia in the EU

Greening ammonia production in the European Union (EU) will require an electrolysis-based renewable hydrogen production capacity of about 3.5 million tons per year (Mt/yr). This is equivalent to 42 gigawatt (GW) of electrolysis if electrolysers are operated for 50% of the time at full load (about 4400 hours), which reduces to 30 GW if 70% full load hour operations is possible (about 6100 hours). To complete the full transition by 2050 at the latest, this means installing an average of 1.1 to 1.5 GW of electrolysis capacity per year for ammonia production only, or about 100 megawatt (MW) per month. This will have to be accompanied by an equivalent expansion of renewable electricity production capacity to power the electrolysers.

The roll-out of projects has not really started yet and is lagging far behind schedule

In the EU only one 20 MW project for ammonia has come online so far, and another one of 10 MW has reached the final investment decision (FID). Many other initiatives have been announced, but they all still have concept or feasibility study status. Furthermore, most parties have no experience with the technology and the technology also still needs improvement. Learning by doing takes time and to minimise risks, developments are more likely to follow a cautious step-by-step expansion from tens of MW to GW scale with intermediate steps on the order of 100 to a few hundred MW. As a result, the necessary deployment rates will only increase in the coming years and decades. And this only concerns ammonia in Europe. According to the IEA, global electrolyser capacity will have to reach 850 gigawatts (GW) by 2030 to get on track for a net-zero emission scenario which stays within 1.5 degrees Celsius global warming in 2050, and ultimately requires 3,600 GW by 2050. This is almost 9 GW per month from January 2023 through the end of 2030 and almost 11.5 GW per months in the period 2031 through the end of 2050. It's about a 100-fold increase from what it takes to completely replace just fossil hydrogen with renewable hydrogen for ammonia production in Europe.

Policy developments do still not yet reflect need for unprecedented policy measures

It will require unprecedented policy measures to make this unprecedented scale-up happen. The European Commission has recognised the need to accelerate the energy transition with the presentation of the ambitious Fit-for-55 policy package and the REPowerEU plan in response to the Paris climate agreement and the recent energy security issues caused by the war started by Russia in Ukraine. Both include significant ambition for the deployment of renewable hydrogen, where the REPowerEU plan aims to further increase the ambition of the Fit-for-55 package. However, the trend in the negotiations under the Fit-for-55 package is more towards a reduction in targets than an

increase, which does not help to achieve the necessary acceleration for timely CO_2 emission reductions to keep global warming within the limit of 1.5 degrees.

Import of green ammonia is part of the solution but not a panacee for acceleration

In case of ammonia, the import of green ammonia from outside the EU will be an option. The REpowerEU plan sets a target of 4 Mt/yr import of hydrogen in the form of green ammonia, equivalent to almost 23 Mt/yr of ammonia. This exceeds current ammonia production and even current ammonia production capacity in the EU. Ammonia is a commodity that is already traded worldwide. Over the past ten years, the import of ammonia into Europe has averaged 4.1 Mt/yr so infrastructure for imports is already in place. However, expansion by at least a factor of 5 is necessary to achieve the REPowerEU target. Although this may be relatively easy to achieve, it does not change the tasking for greening ammonia. The figures stay the same. The required hydrogen and ammonia production capacities will then only have to be installed elsewhere. Next to that, the ammonia will then still have to be transported to Europe, which does not necessarily make the task any easier.

Sector coupling through green hydrogen requires integrated analysis of markets and systems for electricity and hydrogen

Due to targets and developments in the field of ammonia, it seems likely that the near and more distant future will see a mix of renewable hydrogen production for greening domestic EU ammonia production and replacement of ammonia production for fertilisers and the chemical industry with imported green ammonia from outside of the EU. Electrification of domestic hydrogen production for ammonia will be part of the broader trend towards green hydrogen and electrification of the energy system, which will have significant consequences for the power system planning and operation. The impact is studied for a European decarbonisation scenario using a model to simulate an integrated European market for electricity and hydrogen. The current modelling analysis is designed to quantify the impact of high levels of electrification and hydrogen use on the power and hydrogen systems' infrastructure development, generation mix, carbon dioxide (CO_2) emissions and system costs.

Results on the impact of large-scale electrification of hydrogen production on the electricity system in Europe

To measure the effect of H_2 electrification, we compare a reference scenario R2050 with a scenario NoP2H2, where electrolysis is not allowed; that is, all H_2 demand must be supplied via SMR (except for the initial electrolysers installed capacity).

In the reference scenario 58% of the total H_2 demand is electrified, and the remaining 42% is supplied via SMR. This indicates that with the assumed CO_2 price of 250 EUR/ton and the used natural gas price, producing H_2 via SMR with CCS with about 90% CO_2 capture rate still plays a role in the hydrogen (H_2) production. The H_2 electrification level is very sensitive to gas price. Doubling of the natural gas price from 7.5 EUR/GJ (27 EUR/MWh) in the reference scenario to 15 EUR/GJ (54 EUR/MWh) reduces the SMR by 80%, resulting in less than 7% being produced through SMR. As a large part of SMR-based H_2 production in the reference scenario is equipped with CCS already resulting in a relatively low level of CO_2-emssions, doubling of the CO_2-price from 250 EUR/ton to 500 EUR/ton has hardly any effect on the ratio between electrolysis and SMR.

The H_2 transmission capacity is 1.6x higher in R2050 compared to NoP2H2 resulting in different trade patterns compared to NoP2H2 (see Figure 1 and Figure 2) as a natural consequence of more electrolysis from countries with higher variable renewable energy (VRE) investments and generation, such as France and Spain (solar and onshore wind) as well as Norway (offshore wind) towards Germany (high demand center for imports because CCS facilities are not allowed). Ireland also supplies the UK with higher offshore wind. Despite higher VRE investments and generation in R2050 compared to NoP2H2, the (net) electricity trade is considerably lower in R2050 than in NoP2H2.

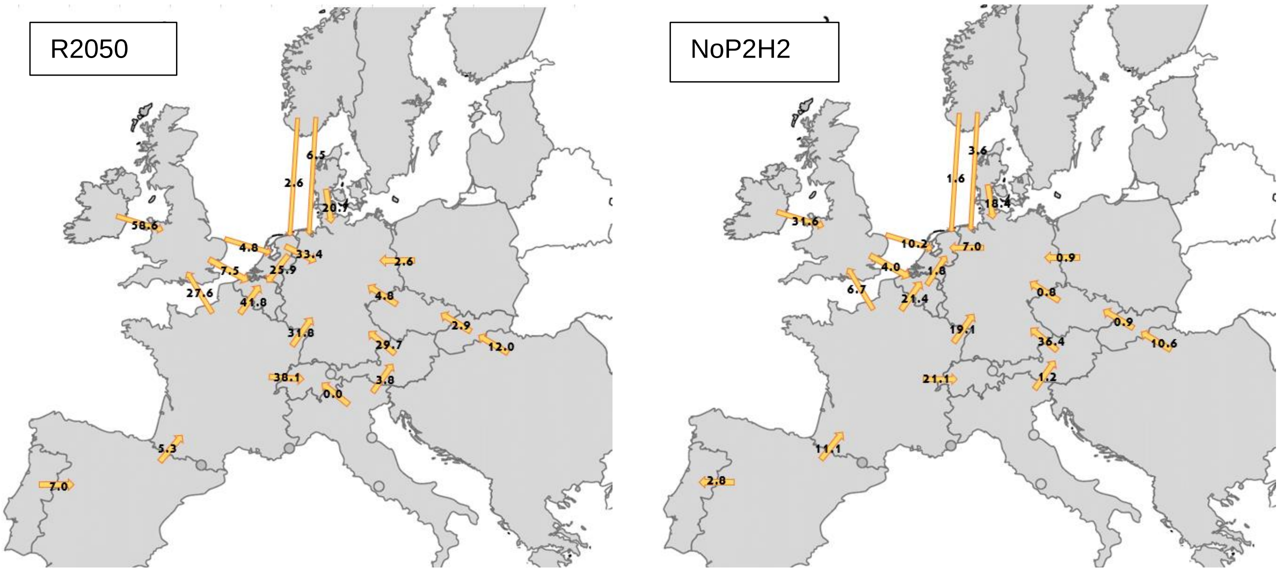

Figure 1 Electricity (net) trade patterns (in TWh)

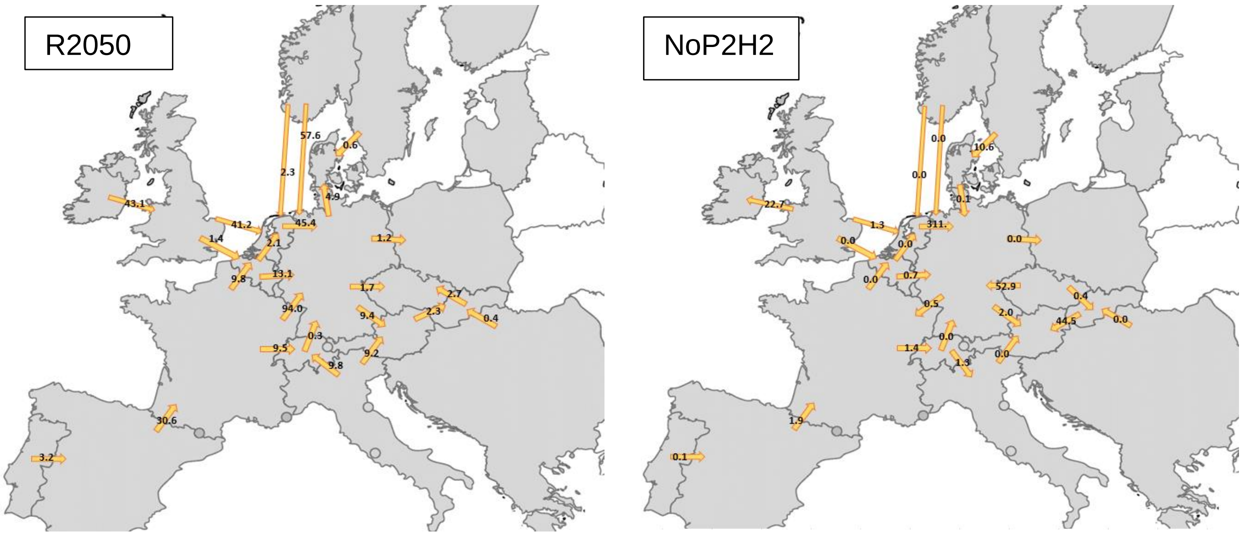

Figure 2 H2 (net) trade patterns in R2050 and NoP2H2 (in TWh)

The current gas infrastructure already offers enough potential to bare the need for H_2 trade. Figure 3 shows the different H_2 transmission investments between countries where no new pipelines were built, and 11% of the existing gas infrastructure was retrofitted for H_2 transport. The additional adjustments are limited compared to the NoP2H2 scenario where only 7% of the gas infrastructure had to be adapted due to the lower need for H_2 trading.

Countries that still find SMR as the most economical way to produce H_2, e.g., because of low cheap VRE potentials, use their maximum allowed SMR production, 50% of the internal demand, and supply the remaining H_2 demand via electrolysis and imports, even moving from a net export position in NoP2H2 to a net import position: this is the case for countries like the Netherlands and UK. Countries that do not allow carbon storage, supply H_2 mainly through imports and electrolysis, e.g., Germany and Austria.

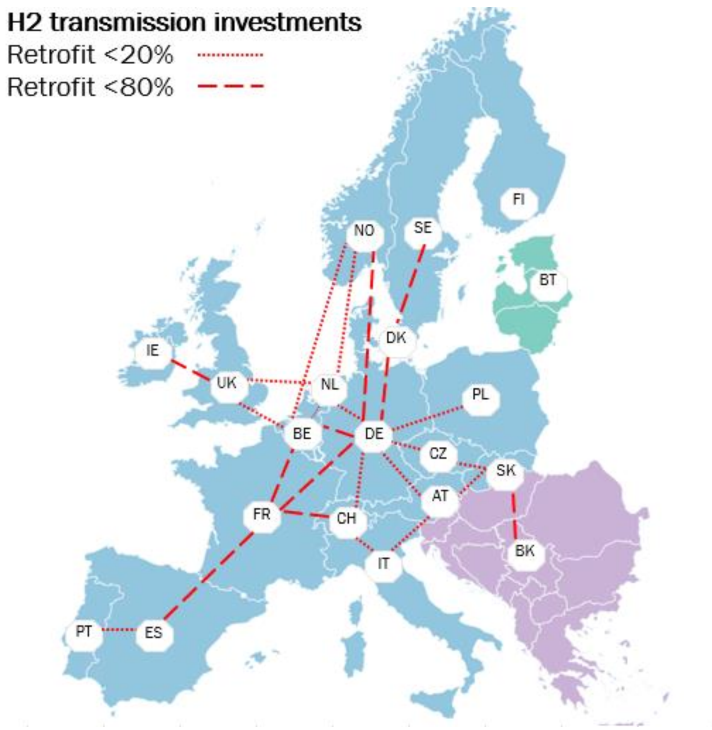

Figure 3 EU H2 transmission investments map in R2050

The 58% level of H_2 electrification requires almost 1841 TWh of extra electricity demand, accounting for nearly 28% of the total demand. To meet the new H_2 electrical demand, the system uses and invests mainly in more solar PV, wind offshore and wind onshore. The total VRE production went from 3316 TWh in NoP2H2 to 4952 TWh in R2050. This VRE production increase is equivalent to 90% of the extra H_2 electrical demand.

The total CO_2 emissions of the system went down from 106 Mton in NoP2H2 to 68 Mton in R2050. This 35% emissions reduction results as a natural consequence of shifting 58% of the H_2 production from SMR, in NoP2H2, to electrolysis, in R2050, where mainly non-pollutive (VRE and nuclear) technologies provide the extra electricity for H_2 production. Note that under the assumptions used in this study, the combined European electricity and hydrogen system still leads to CO2 emissions. In order to achieve a completely energy-neutral system by 2050, these emissions must be compensated elsewhere. How to do this, however, is beyond the scope of this study.

Different variants of the reference scenario R2050 were analysed. By comparing these variants, we can separate the effect of different aspects on the system:

- '**NoP2H2**' does not allow hydrogen production through electrolysis thus showing the effects of electrifying H_2 demand, as discussed in the previous section.
- The **'NoH2Storage'** variant allows us to observe the effect of H_2 flexibility (time shifting) through storage by not allowing investment in H_2 storage.
- In **'NoH2Transmission'**, the countries are forced to only export/import electricity via electricity, highlighting the impact of H_2 transmission.

- The last scenario variant, **'NoETransmission',** does not allow new expansions in the electricity network, thus only using the forecasted electricity transfer capacities. This last variant analyses how investing in a hydrogen network compares to expanding the current power system network.

The key messages of this report, studying the impact of H_2 electrification on the power system, include:

- **H_2 electrification levels**: for the different scenario variants studied here, the electrified H_2 EU demand ranges between 58% and 61%. Indicating that it is still optimal to supply around 40% of the total H_2 demand via SMR with about 90% of CO_2 capture, even though there is an expected CO_2 price of 250 Euro/ton. This 60% of H_2 demand electrification accounts for around 30% of the total electricity demand, mainly supplied by non-pollutive technologies, mostly VRE, becoming 74% of the EU electricity mix, compared to 67% when H_2 is not electrified (NoP2H2). Electrolysers' flexibility also helps non-pollutive technologies partly replace peak units, such as gas, since the extra investment in VRE (and nuclear) is still present during high electricity prices when electrolysis is not competitive. Electrifying part of the H_2 demand (~60%) lowers the total emissions of the power and H_2 sector from 106 Mton (in NoP2H2) up to 68 Mton, as a consequence of reducing emission in both the H_2 sector, by replacing SMR with electrolysis, and also the power sector, by replacing gas units by non-pollutive units. The H_2 electrification level is very sensitive to gas price. Doubling of the natural gas price from 7.5 EUR/GJ (27 EUR/MWh) in the reference scenario to 15 EUR/GJ (54 EUR/MWh) reduces the SMR by 80%, resulting in less than 7% being produced through SMR. As a large part of SMR-based H_2 production in the reference scenario is equipped with CCS already resulting in a relatively low level of CO_2-emssions, doubling of the CO_2-price from 250 EUR/ton to 500 EUR/ton has much less of an effect.
- **Impact of H_2 flexibility:** Not allowing H_2 flexibility in time (NoH2Storage) or space (NoH2Transmission) maintains similar H_2 electrification levels compared with the case where H_2 flexibility is fully exploited (R2050). The combined flexibility of electrolysis-based hydrogen production and storage or transmission is still sufficient to support a significant increase in VRE production. Limitation of H_2 flexibility in time or space translates into significant, though somewhat lower CO_2 emission reductions, from 106 Mton (in NoP2H2) to 81 Mton (in NoH2Storage and NoH2Transmission), instead of reaching 68 Mton in the cases where H_2 flexibility is fully exploited (in R2050 and also in NoETransmission).
- **Electricity vs. H_2 transport:** Relying only on electricity transmission, by not allowing H_2 transmission (in NoH2transmission), provides higher costs (up to 1.2%) and CO_2 emissions (up to 21%) when compared with other H_2-electrification scenario variants. Not allowing extra electricity transmission (in NoETransmission) can achieve similar CO_2 emissions compared to the optimal mix (R2050), although system costs are slightly higher (0.3%, 0.8 billion euros). At the same time, by allowing only investments in an H_2 network, there appears to be no need for extra 28 GW of HVDC interconnectors (in R2050). This indicates that a system with the expected transmission expansion by 2050 is already very near to the optimal solution, hinting that the focus should be on facilitating H_2 transport rather than extra electricity transport.

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1 Introduction

1.1 Background

The European Union (EU) aims to be climate neutral by 2050. This goal is at the heart of the European Green Deal and aligns with the EU's commitment to increase global climate action according to the Paris Agreement commitments. The electrification of end-use services in the transport, residential and industrial sectors coupled with the decarbonisation of power generation is one of the essential pathways to achieve the CO_2 emission reduction targets. The transport and residential sectors can be directly coupled to the power system by adopting electric end-use technologies such as heat pumps in the residential sector and electric vehicles in the transport sector. Nevertheless, a diverse set of energy vectors will likely play a role in decarbonising different sectors in a net-zero future. One of these vectors is low-carbon hydrogen. This includes hydrogen produced by electrolysis of water using electricity from wind and solar energy (also called green hydrogen), or low-carbon grid-mix electricity (with e.g. nuclear and biomass), and hydrogen produced from fossil fuels with capture and storage of the vast majority of the of the CO_2 that is formed in the conversion processes.

Low-carbon hydrogen is a crucial sustainable solution for the decarbonisation of the economy and a key to opening the integration between sectors. It has been identified as a valuable energy vector for end uses where it is the most efficient solution in the decarbonisation process, e.g. hydrogen-intensive industry, high-temperature processes, long-distance heavy duty transport, maritime transport, and aviation. Furthermore, hydrogen can play an essential role as a long-term energy storage option in a system with 100% renewable electricity.

1.2 The H2FUTURE project

The H2FUTURE project is part of the electrolysis technology development trajectory that is taking place. Central to the project is the demonstration of a 6 MW water electrolysis installation. This installation is based on the latest polymer electrolyte membrane (PEM) electrolysis technology of Siemens. The technology is being put into practice for the first time in a complete system in this project. The installation will be realised and tested on the site of the voestalpine steel plant in Linz, Austria. This fits with voestalpine's expectation that a hydrogen-based Direct Reduction (DR) process in combination with an Electric Arc Furnace (EAF) will become the dominant technology for steel production in the future. In order to prepare for this, voestalpine wants to get to know the technology and at the same time assess the state of development of the technology. The project is coordinated by the Austrian utility Verbund, which also wants to gain experience with the technology and is interested in the ability of the technology to respond in a timely manner to price incentives from the market and provide services to support integration of intermittent power sources and the balancing of the power grid. With the view of deployment of the technology for delivering grid services, APG, the Austrian TSO, is also a partner in the project.

The larger part of the H2FUTURE project is related to the design, engineering, building, commissioning, testing, actual operation, and monitoring of the demo-plant. Next to the experimental program, the H2FUTURE project includes a work package that focuses on determining the key performance indicators of the electrolysis system and the techno-economic evaluation of the use of electrolysis in two of the most important industrial applications, i.e. the production of iron and steel and the synthesis of ammonia for fertilisers. The techno-economic evaluation and roll-out perspectives of hydrogen-based steelmaking are addressed in deliverables 9.1 and 9.3 of the project. The techno-economic evaluation of the use of renewable hydrogen from electrolysis in the ammonia/fertiliser industry is addressed in deliverable 9.2. This report reports on the roll-out perspectives of green ammonia and the impact of large-scale renewable hydrogen production through electrolysis on the electricity system.

The application of green hydrogen for ammonia production could help reduce the industry's heavy reliance on fossil fuels and large carbon footprint. Worldwide, ammonia production emits around 450 Mt of CO2. Ammonia synthesis is particularly emissions intensive, with 2.4 tonnes of CO2 emitted per ton of ammonia produced. This is about one and a half times as emissions intensive as crude steel production and four times as intensive as cement production, based on direct emissions. Ammonia production accounts for around 20% of energy consumption of the wider chemical sector and around 35% of its CO2 emissions (IEA, 2021a).

1.3 Scope and objective of the study

This report is part of the deliverables of work package 9 of the H2FUTURE project and focuses on the transition of fossil fuel-based ammonia production to green ammonia in Europe. The report consists of two parts.

The first part aims to provide insight into the challenges for the transition to green ammonia in Europe, and the status and current developments regarding the transition.

The second part aims to provide insight into the impact of large-scale electrification of hydrogen production on the electricity system in Europe. The emerging trend of electrifying sectors, and green and low-carbon hydrogen generation will have significant consequences for the power system planning and operation. The H2FUTURE project focuses in particular on renewable, green hydrogen for steel and ammonia production, but as the development of green hydrogen will not only take place in these industries. The impact on the electricity system has therefore been investigated on the basis of a constructed 2050 scenario based on hydrogen demand data from a European decarbonisation scenario, which includes the steel and ammonia industry, supplemented with electricity demand data from electrification scenarios for heat and transport sector. The combined demand data serve as basis for a detailed power system analysis for the entire EU and selected individual countries. The study was conducted with a model to simulate an integrated European market for electricity and hydrogen. Among other things, we looked at the effect on the electricity system of having or not having the possibilities for large-scale storage of hydrogen and the exchange hydrogen between countries via a pipeline infrastructure. The modelling analysis is designed to quantify the impact of high levels of electrification and hydrogen use on the power and hydrogen systems' infrastructure development, generation mix, CO_2 emissions and system costs.

1.4 Structure of the report

Following this introductory chapter, the next chapter provides an overview of the status and developments regarding the transition to green ammonia in Europe. The chapter first addresses the required roll-out rate of renewable hydrogen production for green ammonia and the current status of green ammonia projects in Europe. Subsequently, the chapter analyses relevant policy target from recent EU policy packages and plans, and looks into the role of import of green ammonia for the transition, including recent initiatives in this field. The remaining chapters concern the study of the impact of large-scale electrification of hydrogen production on the electricity system. Chapter 3 outlines the approach of the modelling analysis, including a description of the integrated electricity and hydrogen market model, and the scenario data and assumptions used for the study. Subsequently, Chapter 4 presents and discusses the results of the study. First, two cases are compared with and without electrolysis for the production of hydrogen to determine the impact of electrolysis on the electricity and hydrogen generation mix and associated generation capacities. Secondly, a number of alternative cases were examined to probe the effect of hydrogen storage and hydrogen cross-border transmission possibilities on the electricity system, including some sensitivity analysis for major parameters such as natural gas price and CO_2-price. Finally, Chapter 5 provides a summary of the major findings and the conclusions of this study.

2 Status and developments regarding the roll-out of green ammonia in Europe

2.1 Electrolyser capacity for green ammonia in Europe

The ammonia production capacity in the EU is about 20 million ton per year including the UK and Norway (Egenhofer & Schefler, 2014) (IFA, 2022). About 17.6% of this 20 Mt is hydrogen which means a hydrogen production capacity of about 3.5 Mt/yr. Replacing the current fossil fuel-based hydrogen production capacity with renewable hydrogen, produced by splitting water using renewable electricity, will require a large amount of electrolysis capacity.

The exact amount depends on the specific electricity use for producing a unit of hydrogen, and in particular the number of full load hours an electrolyser can be operated to produce renewable hydrogen. If the electricity mix consist solely of renewable sources, and the grid only contains renewable electricity, an electrolyser can produce renewable hydrogen all the time. In practice this usually means operation with a capacity factor of about 90% or 8000 hours. If such operations were possible at a specific electricity consumption of 52.5 kWh per kilogram of hydrogen (energy efficiency 75.0% HHV, or 63.5% LHV), then about 23 GW of electrolysis, based on electrical input, would be needed to replace current hydrogen production for ammonia. This is a most ideal situation. Significantly greater capacity is likely to be required.

In most countries, the share of renewables in the grid mix is still limited and the number of full load hours will be much less if only renewable hydrogen were to be produced. A lower number of full load hours also results when electrolysers are used as flexible units for balancing the grid in order to support the implementation of variable electricity supply from wind and solar energy. In that case, electrolysers will, on average, be operated at a power below maximum in order to be able to be adjusted both up and down in the event of an abundance or a limited supply from variable sources. Finally, there is also a lower number of full load hours if the electrolyser is directly connected to a sustainable electricity generator such as a wind farm or a solar-PV farm. On the other hand, there will also be a minimum number of full load hours determined by the maximum production costs at which renewable hydrogen can still be sold in the market.

Assuming that practical and competitive operation requires a capacity factor in the order of 50% to 70%, i.e. approximately 4400 to 6100 hours, replacement of current hydrogen production capacity for ammonia in the EU including the UK would require 30 to 42 GW of electrolyser capacity. To complete the full transition by 2050 at the latest, this means installing an average of 1.1 to 1.5 GW of electrolysis capacity per year for ammonia production only, or about 100 MW per month. This will have to be accompanied by an equivalent expansion of renewable electricity production capacity to power the electrolysers. As there are no signs of this type of deployment rates for the time being, and since there will be a much greater need for renewable, green hydrogen, these figures are expected to be much higher in order to achieve a net zero emission energy supply.

One could argue that the renewable hydrogen does not necessarily have to be produced in Europe and can also be imported from elsewhere. However, this does not change the numbers. The capacity will then only have to be installed elsewhere. In addition, the hydrogen will then still have to be transported to Europe, which does not necessarily make the task any easier. Just as an indication, global production of ammonia currently is about 10 times the level of production in the EU, and production is still increasing (IFA, 2022). So switching the current ammonia industry outside the EU to green ammonia by 2050 would already require at least an installation rate of about 900 MW of electrolysis per month, including associated renewables. And this is only for ammonia. The IEA estimates that global electrolyser capacity will have to reach 850 gigawatts (GW) by 2030 to get on track for a net-zero emission scenario which stays within 1.5 degrees Celsius global warming in 2050, and ultimately requires 3,600 GW by 2050 (IEA, 2021b). This is almost 9 GW per month from January 2023 through the end of 2030 and almost 11.5 GW per months in the period 2031 through the end of 2050. It's about a 100-fold increase from what it takes to completely replace just fossil hydrogen with renewable hydrogen for ammonia production in Europe.

2.2 Status of green ammonia projects in Europe

The amount of renewable hydrogen and electrolysis capacity needed to make the energy supply in general, and ammonia production in particular, more sustainable, is in stark contrast to the actual realisation of electrolysis projects. This is not very surprising. Although attention has been paid to hydrogen as an energy carrier and renewable hydrogen for some time, it has only been since the climate agreement in Paris in 2015 that renewable hydrogen has widely been seen as a necessity and essential part of a sustainable energy supply (see e.g. (IRENA, 2018); (IRENA, 2019); (IRENA, 2022); the difference between (IEA, 2016) and (IEA, 2020); (IEA, 2019); (IEA, 2021b) and (European Commission, 2020). However, real implementation can only take place if this notion is not only endorsed by the "believers" but widely accepted by policy makers in government and in business. It also requires a good understanding of the status of the technology, of all kinds of possible risks associated with the option, and of the numbers and especially the economics associated with the option before final decisions can be made to make investments, both on the side of government as well as on the side of business. Although the future role of hydrogen is now widely accepted, we are still in the middle of the exploratory and preparatory phase. We are still at the very beginning of the transition from fossil hydrogen to low-carbon and renewable hydrogen, and the application of hydrogen for energy purposes.

The vision on the role and importance of hydrogen has led many parties worldwide to develop initiatives around the topic. In 2020, the IEA started with a database of hydrogen projects to monitor the development in this area (IEA, 2021c). The revised 2021-version already contains almost a thousand projects, and the list is most likely non-exhaustive. Projects are characterised, among other things, by status of the initiative, type of technology for hydrogen production, type of energy used for production, (main) product, and type of hydrogen application. As the initial focus of this report is ammonia and the fertiliser industry, only project involving ammonia have been considered in more detail.

Selecting "Ammonia" as "End use" in the database results in 67 hits, which is 6.8% of all listed projects. Not all projects turn out to be electrolysis projects; 13 projects concern fossil fuel-based projects with CO_2 capture, utilisation and storage (CCUS), of which 10 with natural gas. According to the overview, there are 5 projects "in operation", 4 of which are in North America and 1 in China. There are 2 projects in Europe, in Norway and the UK, both with a "Feasibility study" status.

The other 54 projects relate to electrolysis. Considering the type of electrolysis, 10 projects have been marked as "ALK" (Alkaline electrolysis) and 5 as "PEM". The remainder is "Other Electrolysis" with the vast majority having "Concept" or "Feasibility Study" status, suggesting that the initiatives are still in an early stage and no choice has yet been made on the type of electrolysis. Only 42 of these 54 projects remain if "Ammonia" is also selected as "Product", indicating that in the other projects hydrogen is the main product, and that there are different types of end-use or different types of end-use are still under consideration. Furthermore, 3 projects appear to be no new initiatives but projects from the past, of which 2 have already been "Decommissioned". Only an ammonia plant with a 20 MW (alkaline type) electrolyser that has come online in 1975 in Peru seems still in operation.

The 39 new electrolysis-based projects labeled “Ammonia” as both “Product” and “End-use” represent an estimated cumulative size of almost 36 GW of electrolysis. Only 35 projects have an indication of size, resulting in an average size of about 1 GW per project. On closer inspection, however, the cumulative size is dominated by an Australian project with an estimated size of almost 21 GW which reduces the average size of the other projects to about 440 MW. Removing all projects of 1 GW and larger leaves 29 projects with an average estimated size of about 200 MW of which 9 projects are smaller than 100 MW.

Not focusing on size but on location, it turns out that 14 sustainable ammonia projects in the list are in Europe, of which 9 in EU countries and 5 outside the EU. These 5 are all in Norway, with 4 of the 5 projects being consecutive stages of expansion at Yara's production site in Porsgrunn. The cumulative capacity of these 14 projects adds up to about 4 GW, which represents 10 to 13% of the capacity required for a full transition of current ammonia production capacity in Europe to green ammonia. However, 12 out of the 14 projects are still in the “Concept” and “Feasibility study” phase, according to the database. It is therefore by no means clear whether and when these projects will materialise. Only 1 project is “Under construction”, and another one has reached the final investment decision (“FID”) status.

The 2 most advanced green ammonia projects have an electrolyser capacity of 20 MW and 10 MW, respectively, which is about 0.1% of the capacity required for a full transition to green ammonia production in Europe. The latter project is located in Western Jutland, Denmark, and was awarded approximately €11 million from the Danish Energy Technology Development and Demonstration Program in June 2021. It is expected to be operational in 2023. This is reiterated in a recent update of the project, although the design of the installation does not appear to be finalised yet [1]. The “Under Construction” project of 20 MW has clearly made more progress. This is a project by Iberdrola and Fertiberia in Puertollano, Spain, that has meanwhile been completed and inaugurated in May 2022 [2]. The start-up of the Puertollano plant is said to represents the first phase of a plan that envisages development of 210 MW additional electrolyser capacity for up to 40,000 tonnes per year of green hydrogen for the production of ammonia-based fertilisers between 2022 and 2027.

Despite significant advances in hydrogen thinking and the large number of initiatives in the field of electrolysis-based production and application of renewable hydrogen, it is clear that a huge

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1 https://stateofgreen.com/en/solutions/reddap-the-worlds-first-dynamic-green-ammonia-plant/
2 https://www.iberdrola.com/press-room/news/detail/his-majesty-the-king-inaugurates-green-hydrogen-plant-puertollano

acceleration in the actual realisation of green hydrogen projects is needed to reach the quantities that are expected to be needed to eventually arrive at a sustainable energy system by 2050. It goes without saying that this needs to be accompanied with an equivalent acceleration of deployment of renewables. To achieve the acceleration in deployment of electrolysis and renewable hydrogen will be quite a challenge as, due to a lack of experience, investments in large projects right from the start is not likely. This is illustrated by above most advanced projects and also project such as H2FUTURE (6 MW)[3], Refhyne (10 MW)[4], Djewels (20 MW)[5], and many others[6]. Learning by doing requires time and to minimise risks, developments are more likely to follow a cautious step-by-step expansion from tens of MW to GW-scale with intermediate steps on the order of 100 to a few hundred MW.

(Kramer & Haigh, 2009) state that historically it has taken three years to build a demonstration plant, one year to start it up and two to five years to overcome setbacks and reach satisfactory operability. So it can take a decade to reach the point where one is confident enough to build the first full-scale commercial plant. So far, the H2FUTURE project is not really an exception to this. System inertia and conservatism are other factors that do not help rapid scale-up of electrolysis. The replacement rate of existing energy technology and industrial processes is low, and the economic barrier to replace known, optimised and well-functioning equipment is high. At the same time, the human and industrial capacities (knowledge, skills, manufacturing, supply chains) to develop electrolysis are still limited and its development, including mobilising the necessary budgets, also takes time. Ambitions regarding hydrogen are nevertheless now aimed at scaling up in a decade or less to a level that has previously taken at least several decades for other energy technologies and industrial processes (Kramer & Haigh, 2009). It will require unprecedented policy measures to make this unprecedented scale-up happen. On the other hand, with climate change becoming more apparent by the day and the recent geopolitical development on energy supply and security these are also unprecedented times that can trigger swift, concerted and decisive action with hopefully an unprecedented acceleration as a result.

2.3 Renewable hydrogen in Fit-for-55 and REPowerEU

The European Commission has recognised the need to accelerate the energy transition with the presentation of the ambitious Fit-for-55 policy package and the REPowerEU plan in response to the Paris climate agreement and the recent energy security issues caused by the war started by Russia in Ukraine (European Commission, 2021a) (European Commission, 2022a). Both include significant ambitions for the deployment of renewable hydrogen.

The Fit-for-55 package contains binding targets for the use of renewable fuels of non-biological origin (RFNBO) both in industry and transport. The targets are part of the proposal for revision of the Renewable Energy Directive (RED) (European Commission, 2021b). RFNBO are defined as liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass. In addition to renewable hydrogen, this includes renewable hydrogen-derived fuels such

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3 https://www.h2future-project.eu/
4 https://refhyne.eu/ and https://refhyne.eu/refhyne-2/
5 https://djewels.eu/ and https://www.hycc.com/en/projects/djewels-2-delfzijl (see also ‘Projects’ tab)
6 E.g. https://energynews.biz/corfo-awards-green-hydrogen-proposals-to-attract-us1-billion-in-investments/#:~:text=Corfo%20selected%20six%20of%20the%20twelve%20proposals%20submitted,creation%2C%20and%20entrepreneurship%20opportunities%20at%20the%20local%20level.

as synthetic methane, diesel and kerosene, also known as e-fuels, but also renewable hydrogen-based methanol and ammonia.

The binding targets proposed in the revision of the RED, are a translation of the EU hydrogen strategy ambition to let hydrogen become an intrinsic part of our integrated energy system, with domestic renewable hydrogen production from at least 40 GW of electrolysers. The numbers, however are not completely clear. The hydrogen strategy mentions the production of up to 10 Mt of renewable hydrogen in the EU. This can only be realised if the capacity relates to hydrogen output instead of electricity input, which is common for electrolysis, and the capacity factor is about 95%. The REPowerEU document states that about 6.6 Mt of renewable hydrogen is produced domestically and included in the Fit-for-55 scenario (European Commission, 2022b). This is more in line with capacity related to electricity input, but would still require a capacity of about 95%. A closer look to the renewable hydrogen sub-targets in the impact assessment report accompanying the proposal for revision of the RED indicates that 40 GW of electrolysis results in 15.7 Mtoe of renewable hydrogen by taking cost optimisation into account. This is equivalent to almost 5.5 Mt of hydrogen and a more realistic, though still high capacity factor of about 80%.

The REPowerEU plan aims to further increase the ambition of the Fit-for-55 package. The plan considers an increase of domestic renewable hydrogen production by 3.4 Mt on top of the assumed 6.6 Mt of the Fit-for-55 package. This leads to a total of 10 Mt domestic production, which would require 65 to 80 GW of electrolysis according to the Staff Working Document accompanying the plan (European Commission, 2022c). The plan sets a target for 10 Mt of renewable hydrogen imports by 2030. The SWD suggests that this target includes the import of 6 Mt of renewable hydrogen and 4 Mt of hydrogen in the form of ammonia and other derivatives, but the document is not completely clear on this point and leaves room for interpretation. ‘RePowerEU increases the domestic production by 3.4 Mt while 6 Mt of renewable hydrogen and approximately 4 Mt of ammonia are imported’, suggest the import of 4 Mt of renewable ammonia instead of 4 Mt of hydrogen in the form of ammonia. Green ammonia is also an RFNBO. ‘Renewable hydrogen use (including the use of e-fuels derived from hydrogen) reaches 20 Mt by 2030 (of which about 4 Mt as ammonia)’ even seems to suggest import of 4 Mt of renewable ammonia which is used as ammonia. However, ‘the Commission modelling carried out for REPowerEU is based on the assumption of 10 Mt renewable hydrogen produced in the EU and 6 Mt of renewable hydrogen imported from third countries …’, and ‘higher levels of consumption, up to the 20 Mt of hydrogen announced in the REPowerEU communication is assumed to be delivered from third countries in the form of ammonia and potentially in the form of other hydrogen carriers and derivatives’ indicates that the 4 Mt only relates to the hydrogen part of the other import options. According to the SWD, until 2030 the imports of hydrogen to the EU are most cost efficient via pipelines from the neighboring regions and in the form of ammonia through ships over longer distances. Assuming 4 Mt of renewable hydrogen as part of the import of hydrogen carriers and derivates is indeed the right interpretation, and assuming only import of ammonia until 2030, this would mean the import of at least 23 Mt/yr of ammonia, not taking into account possible hydrogen losses upon conversion of ammonia to produce hydrogen.

The increase in hydrogen ambitions in REPowerEU is reflected in a call to increase the binding target for RFNBO use in industry and transport compared to the proposal for revision of the RED in the Fit-for-55 package. The original proposal included a target of 50% for industry and 2.6% for the transport sector. The REPowerEU plan aims for an increase to 75% and 5%, respectively. Saliant detail is that at the same time negotiations are ongoing on refining the Fit-for-55 RED proposal, where the tendency is to lower the industry target for 2030 and shift the 50% target to a later year, e.g. 2035. The transport target seems to double but can probably be reached by double counting of the use of RFNBO, so effectively leaving the initial target unchanged. If the REPowerEU target should prove too ambitious, raising the target in combination with double counting could also be an option to align Fit-for-55 and REPowerEU industry targets for 2030. It would be a cosmetic adjustment for now, but can ensure mutual consistency and could still keep the REPowerEU target in view by keeping the option for interim adjustment of the factor open. At this moment, however, double counting for industry and (interim) factor adjustment is mere speculation, and the conclusion is that targets resulting from the RED-negotiations and the REPowerEU plan are diverging rather than converging.

2.4 Domestic production versus import of ammonia

The original proposal for revision of the RED in the Fit-for 55 package puts an obligation on Member States to ensure that the contribution of RFNBO used for final energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030. For calculation of the percentage, the proposals sets the following rules:

a) For the denominator, the energy content of hydrogen for final energy and non-energy purposes shall be taken into account, excluding hydrogen used as intermediate products for the production of conventional transport fuels.
b) For the numerator, the energy content of the RFNBO consumed in the industry sector for final energy and non-energy purposes shall be taken into account, excluding RFNBO used as intermediate products for the production of conventional transport fuels.

Hydrogen demand data of the Fuel Cell and Hydrogen Observatory show that ammonia production is the second largest hydrogen consumer in Europe next to refineries (FCH 2 JU, 2020). By excluding the hydrogen used in refineries as intermediate product for the production of transport fuels, the hydrogen consumption for ammonia will largely determine the size of the 2030 RFNBO-obligation for industry in many countries. In these cases import of green ammonia to replace domestically produced ammonia can be an attractive option to fulfill the obligation as it reduces domestic hydrogen production from the denominator, thus reducing the size of the obligation, while it can contribute to the numerator if the green ammonia is certified and can be counted as RFNBO. Also from an energy efficiency point of view, replacement of domestically produced ammonia by imported green ammonia, if possible, is to be preferred over cracking of green ammonia to produce hydrogen that may be needed again downstream for ammonia production. However, it is not yet clear whether this option also fits in with the intention of the RED proposal. It is an effective option for fulfilling the obligation, but does not contribute to the realisation of electrolysis capacity in Europe and can result in one import dependency (natural gas) being replaced by another (ammonia/fertilisers). On the other hand, the 4 Mt ambition in the REPowerEU plan for the import of hydrogen in the form of ammonia appears to be equivalent in order of magnitude to the use of about 3 Mt hydrogen per year for the current production of 17 Mt/yr ammonia in Europe (IFA, 2022). It would therefore be strange not to use the option when it is possible to do so both practically, economically and according to regulations, especially in view of safety and risks of domestic transport of large volumes of ammonia.

As indicated before, the import of 4 Mt of hydrogen in the form of ammonia is equivalent to the import of almost 23 Mt of ammonia. Currently, ammonia is a commodity that is already traded worldwide. Over the past ten years, the import of ammonia into Europe has averaged 4.1 Mt/yr while simultaneously exports averaged 1.5 Mt (IFA, 2022). These quantities are an order of magnitude smaller than the ambition for import in the REPowerEU plan. Realising that ambition will therefore require a major expansion of ammonia import terminals and investments in associated options for further transport of ammonia and installations for cracking ammonia for hydrogen production. In Europe, at present there are 23 ports with terminals for import of ammonia which on average means an import of about 0.2 Mt/yr per terminal (Haldor Topsoe, 2020).

Without building terminals in other ports, current terminals must be expanded by at least a factor of 5 on average to be able to accommodate import of 23 Mt ammonia as envisioned in the REPowerEU plan. The market already seems to be preparing for this. Several projects have recently been announced for terminal expansion and new terminals. Ammonia producer OCI announced expansion of the throughput capacity of its import terminal in the Port of Rotterdam from 0.4 Mt/yr to 1.2 Mt/yr by 2023 [7]. A consortium including world's leading independent storage company Vopak is developing a new terminal for the import of ammonia in the Port of Rotterdam, including the possibility to crack ammonia. The planned terminal is strategically located with direct access from the North Sea, connection to Rotterdam's industry and Gasunie's planned hydrogen pipeline infrastructure (Gasunie, 2022), and is planned to start operation in 2026. A similar plan has been announced by Air Products and Gunvor [8]. Also this import terminal is expected to supply the first green hydrogen to the Netherlands in 2026, but details of the capacity of both new terminals are not yet known. A last example is the plan of RWE to build a green ammonia import terminal in Brunsbüttel. The first phase of the plan aims at import and distribution to customers of around 0.3 Mt/yr green ammonia from as early as 2026. The next phase is expected to include expansion to 2 Mt/yr and building of an ammonia cracker to produce green hydrogen as well, which will be transported to industrial customers via a dedicated hydrogen pipeline.

The initiatives to expand import terminals for ammonia take place against the background of the development of large projects at locations with very favorable conditions for "harvesting" of renewable wind and solar energy, and which focus on exporting that energy in the form of green ammonia. A recent overview of 27 renewable energy projects with electrolysis plants of at least 1 GW (electrical input) shows 10 projects - ranging from 1.4 GW to 28 GW electrolysis - which clearly indicate to include production and export of green ammonia (Collins, 2021). These are projects in Australia, which mainly focus on exports to Asia, Saudi Arabia, Oman, Chile and Mauritania. In the meantime, Namibia can also be added to this list.[9] The number could be larger, but the scope of various initiatives is still far from clear. Many of the initiatives were also only announced in 2021, so all are still at an early to very early stage. In addition, many of the initiatives describe a phased development with first a project of limited size and domestic consumption of ammonia or hydrogen, and only at a later stage expansion to larger capacities and exports. This indicates that Europe cannot yet rely on the import of large quantities of green ammonia for the time being. The project that seems closest to realization is the Helios project in Saudi Arabia. At full size the project will produce 240 kt/a of hydrogen for the production of 1.2 Mt/a of ammonia. Some of this could be available for export to Europe, but the amount will depend on the price buyers are willing to pay. According to a recent announcement construction of the green hydrogen plant has begun after

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7 https://www.oci.nl/news/2022-oci-nv-to-expand-port-of-rotterdam-ammonia-import-terminal/
8 https://www.airproducts.nl/news-center/2022/06/0628-air-products-and-gunvor-to-cooperate-on-green-hydrogen-import-terminal-in-rotterdam
9 https://hyphenafrica.com/news/namibia-announces-progress-with-hyphen-hydrogen-energy-to-unlock-us10bn-investment-for-first-green-hydrogen-project-to-help-power-the-energy-transition/

engineers have finished flattening the site last March in north-western Saudi Arabia at the new city of Neom. Start of production is scheduled for 2026.[10]

Despite potential use of ammonia as a fuel for the maritime and also for power plants, the ammonia production capacity is expected to remain relatively unchanged in Europe in more sustainable development scenarios with production growth of less than 10% in 2050 relative to today (IEA, 2021a). Demand from potential new applications is largely compensated by reduction of fertiliser use due to improvements in nutrient use efficiency and structure changes in agriculture. This indicates that volume considerations for renewable hydrogen, as done above, based on current production capacities and quantities of ammonia produced will remain valid in the coming decades. Overall, it seems likely that the near and more distant future will see a mix of renewable hydrogen production for greening domestic EU ammonia production and replacement of ammonia production for fertilisers and the chemical industry with imported green ammonia from outside of the EU.

2.5 Production and transport of renewable energy for ammonia within Europe

Deliverable 9.2 of the H2FUTURE project, reported on a study into the costs and feasibility of different process variants with partial replacement of fossil-based hydrogen production for ammonia, or full production of green ammonia (Dowling, et al., 2022). The study also looked at the need for renewable electricity for those different variants in EU countries with ammonia production capacity. That need has been compared with the current projections for renewable electricity production in those countries for 2040. Results show that in various countries renewable hydrogen production for ammonia would consume a considerable share of renewable electricity up to close to 100% or even more in some cases. This did not yet take into account possible additional demand for renewable electricity due to electrification in other industries (e.g. steel, food, paper and pulp, chemicals etc.), and other sectors (e.g. heat pumps in housing and electric vehicles in transport).

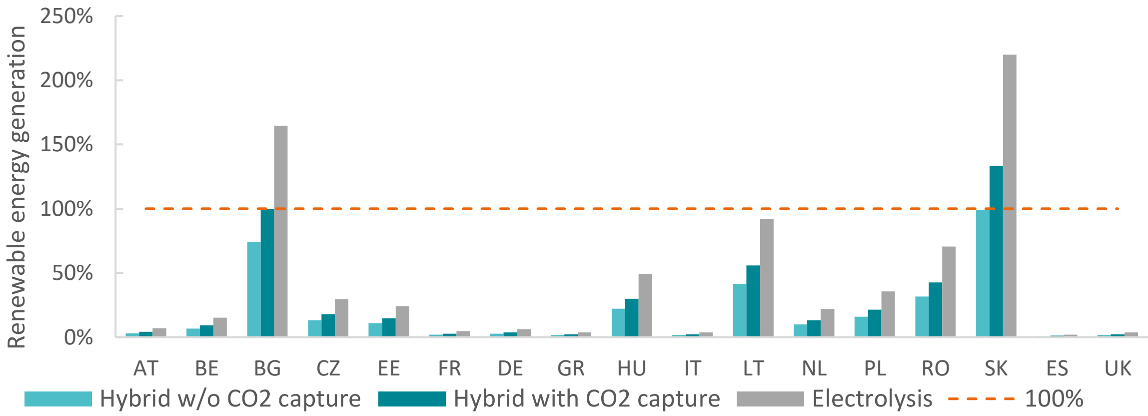


Figure 4: Electricity demand of electrolysis for renewable ammonia production as percentage of projected renewable energy production in 2040.

10 https://gulfbusiness.com/saudi-arabia-to-start-building-green-hydrogen-plant-in-neom/; and https://www.fastcompanyme.com/news/construction-on-neoms-green-hydrogen-project-with-900-epc-contract-has-began/

The mismatch can be solved through different measures. In the first place, much more capacity will have to be installed for the production of sustainable electricity. Importing renewable hydrogen or renewable ammonia will also be part of the solution. Moreover, the renewable electricity does not necessarily have to be produced in the country itself, but can also be imported from neighboring countries. In D9.2 the cumulative electricity demand of the three different process configurations were presented on a time-axis and compared with current and projected cumulative renewable electricity production in the EU. The three variants represent various levels of replacement of current hydrogen production and when considered on a time-axis present some sort of roll-out scenario. The transition will take place gradually as the conditions under which this must be realised are not equally favourable everywhere. The three cases represent a 45% (“lowest hanging fruit” by 2030), a 60% (“can be done with some extra stimulation” by 2040) and a 100% (“most difficult part” by 2050) switch to renewable hydrogen. [11]

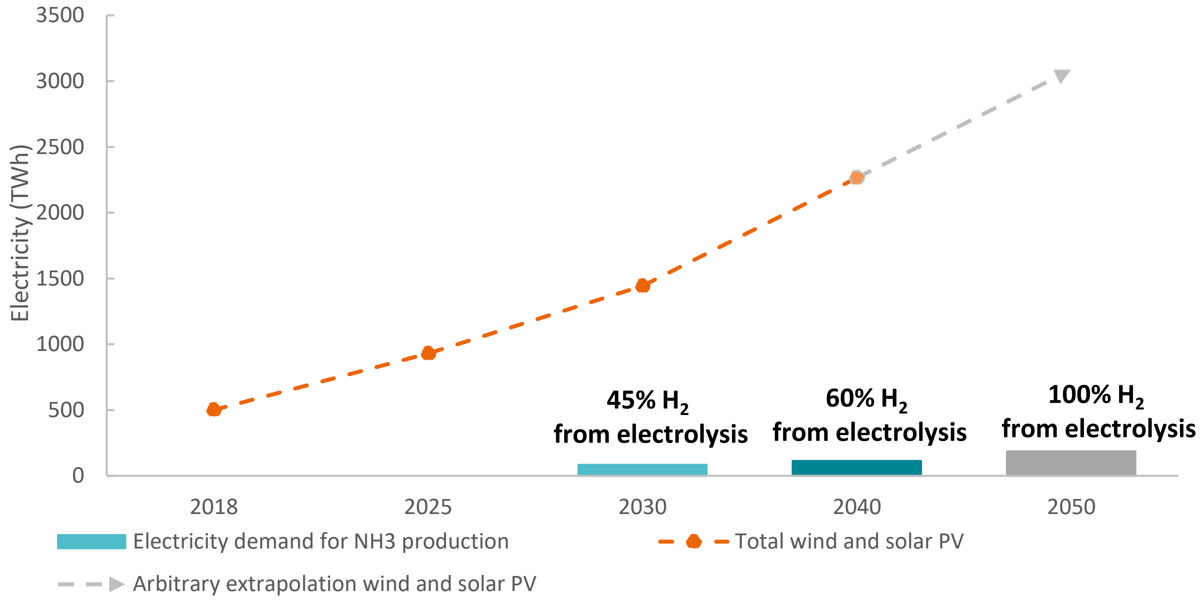


Figure 5: Cumulative electricity demand of an indicative roll-out scenario for renewable ammonia in the former EU28, compared to current and projected cumulative electricity generation from solar PV and wind in the EU28

The results show that the cumulative renewable electricity generation from solar PV and wind in 2018 in the EU (including the UK) already exceeds the demand of about 180 TWh resulting from replacing 100% of current hydrogen use for ammonia production in the EU by renewable hydrogen from electrolysis. In fact, the cumulative renewable electricity generation of about 500 TWh could also cover the demand resulting from an almost full switch of the steel industry to a hydrogen based Direct Reduction Process (DRI), which has been estimated at about 340 TWh in another H2FUTURE study (Sasiain & Rechberger, 2021).

[11] Note that in Figure 5 the cases with a conversion of 45% and 60% should be considered as EU average and do not mean that in all ammonia plants 45% or 60% of the fossil hydrogen is replaced by renewable hydrogen. It can also be a combination of factories that have completely switched, while in other cases no replacement has taken place at all.

Projected renewable electricity generation levels of almost 1500 TWh and more than 2200 TWh in EU countries including the UK, in 2030 and 2040 respectively are certainly enough for steel and ammonia, but should also cover the demand from other electrification options and replacement of current fossil based electricity generation. Electricity demand in the EU is estimated at about 2800 TWh of which about 60-65% is generated from non-renewable sources including 35-40% from fossil fuels (Eurostat, 2022).

Trying to solve the electricity balance on an EU or European level will most likely require significant expansion of electricity infrastructure and electricity trade. Large sources of renewable energy are available in the south of Europe, while the largest centers of demand are mainly in the north-west. This will require net transport of renewable energy from supply to demand centers. This can be done in the form of electricity, but if a significant part of the electricity in the demand centers is needed for hydrogen production, local conversion and transport of hydrogen by pipeline can be a good alternative. This is being recognized more widely and in the meantime the contours for a European hydrogen pipeline system are being worked out (EHB, 2022).

The impact of large-scale electrification of hydrogen production on the electricity system, and the effects of transporting renewable energy in the form of hydrogen instead of electricity is studied in the remaining part of this report. Electrification of hydrogen production for steel and ammonia, applications addressed in more detail as part of the H2FUTURE project, will not take place in isolation. So studying only the impact of both on the electricity system is of limited use value. Instead an integral scenario for deep-decarbonisation of the European energy system is used as basis for the study on the impact of large-scale electrification on the electricity system and the effects of cross-border transmission of hydrogen next to electricity between countries in Europe to cover electricity and hydrogen demands in a sustainable way. The approach of the study, the model used, and the data and assumptions are explained in the following chapter.

3 Approach electricity system impact study

In order to analyse the impact of large-scale electrification of hydrogen production on the electricity system in Europe, this study defines and uses one reference scenario for hydrogen and electricity demand in 2050. This scenario, as well as a variety of sensitivity variants for 2050, are analysed by means of an optimisation model. This model is based on the European Electricity Market Model (COMPETES) which has recently been extended to a model for coupled simulation of an electricity and hydrogen market with the possibility of cross-border transmission of hydrogen in Europe.

This chapter provides a brief description of the approach used in the current study, notably regarding the following components:

- The model used, i.e. COMPETES, a detailed European electricity market model which has been extended to an integrated electricity and hydrogen market model.
- The major model input parameters used for the quantified and analysed scenario and variants

3.1 COMPETES description

COMPETES ('*Competition and Market Power in Electric Transmission and Energy Simulator*') is a power system optimisation and economic dispatch model that seeks to meet European power demand at minimum social costs (maximising social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units and transmission interconnections across European countries and regions.[12]

COMPETES consist of two major modules that can be used to perform hourly simulations for two types of purposes:

- A transmission and generation capacity expansion module in order to determine and analyse least-cost capacity expansion with perfect competition formulated as a linear program to optimise generation capacity additions in the system;
- A unit commitment and economic dispatch module to determine and analyse least-cost unit commitment (UC) and economic dispatch with perfect competition, formulated as a relaxed mixed-integer program considering flexibility and minimum load constraints and start-up costs of generation technologies.

The COMPETES model covers all EU Member States and some non-EU countries – i.e. Norway, Switzerland, the UK and the Balkan (BK) countries (grouped into a single Balkan region) – including a representation of the cross-border power transmission capacities interconnecting these European countries and regions (see Figure 6). The model runs on an hourly basis, i.e. it optimises the European power system over all 8760 hours per annum.

Over the past two decades, COMPETES has been used for a large variety of assignments and studies on the Dutch and European electricity markets. In addition, it is used and regularly updated

[12] Over the past two decades, COMPETES was originally developed by ECN Policy Studies – with the support of Prof. B. Hobbs of the Johns Hopkins University in Baltimore (USA) – but since 2018 it is used/developed commonly by the Netherlands Environmental Assessment Agency (PBL) and TNO Energy Transition Studies.

as part of the energy modelling framework for the annual Climate and Energy Outlook of the Netherlands (NEV/KEV; see, for instance, (PBL, et al., 2021).

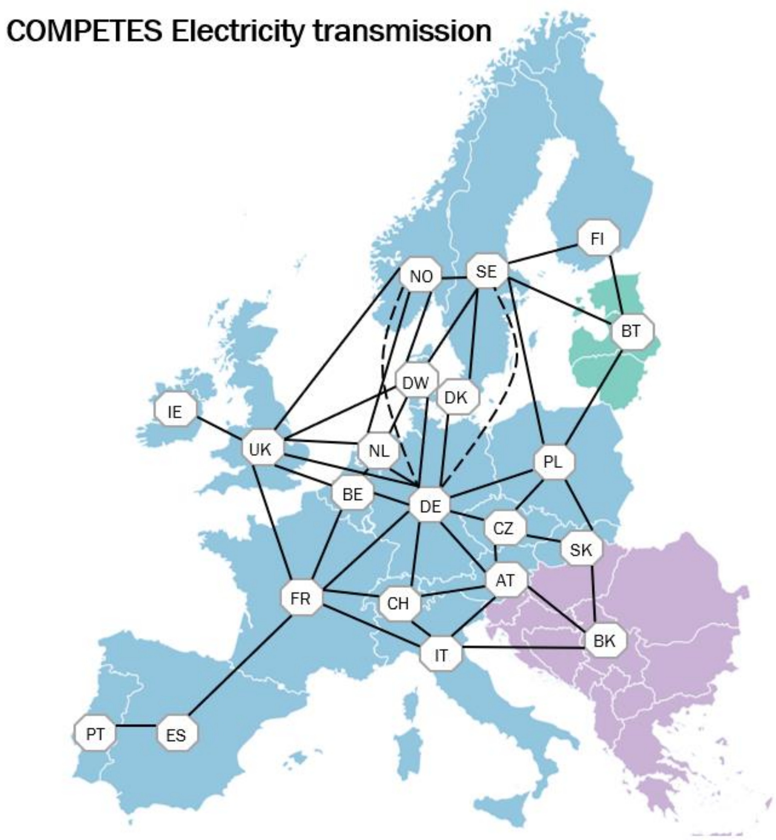


Figure 6: The geographical coverage of the COMPETES power system

3.1.1 COMPETES inputs

For each scenario year, the major inputs of COMPETES include data regarding the following parameters and variables:

- Electricity demand across all European countries/regions, including conventional power demand and additional demand due to further sectoral electrification of the energy system by power-to-heat (P2H) technologies and battery electric vehicles (EV);
- Hydrogen demand across al European countries/regions;
- Power generation technologies, electricity and hydrogen transmission interconnections and flexibility options, including their techno-economic characteristics;
- Country-specific hourly profiles of various electricity demand categories and renewable energy (RE) technologies (notably sun, wind and hydro), including the full load hours of these technologies;
- Assumed (policy-driven) initial installed capacities and potentials of RE power generation technologies;
- Assumptions for future fuel and CO_2 prices;
- Policy targets/restrictions, such as meeting certain RE/GHG targets or forbidding the use of certain technologies (for instance, coal, nuclear or CCS).

3.1.2 COMPETES outputs

On the other hand, for each scenario year and for each European country/region, the major outputs ('results') of COMPETES include:

- Investments and disinvestments ('decommissioning') in conventional and variable renewable energy power generation;
- Investments in interconnection capacities, both for electricity and hydrogen;
- Additional electricity demand due to P2H2 technologies.
- Investments in storage technologies both for electricity and hydrogen;
- Hourly allocation ('dispatch') of installed power generation and interconnection capacities, resulting in the hourly and annual power generation mix – including related CO_2 emissions and power trade flows – for each European country/region;
- Dispatch of newly installed hydrogen generation and interconnection capacities;
- Demand and supply of flexibility options;
- Hourly electricity prices;
- Hydrogen prices
- Annual power system costs for each European country/region.

3.1.3 Flexibility Options

As indicated above, COMPETES includes a variety of flexibility options. These options include:

- Flexible power generation:
  - Conventional: gas;
  - Renewable: curtailment of sun/wind;
- Cross-border power trade;
- Storage:
  - Pumped hydro (EU level);
  - Compressed air energy storage (CAES/AA-CAES);
  - Batteries including EVs, Li-ion, lead-acid (PB), vanadium redox (VRB);
- Demand response:
  - Power-to-Mobility (P2M): electric vehicles (EVs), including grid-to-vehicle (G2V) and vehicle-to-grid (V2G);
  - Power-to-Heat (P2H): industrial (hybrid) boilers and household (all electric) heat pumps;
  - Power-to-Gas (P2G), notably power-to-Hydrogen ($P2H_2$), i.e. water-electrolysis;

3.1.4 Hydrogen technologies and transmission

The COMPETES model has undergone a significant overhaul to integrate the hydrogen system fully. Hydrogen generation, storage and trade technologies techno-economic characteristics have been included. The following summarises the represented hydrogen technologies. Section 3.2.3 describes in more detail the hydrogen technologies and modelling assumptions:

- Hydrogen generation:
  - SMR with different degrees of CO_2 capture rate;
  - Electrolysis
- Hydrogen storage:
  - Underground storage of hydrogen;
- Cross-border hydrogen trade.

See (Sijm, et al., 2017) notably Appendix A., and also see (Özdemir, et al., 2019) and (Özdemir, et al., 2020) for a more detailed description of the COMPETES model. For a more specific discussion of the 2050 reference scenarios quantified and analysed in this study – including the significant scenario input parameters used – see Sections 2.2 and 2.3. below.

3.2 Reference scenario parameters

3.2.1 Energy demand

Electricity demand

Figure 7 provides an overview of the main electricity demand parameters used in COMPETES for the EU countries in the reference scenario, referred to as **'R2050'**. In this figure, the electricity demand is divided into three categories:

- Conventional power demand - For the R2050 scenario, the figures assume that the traditional demand for power growth is offset more or less equally by the energy efficiency improvements. The hourly profile and demand per country are based on historical demand values (ENTSO-E, 2018).
- Power-to-Mobility – this demand for electric passenger vehicles (EVs) is assumed to be flexible to a certain extent. The electricity can go both ways – i.e. grid-to-vehicle (G2V) and vehicle-to-grid (V2G). The projections on EV passenger vehicles for the EU countries are based on (ENTSO-E, 2018) data and scaled to 2050 based on the National Management scenario for the Netherlands (Berenschot; Kalavasta, 2020).
- Power-to-heat by households – This demand comes from electric heat pumps; similar to the EVs, this demand is assumed to be flexible. A set of constraints limits the flexibility of the heat pump.[13] Similar to the EV demand, the projections on household heat pumps for the EU countries are based on (ENTSO-E, 2018) data and scaled to 2050 based on the National Management scenario for the Netherlands (Berenschot; Kalavasta, 2020).

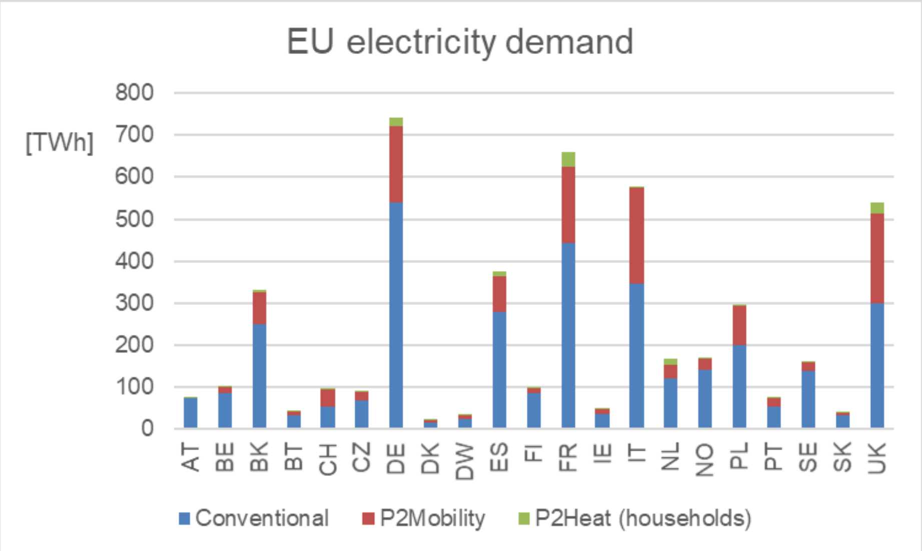


Figure 7. EU electricity demand per country

[13] For more information on the underlying flexibility assumptions and limitations of the electric vehicles and heat pumps see (Sijm, et al., 2022)

Hydrogen demand

The hydrogen demand is based on one of the eight scenarios from the European Commission's long-term strategy to reduce greenhouse gas (European Comission, 2018). The Commission's analysis is based on the PRIMES, GAINS, and GLOBIOM model suite. It explores scenarios to achieve different levels of ambition for 2050, covering the potential range of reduction needed in the EU to contribute to the Paris Agreement's temperature objectives of between well below 2°C and to pursue efforts to limit to 1.5°C temperature change. The selected scenario '1.5TECH' focuses on technical solutions to achieve net-zero GHG emissions. It increases CCS aiming to lower more the remaining emissions. Similarly, it uses e-gases and e-fuels based on hydrogen produced via electrolysis and air captured or biogenic CO_2 to reduce remaining emissions. It applies negative emission technologies via biomass coupled with CCS and the storage of biogenic CO_2.[14]

Figure 8 shows the hydrogen demand per country and sector for the EU countries. Furthermore, the industry sector's hydrogen demand is presented per industrial activity.

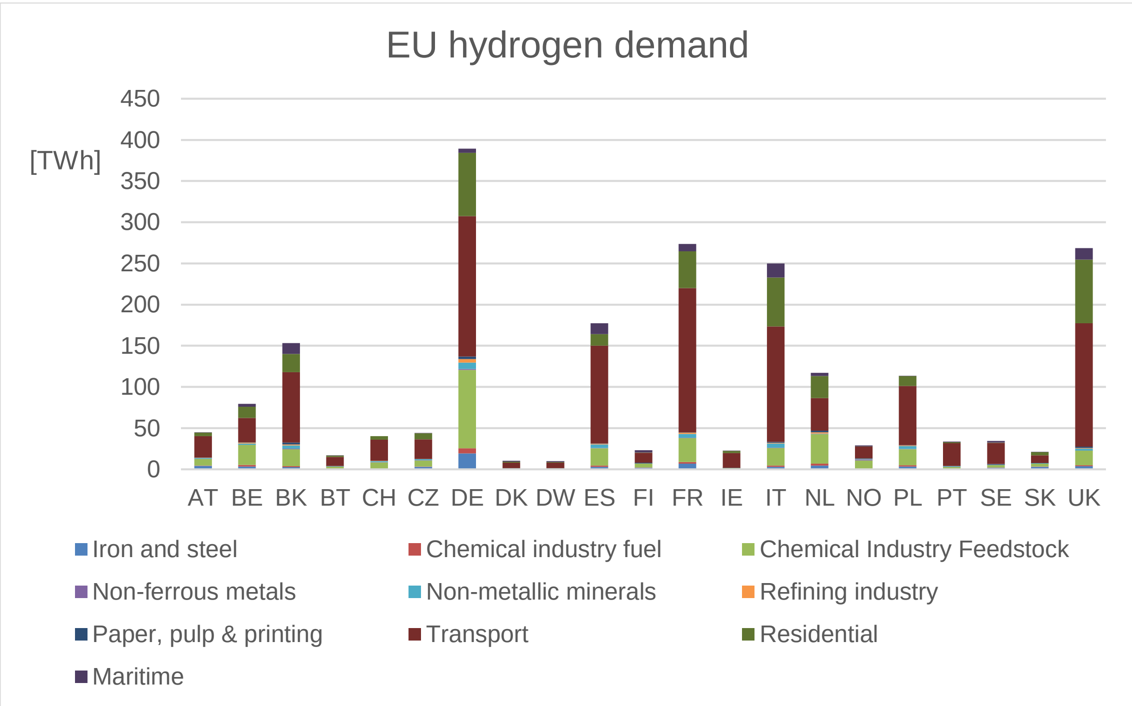


Figure 8. EU hydrogen demand per country and sector[15]

3.2.2 Energy supply: sources and technologies

COMPETES uses its investment module to meet the demand of the different energy vectors, i.e. electricity and hydrogen, in a cost-optimal way. COMPETES includes a variety of primary energy sources and technologies and energy conversion technologies. These technologies are described in sections 3.1.3 and 3.1.4

[14] The hydrogen demand per country and sector can be found in the Appendix

[15] For the purpose of this study all hydrogen demand has been assumed constant throughout the year. This is a realistic assumption for the industry and transport sector but is a simplification for hydrogen demand from the residential sector.

Figure 9 shows the initial power generation capacities used for the reference scenario and sensitivity variants. These initial capacities are input and serve as a starting point for the model, which will endogenously determine the required capacity to meet the 2050 electricity and hydrogen demand. The initial exogenous values are based on the 2040 data of the ENTSO-E National Trends scenario (ENTSO-E, 2020).

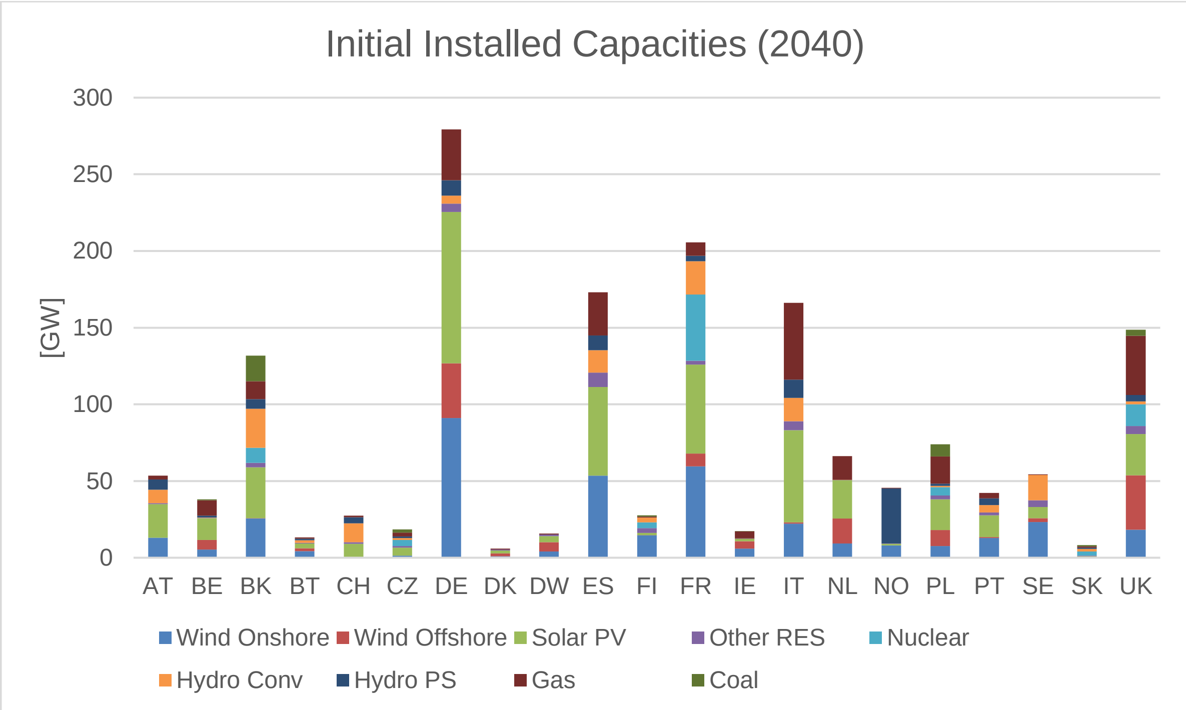


Figure 9. Initial installed capacities per country

3.2.3 Hydrogen technologies

Hydrogen generation

Like power generation, initial hydrogen generation values are endogenously defined for the model. The hydrogen generation technologies in COMPETES are:

- Steam methane reforming (SMR);
- SMR standard CO_2 capture (SMR/CCS-STD) - 55% CO_2 capture rate (IEAGHG, 2017);
- SMR advanced CO_2 capture (SMR/CCS-ADV) - 90% CO_2 capture rate (IEAGHG, 2017);
- Electrolysis;

Table 1 presents the initial H2 generation output capacities assumed in this study. These are based on (Maisonnier, et al., 2007) and (FTI Consulting, 2020).

Table 1. Initial installed hydrogen output capacities

Country	Electrolyser [MW H2]	SMR [MW H2]
AT	0	90
BE	0	783
BK	0	523
BT	0	221
CH	0	28
CZ	0	141
DE	680	1900
DK	0	30
DW	0	30
ES	2720	554
FI	0	413
FR	4420	530
IE	0	0
IT	0	411
NL	2040	1144
NO	0	0
PL	0	0
PT	1360	25
SE	0	0
SK	0	115
UK	3400	144

Hydrogen transport

COMPETES recently introduced the possibility of investing in hydrogen pipelines for long-distance, high-volume hydrogen transport between the European countries. Figure 10 shows the existing natural gas transport links, which can be repurposed to deliver hydrogen instead of natural gas.Table 2 shows the assumed initial natural gas interconnection capacities, which can be retrofitted to transport hydrogen. Also, the model can invest in new hydrogen pipelines. The following decisions can be made endogenously by de model:

- Retrofit to 60% of initial gas capacity
- Retrofit to 80% of initial gas capacity (more expensive than 60% due to extra compression needed)
- Invest in new hydrogen pipelines

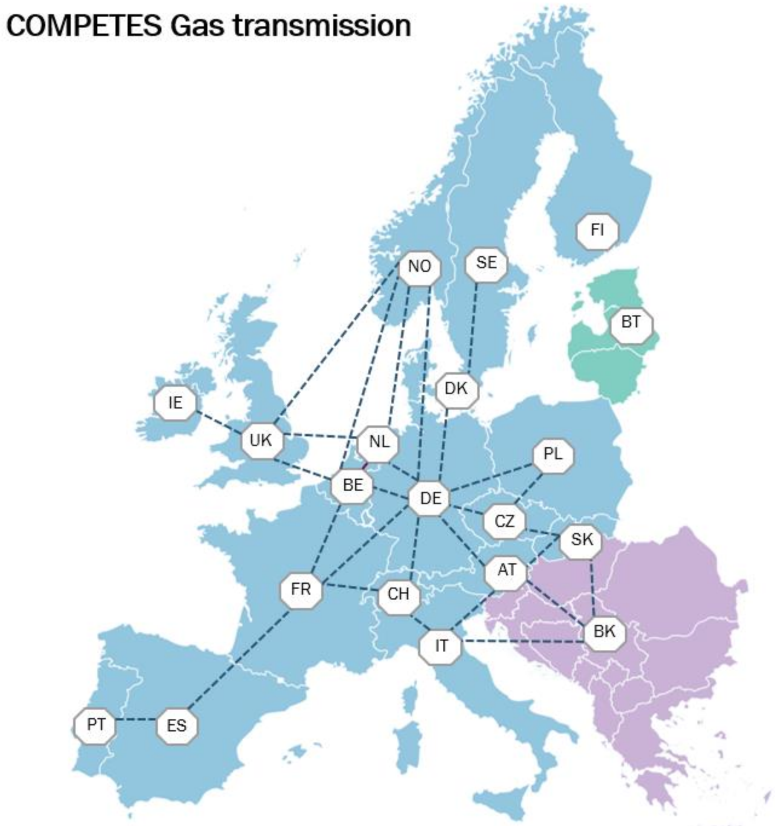


Figure 10. The geographical coverage of the COMPETES gas interconnection system

Modelling assumptions:

- Retrofit and investment decisions are only possible where there is an existing pipeline.
- Transport capacities are assumed to be bidirectional. If the gas trading capacity between two countries is different depending on the trade direction. In these cases, we consider the highest capacity for both directions.
- No losses are assumed in transport nor variable costs for compression.
- The model makes continuous investment decisions in the pipeline retrofitting e.g. in can make use of a part of the total natural gas pipeline capacity to transport hydrogen.

Furthermore, it is assumed that SMR can supply a maximum of 50% of the H_2 demand of a country. This is enforced with a constraint in COMPETES, which is based on the RED II revision proposal within the EU “Fit for 55 package” (European Commission, 2021b) to set a binding target for the use of renewable fuels of non-biological origin (RFNBO) for energy (fuel) and non-energy (feedstock) purposes in the industry. The initial proposal indicates that the use of RFNBO should be 50% of the hydrogen used in the industry by 2030. In the current study, this value is used as a minimum value for hydrogen from electrolysis and is applied to industry and to the use of hydrogen in general in 2050.

Table 2. Natural gas interconnection capacity between countries (ENTSO-G; GIE, 2019)

Country A	Country B	Hourly Capacity [MW]
AT	DE	16250
AT	IT	47875
AT	SK	65417
BE	DE	16667
BE	FR	35417
BE	NL	58333
BE	UK	33458
CH	DE	13250
CH	FR	9708
CH	IT	26458
CZ	DE	58625
CZ	PL	1167
CZ	SK	38083
DE	DK	5167
DE	NL	60375
DE	PL	38875
DE	FR	25208
DK	SE	3375
ES	FR	9333
ES	PT	6000
NL	UK	20583
UK	IE	16125
BK	IT	1167
AT	BK	11083
SK	BK	5292

3.2.4 Fuel and CO_2 prices

Fuel prices are primarily based on prices before the huge increase that started in the second half of 2021 and became more pronounced after the invasion of Russia in Ukraine on February 24. 2022. The effect of these high prices is not part of the current study. Nevertheless, due to the importance of reflecting the uncertainty of commodity prices, especially when simulating the year 2050, section 4.2 aims to provide an insight into the effect of high CO_2 and gas prices on hydrogen production. Table 3 shows the assumed fuel and CO_2 prices used for the reference and scenario variants throughout the study.

Table 3. Fuel and CO_2 prices (Berenschot; Kalavasta, 2020) (PBL, et al., 2021) H_2 future gas price

	Unit	Price 2050
Biomass	€_2015/GJ	9.00
Coal	€_2015/GJ	2.25
Coke Oven Gas	€_2015/GJ	7.54
Lignite	€_2015/GJ	1.10
Natural Gas	€_2015/GJ	7.54
Nuclear	€_2015/GJ	0.78
Oil	€_2015/GJ	10.63
CO2	€_2015/GJ	250

3.2.5 Carbon capture and storage

COMPETES endogenously optimises the investments in electricity and hydrogen generation units with carbon dioxide capture and storage (CCS), such as:

- VRE power plants (wind and solar)
- Biomass plants with CCS
- Natural gas-fired CCGT plants with CCS
- Coal-fired plants with CCS
- SMR with a 55% CO2 capture rate
- SMR with a 90% CO2 capture rate

It is important to note that CO_2 geological storage is currently prohibited in some countries; this study assumes current national legislations and regulations to determine whether the model can invest in the technologies mentioned above. Based on the EU Directive 2009/31/EC on the geological storage of CO_2 as cited on (CO2GeoNet Association, 2021) Germany, Austria, Estonia, Latvia, Lithuania, Denmark, Finland and Ireland do not allow CO2 geological storage.

4 Impact of H2 electrification

4.1 Reference scenario and the impact of H2 electrification

This section provides the main results of the reference scenario described in section 3.2 and the impact of H_2 electrification. To measure the effect of H2 electrification, we compare the reference scenario R2050 with the scenario NoP2H2, where electrolysis is not allowed; that is, all H2 demand must be supplied via SMR (except for the initial electrolysers installed capacity).

The reference scenario R2050 electrifies 58% of the total H_2 demand, see Figure 11, and the remaining 42% is supplied via SMR. This indicates that with the assumed CO_2 price of 250 EUR/ton and the used natural gas price, producing H_2 via SMR with CCS with an 89% CO2 capture rate is still optimal. Notice that 5% of the H_2 demand in NoP2H2 is provided by electrolysis, which results from the initial installed capacities of electrolysers. Similarly, the model uses existing SMR without CCS facilities to supply 4% and 2% of the H2 demand in R2050 and NoP2H2, respectively.

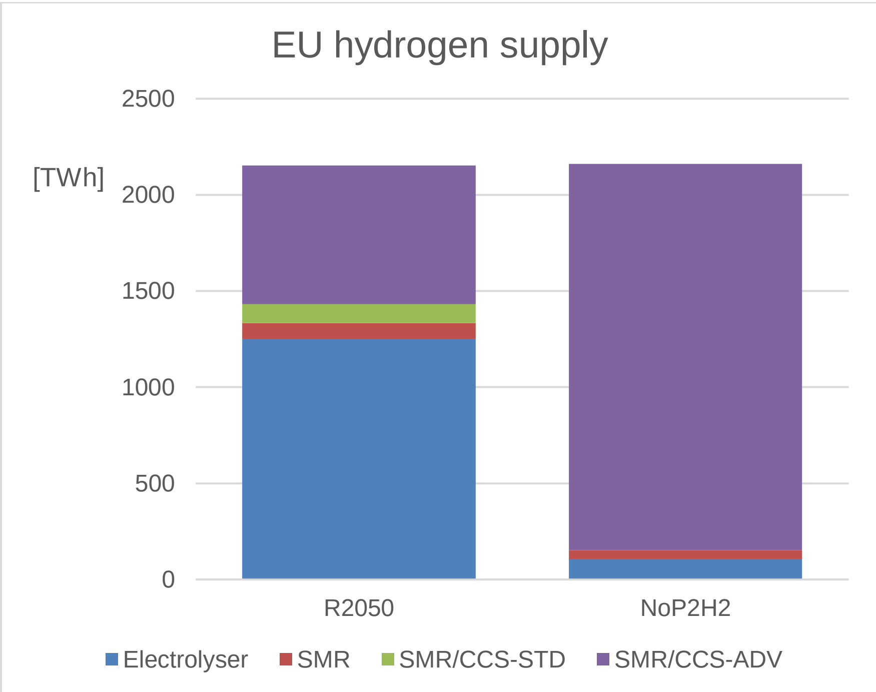
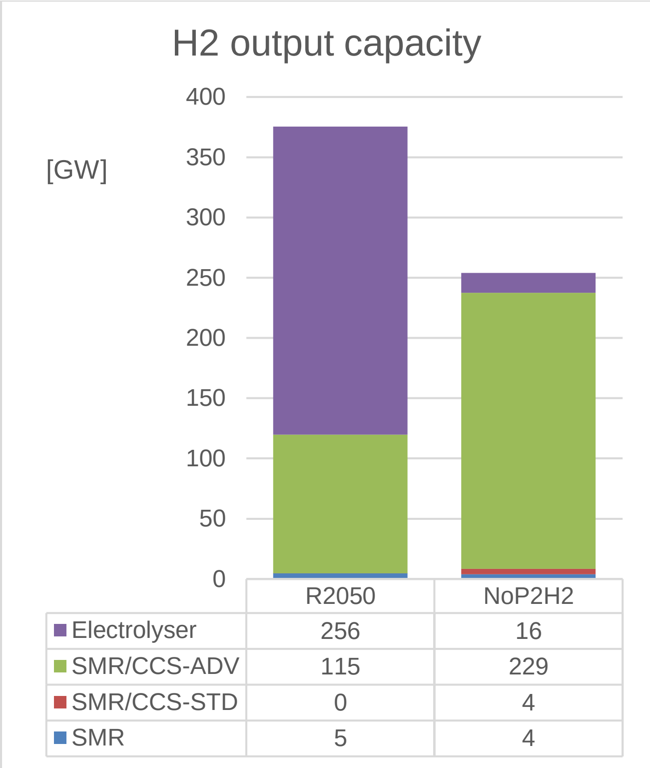


Figure 11. EU hydrogen supply in R2050 and NoP2H2

Figure 12 shows the total installed capacities for H_2 supply. Notice that the total H_2 installed capacity of R2050 increases 48% compared to NoP2H2. This larger capacity indicates that it is more economically efficient to invest in a larger capacity to produce H_2 during periods with low electricity prices (VRE dominated production) and store it for later use, thus avoiding producing H_2 during hours and periods with high electricity prices, than to produce hydrogen by SMR with or without CCS. Electrolysers present 4900 full load hours (FLH) in R2050, whereas SMR operates 7500 FLH in R2050 and 8650 FLH in NoP2H2.



	R2050	NoP2H2
Electrolyser	256	16
SMR/CCS-ADV	115	229
SMR/CCS-STD	0	4
SMR	5	4

Figure 12. EU H_2 output capacity in R2050 and NoP2H2

Figure 13 shows how the H_2 is supplied in different countries via SMR, Electrolysis, or Imports. One can observe three different types of countries:

- Countries with very high VRE production, like France and Spain, shift most of their H_2 production from SMR in NoP2H2 to electrolysis in R2050, and they even become net exporters.
- Countries that still find SMR as the most economical way to produce H_2, e.g., because of low cheap VRE potentials, use their maximum allowed SMR production, 50% of the internal demand, and supply the remaining H_2 demand via electrolysis and imports, even moving from a net export position in NoP2H2 to a net import position: this is the case for countries like the Netherlands and UK.
- Countries that do not allow carbon storage, supply H_2 mainly through imports and electrolysis, e.g., Germany and Austria.

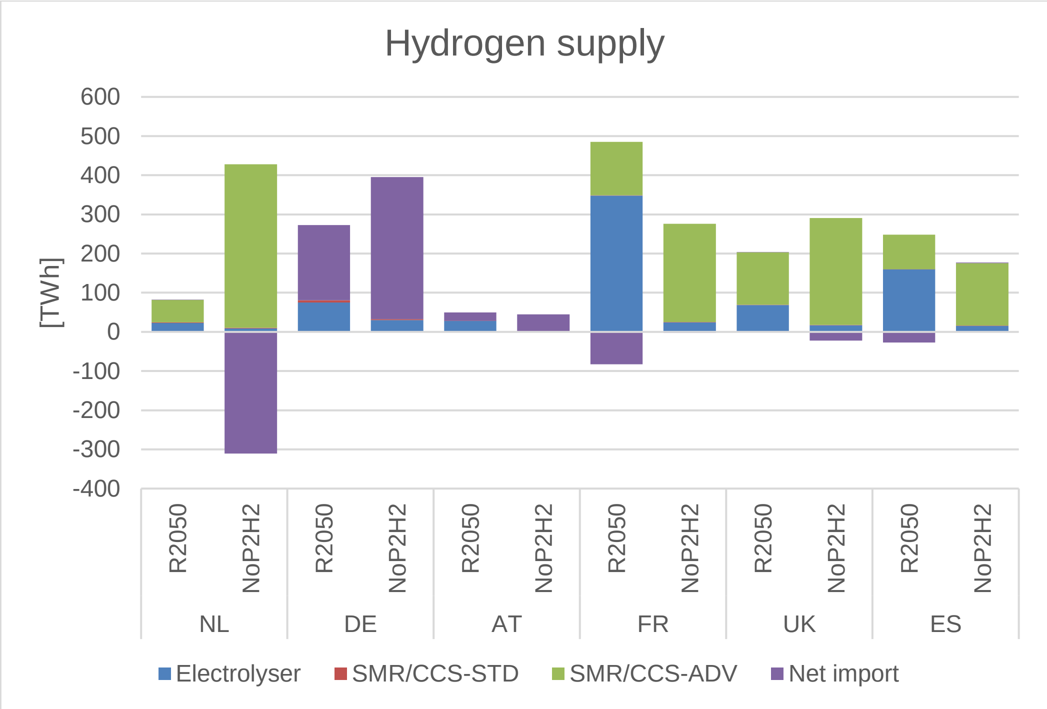


Figure 13. NL, DE, AT, FR , UK and ES hydrogen supply in R2050 and NoP2H2

The 58% level of H_2 electrification requires almost 1841 TWh of extra electricity demand, accounting for nearly 28% of the total demand. See Figure 14, which shows the electrical energy mix for both scenarios R2050 and NoP2H2. To meet the new H_2 electrical demand, the system uses and invests mainly in more solar PV, wind offshore and wind onshore, see Figure 15. The total VRE production went from 3316 TWh in NoP2H2 to 4952 TWh in R2050. This VRE production increase is equivalent to 90% of the extra H_2 electrical demand. Nuclear production also increased from 463 TWh to 789 TWh, equivalent to 18% of the additional H_2 electrical demand. The production of non-polluting technologies, VRE and nuclear covered the extra H_2 demand. It even replaced part of the gas production, which went down from 295 TWh in NoP2H2 to 93 TWh in R2050. This reduction of almost 70% in H2 SMR-based output appears due to the flexibility offered by the electrolysers, through shifting the H_2 production in time (storage) and shifting source (to SMR), where electrolysis increases when electricity prices are low (e.g., due to VRE abundance) which allows the new VRE and nuclear investments to be better used. Conversely, electrolysis may not be viable when electricity prices are high (e.g., due to production of gas-fired power plants). However, the extra investment in VRE and nuclear is still present, thus replacing gas-fired power plants.

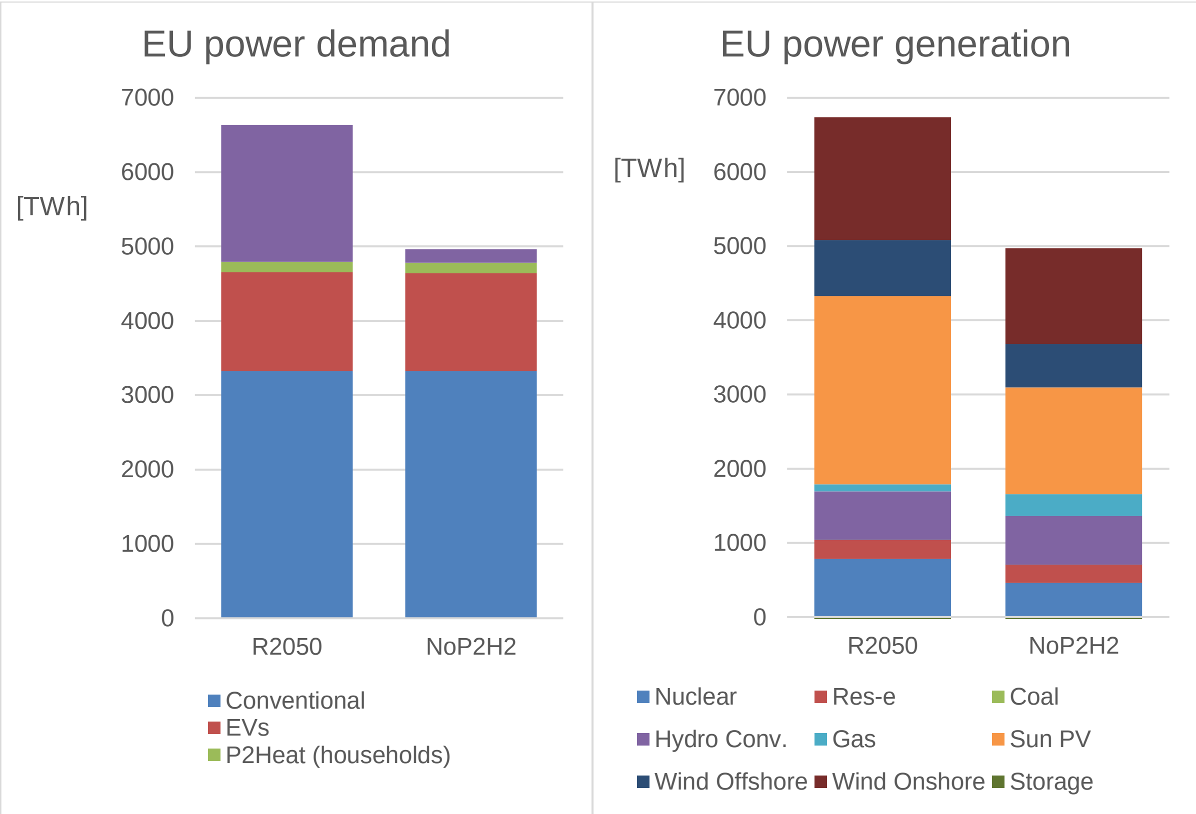


Figure 14. EU power demand and supply in R2050 and NoP2H2

Figure 15 shows that apart from the significant increase of VRE capacity to cover the new H_2 electrification in R2050, the flexibility of electrolysers also allows relying less on peak units: where the gas-fired CCGT/CCS power plants' installed capacity is eight times higher in NoP2H2 than in R2050.

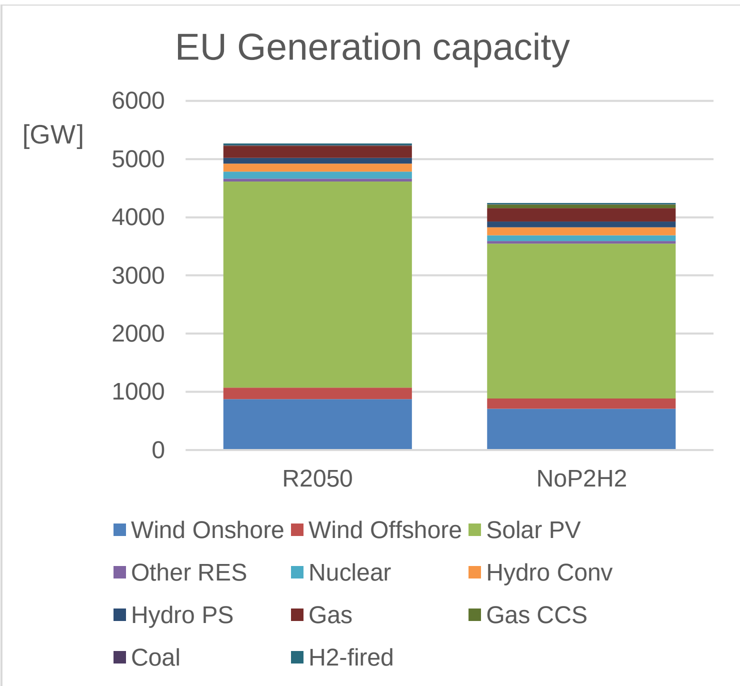
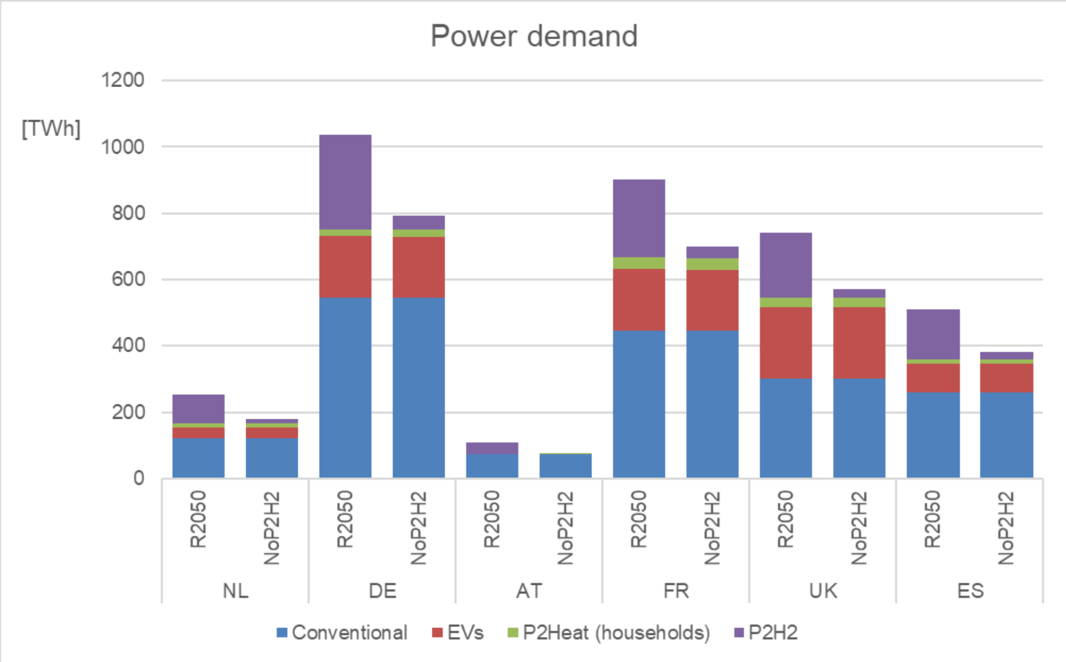


Figure 15. EU Generation capacity in R2050 and NoP2H2

It is interesting to notice that although some countries do not allow carbon storage, they have to cover their H_2 demand partly by import, which is mostly produced via SMR with CCS in NoP2H2, even using this H_2 to generate electricity.[16] In the case of Germany, for example, this H_2 is used as fuel in H_2-fired power plants to produce 3TWh, as shown in Figure 16. Furthermore, it is possible that even in the case of R2050, these countries still import H_2 that is produced with SMR with CCS since once the H_2 is produced and injected into the pipeline, it is not possible to know if some given molecules of H_2 were produced via electrolysis or SMR.



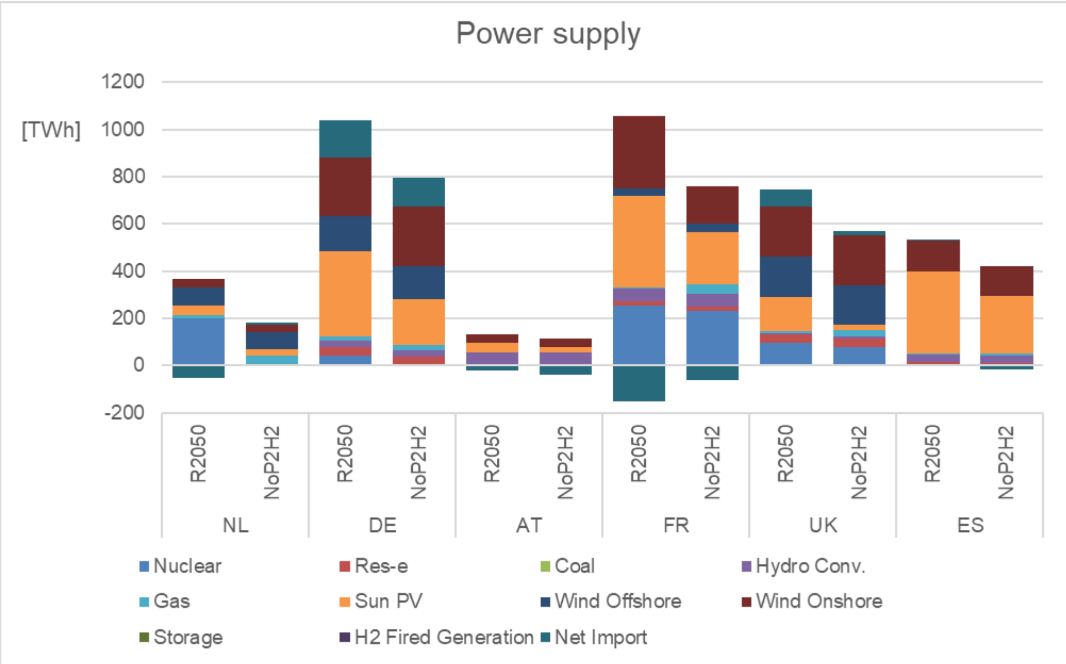


Figure 16. NL, DE, AT, FR, UK and ES power supply and demand in R2050 and NoP2H2

[16] This modelling study does not take into account the possibility of green hydrogen import from outside Europe. In practice this can be an alternative for import of fossil-based low-carbon hydrogen.

Figure 16 shows how the demand and supply of electricity are divided within different EU countries. As expected, the countries with the highest electrolysis also have the highest VRE production. For example, France, Spain and Germany, with an extra electrolysis demand of 198 TWh, 127 TWh and 249 TWh in R2050, respectively, show an increase in VRE production of 398 TWh, 138 TWh, and 170 TWh, respectively, compared with NoP2H2.

Table 4 shows the electricity and H_2 transmission infrastructure investments for R2050 and NoP2H2. Interestingly, R2050 requires almost a 45% lower electricity transmission capacity even though its electricity demand is ~35% higher than NoP2H2. This results from the flexibility offered by the electrolysers, where the H_2 electrification helps to rely less on other sources of flexibility like electricity trade and peak units. Opposite to the lower electricity transmission capacity Figure 17 shows a general pattern of increase in net electricity trade, especially in the direction of Germany. This is due to the large hydrogen demand in Germany resulting in a large electricity demand for electrolysis in R2050. In particular, countries presenting VRE abundance show an increase in net trade, as in the case of Portugal and Spain exporting more to France, which in turn exports more to neighboring countries. Portugal even changes from being a net importer in NoP2H2 to a net exporter in R2050. Another country that became a net exporter is the Netherlands, not only because of its extra VRE production but also of its assumed extra nuclear production (see Figure 16).

Table 4. Investments in EU electricity and H_2 transmission capacity in R2050 and NoP2H2

Scenario	Unit	E-transmission	H2 Transmission
R2050	GW	28.2	90
NoP2H2	GW	52	56

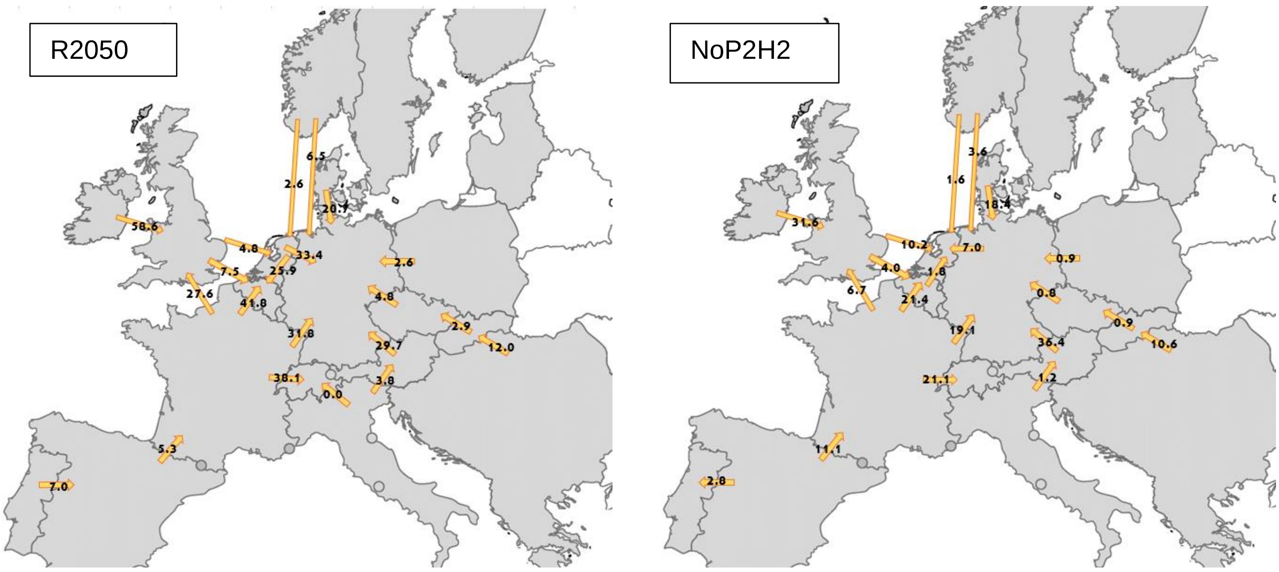


Figure 17. Electricity (net) trade patterns (in TWh).

The H_2 transmission capacity is 1.6x higher in R2050 (see Table 4), resulting in different trade patterns compared to NoP2H2 (see Figure 18) as a natural consequence of more electrolysis from countries with higher VRE investments and generation, such as France and Spain (solar and onshore wind) as well as Norway (offshore wind) towards Germany (high demand center for imports because CCS facilities are not allowed). Ireland also supplies the UK with higher offshore wind.

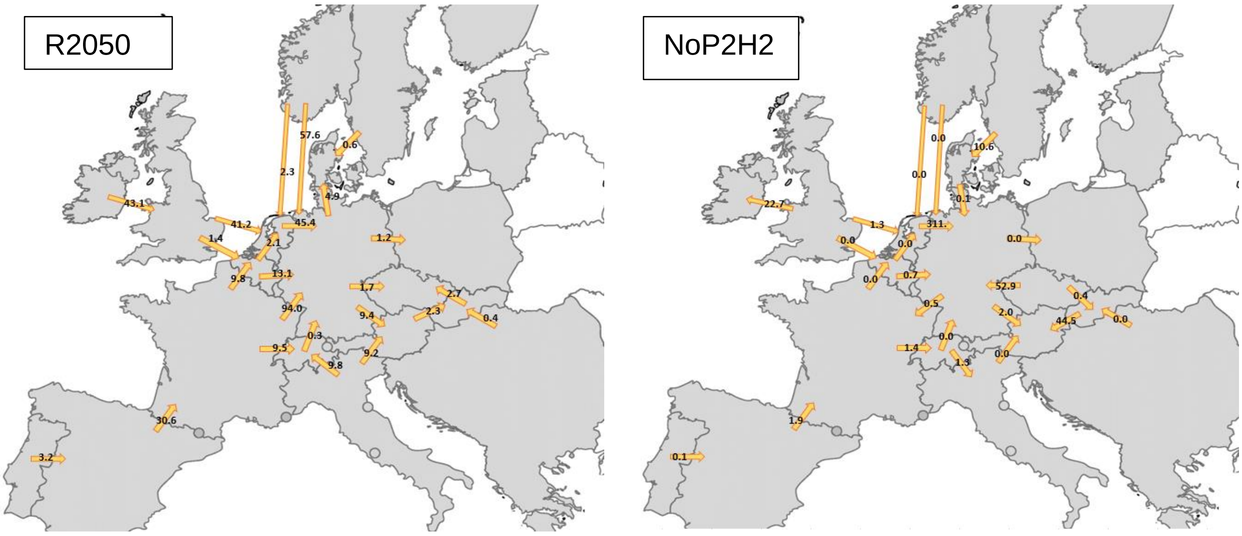


Figure 18. H_2 (net) trade patterns in R2050 and NoP2H2 (in TWh)

The current gas infrastructure already offers enough potential to bare the need for H_2 trade. Figure 19 shows the different H_2 transmission investments between countries where no new pipelines were built, and 11% of the existing gas infrastructure was retrofitted for H_2 transport. The additional adjustments are limited compared to the NoP2H2 scenario where only 7% of the gas infrastructure had to be adapted due to the lower need for H_2 trading.

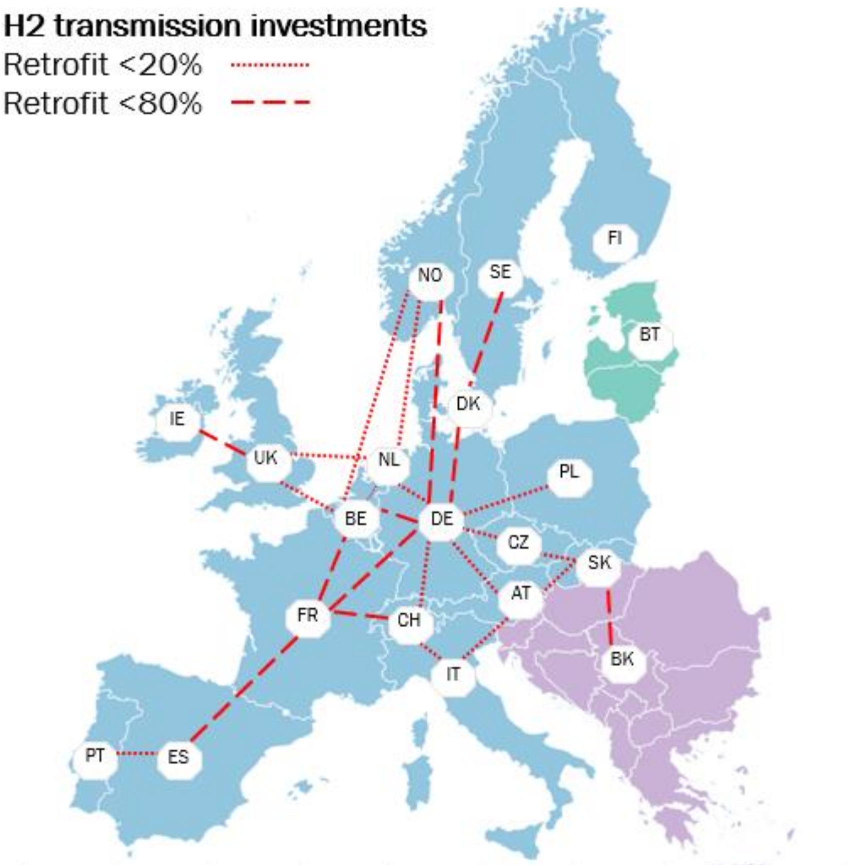


Figure 19. EU H_2 transmission investments map in R2050

The total CO_2 emissions of the system went down from 106 Mton in NoP2H2 to 68 Mton in R2050. This 35% emissions reduction results as a natural consequence of shifting 58% of the H_2 production from SMR, in NoP2H2, to electrolysis, in R2050, where mainly non-pollutive (VRE and nuclear) technologies provide the extra electricity for H_2 production. Even though the electric system has to cover the extra demand for H_2 production, the CO_2 emissions of the electric system are even lower in R2050 since non-polluting technologies are also replacing part of the gas-fired electricity production that was present in NoP2H2. As observed in Figure 20, the CO_2 emissions in the power sector went from 44 Mton in NoP2H2 to 42 Mton in R2050. In short, electrifying part of the H_2 demand lowers emissions in the H_2 sector and helps the power sector reduce its emissions thanks that flexible electrolysis helps to better accommodate non-pollutive production into the electric system.

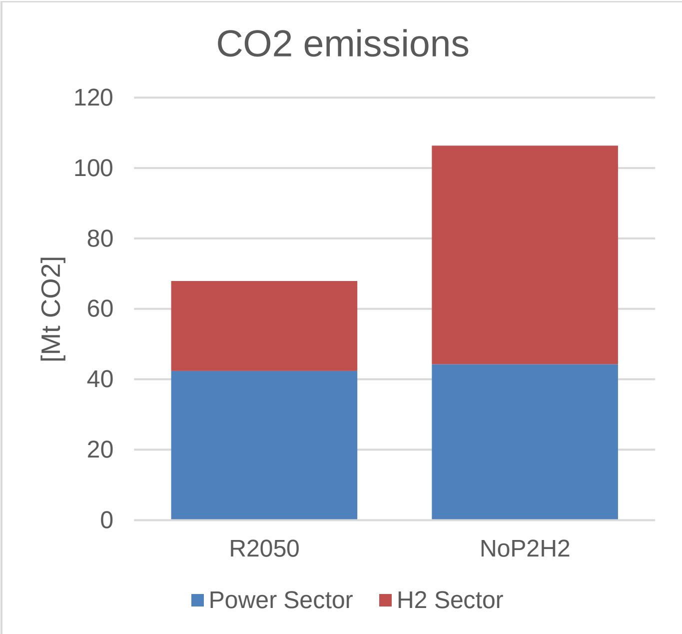


Figure 20. EU CO_2 emissions for the power and H_2 sector in R2050 and NoP2H2

The resulting average hydrogen and electricity prices are shown in Table 5 for the selected countries. The hydrogen prices in the R2050 scenario are higher due to the higher cost of producing hydrogen via electrolysis. In the NoP2H2, hydrogen prices fall due to its production via SMR, which is cheaper given the assumed gas prices. Nevertheless, the effects of not allowing electrolysis increase CO_2 emissions in the H_2 sector, which contradicts the efforts to reduce GHG emissions. Similar to hydrogen prices, electricity prices are higher in the R2050 scenario. This is due to a higher electricity demand from H_2 production via electrolysis.

Table 5. NL, DE, AT, FR, UK and ES average hydrogen and electricity prices in R2050 and NoP2H2

Average hydrogen price	Unit	NL	DE	AT	FR	UK	ES
R2050	[€/kg]	3.2	3.2	3.2	3.2	3.2	3.1
NoP2H2	[€/kg]	2.9	2.9	2.9	2.9	2.9	2.9

Average electricity price	Unit	NL	DE	AT	FR	UK	ES
R2050	[€/MWh]	68.8	75.6	70.8	63.0	67.2	59.2
NoP2H2	[€/MWh]	65.8	69.5	63.2	60.9	61.5	59.1

Figure 21 shows the total system cost of the system for R2050 and NoP2H2. Interestingly, although the total costs between the two scenarios are very similar (being R2050 0.4% lower), there is a significant redistribution of costs, and R2050 presents 35% lower emissions. As expected, R2050 shows a significantly higher investment in power2H2 and VRE while incurring in significantly lower SMR (investment and variable) costs and variable generation costs.

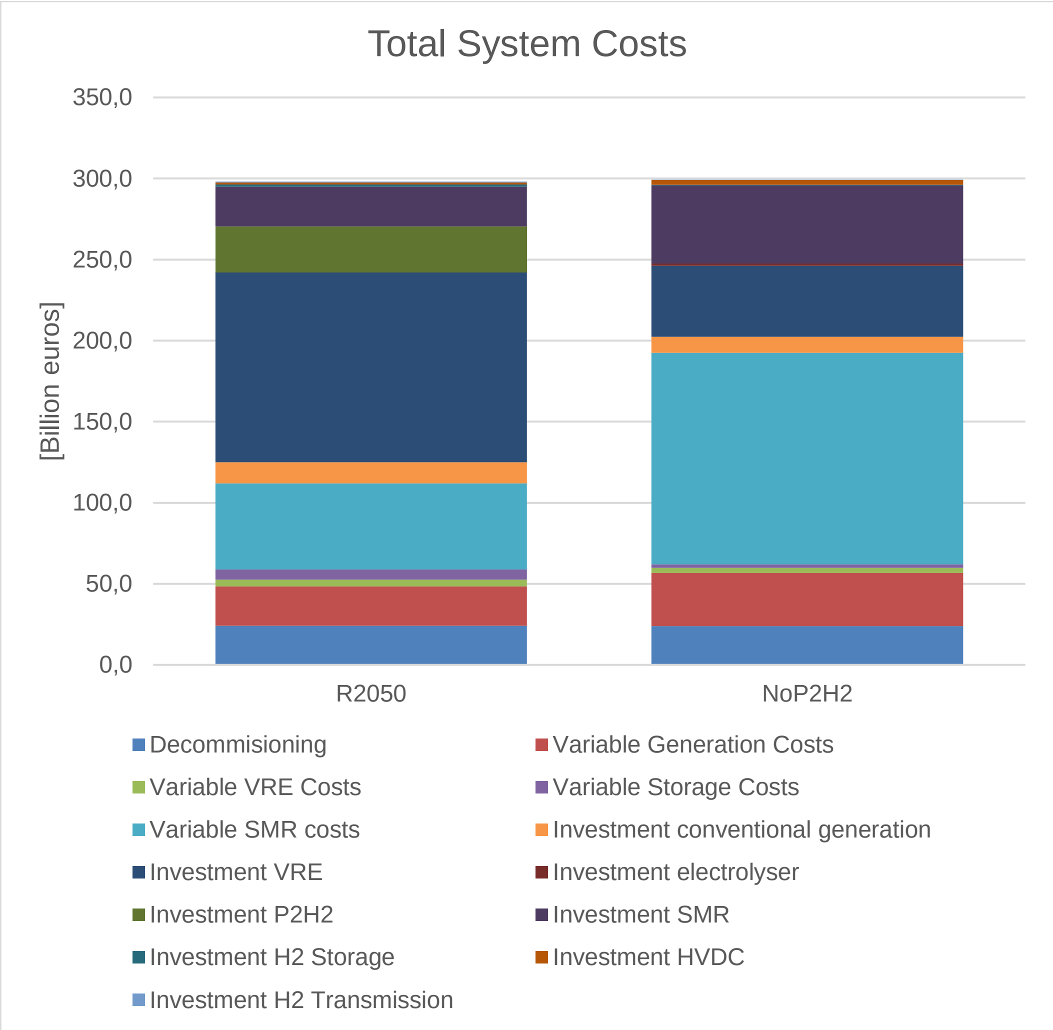


Figure 21. EU total system costs in R2050 and NoP2H2

4.2 CO_2 and gas price effects

This section introduces two sensitivity cases, **'Gas_high'** and **'CO2_high',**. In the former, the gas price is doubled; in the latter, the CO2 prices are also doubled compared to the prices shown in Table 3. Besides gas and CO_2 prices, the rest of the assumptions in these two sensitivities are the same as in **'R2050'**. Figure 22 introduces the effects of higher commodity prices in hydrogen production. Results show that doubling the CO_2-price has only a limited impact on the distribution of hydrogen production through electrolysis or SMR. This is because the CO_2-price does not affect production cost of SMR with that much, especially in case of SMR with high CO_2 capture rate. Doubling of the natural gas price, on the other hand has a large impact, and hydrogen production almost completely switches to electrolysis. The hydrogen production via SMR is reduced by 12% and 80% in the **‘CO2_high’** and the **‘Gas_high’** sensitivities, respectively, compared to **‘R2050’**.

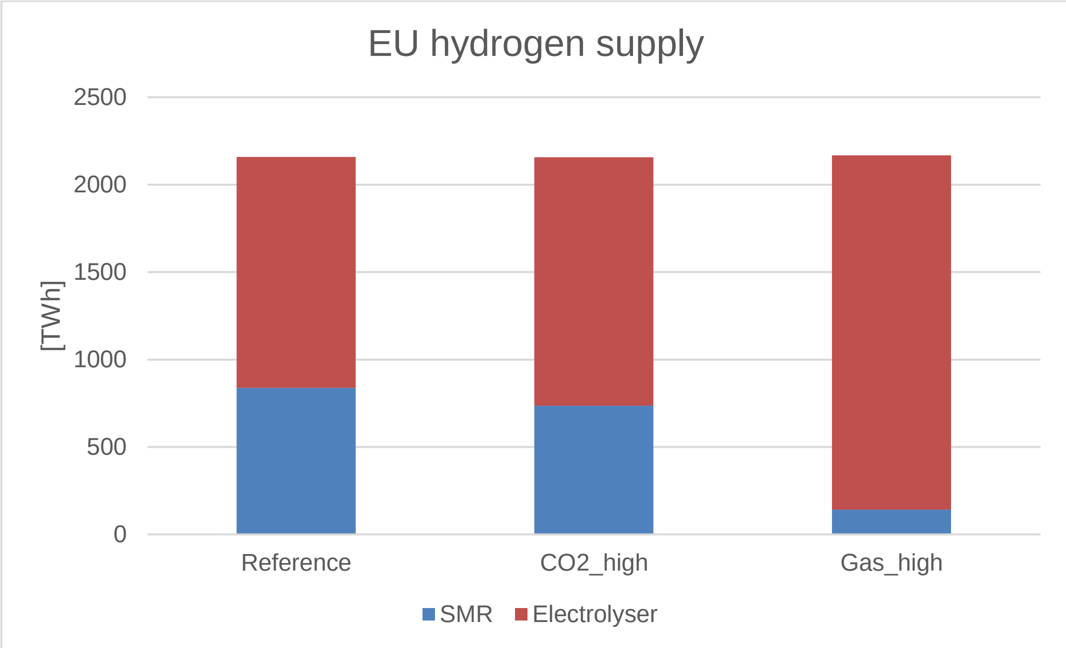


Figure 22. EU hydrogen supply in R2050, Gas_high and CO2_high

The increase in hydrogen production from electrolysers in the **‘Gas_high’** sensitivity comes with a rise in production from countries with low H_2 production costs, such as Spain, as shown in Figure 23. It shows how flows increase from Spain (important production node) towards Germany (consumption node). This increase in hydrogen via electrolysis also requires an increase in renewable capacity. Only in Spain 500 GW of extra solar energy is needed. One may wonder whether it is possible to reach such high levels of installed capacity by 2050 in the EU and certain countries. It stresses the importance to also start developing supply chains of green hydrogen from regions outside the EU, such as North Africa, the Middle East and Latin America.

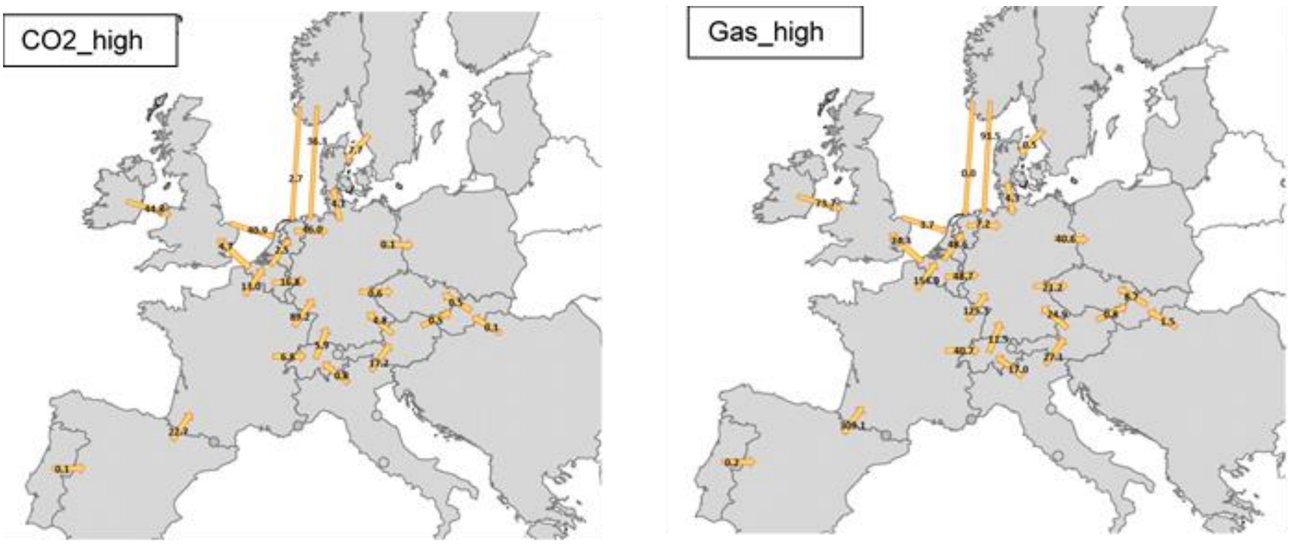


Figure 23 H_2 (net) trade patterns in CO2_high and Gas_high (in TWh)

4.3 Scenario variants

Table 6 presents different variants of the reference scenario R2050. By comparing these variants, we can separate the effect of different aspects on the system:

- '**NoP2H2**' does not allow P2H2, thus showing the effects of electrifying H2 demand, as discussed in the previous section. Some results are shown again here for the sake of completeness.
- The **'NoH2Storage'** variant allows us to observe the effect of H2 flexibility (time shifting) through storage by not allowing investment in H2 storage.
- In **'NoH2Transmission'**, the countries are forced to only export/import electricity via electricity, highlighting the impact of H2 transmission.
- The last scenario variant, **'NoETransmission',** does not allow new expansions in the electricity network, thus only using the forecasted electricity transfer capacities. This last variant analyses how investing in a hydrogen network compares to expanding the current power system network.

Table 6. Reference scenario and different scenario variants

	Reference	**Scenario variants**			
Investment options	R2050	NoP2H2	NoH2Storage	NoH2Transmission	NoETransmission
Power-2-H2 (electrolysis)	✓	X	✓	✓	✓
H2 storage	✓	✓	X	✓	✓
H2 transmission retrofit and new pipelines	✓	✓	✓	X	✓
Electrical transmission*	✓	✓	✓	✓	X

*Existing and forecasted initial electrical infrastructure is utilised.

4.3.1 Hydrogen supply and storage

Figure 24 shows the hydrogen balances at EU level for the different scenario variants. The main highlights include:

- In R2050, NoH2Storage, NoH2Transmission and NoETransmission, the electrified H_2 demand ranges between 58% and 61%. It is still optimal to generate around 40% of the total H_2 demand via SMR/CCS-ADV, with 90% CO_2 capture, even though there is a 250 Euro/ton CO2 price. Moreover, the limit imposed on the SMR generation (up to 50%) is not reached at the EU level.
- In the NoH2Storage variant, SMR-STD CO_2 is a viable alternative in some countries. However, it only produces 5% of the total hydrogen demand. Still, the preferred SMR generation technology across the variants is the SMR/CCS-ADV.
- The NoH2Transmission variant shows the highest production of SMR without CCS, producing 97 TWh of hydrogen, where 80% of this H_2 production comes from Germany, which is not allowed to invest in CCS technologies and cannot import H_2 by pipeline from other European countries.

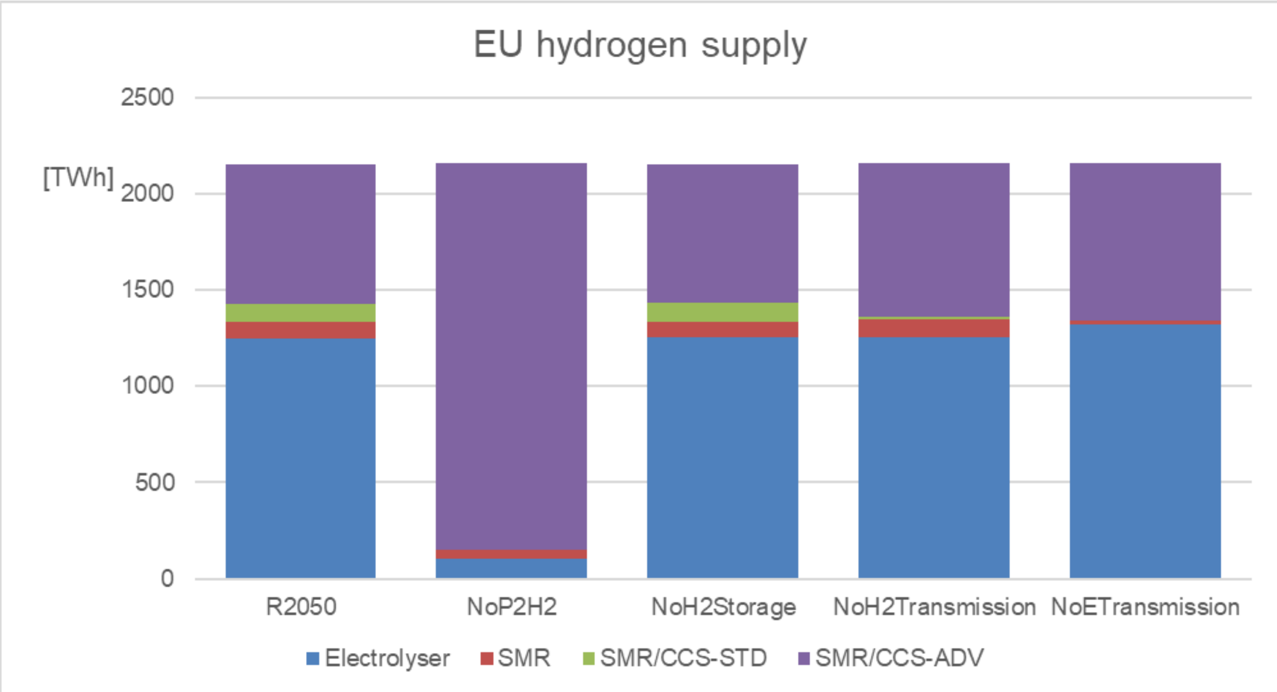


Figure 24. EU hydrogen generation - comparison of R2050 and scenario variants

Figure 25 presents the underground H_2 storage investment for the scenario variants versus the reference scenario R2050. The significant observations regarding these results are:

- The H_2 underground storage reduces significantly when there is no electrification of the hydrogen demand. In the NoP2H2 case, 58.4 TWh less storage is needed compared to the R2050 case. Due to the constant hydrogen supply from SMR, there is no need to shift VRE-based hydrogen in time to match the more or less constant demand from industry and the transport sector.
- Not allowing H_2 transmission in NoH2Transmission, increases the H_2 storage requirements by 12% (9.2 TWh) compared to the R2050 case. There is a higher need to shift H_2 in time to compensate for the flexibility missing from geographical shifting.

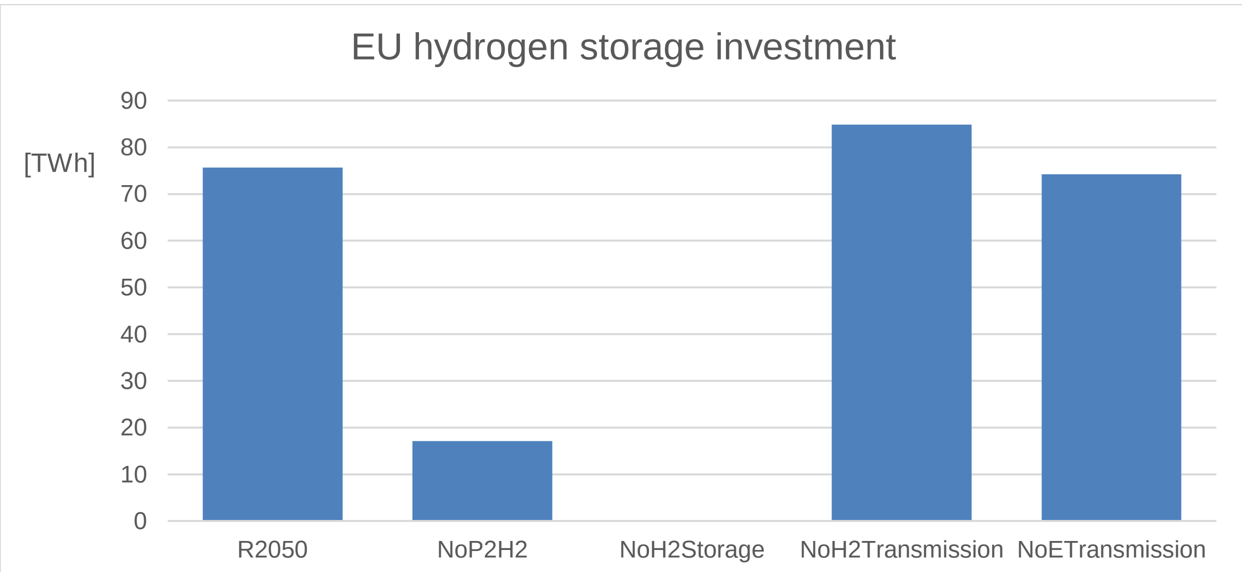


Figure 25. EU hydrogen storage investments - comparison of R2050 and scenario variants

4.3.2 Power demand and supply

Figure 26 and Figure 27 present the EU power demand and supply of the scenario variants compared to the reference scenario R2050. The major observations regarding these results are:

- The H_2 electrical demand is similar in R2050 and in the NoH2Storage case. There is only a 3 TWh difference, similar to the NoH2Transmission case. This meagre demand change can be explained since the system can use spatial or temporal flexibility to achieve similar levels of H_2 electrification.
- The H_2 electrification levels and energy mixes are very similar for R2050 and NoETransmission, indicating that a system with transmission capacities in 2050 similar to expected transmission expansions by 2040 in (ENTSO-E, 2020). In this regard, NoETransmission is already very near to the optimal solution.
- Compared with R2050, the H_2 electrification levels are similar in NoH2Storage and in NoH2Transmission. Nevertheless, there are VRE production drops of 0.5% (21 TWh) and 3% (140 TWh), respectively, showing how the H_2 ability to follow VRE production either in time or in space help to increase VRE production by increasing (flexible) H_2 electrification levels. In contrast, nuclear production increased by 5% (40 TWh) in NoH2Storage, appearing as a better alternative for VRE-based H_2 electrification than replacement by SMR-based hydrogen production.

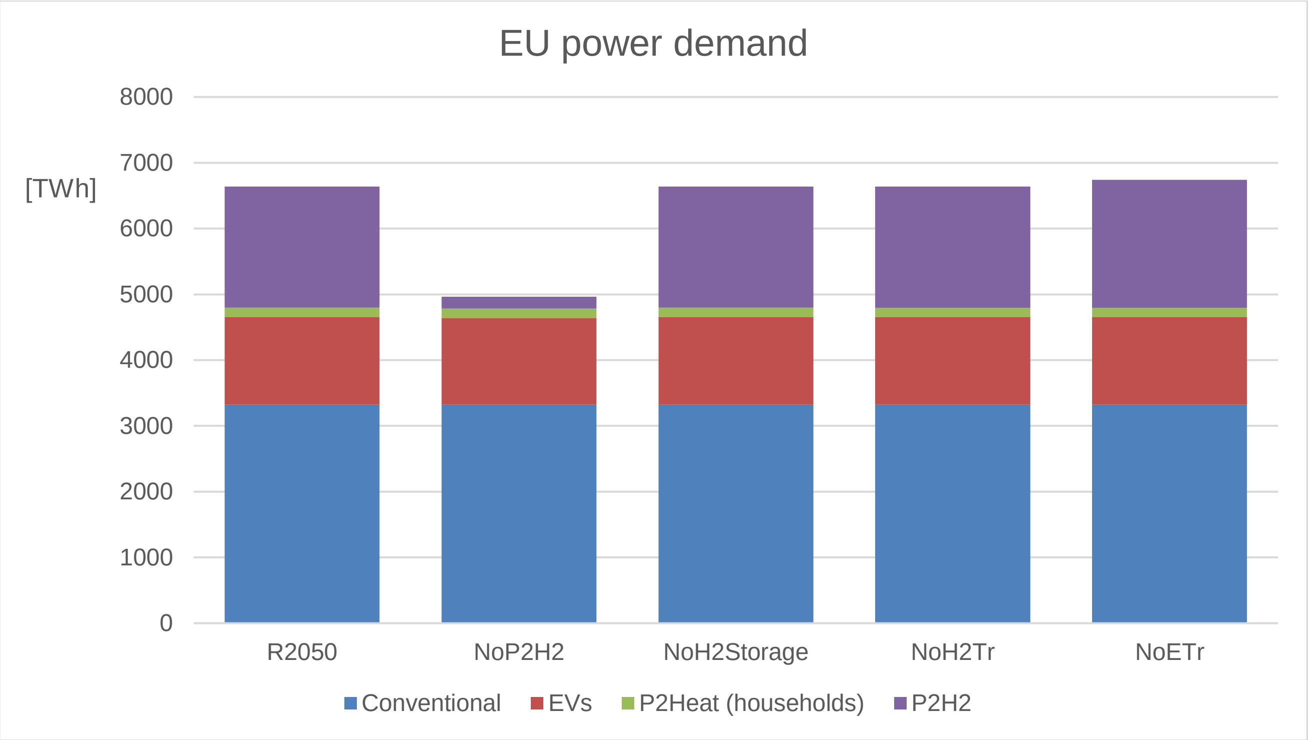


Figure 26. EU power demand - comparison of R2050 and scenario variants

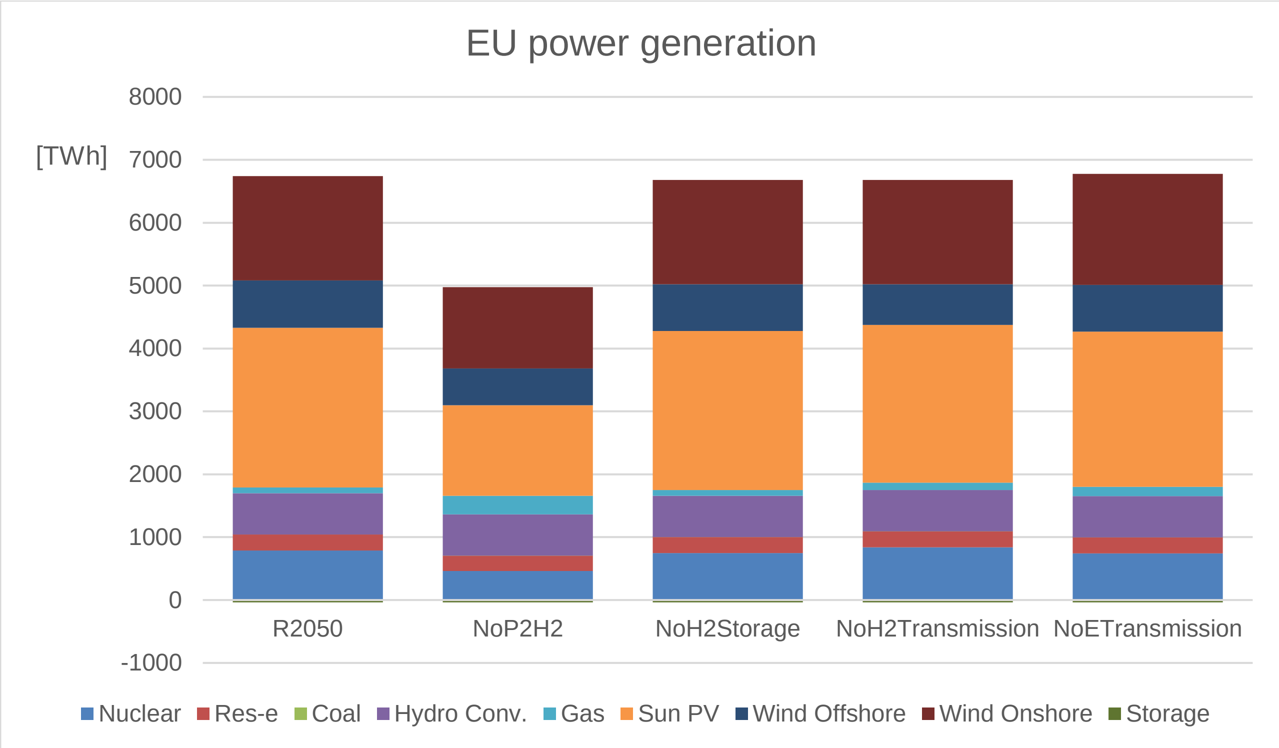


Figure 27. EU power generation - comparison of R2050 and scenario variants

4.3.3 Energy transmission

The required electrical transmission and hydrogen transmission results, including their investment costs for the reference and scenario variants, are shown in Figure 28. As described in section 3.1, COMPETES determines the optimal cross-border transmission infrastructure required to couple the demand and supply of electricity and hydrogen among the different countries. Below we summarise the main findings:

- As expected, the required hydrogen transmission in the NoP2H2 case decreases significantly from 90 GW in the R2050 case to 56 GW. Since the model assumes an unlimited SMR potential within every country, the need for H_2 transport decreases significantly.[17] Moreover, the total costs in this variant are the highest due to the required expansion of the electricity network. This decrease in hydrogen transmission requirements is also driven by the impossibility of accessing green hydrogen from rich VRE resource countries such as Spain and France.
- In the NoH2storage case, the required expansion on the electricity network decreases by 6 GW compared to the R2050 case, while the required H_2 transmission increases by 72 GW. The total costs decrease compared to the R2050; this is a result of avoiding extra investment in the electricity network, which is more costly (per GW) than expanding the hydrogen network.
- Perhaps the most interesting result occurs in the NoETransmission case, which only uses the future forecast of transfer capacities. The results show that only 5GW of extra investment

[17] An unlimited SMR potential implicitly assumes an unlimited natural gas supply. The NoP2H2 is used as an extreme case to study the impact of H_2-electrification on the electricity grid. It is clear that an unlimited supply of natural gas is no longer tenable in the future, partly because Europe does not want to be dependent on, and can no longer rely on the supply of natural gas from Russia since Russia's invasion of Ukraine in February 2022 (European Commission, 2022a).

in hydrogen transmission is required compared to the R2050 case. The associated energy transmission investment costs are reduced by 180% compared to the R2050 case.

- In the NoH2Transmission, there is no possibility of investing in hydrogen transmission, which naturally drives the expansion of the electricity network. Investments in cross-border electricity links increased by 130% compared to the R2050 case. As shown in Figure 25, this expansion in the electricity network is complemented by higher investment in hydrogen storage.
- Not allowing H_2 storage in NoH2storage increases H_2 transmission capacity by 80% compared to R2050. This increase results from the need to balance the supply and demand of hydrogen, in this case by shifting hydrogen geographically as the ability to shift supply in time is restricted.

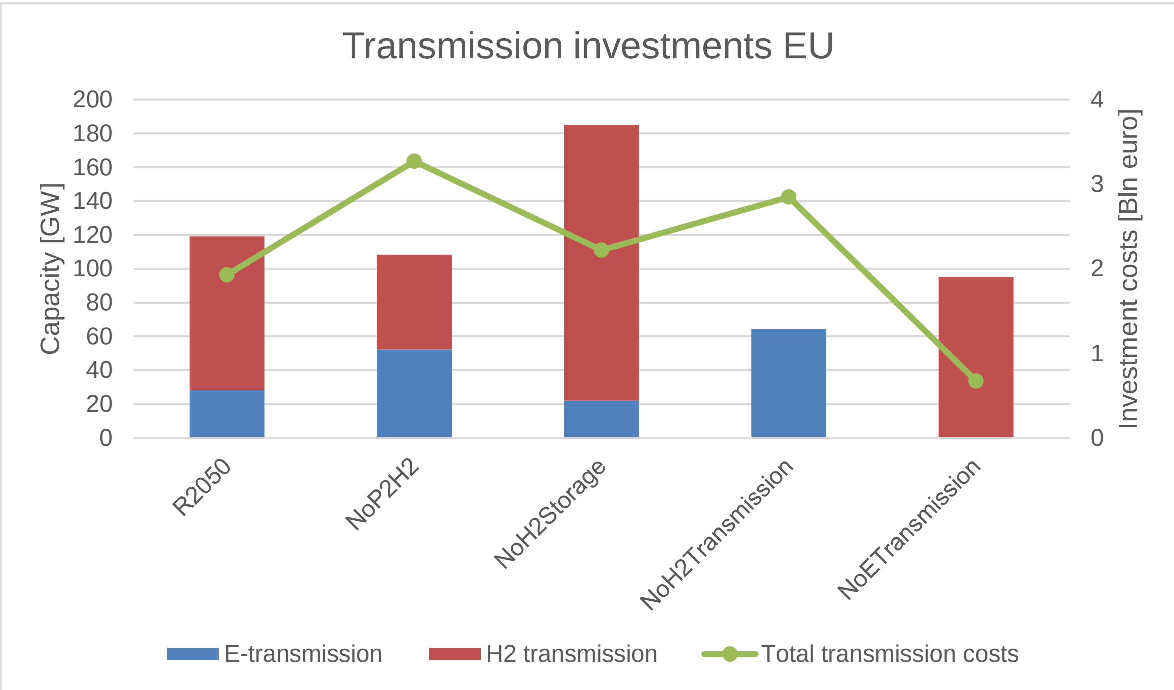


Figure 28. EU transmission investments and costs- comparison of R2050 and scenario variants

4.3.4 CO_2 emissions

Figure 29 presents the results of the scenario variants regarding the EU CO_2 emissions in the power and hydrogen sector.

- The total CO_2 emission increased by 19.5% and 20% in the NoH2Storage and the NoH2Transmission cases, respectively, compared to the R2050 case.
- The increase in CO_2 emissions in the H_2 sector is easily explained by the rise in the use of SMR technologies to supply the H_2 demand in both the NoH2Storage and the NoH2Transmission cases.
- Striking is that CO_2 emissions are very similar in the R2050 and the NoETransmission case. Obviously, further expanding the electricity network does not necessarily result in CO_2 emissions reductions after a specific transmission capacity between countries has been achieved. In the NoETransmissionc case, CO_2 emissions from SMR are slightly lower than in the R2050 case due to an increase in SMR/CCS-STD production.

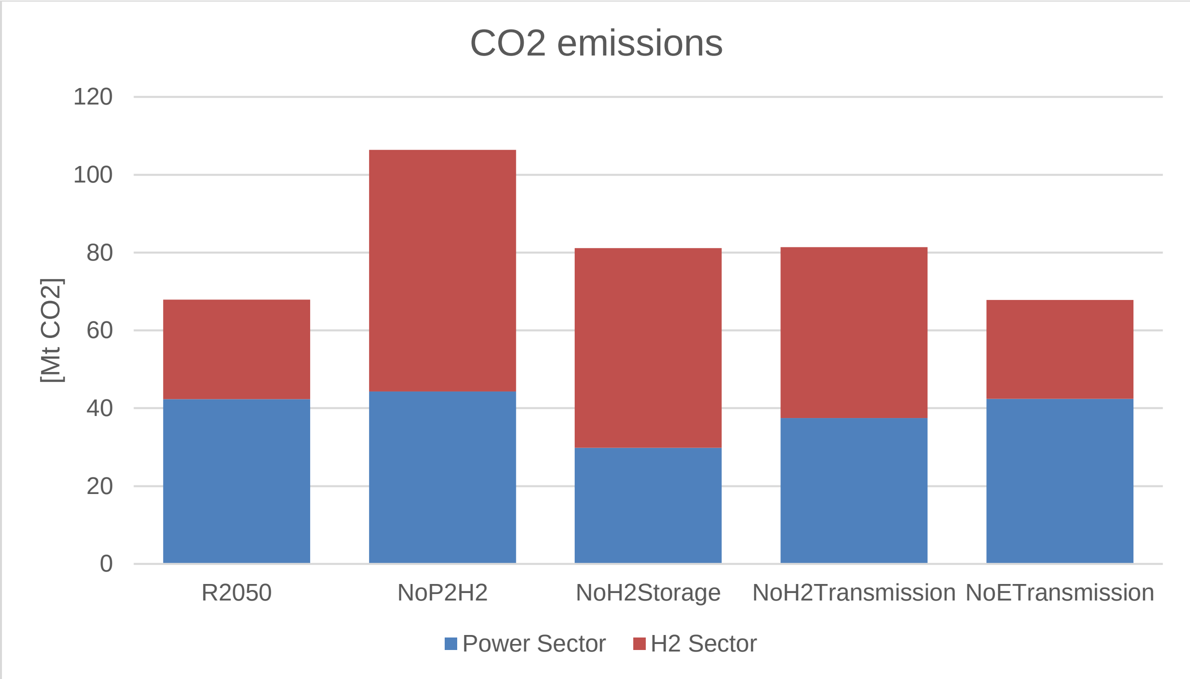


Figure 29. EU CO2 emissions - comparison of R2050 and scenario variants

4.3.5 Total system costs

Figure 30 shows the system cost distributions for the R2050 and the scenario variants. The major observations from this figure include

- Of all cases, the R2050 case achieved the lowest total system costs, although the differences are small. This is expected since every investment option is available to reach an optimal solution. Therefore, it will use the optimal mix of electrification, storage and transmission, which results in the lowest system costs.
- The highest total system costs refer to the NoH2Storage case, around 3.4% (10.3 b€) higher than the R2050 scenario. On the one hand, the VRE investment costs, (wind and solar) are lower. On the other hand, the variable H_2 costs increase. These costs include the gas costs for hydrogen production via SMR.
- There is a significant shift of costs from VRE investments in the R2050 to Variable H_2 costs in NoP2H2. This is due to the lack of H_2 electrification, which requires less VRE capacity and a higher demand for gas to produce H_2. Moreover, as shown in Figure 14, there is an increase in gas-fired power plant output in NoP2H2, resulting in a 8.5 b€ increase in variable generation costs (fuel costs).
- The NoETransmission variant shows only a 0.3% total system cost increase compared to the R2050. This variant shows a decrease in the new VRE generation investment but an increase in the conventional generation. Since the electricity network cannot expand further, it is not possible to integrate more VRE, and traditional generation is required.

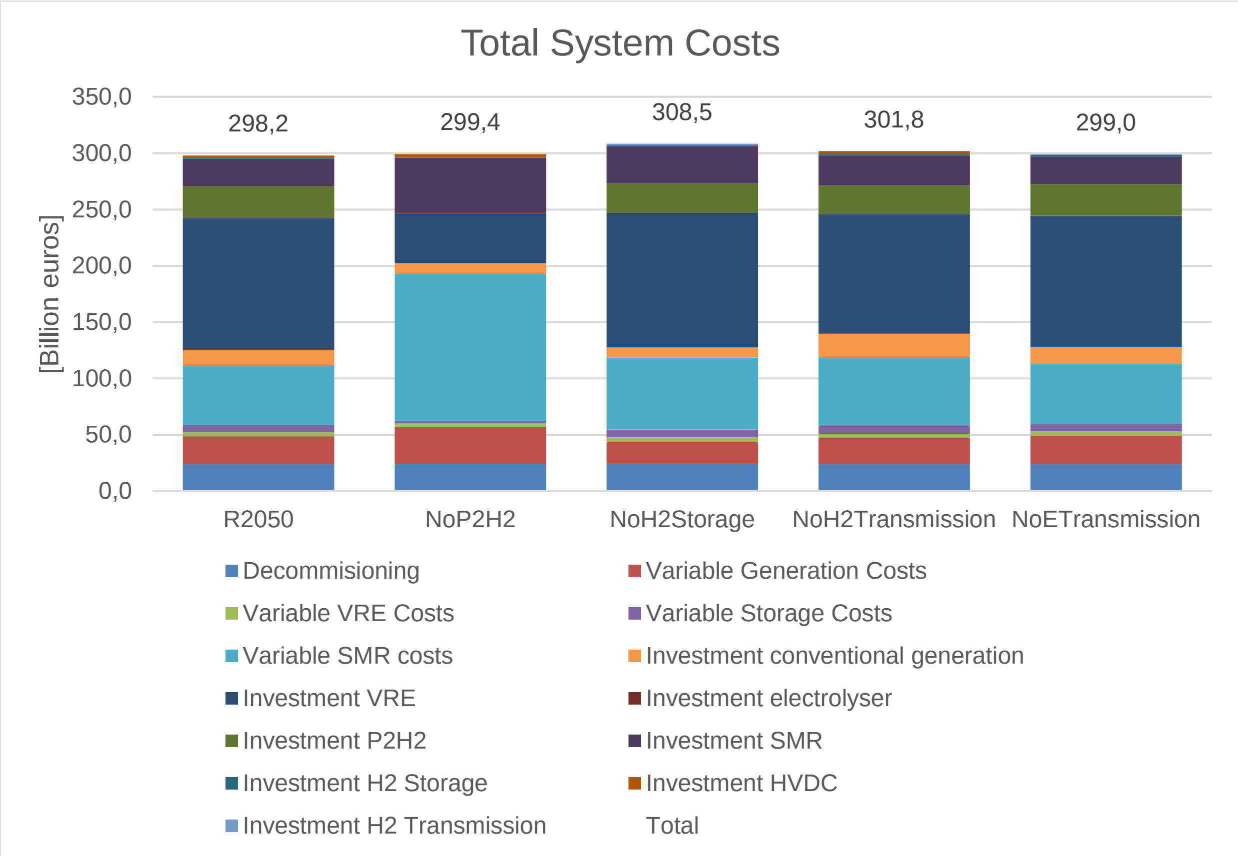


Figure 30. EU total system costs - comparison of R2050 and scenario variants

4.3.6 Electricity vs Hydrogen Transport

Finally, it is interesting to study how H_2 transport compares to extra electricity transport. Figure 31 shows the total system costs and CO_2 emissions for the reference and the two extreme transmission scenario variants: the NoETransmission, where no further expansion of the electricity network is allowed, and the NoH2Transmission, where there is no hydrogen transport via pipelines. In the middle is the R2050 reference scenario, where the optimal tradeoff between electricity and H_2 transmission expansion is achieved. It is interesting to highlight the following:

- Relying only on electricity transmission, by not allowing H_2 transmission in NoH2Transmission, provides the worst result leading to higher costs and CO_2 emissions. When compared to both R2050 and NoETransmission, NoH2transmission costs 1.2% more and also emits around 20% more CO_2.
- The NoETransmission variant can keep CO_2 emissions equal as in the optimal mix (R2050), although system costs are slightly higher (o.3%, 0.8 billion euros). Nevertheless by investing only in an H_2 network, there is no need for extra 28 GW HVDC interconnectors as shown in Figure 28.[18] This indicates that a system with the expected transmission expansion by 2050 is already very near to the optimal solution; hence the focus should be on facilitating H2 transport rather than extra electricity transport.

[18] Currently only HVDC investments are implemented in COMPETES

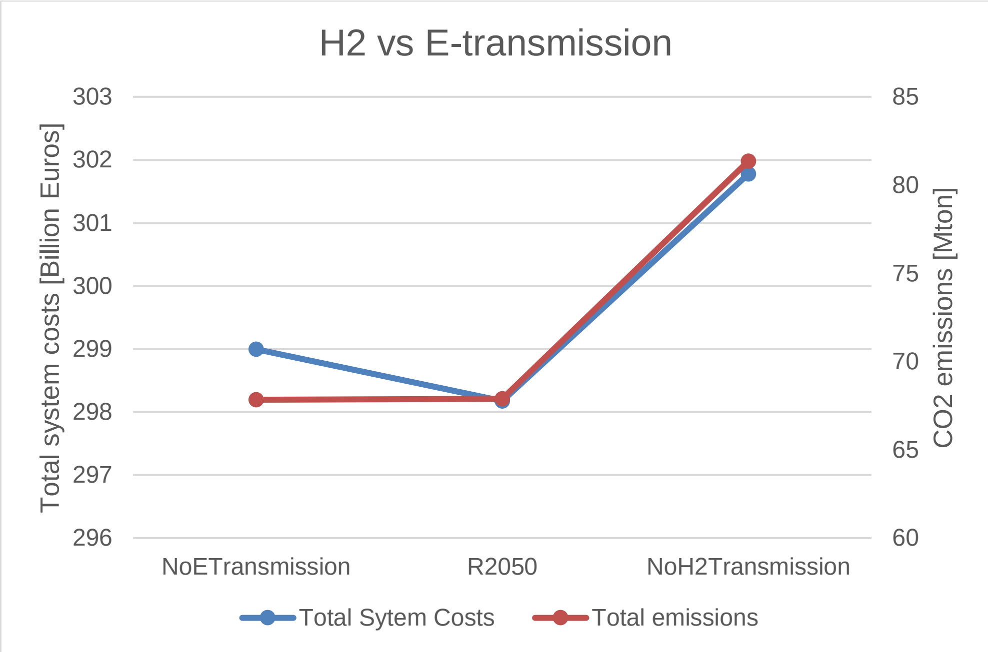


Figure 31. Hydrogen vs. electricity transmission

5 Summary and conclusions

The first part of this report focused on the perspectives for the roll-out of green ammonia in Europe. The key messages of this part are as follows:

- Greening ammonia production in the European Union (EU) will require an electrolysis-based renewable hydrogen production capacity of about 3.5 million tons per year (Mt/yr). This is equivalent to 42 gigawatt (GW) of electrolysis if electrolysers are operated for 50% of the time at full load (about 4400 hours), which reduces to 30 GW if 70% full load hour operations is possible (about 6100 hours). To complete the full transition by 2050 at the latest, this means installing an average of 1.1 to 1.5 GW of electrolysis capacity per year for ammonia production only, or about 100 megawatt (MW) per month. This only concerns hydrogen for ammonia in Europe, and not the hydrogen that is needed for many other applications such as DRI-based steel production, let alone the hydrogen that is needed on a global scale for the transition to an energy system that is largely based on variable renewable energy sources.
- In the EU only one 20 MW project for ammonia has come online so far, and another one of 10 MW has reached the final investment decision (FID). Many other initiatives have been announced, but they all still have concept or feasibility study status. Furthermore, most parties have no experience with the technology and the technology also still needs improvement. Learning by doing takes time and to minimise risks, developments are more likely to follow a cautious step-by-step expansion from tens of MW to GW scale with intermediate steps on the order of 100 to a few hundred MW. As a result, the necessary deployment rates will only increase in the coming years and decades.
- In case of ammonia, the import of green ammonia from outside the EU will be an option. The REpowerEU plan sets a target of 4 Mt/yr import of hydrogen in the form of green ammonia, equivalent to almost 23 Mt/yr of ammonia. This exceeds current ammonia production and even current ammonia production capacity in the EU. Ammonia is a commodity that is already traded worldwide. Over the past ten years, the import of ammonia into Europe has averaged 4.1 Mt/yr so infrastructure for imports is already in place. However, expansion by at least a factor of 5 is necessary to achieve the REPowerEU target. Although this may be relatively easy to achieve, it does not change the tasking for greening ammonia. The figures stay the same. The required hydrogen and ammonia production capacities will then only have to be installed elsewhere. Next to that, the ammonia will then still have to be transported to Europe, which does not necessarily make the task any easier.
- Due to targets and developments in the field of ammonia, it seems likely that the near and more distant future will see a mix of renewable hydrogen production for greening domestic EU ammonia production and replacement of ammonia production for fertilisers and the chemical industry with imported green ammonia from outside of the EU. Whatever the exact distribution will be, swift, concerted and decisive action is required, without any further delay, on both government and private sector sides to be able to realize the unprecedented roll-out rates of new hydrogen technologies and infrastructures needed as part of the wider energy transition.

The key messages of the second part of this report, studying the impact of H_2 electrification on the power system, include:

- **H_2 electrification levels**: for the different scenario variants studied here, the electrified H_2 EU demand ranges between 58% and 61%. Indicating that it is still optimal to supply around

40% of the total H_2 demand via SMR with 89% of CO_2 capture, even though there is an expected CO_2 price of 250 EUR/ton. This 60% of H_2 demand electrification accounts for around 30% of the total electricity demand, mainly supplied by non-pollutive technologies, mostly VRE, becoming 74% of the EU electricity mix, compared to 67% when H_2 is not electrified (NoP2H2). Electrolysers' flexibility also helps non-pollutive technologies partly replace peak units, such as gas, since the extra investment in VRE (and nuclear) is still present during high electricity prices when electrolysis is not competitive. Electrifying part of the H_2 demand (~60%) lowers the total emissions of the power and H_2 sector from 106 Mton (in NoP2H2) up to 68 Mton, as a consequence of reducing emission in both the H_2 sector, by replacing SMR with electrolysis, and also the power sector, by replacing gas units by non-pollutive units. The H_2 electrification level is very sensitive to gas price. Doubling of the natural gas price from 7.5 EUR/GJ (27 EUR/MWh) in the reference scenario to 15 EUR/GJ (54 EUR/MWh) reduces the SMR by 80%, resulting in less than 7% being produced through SMR. As a large part of SMR-based H_2 production in the reference scenario is equipped with CCS already resulting in a relatively low level of CO_2-emssions, doubling of the CO_2-price from 250 EUR/ton to 500 EUR/ton has much less of an effect.

- **Impact of H_2 flexibility:** Not allowing H_2 flexibility in time (NoH2Storage) or space (NoH2Transmission) maintains large, though somewhat lower levels of H_2 electrification levels compared with the case where H_2 flexibility is fully exploited (R2050). The combined flexibility of electrolysis-based hydrogen production and storage or transmission is still sufficient to support a significant increase in VRE production. Limitation of H_2 flexibility in time or space translates into significant, though somewhat lower CO_2 emission reductions, from 106 Mton (in NoP2H2) to 81 Mton (in NoH2Storage and NoH2Transmission), instead of reaching 68 Mton in the cases where H_2 flexibility is fully exploited (in R2050 and also in NoETransmission).
- **Electricity vs. H_2 transport:** Relying only on electricity transmission, by not allowing H_2 transmission (in NoH2transmission), provides higher costs (up to 1.2%) and CO_2 emissions (up to 21%) when compared with other H_2-electrification scenario variants. Not allowing extra electricity transmission (in NoETransmission) can achieve similar CO_2 emissions compared to the optimal mix (R2050), although system costs are slightly higher (0.3%, 0.8 billion euros). At the same time, by allowing only investments in an H_2 network, there appears to be no need for extra 28 GW of HVDC interconnectors (in R2050). This indicates that a system with the expected transmission expansion by 2050 is already very near to the optimal solution, hinting that the focus should be on facilitating H_2 transport rather than extra electricity transport.

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Hydrogen demand

The hydrogen demand is based on the European Commission's model suite results, precisely the 1.5 TECH scenario. For a detailed description of the scenarios and main modelling assumptions, see (European Comission, 2018). The 1.5TECH scenario-derived hydrogen demand was complemented by the bottom-up industry model FORECAST results. This model includes scenarios for the future demand of individual energy carriers, which result in a more precise allocation of hydrogen to specific industrial sectors. The FORECAST modelling results are also available in (European Comission, 2018). Moreover, the 1.5TECH steel industry H_2 demand was complemented by the results of the D9.1 of the H2FUTURE (Sasiain & Rechberger, 2021). These results were used to distribute the demand for hydrogen in the steel industry in the 1.5TECH scenario into the different countries that showed DRI conversion potential.[19] Further sources to construct the dataset shown in Table 7 are (Eurostat, 2020), and (E3M Lab - National Technical University of Athens, 2016).

Table 7. 1.5TECH EU hydrogen demand in TWh per country per sector [20]

Country	Iron and steel	Chemical industry	Feedstock	Non-ferrous metals	Non-metallic minerals	Refining industry	Paper, pulp & printing	Transport	Residential	Maritime
AT	4.0	0.5	8.0	0.1	1.2	0.4	0.1	25.9	4.2	0.4
BE	3.5	1.6	24.6	0.1	1.4	1.1	0.5	29.6	13.4	3.7
DE	19.3	6.3	95.2	1.0	7.6	4.4	3.0	170.6	76.9	4.8
DK	0.0	0.1	0.8	0.0	0.2	0.0	0.2	6.9	1.0	1.4
DW	0.0	0.1	0.8	0.0	0.2	0.0	0.2	6.9	0.5	1.4
CZ	3.1	0.5	7.4	0.0	1.4	0.3	0.0	23.5	7.6	0.1
ES	3.2	1.4	20.8	0.5	4.1	1.0	0.2	118.9	14.2	13.1
IT	2.9	1.4	21.6	0.3	4.8	1.0	1.1	140.2	59.2	17.2
IE	0.0	0.1	1.3	0.2	0.4	0.1	0.0	17.6	2.8	0.4
FR	6.8	1.9	29.0	0.6	4.8	1.3	0.5	175.0	44.8	8.7
FI	1.8	0.3	4.8	0.1	0.2	0.2	0.4	12.4	0.1	2.7
PL	3.5	1.3	19.5	0.2	3.5	0.9	0.3	71.8	12.2	0.1
NL	4.4	2.4	36.0	0.1	0.5	1.7	1.7	39.7	26.6	4.2
UK	3.7	1.2	17.8	0.2	2.2	0.8	1.5	149.8	77.4	13.9
SK	3.1	0.2	3.6	0.1	0.5	0.2	0.0	9.2	4.0	0.2
SE	1.8	0.2	3.1	0.1	0.4	0.1	0.5	25.9	0.3	1.9
NO	0.0	0.7	10.2	1.0	0.4	0.5	0.6	14.5	0.1	1.0
CH	0.0	0.5	8.0	0.1	1.2	0.4	0.0	25.9	4.3	0.0
PT	0.0	0.2	2.7	0.0	1.1	0.1	0.3	27.4	1.3	0.6
BT	0.0	0.2	3.2	0.0	0.5	0.2	0.0	10.8	1.5	0.3
BK	2.5	1.4	20.6	0.8	4.0	1.0	2.2	85.8	22.0	13.1

[19] According to (Sasiain & Rechberger, 2021) full conversion of the steel industry to DRI would require 187 TWh H_2. The 1.5TECH scenario indicates partial conversion as the sum of the column "Iron and Steel" amounts only 64 TWh.

[20] E-liquid and e-gas demand were converted to hydrogen demand and allocated to the sector in which they are used. It is assumed that 1.36 TWh of hydrogen are required to generate 1 TWh of e-liquid and 1.2 TWh to generate 1 TWh of e-gas.

Hydrogen transport by pipeline

Hydrogen and gas pipeline networks have essentially the same components. Nonetheless, gas and hydrogen have different properties that must be considered when repurposing or designing a new pipeline network. Technical issues of repurposing natural gas pipelines can be found on (ACER, 2021). Table 8 show the associated capital costs of retrofitting gas pipeline of different diameters to transport 100%, 75% and 25% of their theoretical hydrogen throughput capacity (Wang, et al., 2021). Since the European gas network consists of pipelines with different diameters, hence a mean value was used to represent the various available options.

Table 8. Pipeline retrofit and new investments costs

48-inch	Unit	100%	75%	25%
Capacity in H2	GW	16.9	12.7	4.2
Pipeline new	mln€/km	2.8	2.8	2.8
Pipeline retrofit	mln€/km	0.5	0.5	0.5
Compressor CAPEX	mln€/MWe	3.4	3.4	3.4
Compressor Capacity	MWe/km	0.4340	0.1830	0.0060
36-inch	**Unit**	**100%**	**75%**	**25%**
Capacity in H2	GW	4.7	3.6	1.2
Pipeline new	mln€/km	2.2	2.2	2.2
Pipeline retrofit	mln€/km	0.4	0.4	0.4
Compressor CAPEX	mln€/MWe	3.4	3.4	3.4
Compressor Capacity	MWe/km	0.0930	0.0400	0.0020
20-inch	**Unit**	**100%**	**75%**	**25%**
Capacity in H2	GW	1.2	0.9	0.3
Pipeline new	mln€/km	1.5	1.5	1.5
Pipeline retrofit	mln€/km	0.3	0.3	0.3
Compressor CAPEX	mln€/MWe	3.4	3.4	3.4
Compressor Capacity	MWe/km	0.0260	0.0060	0.0006

VRE Potentials

Table 9 Potentials potentials for wind and solar energy capacities

Country / Region	Wind onshore [GWe]	Wind offshore [GWe]	Sun PV [GWe]
AT	4.8	-	146.9
BE	0.6	2.3	104.1
CH	4.8	-	73.5
CZ	10.6	-	223.1
DE	11.7	35.0	987.8
DK	7.6	17.0	76.0
DW	7.6	17.0	76.0
ES	89.0	0.8	1316.8
FI	5.5	26.7	72.5
FR	152.4	19.7	1644.5
IE	40.6	1.2	226.6
IT	17.9	4.3	886.0
NO	30.4	39.0	141.1
PL	21.8	15.5	893.4
PT	1.4	0.0	183.8
SE	30.4	39.0	141.1
SK	3.9	-	119.9
UK	61.0	130.2	693.1
BT	5.7	1.6	55.3
BK	1.7	0.6	298.9
NL	12.0	60.0	134.8

Sources: (Ruiz Castello, et al., 2019), (Scheepers, et al., 2020)

Capacity factors

Table 10 Capacity factors of wind and solar energy

Country / Rgeion	Wind onshore	Wind offshore	Sun PV
AT	0.32	0.00	0.13
BE	0.32	0.54	0.12
CH	0.19	0.00	0.14
CZ	0.29	0.00	0.13
DE	0.31	0.50	0.12
DK	0.39	0.54	0.11
DW	0.39	0.54	0.11
ES	0.30	0.37	0.18
FI	0.31	0.52	0.06
FR	0.31	0.48	0.15
IE	0.47	0.61	0.11
IT	0.30	0.34	0.16
NO	0.31	0.61	0.09
PL	0.30	0.52	0.12
PT	0.30	0.39	0.19
SE	0.36	0.51	0.10
SK	0.29	0.00	0.13
UK	0.40	0.56	0.10
BT	0.30	0.53	0.11
BK	0.29	0.39	0.15
NL	0.34	0.54	0.12

Source: (Ruiz Castello, et al., 2019); (Beurskens, 2021a); (Beurskens, 2021b); (Pfenninger & Staffell, 2016)