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Hydrogen Infrastructure in the Future CO_2-Neutral European Energy System—How Does the Demand for Hydrogen Affect the Need for Infrastructure?

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The fast rollout of hydrogen generation, transport, and storage infrastructure has become a top priority of the European Union and its member states. Planning hydrogen infrastructure requires a thorough understanding of the future role of hydrogen in the energy system. At the same time, there is still huge uncertainty about the future demand for hydrogen and its overall role. An energy systems analysis is conducted with high temporal and spatial as well as technological resolution under alternative demand scenarios. An energy system model is used to optimize the entire European energy system with hourly time resolution and high spatial consideration of renewable energy potentials. The hydrogen demand in the five scenarios ranges from about 700 TWh for mainly industrial uses to 2800 TWh in all sectors in the EU27 + UK by 2050. The results show that an integrated European hydrogen system is a robust element of the cost-optimal system design in all scenarios. This encompasses flexible electrolyzers at the most favorable wind and solar locations, long-distance hydrogen transport network, large-scale seasonal underground storage, and electricity generation for peak demand periods. Conclusions about the individual components are provided and high-resolution data on hydrogen demand are available for future research.

1. Introduction

CO_2-neutral hydrogen plays a key role in decarbonizing the energy system. Hydrogen is under discussion to replace large quantities of fossil fuels in various sectors. Expectations are particularly high for so-called "hard-to-abate" emissions, resulting from fossil fuels used as feedstock for basic chemicals or for process heat at high temperature and with high heat densities, as well as in steel production for the direct reduction of iron ore. Hydrogen is also expected to play a role in central power and heat supply, particularly at times when renewables are less available. There are also high expectations for using hydrogen and its derivatives in the transport sector, especially for air and sea transport and for heavy goods transport. Some actors also expect hydrogen to play a role in passenger cars and heat supply in buildings, while this is challenged by others. The political goals for ramping up hydrogen demand and supply are correspondingly ambitious, both at EU level and at member state level. As published in the REPowerEU plan,[1] the European Commission has set a very ambitious target of 10 million metric tons of domestic hydrogen production and an additional 10 million tons of imported hydrogen (and derivatives) in 2030. CO_2-neutral hydrogen currently plays almost no role in the current system, at the same time as stakeholders are calling for a rapid build-up of the hydrogen system. A large number of pilot and demonstration projects have been implemented targeting the rapid ramp-up to industrial level. Simultaneously, there is huge uncertainty regarding the future use of hydrogen in the European energy system to supply industry, transport, and buildings. Decision-makers in politics and industry face the dilemma of having to realize a rapid uptake of the hydrogen system despite the major uncertainty about the quantity of hydrogen needed in a CO2-neutral system.

Against this background, we aim to analyze how the needs for hydrogen infrastructure change with varying demand of hydrogen from industry, transport, and buildings using energy systems modeling. While many energy systems studies addressed the potential role of hydrogen in the future European energy system, none specifically focused on the impact of varying demands.

Several quantitative studies have been published recently, supporting the planning and development of the future hydrogen infrastructure in Europe. European gas transmission operators have already published several updated plans for a Europe-wide hydrogen network as part of the "European Hydrogen Backbone"

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initiative.[2,3] These are based on comprehensive quantitative analyses of the European energy system but did not use an integrated energy system model. They show how a European hydrogen transport system could be used to move large quantities of energy from Europe's peripheries where good solar and wind potentials are available to Central Europe where renewable energy sources (RES) are less competitive and at the same time large potential hydrogen demand is expected. Based on these studies, the European gas industry has published a study that assesses the benefits of a pan-European hydrogen backbone for the energy system.[4] Among others, they underline huge potential cost savings if this backbone is established in combination with cost-optimal deployment of RES, compared to a case without hydrogen trade between countries.

Recent energy systems analyses also find strong evidence that a European hydrogen transport system based to large extent on repurposing existing natural gas pipelines will contribute to reducing overall net system costs.[5,6] Systems studies also reveal that the availability of a pan-European hydrogen transport network could lower the levelized costs of hydrogen production.[7,8] Such a network would facilitate the optimal utilization of the continent's unevenly distributed large-scale hydrogen storage capacities, particularly salt caverns, and enable the strategic deployment of RES at the most advantageous locations. One systems study compared two alternative scenarios, one focusing on hydrogen and one on electricity in sectors with high energy demand.[9] Both scenarios show the need for infrastructure to enable hydrogen to be traded from areas rich in wind and PV to central Europe, where the demand centers are located. Caglayan et al. looked at supply security in the system by analyzing the impact of 38 different weather years.[10] Their analysis shows that Central Europe is clearly a region that will have to import hydrogen—a conclusion supported by most other systems studies.

Other studies investigate hydrogen demand at national level for Italy,[11] and Germany,[12–14] but lack an integrated European perspective.

Further studies look at the interplay between flexibility options and the hydrogen system.[15,16] They highlight the substantial potential that a whole energy systems approach, cross-border infrastructure, and multifuel flexibility have to reduce the need for other flexibility options. In addition, these studies vary the import prices for hydrogen and find that even with the lowest assumed prices, most hydrogen is produced domestically within Europe, indicating competitive RES potentials in Europe and energy system benefits from hydrogen infrastructure. A systems analysis focusing on the role of hydrogen in the German energy system also finds evidence that domestic hydrogen production from electrolyzers increases with increasing flexibility restrictions, e.g., as a result of grid expansion or as electricity from solar energy increases.[17]

Additional studies address various other aspects of the future hydrogen system. Two recent studies indicate that the optimal hydrogen system is heavily dependent on the assumed import prices for hydrogen.[18,19] Competition between blue hydrogen (from steam methane reforming plus carbon capture and storage) and green hydrogen is investigated by others.[20,21] According to the authors, blue hydrogen can be competitive, particularly in the transitional phase between 2030 and 2040, while green hydrogen dominates in the long term. Another systems study looks at the potential of wind energy as source for hydrogen production and finds that, even if electricity is produced offshore, it is more competitive to produce hydrogen onshore.[22]

While such systems studies look at different aspects of the European/national future hydrogen systems, they do not comprehensively address the huge uncertainty on the demand side by defining alternative pathways for the future demand of hydrogen in industry, transport and buildings.

Our study aims to fill this gap by analyzing the potential role of hydrogen infrastructure under alternative demand developments in a future climate-neutral European energy system. We do so by combining the energy system model Enertile with detailed sector models for buildings, industry, and transport. The sector models are used to develop alternative pathways for the uptake of hydrogen demand in the respective sectors using a simulation approach. We define five alternative demand scenarios to capture the potential range of future hydrogen demand. These are regionally distributed based on subsector-specific distribution keys, before being fed into the system model Enertile. The subsequent system modeling with Enertile is using a linear cost optimization.[17] It reveals the potential contribution of the various elements of hydrogen infrastructure to a cost-optimal European energy system. These include cross-country transport corridors, electrolyzers, hydrogen-fired power plants, and large-scale underground storage. The analysis looks at how a European hydrogen system can evolve that is based on hydrogen produced via electrolysis (plus potential imports).

The article is structured as follows. We first give an overview of the methodology and scenario definition, before we describe the approach for each sector in detail including the main techno-economic assumptions and interim results like the diffusion paths of hydrogen technologies. The results focus on the role of hydrogen infrastructure in the overall energy system and compare the scenarios analyzed. Supporting Information data provide additional assumptions and aggregated energy balance with spatially distributed hydrogen demand. The full results including detailed spatial energy balances are available at the data repository Zenodo (https://doi.org/10.5281/zenodo.13236226).

2. Methodology Overview

2.1. Overview of Model System

We use an energy system toolbox able to model the European energy system with high spatial and temporal resolution. We combine the state-of-the-art energy system model Enertile with the detailed sector models FORECAST (for buildings and industry) and ALADIN (for transport) and perform the modeling in two sequential steps, as shown in **Figure 1**.

First, the sector models are used to develop alternative pathways for the uptake of hydrogen in the respective sectors. They feature a very high level of detail. Market dynamics are captured by simulating technology competition using the total cost of ownership (TCO) approach extended by behavioral parameters. All the demand models simulate technology competition and investment at national level for EU27 + UK countries and calculate the energy demand for each country and each year from

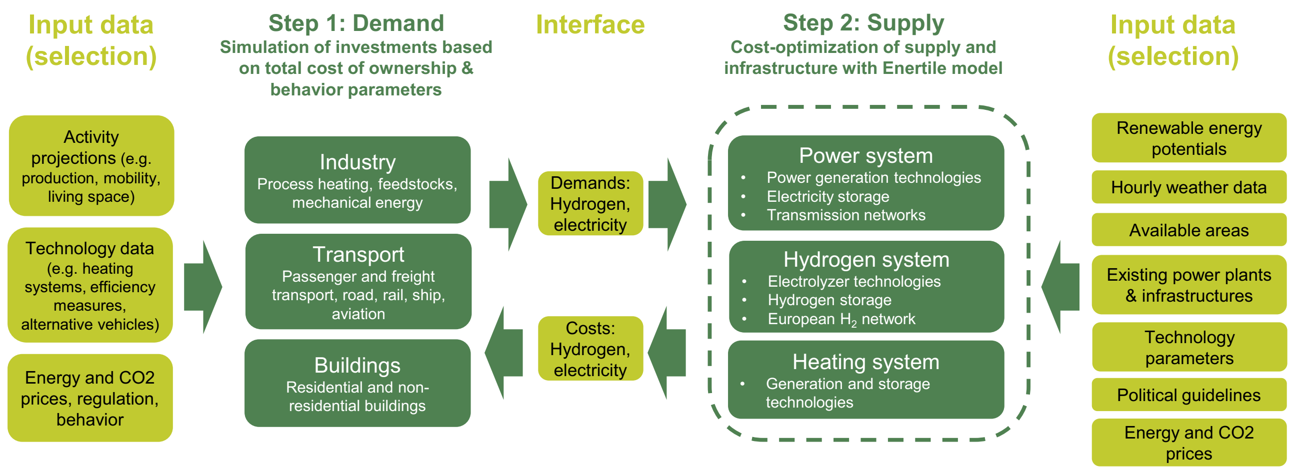

Figure 1. Simplified model system overview.

2018 until 2050 (see Section 3 for detailed model descriptions). The resulting national-level energy demands are distributed to individual nomenclature of territorial units for statistics (NUTS)1 regions (see Section 2.2). The data availability for Germany allows even higher NUTS 3 resolution.

In a **second** step, the resulting energy demands are used by the system model Enertile to calculate the least-cost energy supply (see Section 3.4.1). The Enertile model uses a different geographic resolution than the NUTS 1 framework used in the demand models. Further details about the division are given in Section 3.4.1 and Figure A1. The Enertile model has an hourly resolution and calculates a pathway toward 2050 in 5 year steps. The interface between demand and supply was also used to provide cost assumptions for hydrogen and electricity to the demand models.

The approach is a mixed simulation and optimization method. The use of simulation on the demand side can capture behavioral and policy parameters, which model a more realistic technology diffusion, while considering the TCO as the driving factor. This makes it possible to develop alternative demand-side scenarios. On the supply side, the strict least-cost optimization using perfect foresight gives insights into the cost-optimal energy supply for a given demand scenario.

2.2. Breakdown of Demand Data to Regions

The disaggregation of the national demand to regions (NUTS classification or raster level) is conducted as a separate step after calculating the national energy demand using so called distribution keys that reflect the main drivers of energy demand. Examples are the number of buildings per region, industrial production per region, and registered cars per region. Distribution keys are defined for individual end-uses of each sector, which means that the regional disaggregation can account for structural changes between the different end-uses. Furthermore, we consider that distribution keys will change in the future. The sector-specific main parameters for the distribution keys are listed in **Table 1**. For each category (sector, subsector, energy carrier, end-use, and year), the distribution keys add up to 100% for each country. For each end-use, the specific national energy demand is multiplied by the related distribution key, so the regional results feature the same level of technology detail as the national results. The final energy demand is shown at the spatial resolution of NUTS 1 (NUTS 3 for Germany). Additional assumptions are described in the sector-specific sections.

2.3. Scenario Definition

We define five main scenarios spanning a range of possible future hydrogen demands. The scenarios are based on the same boundary conditions and assumptions in order to ensure the highest possible comparability and able to assess the effect of additional hydrogen demand on the energy system in isolation. The scenario approach aims to address the huge uncertainty facing the future energy system with regard to the quantity of hydrogen demanded.

All scenarios are based on the following six main assumptions that together define the frame of the model analysis: 1) All scenarios reach a climate-neutral EU energy system; 2) Biomass use is limited so that the overall land needed to produce energy crops does not increase. This limits biomass use in all scenarios, which would otherwise have increased drastically with the assumed CO_2 prices; 3) Carbon capture and storage (CCS) is only allowed where alternative mitigation technologies are unlikely to become relevant for climate neutrality by 2050. These are mainly the hard-to-abate sectors of cement and lime production. Similarly, blue hydrogen or DACC are not options the model can choose; 4) The CO_2 price is assumed to apply to energy supply and to industry. It increases to 350 euros/ton of CO_2 by 2050; 5) Synfuels used in the transport sector are imported from outside Europe. Only PtX products used as feedstocks are varied across scenarios including imports and the domestic production of methanol, PtL, and ammonia; and 6) Imports of hydrogen are represented as supply cost curves at selected entry points. This includes the potential transport of liquid hydrogen by ship and of gaseous hydrogen by pipeline.

To properly interpret the results, it is essential to bear these conditions and assumptions in mind. We exclude the widespread

Table 1. Main sources for derived distribution keys per technology, end use and/or energy carrier.

Sector	Technology/end use	Energy carrier	Main parameter for distribution key	Source
All	Validation of distribution	Not specified	Population	Eurostat[57]
All	Development of energy demand	Not specified	Population development	Eurostat[58]
Industry	Energy-intensive processes (e.g., steel, aluminum, cement, glass, and chemicals)	Not specified	Production at industrial sites	Fraunhofer ISI Industrial Database[59,60]
Industry	Nonenergy-intensive subsectors	Not specified	Employees per subsector	Eurostat[61]
Buildings	Residential buildings heating	Useful energy demand	Living area, Heating degree days	Census[62]
Buildings	Residential buildings—heating	Electricity	Number of single-family houses (SFH)	Census[62] Espon[63]
Buildings	Residential buildings—heating	Hydrogen	Spatial proximity to industrial sites	[30]
Buildings	Residential buildings—heating	Gas	Gas demand	Census[62]
Buildings	Residential buildings—heating	District heating	–	HDHCD[64]
Buildings	Service buildings	Not specified	Employees per subsector	Eurostat[61]
Transport	Cars	All	Regression with GDP and population	[65]
Transport	Heavy duty vehicles	All	GDP and length of motorways	[65,66]
Transport	Rail	All	Railroad tracks	[66]
Transport	Aviation and shipping	All	Passenger and freight turnover at airports and harbors	Aviation:[67] Shipping:[68]

use of biomass and CCS to understand how the European energy system can supply the required demand using green hydrogen without relying on these two solutions.

Table 2 provides an overview of the definition of the five scenarios for the industry, transport, and buildings sectors. The scenarios build on each other and depict an increasing hydrogen demand from S1 to S5 by gradually switching more end-uses to hydrogen.

Scenario *S1_NewIndVC* has the lowest hydrogen demand. There is no demand for hydrogen in buildings, marginal use of hydrogen in trucks, and large-scale use as a synthetic fuel for aircraft and ships in transport. In the industrial sector, it is assumed that selected very energy-intensive intermediate products (sponge iron, ammonia, and synfuels) are imported to a large extent. As a consequence, current large potential users do not need hydrogen or have limited demand. Hydrogen is only used in selected applications in industry, where the electrification of process heat is difficult due to high temperatures and energy densities.

Scenario *S2_ChemSteel* builds on scenario S1 and differs only regarding the use of hydrogen in the industrial sector. Here, energy-intensive intermediate products are not outsourced as in S1. Instead, hydrogen is used to produce steel, ethylene (and other olefins), methanol, and ammonia in Europe. In scenario *S3_Ind*, hydrogen is also used to supply other areas of process heat that are predominantly electrified in scenario S2. For instance, hydrogen also plays an important role for steam generation in S3. Scenario *S4_IndMob* assumes that a high share of long-distance truck freight transport is additionally converted to run on hydrogen as an energy carrier. For passenger cars, however, hydrogen propulsion remains a niche market in scenario S4, and electric passenger cars dominate the fleet. In *S5_AllSec*, hydrogen is additionally used to heat buildings. Although electric heat pumps still dominate the heating stock

Table 2. Definition of five scenarios by sector.

Short name	Title	Industry	Transport	Buildings
S1_newIndVC	New global industrial value chains	Import of green energy-intensive basic materials like iron sponge, ammonia, and methanol; high-temperature process heat supplied by H_2	Electrification of passenger cars and trucks; synfuels for sea and air transport	No direct use of H_2 in buildings
S2_ChemSteel	Focus H_2 in chemicals and steel	=S1 plus domestic H_2-based production of green steel and chemicals	=S1	=S1
S3_Ind	Focus H_2 in industry	=S2 plus broad use of hydrogen for process heating including steam generation	=S1	=S1
S4_IndMob	Focus H_2 in industry and transport	=S3	=S1, but H_2 also for long-distance trucks	=S1
S5_allSec	H_2 in all sectors	=S3	=S4	=S1, but H_2 for decentralized heat supply

in S5, hydrogen-powered heating systems also play a certain role here in some segments.

This overarching scenario design was implemented in the sector models using a wide range of model parameters. These assumptions are described in the following chapter.

3. Sector-Specific Method, Data, and Assumptions

3.1. Transport Sector

3.1.1. The Transport Sector Model ALADIN

ALternative Automobile Diffusion and INfrastructure (ALADIN) is an agent-based model that incorporates driving data from numerous vehicles to analyze alternative drive purchase decisions.[23] It calculates the total cost of ownership for different drivetrains (e.g., gasoline, diesel, battery electric vehicles (BEV), plug-in hybrid electric vehicles, and fuel cell electric vehicles (FCEVs)) based on detailed driving behavior datasets. The model considers factors such as infrastructure limitations and the availability of new drivetrain technologies and aims to determine the optimal driving option while accounting for these restrictions.[24,25] This approach yields market share estimates for each drivetrain technology. Energy demand for road transport (e.g., hydrogen and electricity) can be calculated using these market shares and the driving data.

ALADIN examines the market diffusion of alternative vehicles in both passenger cars and light to heavy-duty vehicles, especially for Germany, but has been extended to all EU27 + 3 (EU27+3: EU countries, Norway, Switzerland, and the United Kingdom) countries accounting for national differences in energy prices, current alternative fuel vehicle diffusion, and the development of charging infrastructure. For aviation and shipping, it is assumed that mostly the admixture of alternative fuels, which consist of biogenic, hydrogen, and hydrogen-based e-fuels, contributes to CO_2 neutrality.

To disaggregate the national energy demand in Germany to the district level (NUTS3), ALADIN utilizes specific regional alternative drive shares. The other EU27 + 3 countries are disaggregated at the regional level of federal states (NUTS1). Regional shares are determined using mode-specific and macroeconomic parameters (e.g., vehicle stocks, passenger turnover, or volume of traffic). Regional values are determined by multiplying these shares by the final energy values determined in the initial step for each country.

3.1.2. Scenario Specification and Techno-Economic Data

For the transport sector, two main sets of scenarios are defined that differ in the attractiveness of hydrogen versus electrification. Scenarios S1, S2, and S3 consider techno-economic assumptions that favor electrification, while scenarios S4 and S5 favor hydrogen. The other assumptions are similar within these two groups of scenarios. In the following, the techno-economic assumptions are discussed for each transport mode.

For road and rail transport, the assumed energy carrier prices are shown in **Table 3**. The final prices for petrol and diesel are not merely a reflection of production costs, but the culmination of a broader array of factors including taxes, levies, and profit margins. The inclusion of a CO_2 tax at 300 euro/ton embodies the shifting regulatory landscape and is intended to integrate the environmental costs of fuel consumption into its market price.

Table 3. Energy carrier prices (end user prices in Germany) for road transport.

Commodity	Scenarios S1, S2, and S3 [€ kWh^{-1}]		Scenarios S4 and S5 [€ kWh^{-1}]	
	2030	2050	2030	2050
Electricity (residential)	0.286	0.296	0.286	0.296
Hydrogen	0.285	0.221	0.264	0.164
Diesel	0.182	0.334	0.182	0.334
Petrol	0.188	0.354	0.188	0.354

Passenger Cars: The assumptions for passenger cars are similar in all scenarios: Hydrogen systems in passenger cars cannot compete with BEV because of efficiency reasons and the already high market penetration of BEV. Alternative scenarios with more optimistic hydrogen assumptions for passenger cars were analyzed, but revealed that FCEVs could still not compete with BEVs. Furthermore, once the transition to BEVs is fully realized, it is unlikely to be reversed in a few years, as transformation processes in production and the market require significant amounts of time and investment.

To adjust the annual national growth rates for alternative drives for each EU country, factors such as national fuel-electricity price ratios and national monetary incentives were considered as regression coefficients. The national influence of government monetary incentives, electricity-to-diesel price ratio and of charging infrastructure is quantified based on a panel analysis by Münzel et al. (2019).[26] The monetary incentives encompass all cost savings for electric vehicles compared to conventional vehicles. The number of fast-charging stations for cars in EU27 + 3 countries is estimated to be 200 000 stations by 2030 and 400 000 stations by 2050. The ALADIN model incorporates the costs of charging infrastructure as an average between public and private charging expenses to reflect a comprehensive perspective of accessibility to EV charging.

Heavy-Duty Vehicles and Buses: ALADIN calculates the energy demand for heavy-duty vehicles and buses in Germany. For other European countries, the energy demand is adjusted based on their territorial transport performance (tkm. Efficiency improvements of up to 30% are observed for both alternative and conventional propulsion systems across all European countries. The following assumptions were made for the ALADIN model (**Table 4**).

All scenarios assume that LNG and methanol will not have a significant share of fuel consumption and that there is no demand for e-fuels until 2050. The use of biofuels is expected to increase significantly in all scenarios, accounting for a 59% share of conventional fuels by 2050.

The main differences between the sets of scenarios reflect uncertainties in the main parameters that will decide whether

Table 4. Main assumptions for heavy duty vehicles and buses.

Parameter	Unit	Scenarios S1, S2, and S3		Scenarios S4 and S5	
		2030	2050	2030	2050
Hydrogen truck market availability	%	50% by 2028		50% by 2025	
Electrified highway km (fast charging)	Km	3,000	8,000	1500	4,000
Fuel cell costs	€ kW^{-1}	80	70	80	55
Battery costs (BEV)	€ kW^{-1}	100	80	120	100

electrification or hydrogen will dominate heavy-duty vehicles. The scenario sets differ as follows: 1) S1, S2, and S3 assume the deployment of catenary trucks and buses, which are not available in S4 and S5; 2) S4 and S5 assume a lower hydrogen price than S1, S2, and S3 (Table 3); 3) The cost of fuel cells remains the same in all scenarios until 2030, after which the price per kW decreases faster in S4 and S5 (Table 4); and 4) Battery prices for BEVs are consistently lower in S4 and S5 compared to S1, S2, and S3 (Table 4)

When combined, these assumptions define an overall framework that favors electrification in S1, S2, and S3 and favors hydrogen in S4 and S5.

Rail: In S4 and S5, it is assumed that no further railway lines will be electrified between 2020 and 2050. As a result, hydrogen-powered trains are partially deployed on non-electrified routes. The goal is to achieve 90% of train mileage using hydrogen propulsion by 2050. In contrast, S1, S2, and S3 continue to electrify railway lines, making rail less favorable for hydrogen propulsion. Both scenario sets assume a gradual increase in the share of biofuels to 59% by 2050 and an efficiency increase of 20% in 2050.

Aviation: It is assumed that air traffic in Europe will grow annually at a constant rate of 0.5%. The aviation sector expects hydrogen to become the predominant fuel in domestic air travel, which mainly comprises short-distance flights. Thus, we assume that by 2050, the entire fuel demand in this segment will be met with hydrogen in all scenarios. Apart from hydrogen, no other propulsion technology is expected to prevail in short-distance flights by 2050: 1) For long-distance international flights, the share of e-kerosene is projected to increase to 63% by 2050 in S1, S2, and S3, while the blending ratio for e-kerosene in S4 and S5 increases to 100% by 2050 (**Table 5**); 2) In all scenarios, the share of conventional fuels in overall fuel consumption will steadily decline to zero by 2050 (Table 5); and 3) In addition to e-kerosene, 37% of the overall fuel demand is planned to be covered by bio-based alternatives by 2050 in S1, S2, and S3, whereas biogenic kerosene disappears in S4 and S5 due to limited sustainable biomass (Table 5).

The efficiency of propulsion systems improves significantly to 35% by 2050 in all scenarios.

Shipping: S1, S2, and S3 assume that today's propulsion systems continue to be used and alternatives are not deployed. Power-to-liquid (PtL) fuels and biofuels are expected to completely replace conventional fuels by 2050 and conventional ships operate with a blend of PtL and biofuels. In S4 and S5, hydrogen propulsion is assumed to reach a share of 20% by 2050 (**Table 6**). All the scenarios anticipate a substantial increase in efficiency of up to 30% by 2050. Efficiency improvements can be achieved in shipping through behavioral adjustments such as slow steaming, weather routing, and increased use of autopilot. Additionally, drive-independent improvements like hull coatings could be legally mandated, similar to the enforcement of emission limits in emission control areas. We assume these significantly reduce fuel consumption by 30% until 2050.

Table 5. Main assumptions for domestic and international flights: percentage of direct hydrogen use (only relevant for distances shorter than 2000 nautical miles) and admixture quotas for e-fuels (synthetic kerosene from green hydrogen).

Parameter	S1, S2, S3 [%]	S4, S5 [%]
H2 short distance flights 2050	100	100
H2 long distance flights 2050	0	0
e-kerosene all flights 2030	5	5
e-kerosene all flights 2035	30	30
e-kerosene all flights 2050	63	100
Bio-jet fuel all flights 2030	10	10
Bio-jet fuel all flights 2035	15	9
Bio-jet fuel all flights 2050	37	0

Table 6. Main assumptions national shipping.

Parameter	Start Scenario [%]	H2 Scenario [%]
Share H_2 2035	0	5
Share H_2 2050	0	20
Share PtL 2035	28	28
Share PtL 2050	75	80
Share Bio 2035	15	15
Share Bio 2050	25	0

3.1.3. Technology Pathways

Passenger Cars: As mentioned earlier, direct electrification is an alternative to hydrogen for decarbonizing passenger car transportation. From a systems perspective, this option is significantly more efficient. In recent years, advancements in battery technology have led to a steady increase in the range of battery-electric vehicles.[27] Battery-electric cars also have economic advantages over hydrogen fuel cell vehicles and the development of the sales shares of plug-in electric vehicles (PEV), especially in Norway (see **Figure 2**), suggests that hydrogen will not play a significant role for passenger cars. This is because direct electrification offers both technical (efficiency) and economic benefits.

Heavy-Duty Vehicles: In heavy-duty vehicles, both battery-powered and hydrogen-powered trucks are conceivable, so the differences between the scenarios depend heavily on the price assumptions for hydrogen, fuel cell systems, and infrastructure. As smaller trucks will mostly be decarbonized by PEV, there is a high degree of uncertainty, especially for long-haul trucks regarding the demand for hydrogen. Any direct use of hydrogen in transportation will start late (after 2035) due to limited

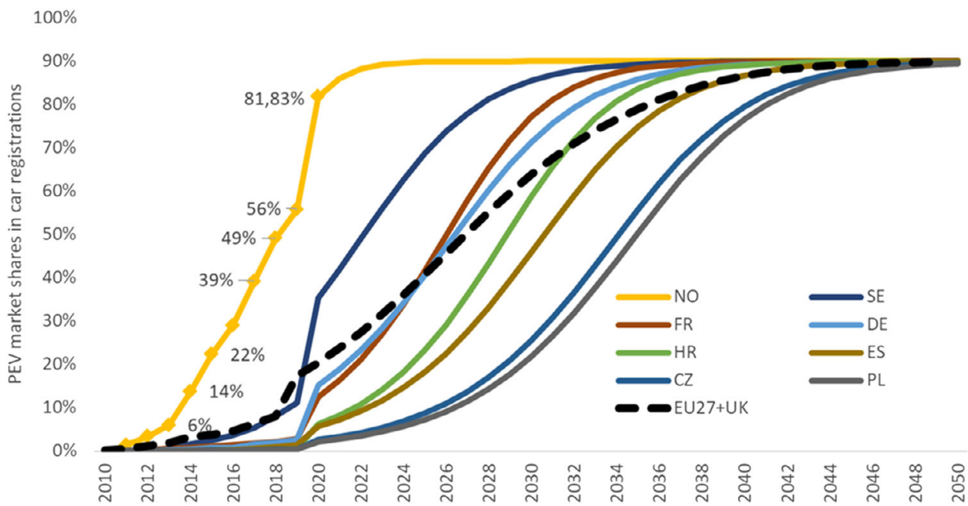

Figure 2. Market shares of plug-in electric vehicles (PEV) in passenger car registrations in a selection of European countries.

technology and infrastructure accessibility, as well as initially higher hydrogen market prices (**Figure 3**).

In addition to the discussed advantages of battery-electric vehicles, there are also differences with regard to infrastructure. The infrastructure requirements for hydrogen-powered vehicles resemble those of conventionally fueled vehicles: Distributed refueling stations are supplied with hydrogen, which is then dispensed into vehicles through pumps. This process still faces technical challenges. First, there is no consensus on the standardized state of hydrogen for vehicle use. There are differences between using hydrogen in gaseous form at pressures of 350 or 700 bar, or in the form of liquefied hydrogen. Varying standards and the lack of a prevailing standard make coordination between manufacturers and refueling station operators difficult.

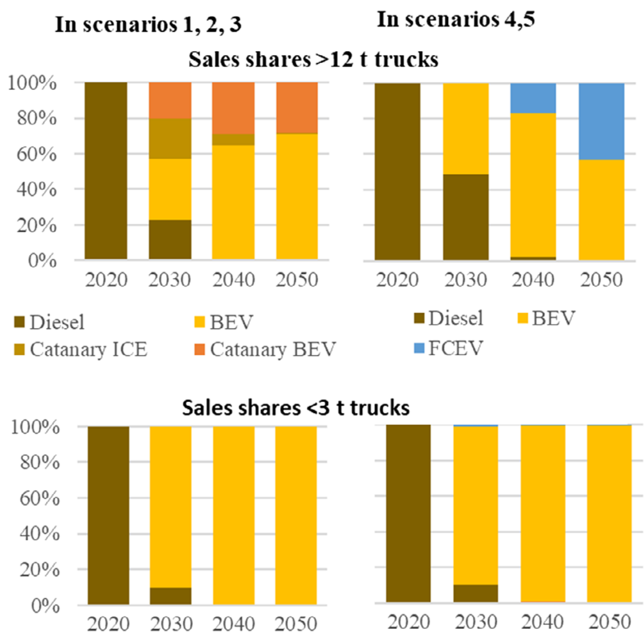

Figure 3. Sales shares of different heavy-duty vehicle types.

Additionally, hydrogen at 350 bar has a significantly lower energy density than at 700 bar and is even lower than hydrogen in its liquid form. Lower energy densities result in vehicles with shorter driving ranges that require more frequent refueling, even in comparison to conventionally fueled ones. The uncertainties persist when considering how hydrogen is supplied to refueling stations. Overall, the use of hydrogen in road transportation poses several open questions that depend on various factors concerning the energy system as a whole: How will refueling stations be supplied? Through tanker trucks, pipelines, or by on-site electrolysis? However, there are also numerous infrastructure questions related to direct electrification. Vehicles will be charged with electricity. This can be done at various charging rates, from depot charging to fast charging at 1 MW. Depending on the charging rate, the charging times are much longer than for hydrogen refueling, which in turn makes it challenging to accommodate driving profiles with high mileage and limited downtime. The EU already has a comprehensive electricity distribution infrastructure in place, especially in northern and central Europe. Although this may need expansion in some areas, especially in south-eastern Europe due to increased demand from transportation, the technology for electricity distribution is already mature compared to hydrogen.

Aviation and Shipping: The direct use of hydrogen in aviation and shipping is strictly limited to longer transportation routes due to hydrogen's low energy density. Furthermore, the diffusion of new, carbon-free technologies in both modes of transport is too slow to achieve decarbonization by 2050. Therefore, in this sector, the admixture of so-called "sustainable fuels" is the essential driving factor. As sustainable biogenic fuels are also limited, higher quantities of e-fuels, produced using green hydrogen, will be used in shipping and aviation in both scenario sets.

Ammonia, for example, shows promise as a sustainable fuel for shipping and aviation due to its high energy density and transportability. It enables the use of hydrogen for long-distance transportation and the utilization of existing infrastructure, as ammonia is already produced globally for various industrial purposes. However, there are safety concerns due to ammonia's toxicity and its incomplete combustion can lead to additional NOx pollution. Nevertheless, worldwide transport of ammonia over many decades has proven that safe handling of the chemical is possible. Further development of infrastructure would be needed to support the production, storage, and distribution of ammonia as a fuel in the shipping and aviation sectors. The more expensive alternatives in terms of energy carrier prices are methanol and Fischer–Tropsch fuels that fulfill the existing standards for kerosene in aviation and diesel in shipping.

3.2. Industry Sector

3.2.1. The FORECAST Industry Model

Possible pathways for the industry sector build on a mix of climate-neutral technologies, but there is still very high uncertainty about the relevance of the individual main strategies. These include electrification, use of hydrogen or biogenic resources, and carbon capture and storage or use. These major technological directions will be accompanied by improvements in energy and material efficiency and circularity along the various value chains. The FORECAST simulation model considers all these strategies and make is possible to develop consistent technology pathways.

FORECAST is a bottom-up energy demand model. It maps the technological structure of industry and calculates energy consumption and emissions as well as costs at the process level. FORECAST Industry is hierarchically structured and divides industry into individual economic sectors or subsectors based on energy balances. These are assigned to processes, which are described by a specific energy consumption and an activity variable. Furthermore, technology areas such as electric motors, industrial furnaces, space heating, and steam generation are modeled separately. Input data for the modeling are activity variables such as economic performance per industry, energy and CO_2 prices, assumptions on policy instruments, structural data such as energy and greenhouse gas balances, and techno-economic data of the technologies included. Statistical data, empirical studies, literature, and assessments of experts form the data basis of the model and are used for parameterization.

All the major decarbonization strategies can be considered when constructing scenarios: 1) Process change to low-carbon or CO_2-neutral processes: Exogenous assumption for diffusion of new processes; 2) Fuel and feedstock switch (electrification, hydrogen, and biomass): Endogenous modeling via discrete choice method based on cost competitiveness of alternative technologies;[28] 3) Carbon capture and storage (CCS): Exogenously defined at process level; 4) Energy efficiency improvement through best available technology (BAT) of existing plants: Diffusion depends on cost-effectiveness and additional parameters;[29] and 5) Circularity and material efficiency along the value chain: Exogenous assumptions about the progress of material efficiency and the circular economy at process level.

A more detailed description of the model is available in Fleiter et al.[30]

For the regional breakdown, two approaches are combined depending on the energy intensity of processes (Table 1). The national energy demand for energy-intensive subsectors is regionalized using the Fraunhofer ISI Industrial Sites Database.[31] This uses over 1500 locations of energy-intensive subsectors with information on processes and production quantities. Based on this, more detailed rules are then defined for specific processes (e.g., ethylene and high-value chemicals (HVC) produced at refinery sites), and their energy demand can be quantified site specifically or regionally for all years. Any energy demand that cannot be allocated to specific sites is broken down by subsector using employment statistics. The basic assumption here is that all locations are maintained, no regional shifts in production volumes take place, and all locations are decarbonized at the same speed of transformation.

3.2.2. Scenario Specification and Techno-Economic Data

The main activity drivers used by the model are the value added of individual industrial subsectors and the production output of individual energy-intensive bulk products.

All scenarios use the same macroeconomic framework data based on the European Reference Scenario.[32] Accordingly, an average annual growth rate in gross value added (GVA) of around 1.6% per annum (p.a.) is assumed for industry until 2030; the growth rate subsequently declines to 0.8% p.a. The energy-intensive basic industries are assumed to grow at slower pace than the industry average. In addition, a moderate decoupling of the value added and the physical production volumes in the basic industry is assumed in the long run.

Based on the assumptions about economic development in terms of value added per sector, we derive assumptions about the future production of major energy-intensive products. Improved material efficiency along the value chain is assumed depending on potentials for each product. The resulting production is about 2 to 14% below 2018 values by 2050 for most products (see **Figure 4** plus extended list of products in the Supporting Information).

Important process-specific data include the specific energy consumption (SEC) and process emissions per ton of material produced, investment costs, lifetimes and temperature distribution of process heat demand. Such assumptions (e.g., SEC and temperature level by process) are based on ref. [33] for existing processes. New climate-neutral processes are added and the combined data set is available in the Supporting Information.

The scenarios S1, S2 and S3 vary in the importance of hydrogen to supply industry. In S1, hydrogen is mainly used to supply high-temperature process heating, which is often hard-to-electrify. Very energy-intensive intermediate products that potentially require huge quantities of hydrogen like sponge iron, ammonia or chemical feedstocks are imported to a large extent in S1. In scenario S2, these intermediate products are produced domestically based on climate-neutral hydrogen, substantially increasing the demand for hydrogen compared to S1. Scenario S3 builds on S2, but also uses hydrogen for low-to-medium temperature process heating, which is mostly electrified in S1 and S2. The specific technology assumptions for the individual pathways and sectors are presented in the following section.

3.2.3. Technology Pathways

It is assumed that the iron and steel industry will undergo a transformative shift toward hydrogen-based direct reduction of

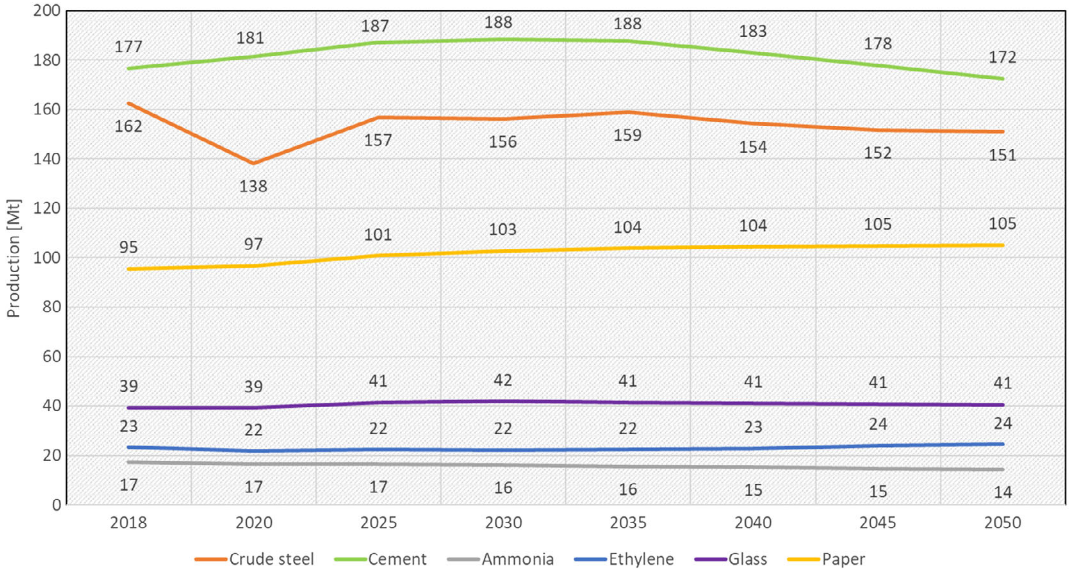

Figure 4. Assumed production output of selected basic material products in Mt for EU 27 + UK (2018–2050).

iron ore (H_2-DRI). We assume that H_2-DRI will fully replace blast furnace primary steel production in S2 and S3 with about 56 Mt production by 2050 (see **Figure 5**). This substantial switch to H_2-DRI reflects the plans and strategies of major steel producers throughout Europe, of which many have already announced investment decisions.[34] S1 assumes a similar technology transition with the difference that a major share of DRI production takes place outside Europe and domestic production of DRI is reduced to 19 Mt by 2050. The competition between imports and domestic production of climate-neutral DRI is highly debated and there is an indication that future competitiveness will depend on local renewable energy resources, which could strongly influence the future location of climate-neutral steelmaking value chains.[35] The difference in scenario design captures this high degree of uncertainty. The process switch is accompanied by accelerated improvement in circularity. In all scenarios, the secondary steel production route using electric arc furnaces (EAF) in the EU27 + UK is assumed to increase from 69 Mt in 2018 to ≈95 Mt by 2050. In addition, material efficiency gains along the value chains result in lower demand for and production of steel (−9% by 2050 compared to 2018). The various downstream processes switch from using natural gas for process heating to a mix of hydrogen and electrification.

The basic chemicals industry covers a broad range of products and processes. Here, we present the most energy-intensive ones. A full list of the considered processes is included in the Supporting Information. The production of HVC like ethylene via steam cracking of fossil naphtha is the largest energy consumer in EU industry. Naphtha is not only used as an energy carrier, but also as a feedstock. The EU's petro-chemical industry does not have a strong shared vision of a suitable transformation pathway.[36] S2 and S3 assume that 83% of ethylene production will use imported climate-neutral methanol by switching to a new route, Methanol-to-Olefins (MTO) (see Figure 5). The methanol is produced in Europe based on green hydrogen. The remaining 17% will use imported climate-neutral naphtha in electrical steam crackers (ESC). S1 assumes that HVCs will shift to 100% ESC using imported climate-neutral naphtha. In all scenarios, this process switch is accompanied by circularity and material efficiency improvements along the value chain, which slow down the rising demand for and production of HVCs.

For ammonia production, S2 and S3 assume that 100% of production uses hydrogen supplied by the hydrogen transport network in Europe by 2050 replacing today's local production of (grey) hydrogen by steam reforming of natural gas (see Figure 5). The production of hydrogen is determined by the energy system model (see Section 3.4). At the same time, S2 and S3 assume that ammonia demand and production decreases by 14% in 2050 compared to 2018 as a result of more efficient fertilizer use in agriculture. S1 assumes that climate-neutral ammonia will be completely imported from outside the EU. This reflects a major trend of importing green ammonia to Europe for use as a hydrogen carrier: Once established import corridors exist, it is likely that economic pressure will be very high to use green ammonia directly as a feedstock because cracking it to produce hydrogen is accompanied by substantial energy and cost penalties.[37]

The cement industry uses a mix of strategies. We assume that the clinker share in cement is reduced to about 48% by 2050. Low-carbon types of cement with innovative binders account for a market share of 5% by 2050. More efficient use of concrete in the construction industry reduces overall demand by 6% by 2050 compared to 2018. Fossil fuels are replaced by a mix of waste, hydrogen, biomass, and partial electrification. However, there are still substantial non-energy-related CO_2 emissions from the calcination process. Thus, we assume that all major cement plants will use carbon capture and storage by 2050. In scenarios S2 and S3, the captured CO_2 is used in the chemical industry to produce green methanol (CCU), while all the captured CO_2 is stored in S1.

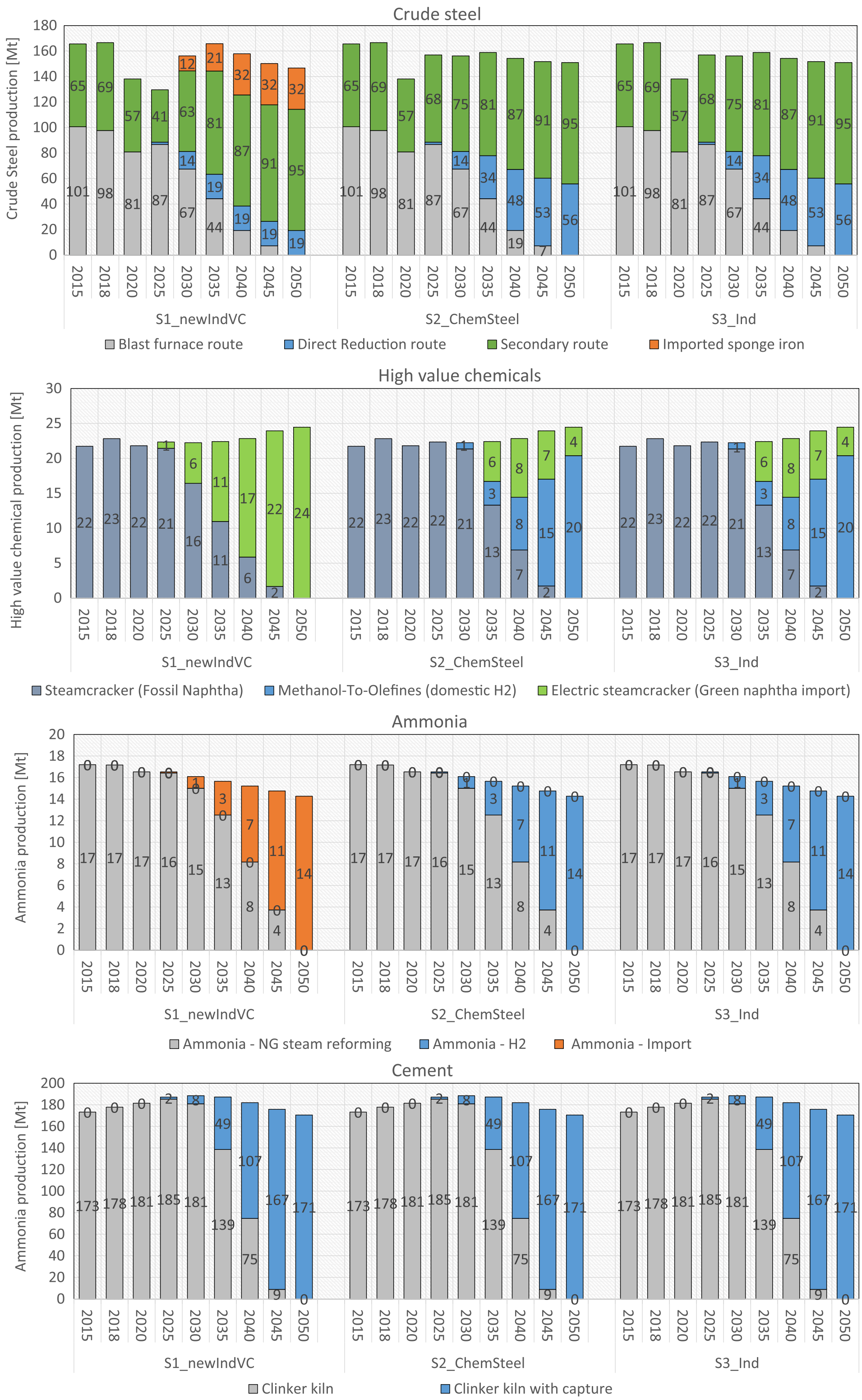

Figure 5. Assumed evolution of technology shares for crude steel production (top), high-value chemicals (middle top), ammonia (middle bottom), and cement (bottom).

The future supply of process heating is a major uncertainty when estimating hydrogen demand. Process heating can be split into high-temperature applications in furnaces and low-to-medium temperature applications below 500 °C that mostly involve process steam. Both segments are highly relevant, each accounting for roughly 1000 TWh of final energy demand in 2018. Process heating in furnaces typically is very integrated into the production process and mostly relies on natural gas at present. Switching to hydrogen can often be done by retrofitting existing plants, while electrification requires more substantial modifications or entirely new furnace designs. Particularly challenging for direct electrification is the supply of high temperature and high energy density process heat, which still requires further technology development, demonstration, and upscaling. Hydrogen may have advantages here, but also needs more technology development. Overall, the competitiveness of hydrogen or direct electrification to provide high-temperature process heating in furnaces varies across the different processes and sectors with their specific technical parameters and operational needs.[38] However, hydrogen can play a major role in this segment, and all scenarios assume a substantial share of hydrogen with partial electrification (see **Figure 6**). The specific shares vary by process and sector.

There is a different picture for the provision of process heat via steam in the low-to-medium temperature range. Here, direct electrification technologies like electric boilers are mature and industrial heat pumps even allow substantial efficiency gains compared to the use of hydrogen or natural gas.[38] Accordingly, these applications are dominated by electrification in scenarios S1 and S2 with only a niche for hydrogen. S3 captures the possibility that steam generation could be supplied by hydrogen to a larger extent, but electrification still plays a role (see **Figure 7**).

3.3. Building Sector

3.3.1. The FORECAST Buildings Model

FORECAST Buildings is a bottom-up simulation model that covers residential and commercial (service) sector buildings when long-term scenarios for future energy demand have to be developed. The model considers the dynamics of technologies and socioeconomic drivers. It calculates the overall energy demand of the EU27 + 3 buildings, including lighting, electric appliances, and heating and cooling systems.

The model includes two modules, one for appliances, lighting and air conditioning, and another one for heating. The first module is designed as a vintage stock model that captures the individual end-uses in the market with detailed techno-economic parameters, in combination with their age distribution. The second module comprises a detailed representation of the European building stock based on building typologies by construction period, building type, and building standards. The heating systems are discretely assigned to the different building segments. This direct link between buildings and heating systems allows modeling the diffusion of heating systems in a differentiated manner, as all segments of the building typology vary in technology and cost characteristics. The driving parameters like the number of dwellings or the number of employees are used to calculate future heated floor space and directly affect future energy demand.

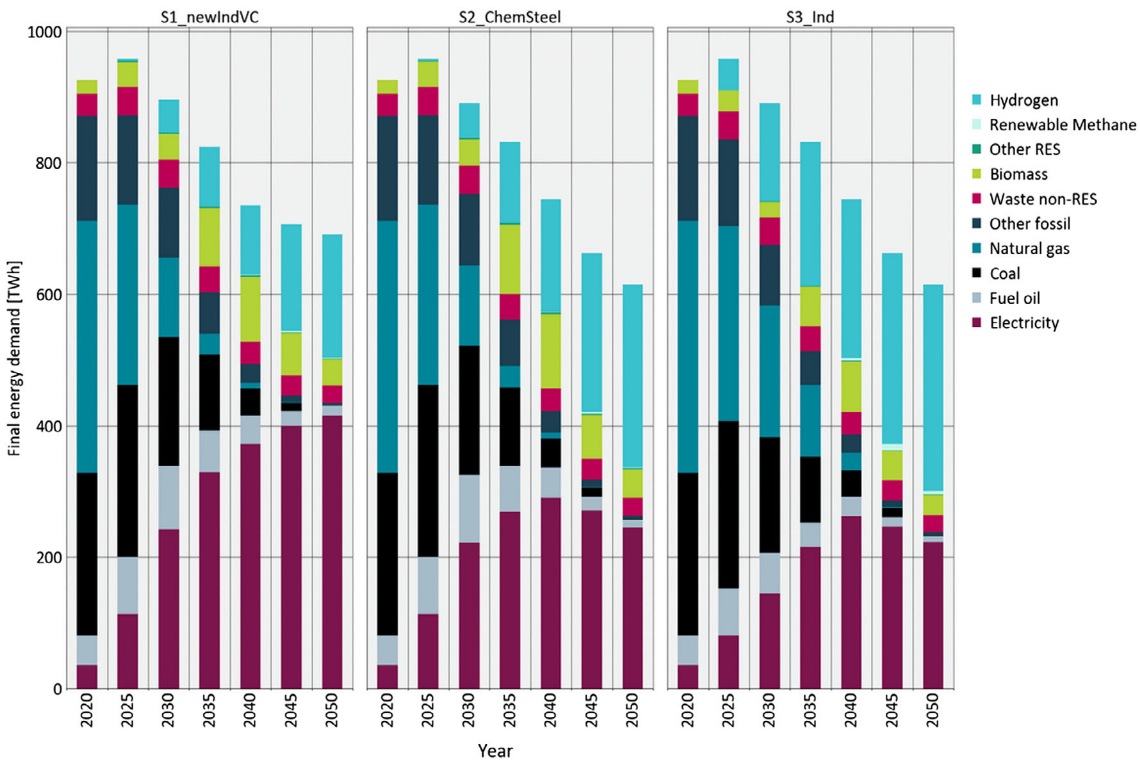

Figure 6. Resulting energy demand to supply high-temperature process heat in the EU27 + UK.

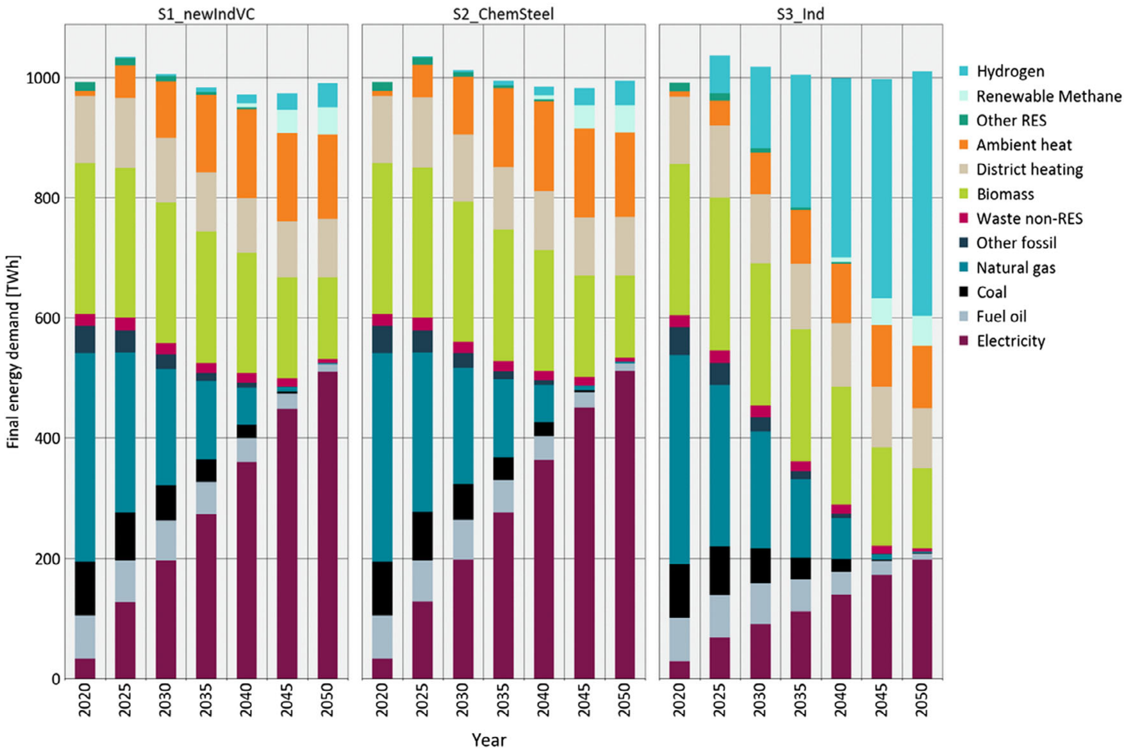

Figure 7. Resulting energy demand to supply steam and hot water for process heat in the EU27 + UK.

The diffusion of alternative types of heating systems is a direct result of a TCO-based simulation of individual investment decisions. The sum of investment decisions in a certain year leads to the transformation of the building and end-use stock. In a last step, the energy demand is calculated based on the specific consumption per end-use and their market shares.

In the regionalization of building demand, a distinction is made between residential and nonresidential buildings. The projection of households and the population until 2050 in the NUTS 3 regions is included in the distribution key. Assumptions about new construction, demolition, and renovation, as well as how utility energy demand is met by technology selection, is consistent with national modelling. As shown in Table 1, survey data from Census on single-family houses, gas demand, and living areas are used among other assumptions to distribute the national demand to respective NUTS regions.

3.3.2. Scenario Specification and Techno-Economic Data

The building stock and its heating-systems stock have dynamics resulting from the investment and refurbishment decisions. Investment cycles are dependent on the technological lifetimes of each component. All scenarios use similar assumptions: In order to accelerate building renovations, the technical lifetime of building components is reduced by 20% compared to their statistical values. The lifetime of fossil heating systems is similarly shortened, in order to accelerate the transition to renewable heating. In addition, new installations of fossil fuel boilers are not allowed in any scenario after 2025, except S5: In S5, new gas boilers are assumed to be H_2-ready boilers and, thus, they are allowed to be installed.

The market shares of the different heating systems depend on their TCO plus additional behavioral parameters. The (upfront) investment costs are the main share of TCO. Investment costs as euro per kW heat output depend on the size of the equipment, larger heating systems have lower specific costs. Further, we define different reinvestment cases, as most investments are actually replacing existing heating systems. Switching to a different system might entail higher costs than simply reinvesting in the same system again. Accordingly, we use three different cost curves for each heating system; one when installing the system in a new building (new), one when replacing the same type of existing system (similar), and one when replacing a different type of existing system (different). In scenarios S1 to S4, the focus is on the electrification of heating in buildings; and, therefore, 50% net subsidies are applied on top of the investment costs of heat pumps. Whereas net subsidies for heat pumps are assumed to be 30% in S5. Only in S5, replacing an existing gas boiler with a H_2-ready boiler is considered to be a “similar replacement”. In addition to this cost advantage, wider hydrogen infrastructure is available after 2035. This also affects the customers willingness to pay for hydrogen boilers in S5. **Figure 8** shows exemplary cost curves of important heating system options in case of a gas boiler replacement in a building in Germany in 2045. The two heat pump curves are costs after the respective subsidy. S2 is representative for all scenarios from S1 to S4. Similar cost curves are used for all countries and years.

Electrification is the main decarbonization method of heating in all scenarios. Only in S5, hydrogen will be available to

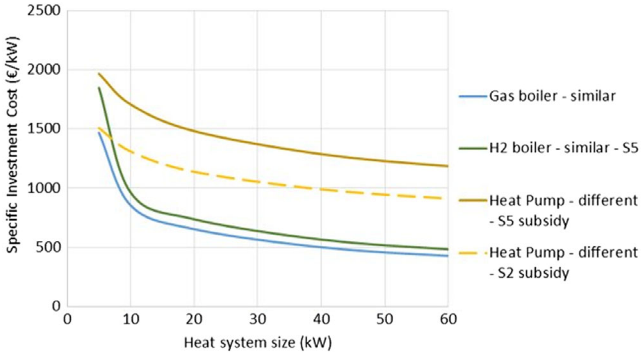

Figure 8. Investment cost curves of gas boiler replacement by heat pump, gas or hydrogen boilers as example for Germany in 2045.

individual buildings. It will already be available for households and buildings in isolated cases through a distribution network after 2030. The regional break-down of other energy carriers is estimated as follows. Regions close to steel and chemical industry sites will have access to a hydrogen distribution network first. Steel and chemical sites are expected to have a significant demand for hydrogen already before 2030, so that the regions and cities in the vicinity (same or neighboring NUTS 3 region) can be connected to the infrastructure that will be in place by then. It is assumed for the following years until 2040 that regions where natural gas is used disproportionately today have a distribution network that can be adapted and used for hydrogen.

District heating will be in place where it is located today, with new networks that are installed in regions with high heating demand and no gas infrastructure. Furthermore, biomass is assumed, where the other options are not available or not sufficient to cover the complete heating demand.

3.3.3. Technology Pathways

Transformation of the building stock is decisive on the decarbonization path. The renovation rate is a key indicator that allows to understand the ambition to refurbish buildings. We define the renovation rate as the floor area affected by above-threshold (>30% energy savings) renovations divided by the total floor area. In all scenarios, the resulting average renovation rate of all buildings in EU27 + UK between 2020 and 2030 is 1.4%. It increases to 1.7% between 2030 and 2050. In the past decade, this rate was estimated to be around 1% in the EU.[39]

Figure 9 shows the share of energy carriers in the heating EU27 + UK buildings according to building segment. The importance of district heating is relatively robust in each building segment across the scenarios. 15–18% of the heating demand in multifamily houses and service sector buildings are served by district heating in all scenarios. This share is around 10% in the single-family house segment in all scenarios. The district heating grid expansion is conservative in the modeling because high investment costs are assumed. By 2050, heat pumps serve as much as 75% of the total heating demand in single-family houses (S1–S4). While they reach a 64% share in this building segment in S5, multifamily house buildings show the highest range between the scenarios in terms of heat pump share. In S1 to S4, heat pumps serve 52% of the total heat demand in these buildings; while, in S5, they serve 33%. This shows that

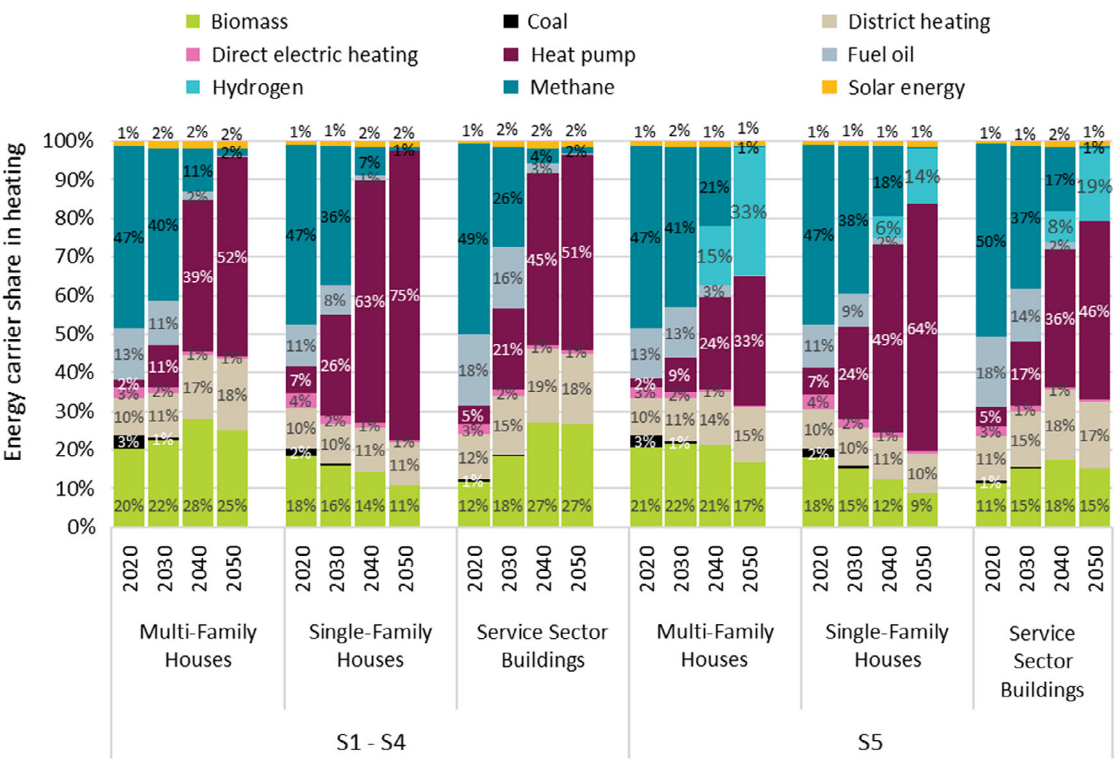

Figure 9. Share of energy carriers in heating of EU27 + UK buildings.

the hydrogen availability starting in 2030 mainly competes with the further take up of heat pumps in this building segment. In S5, hydrogen serves 33% of the total heating demand in multi-family houses. Roughly 50% of the heating demand in service sector buildings are served by heat pumps in all scenarios. Biomass is the second competing energy carrier in heating of multi-family houses and service sector buildings. In S1-S4, its share is around 25% in 2050 in these buildings; while, in S5, the share is between 15% and 17% due to the competition with hydrogen. Contrarily, its share in single-family houses is stable at around 10% by 2050, as heat pumps dominate the market.

In S5, today's gas distribution network is assumed to be adapted and used for hydrogen starting at around 2035. Consequently, countries that lead in hydrogen use in buildings by 2050 are Italy, the UK, Germany, France, and the Netherlands in S5. Detailed information on the hydrogen demand by country and region is available in the Supporting Information.

3.4. Energy System

3.4.1. The Enertile Model (Energy System)

The ENERTILE model is composed of two different parts, the renewable potential calculator 2.0 and the system optimizer. **The Renewable Potential Calculator 2.0** from Enertile was used to calculate the electricity generation potentials for five different technologies, rooftop PV, utility-scale PV, concentrated solar power (CSP), wind offshore, and wind onshore. The modeling process began with a worldwide model grid consisting of tiles with a constant area of 42.25 km^2. For example, in Germany, which includes its Exclusive Economic Zone, there are ≈10 000 tiles. Land use criteria were allocated into the tiles. A technology-specific use factor was given for each land-use category per technology (see Table A1). The factors used here are lower than the ones used in the long-term scenarios project.[40] Areas designated as protected areas categories Ia, Ib, and II according to the International Union for Conservation of Natural and Natural Resources (IUCN) were excluded.[41]

Real weather data were allocated on an hourly basis from the closest weather stations to each specific tile. For rooftop PV, utility-scale PV, and onshore wind, weather data come from COSMO-REA6, while data from ERA5 are used for CSP. For the case of COSMO-REA6, average weather data from the years 2010 to 2018 were used. For ERA5 just the year 2010 was used. The weather data are then used to calculate the possible generation in each tile. By integrating the weather data calculation with the available land, the maximum installable capacity is determined for each tile. Further details about the renewable potential calculator from Enertile are available in refs. [40,42,43].

The costs of each technology within the ENERTILE Renewable Potential Calculator 2.0 consider the system costs without any transmission costs or storage. Only wind offshore is an exception, where the costs are a function of the distance from the tile to the coast (4 € kW^{-1} pro km) and the water depth (12 € kW^{-1} pro m). So, the transmission lines to connect offshore windfarms with the coast are included in the generation costs. A summary of the CAPEX cost for each technology is presented in Section 3.4.2 and in the Appendix (see Table A2–A6). Further information about the costs can be found in ref. [40]. Similarly, different park effect losses (wind farm shading) are considered for wind onshore (63%) and wind offshore (43%) as we assumed a higher density of turbines in the wind offshore areas.

The tile results are grouped into regions, and the regional potentials are organized into potential steps based on specific costs. The steps are sorted from lowest to highest costs. Within each step, hourly time series data are collected and averaged over all tiles within a region. The regions are different from those used for the demand models in Section 3 and do not have NUTS-1 resolution. Some countries were merged into larger regions; for example, Spain and Portugal are combined in region IBEU_0. This aggregation is due to storage limitations for the computed time series of each tile and to optimize the computational cost of the system optimization. The final regions used in the renewable potential calculator and optimization in ENERTILE are detailed in Figure A1 in the Appendix.

The **ENERTILE system optimizer** is a cost minimization model that is used to model the supply side of the energy system. It simultaneously calculates the provision of electricity, heat, and hydrogen for given exogenous demands using the previously determined renewable potentials. The exogenous demands are calculated using the sector models and methodology described in Section 3. Its main objective is to find the least cost dispatch and expansion of the, generation, conversion, and distribution of these energy carriers in the given Enertile regions. The electricity supply aspect encompasses both conventional and renewable power generation technologies, including combined heat and power (CHP) plants, storage technologies, and electricity transmission networks. Regarding heat supply in heat grids, the model incorporates conventional and renewable heat generation technologies as well as heat storage solutions. Certain rules apply to the construction of new facilities. Plants built must be used until the end of their lives. At the end of the plants' lifetime, the land can be used again, but preferably with the same technology. The percentage of land that can be reallocated between technologies changes over time: in 2030, 10% (90% must be used for the same technology). Thereafter, the percentage increases by 10% every 10 years. For countries with a large number of installations, this is a disadvantage, as the model may not further optimize the land. Besides these assumptions, the demand characteristics applicable to each one of the scenarios are taken into account. Lastly, for the supply of hydrogen, ENERTILE considers electrolyzer technologies, hydrogen storage options, and hydrogen transport pipelines. The expansion and utilization of electricity and hydrogen transportation networks across model regions are simulated through net transfer capacities. Further details about the calculation of the different energy carriers are available in refs. [44–47].

ENERTILE operates with a high level technical, temporal, and spatial framework. In the conversion sector, the scenario calculations encompass the years 2030 to 2050 in 5 year steps, with hourly resolutions. The model integrates the expansion and deployment of infrastructures across all these years in a unified run. This implies that decisions made in 2030 have repercussions in subsequent years, assuming perfect foresight. The scope of the energy supply modeling extends to the European Union (EU), Norway, Switzerland, the UK, and the Balkan states in all scenarios. With the exception of Germany, which is divided into seven sub regions, each model region corresponds to one or more national states. The transmission of electricity and hydrogen among the regions as part of the system balance is considered by the model.

3.4.2. Scenario Specification and Technoeconomic Assumptions

Energy and Fuel Prices: Fuel prices and CO_2 prices play a key role as input parameters in energy system modeling. The magnitude and dynamics of fuel prices directly influence the expansion and operational choices of technologies within ENERTILE. All scenarios assume identical price trends for natural gas, hard coal, lignite, oil and imported hydrogen from non-European sources, and CO_2 certificates. The assumptions are shown in **Table 7**.

The price assumptions for fossil fuels are based on the World Energy Outlook 2021, Sustainable Development Scenario for Europe.[48] The prices for 2045 and 2050 are extrapolated as the IEA provides prices only until 2040.

In supply-side modeling, the CO_2 price is a key driver for reducing the use of fossil fuels. This price acts as a penalty for emissions resulting from the use of fossil fuels for electricity and heat generation. To achieve greenhouse gas (GHG) neutrality by the middle of the century, the CO_2 price in all scenarios rises gradually from €150/tCO_2 in 2030 to €350/t CO_2 in 2050.

ENERTILE considers the possible import of hydrogen from outside Europe in addition to the model´s endogenous hydrogen production and distribution within Europe. Two different routes for hydrogen imports may be used a pipeline from the MENA region (through Spain and Italy) and ships coming from Namibia (through the different sea ports in the region). The pipeline hydrogen import prices decrease from 97 to 71 € MWh^{-1}. Similarly, the ship import prices decrease from 117 to 93 € MWh^{-1}. The prices are calculated using own assumptions and a 2% interest rate.

Additional Constraints: The scenario design in ENERTILE includes several constraints that reflect the climate law and political objectives for Germany. The national expansion targets for the different RES are set in Enertile as minimum construction targets for the RES. The photovoltaic targets are in line with the national expansion targets set out in the EEG 2023. These are set at 400 GW in 2045 and 2050. The wind onshore targets are set at 115 GW in 2030 and 160 GW in 2040, as in the EEG 2023. An interim target of 157.7 GW is set for 2035. In 2045 and 2050, the targets are set at 160 GW. Similarly, offshore wind targets are set at 70 GW in 2045 and 30.5 GW in 2030. The construction target is set earlier, at 70 GW in 2040, in order to assess the full construction potential at an earlier stage. In addition to these assumptions, restrictions as goals on the production of offshore wind energy in other European countries have been incorporated. Besides these, a limit to the onshore potential that may be installed has also been applied as a cap.[40] The cap is set to prevent a total use of the wind onshore potential in specific regions. Table A2 and A3 in the appendix outline these restrictions.

For hydrogen, the objectives of the German National Hydrogen Strategy are taken into account, with a minimum construction target of 10 GW of electrolyzers in 2030. Regarding biomass, its use is progressively phased out till 2050 as there is a limit to the sustainable availability of biomass for the transformation sector. This allows biomass to be used in other sectors where its substitution represents a greater hurdle. Finally, the phase out of coal is considered by 2038.

Hydrogen Infrastructure: To link the hydrogen sector with the electricity and heat sectors, several components are needed, such as electrolyzers to convert electricity into hydrogen and hydrogen turbines to convert hydrogen back into electricity. The technoeconomic parameters for these components are given in **Table 8**. All scenarios in this context use these parameters without any variations.

In the context of hydrogen pipelines, a distinction is made between onshore and offshore pipelines. The conversion of the current natural gas network is taken into account and it is assumed that 70% of hydrogen pipelines will be converted from existing natural gas pipelines. The parameterization of the hydrogen pipelines is detailed in **Table 9**, where the parameters are based on ref. [49]. The electricity transmission is just considered among the regions that act as nodes. No transmission within the region is considered. The characteristics for the electricity network are given in ref. [50,51]. In addition to the infrastructure for the transmission and the generation of hydrogen, storage has an important role. Enertile considers the storage potential for the different regions. The use of salt caverns for hydrogen storage is considered according to ref. [52].

Renewable Energy Potentials: **Figure 10** depicts the generation potential and specific costs for electricity generation from renewable energies in Europe for 2030 and 2050 (see method in Section 3.4). In 2030, the lowest generation potential is observed at prices below 30 € MWh^{-1}. Most of this potential comes from utility-scale PV, mainly concentrated in southern Europe, especially the Iberian Peninsula, the Balkans, Italy and France. In addition, a smaller share is attributed to onshore wind, mainly located in Denmark, the UK, Ireland and Norway.

As the price threshold rises below 40 € MWh^{-1}, the share of onshore wind in the total potential increases, particularly in the regions mentioned above, as well as in France, northern Germany and the Baltic region. Notably, countries such as Italy and Austria have no onshore wind potential at this cost.

Furthermore, at costs below 50 € MWh^{-1}, both onshore wind and utility-scale photovoltaic generation potential becomes available in all countries and regions. The Iberian Peninsula stands out as the only region with rooftop PV potential below this cost.

Moving below 60 € MWh^{-1}, the rooftop PV potential extends beyond the Iberian Peninsula to other southern countries such as

Table 7. Fuel and CO_2 prices assumptions for the different scenarios and simulation years.

	Unit	2030	2035	2040	2045	2050
Natural gas	EUR/MWh	25	14	14	14	14
Hard coal	EUR/MWh	14	7	7	7	7
Lignite	EUR/MWh	4	4	4	4	4
Oil	EUR/MWh	29	29	28	27	27
CO_2	EUR/t	150	200	250	300	300
NON-EU hydrogen imports						
Pipeline (IT, ES)	EUR/MWh	97	87	76	73	71
Ship (Sea port)	EUR/MWh	117	107	98	95	93

Table 8. Parameters of hydrogen conversion technologies in all scenarios.

Technology	Parameter	Unit	2030	2050
Electrolyzer (low temperature)	Efficiency	%	70	70
	Specific Investment	€ $kWel^{-1}$	705	410
	Lifetime	Years	20	20
	Fix OPEX	€ $kWel^{-1}$	28,2	16,4
Hydrogen turbine	Efficiency	%	41	41
	Specific Investment	€$kWel^{-1}$	400	400
	Lifetime	years	30	30
	Fix. OPEX	€ $kWel^{-1}$	7.5	7.5
	Var. OPEX	€ $kWel^{-1}$	1.5	1.5
Hydrogen turbine (CHP)	Efficiency (el)	%	33	33
	Efficiency (CHP)	%	85	85
	Specific Investment	€ $kWel^{-1}$	730	730
	Lifetime	years	30	30
	Fix. OPEX	€ $kWel^{-1}$	30	30
	Var. OPEX	€ $kWel^{-1}$	2.7	2.7
Combined cycle hydrogen turbine	Efficiency	%	60	60
	Specific Investment	€ $kWel^{-1}$	775	750
	Lifetime	years	30	30
	Fix. OPEX	€ $kWel^{-1}$	11.3	11.3
Hydrogen boiler	Efficiency (CHP)	%	104	104
	Specific Investment	€ $kWel^{-1}$	50	50
	Lifetime	years	25	25
	Fix. OPEX	€ $kWel^{-1}$	1.8	1.8
	Var. OPEX	€ $kWel^{-1}$	0.9	0.9
Combined cycle hydrogen turbine (CHP)	Efficiency (el)	%	48	48
	Efficiency (CHP)	%	88	88
	Specific Investment	€ $kWel^{-1}$	950	950
	Lifetime	years	30	30
	Fix. OPEX	€ $kWel^{-1}$	30	30
	Var. OPEX	€ $kWel^{-1}$	3	3

Table 9. Parameters of hydrogen pipelines in all scenarios.

Technology	Parameter	Unit	2030	2050
Onshore hydrogen pipeline (new)	Specific Investment	€ $(kM\ MWH2)^{-1}$	945	945
	Fix OPEX	% of invest	1.4	1.4
Onshore hydrogen pipeline (refurbished)	Specific Investment	€ $(kM\ MWH2)^{-1}$	623	623
	Fix OPEX	% of invest	1.4	1.4
Offshore hydrogen pipeline (new)	Specific Investment	€ $(kM\ MWH2)^{-1}$	1,449	1,449
	Fix OPEX	% of invest	1.4	1.4
Offshore hydrogen pipeline (refurbished)	Specific Investment	€ $(kM\ MWH2)^{-1}$	753	753
	Fix OPEX	% of invest	1.4	1.4

Italy and the Balkan region. In addition, offshore wind potential begins to emerge in the UK at this cost level. Finally, below 70 € MWh^{-1}, offshore wind potential continues to expand in the UK, the Netherlands, Denmark and Germany.

Looking ahead to 2050, the distribution of potential energy sources remains similar across regions. Southern Europe continues to have a significant potential for low-cost utility-scale solar power, while northern Europe has a concentrated potential for onshore wind power. Over time, the cost of utility-scale photovoltaic (PV) energy is falling faster, increasing the potential for utility-scale projects at lower costs. For example, projections suggest that by 2050, utility-scale PV could generate 155 terawatt hours (TWh) at a cost of less than 20 € MWh^{-1} and 3070 TWh at a cost of less than 30 € MWh^{-1}. For further information about the regional location, please refer to Figure A2 and A3 in the appendix.

4. Results

In the following sections, we show and discuss main results for the different components of Europe's future hydrogen system starting with the potential future hydrogen demand in industry, transport and buildings. Then, we show where hydrogen is produced in Europe and in how far imports from other world regions are needed, before we show the resulting pan-European hydrogen transport. Finally, we discuss resulting needs of hydrogen as energy storage, before we give an overview of the resulting hydrogen system.

4.1. Hydrogen Demand

Resulting energy demands from industry, buildings and transport sector are summarized in **Figure 11**. This includes both final energy demand and feedstock used for the production of chemical products like ethylene or ammonia. **Figure 12** zooms into resulting hydrogen demands while a more detailed table is available in the Supporting Information.

The energy demand of EU27 + UK accounted for about 13 600 TWh in 2020, the base year of the analysis was heavily dominated by fossil fuels that had a share of about 67%. All five scenarios show a reduction of the total energy demand towards 2050 ranging between 31% and 35%. This reduction of about 4200 to 4700 TWh yr^{-1}. is mainly driven by efficiency gains in transport and buildings. If ambient heat is not accounted for, a reduction of up to 6000 TWh is observed. More specifically, in buildings the heat supplied by electric heat pumps increases from 5% to 60% by 2050. Similarly, as electric vehicles diffuse fast and widely electric passenger cars account for about 100% of the car fleet by 2050.

As a direct consequence, electricity demand is sharply increasing and growing by a range of 44% to 74% across all scenarios. Scenario S1 shows the highest increase with additional 1900 TWh yr^{-1}. by 2050 compared to 2020. Even scenario S5 with the highest share of hydrogen in all sectors experiences a strong increase in electricity use. By 2050, electricity demand ranges between ≈3700 to ≈4400 TWh across the scenarios.

The role of hydrogen increases in importance from scenario S1 towards scenario S5 and mainly competes with electrification and biomass. Scenario S1 includes about 300 TWh of hydrogen by 2050 (not accounting for its derivatives and synfuels). However, in this scenario, the EU27 + UK imports large quantities of CO_2-neutral feedstocks, accounted for as synfuels in

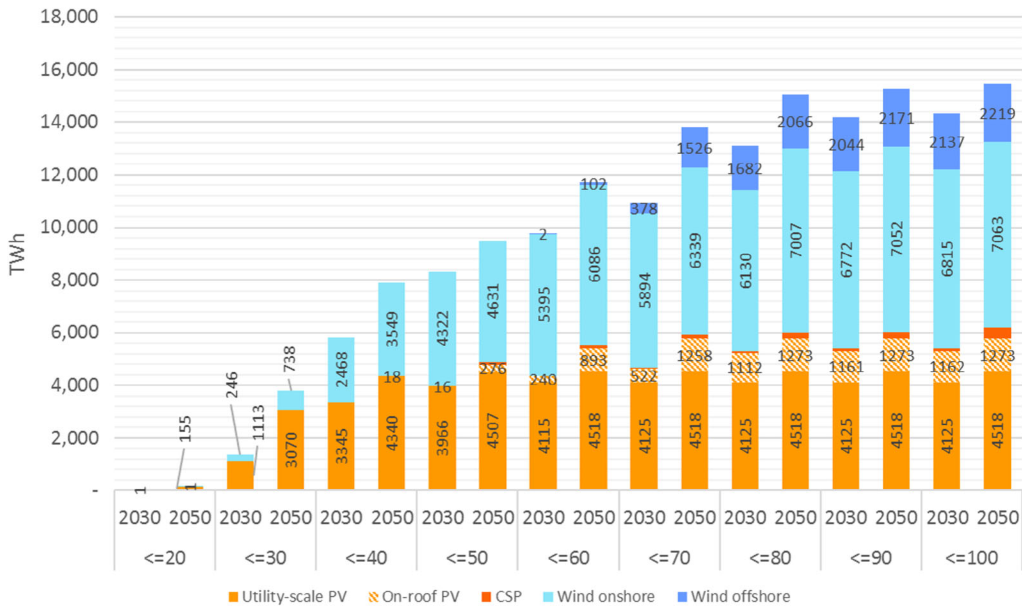

Figure 10. Potential and costs for electricity generation in Europe in 2030 and 2050 from renewable energy sources.

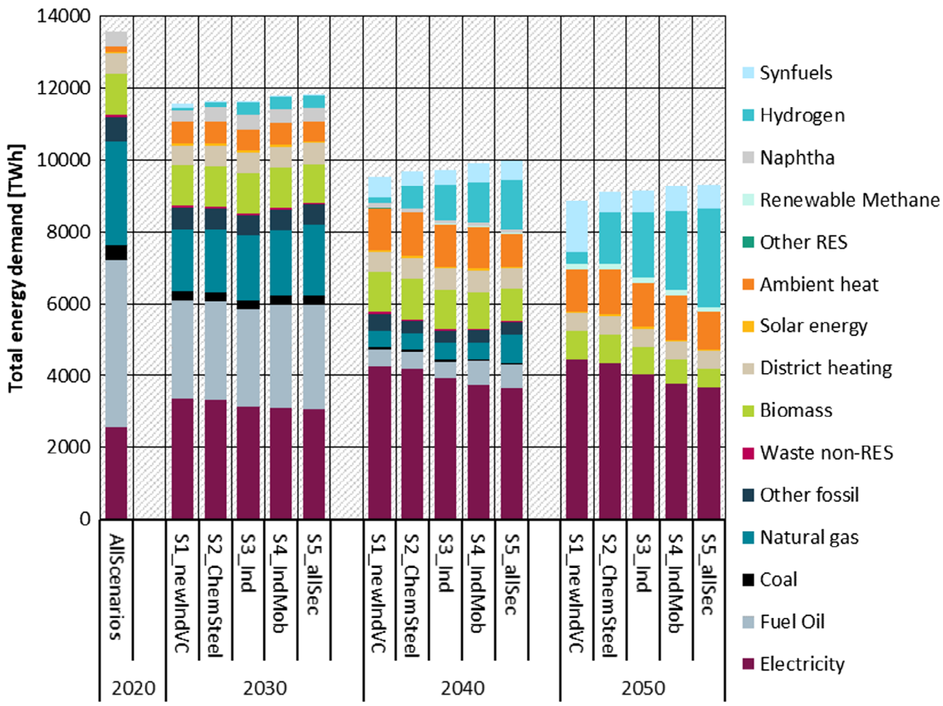

Figure 11. Resulting total final energy demand from buildings, industry and transport plus feedstocks for chemicals, EU27 + UK.

Figure 11. The total demand for such synfuels is about 1400 TWh by 2050 in scenario S1. In other scenarios it ranges between 600 and 700 TWh and is mainly used for long-distance transport.

Other important energy carriers in 2050 are ambient heat, biomass and district heating. Ambient heat is used in heat pumps in the buildings sector and biomass supplies some industries where biogenic production residues are used.

Figure 12 depicts insights which sectors and applications have a demand for hydrogen. Here, we show the complete hydrogen demand by adding the conversion sector (i.e., the central production of electricity and heat) on top of the final energy demand and feedstocks shown in Figure 11.

The scenarios show a huge difference in long-term hydrogen demand and range from 690 to 2800 TWh by 2050. Looking at

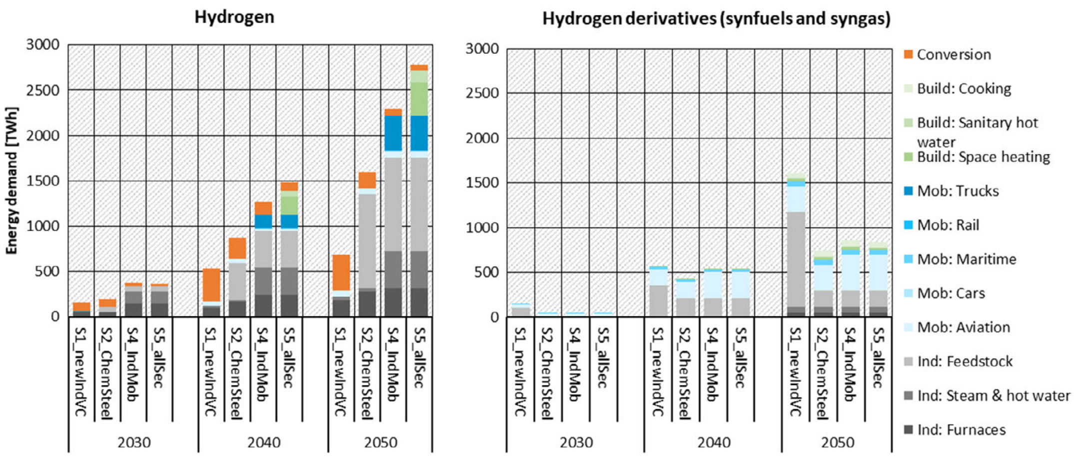

Figure 12. Demand for hydrogen and derivatives from industry, buildings, transport and conversion (electricity and heat supply) sectors, EU27 + UK.

the individual sectors and end-uses reveals that across all scenarios, industry will be the main user. There is a relatively robust demand of about 190 (S1) to 315 TWh (S3, S4, S5) for high temperature process heat uses in industry. These are located in metal and mineral processing and use highly specialized furnaces at high temperatures and high energy densities. Today the main energy carrier is natural gas. Electrification can be possible in the future, yet it also still faces major challenges and requires substantial reinvestment. If feedstocks are fully produced in Europe based on climate neutral hydrogen, this will become the main use of hydrogen with about 1000 TWh by 2050 (S2–S5). This assumes that ethylene and other so called HVCs, methanol and ammonia are produced from climate-neutral hydrogen replacing naphtha and natural gas as main feedstocks. If, however, the global value chain for these basic chemical products will materialize in a different way and large quantities of climate neutral interim products like chemical feedstocks or iron sponges are imported instead of produced within the EU, overall hydrogen demand can drop to a minimum of 700 TWh by 2050 as a total across all sectors (S1). Thus, the demand for future climate-neutral value chains of a few basic chemical products will highly affect the overall hydrogen demand. At the same time, it is yet very uncertain how these value chains will evolve in the future.

On the other hand, if also the industrial steam generation will use large quantities of hydrogen instead of direct electrification, this can add another 400 TWh by 2050 (difference from S2 to S3). Here, hydrogen will mainly replace direct electrification via electric boilers, which are already available and applicable on an industrial scale. It is yet very uncertain whether electrification or hydrogen will dominate the future supply of process steam in industries like pulp & paper production and chemicals. Next to site-specific conditions (e.g., access to either electricity at sufficient capacity or hydrogen), the energy carrier prices strongly influence the outcome.

The scenarios S4 and S5 explore potential additional hydrogen demands beyond the industry sector. Scenarios S1 to S3 hardly have any direct use of hydrogen in transport except domestic flights that account for about 60 TWh by 2050. Other transport modes like electric cars and heavy-duty vehicles are dominated by direct electrification. Synfuels based on hydrogen, however, play an important role in international aviation and shipping with a total of about 450 TWh by 2050 (not included in Figure 12). The main uncertainty in the transport sector is in the competition between electrification and hydrogen for long-haul trucks. Here scenarios S4 and S5 show an additional hydrogen demand of about 380 TWh by 2050 compared to scenarios S1–S3. See Section 3.1.2 for further details.

Also, for heating of individual buildings, hydrogen is under discussion in some member states. If hydrogen becomes available in the distribution grid and can compete economically with electric heat pumps and district heating, it can add a substantial demand. Assuming the possibility that in scenario S5, additional hydrogen demand by 2050 is 500 TWh, and still assuming that the heat supply of buildings will be dominated by heat pumps.

In both 2030 and 2050, the conversion sector (electricity and heat supply) exhibits greater involvement in the overall demand when the endogenous demand is lower in other sectors. In 2030 it ranges from 100 TWh in S1 to 28 TWh in S5. The difference is even higher in 2050 when it ranges from 389 TWh in S1 to 61 TWh in S5. The reasons behind this are further explained in Section 4.2.

By 2030, all scenarios show only a marginal share of 12 to 23% of the 2050 hydrogen demand to be deployed and total demand in 2030 for EU27 + UK ranges between 160 and 370 TWh. Given the challenging uptake of needed infrastructure, this can be considered optimistic. Industry and the energy transformation sector (conversion sector) have the highest demand by 2030. These are mainly large individual sites that will be connected to the hydrogen transportation network. In addition, the scenarios assume a demand of 42 (S2S5) to 145 TWh (S1) of synthetic fuels based on hydrogen by 2030. The resulting total demand for hydrogen, including its derivatives, ranges between 204 (S1) and 383 TWh (S5), which is substantially below the 2030 target of about 665 TWh announced by the EU in its REPowerEU[1] plan (equals 20 million tons of H_2).

The regional demand patterns for hydrogen exhibit variations across different scenarios and sectors of usage (see **Figure 13**). The utilization of hydrogen differs significantly depending on the specific sector structure within each region. If basic green materials like climate neutral iron sponge, ammonia, methanol and HVCs, will be produced at their current locations as

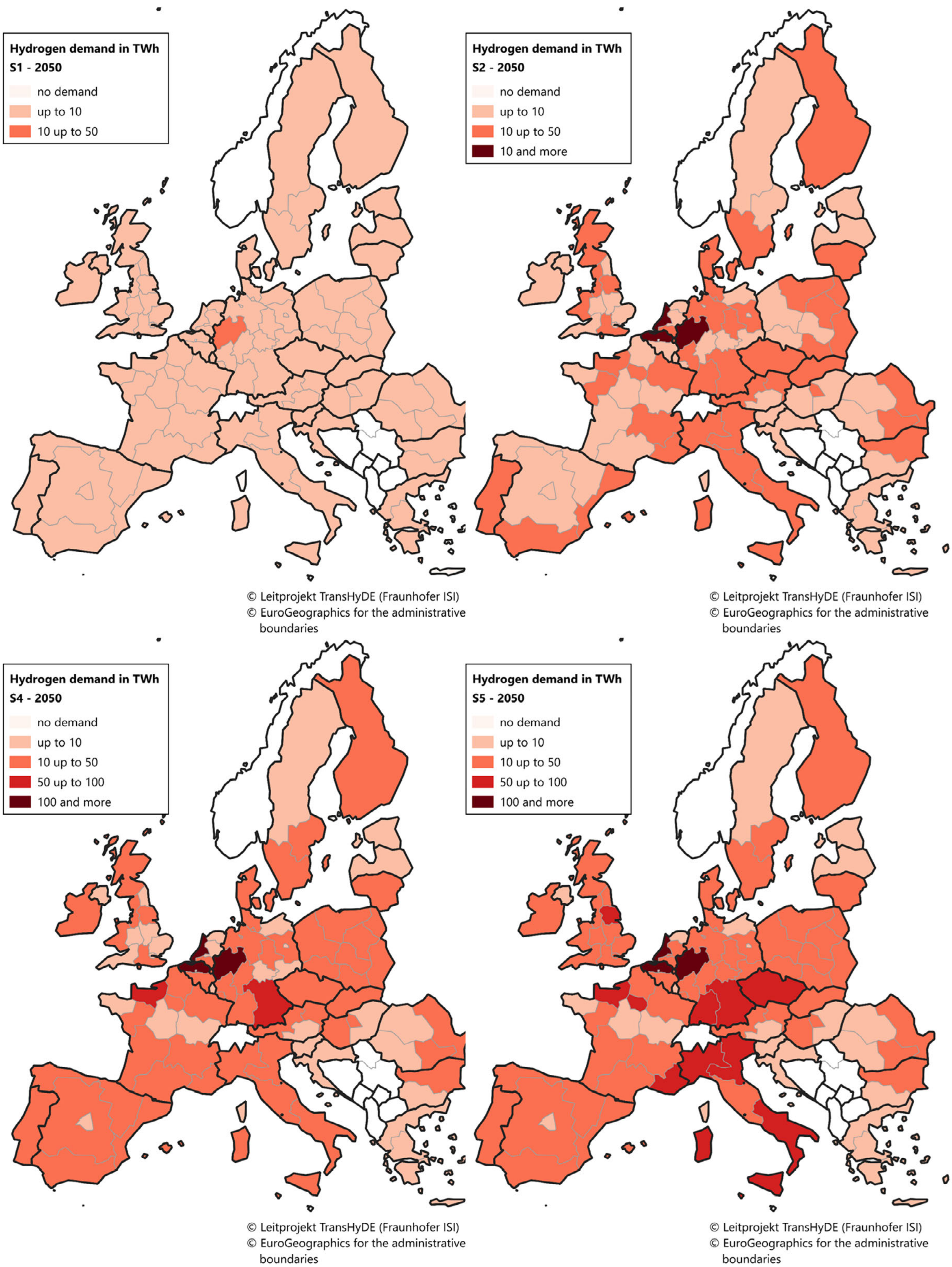

Figure 13. Resulting hydrogen demand of industry, transport and buildings (excluding conversion sector) by NUTS 1 region and scenario in comparison.

assumed in scenarios S2–S5, numerous regions showcase a substantial demand for hydrogen, surpassing 10 TWh by 2050. This indicates a significant requirement for hydrogen in these regions. Particularly, the chemical/steel cluster in Northwest Europe stands out as a hot spot, with three regions displaying a demand exceeding 100 TWh for hydrogen. These regions are North-Rhine Westphalia in Germany (104 TWh), West Netherlands (139 TWh), and North Belgium (Flanders) (103 TWh). The demand for hydrogen in these regions is primarily driven by the transformation towards hydrogen-based green basic materials. This includes the transition of integrated steelworks to DRI, steam crackers to Methanol to Olefins (MtO), and the adoption of green hydrogen as a feedstock for ammonia production. One additional factor contributing to concentrated hydrogen demand is its use in industrial process heat, which primarily focusses on a few regions. Moreover, the usage of hydrogen in the transport sector contributes to a wider demand across various regions in scenarios S4 and S5. Additionally, the utilization of hydrogen in buildings in scenario S5 leads to a broader adoption of hydrogen across NUTS 1 regions, particularly in areas with high natural gas consumption. As a result, in scenario S5 most regions are projected to have hydrogen demands exceeding 10 or 20 TWh in 2050, with several regions even surpassing 50 TWh. It is worth noting that despite the widespread diffusion of hydrogen technologies across all sectors, the concentrated demand in the industrial sector remains the primary driver for high local demands.

4.2. Hydrogen Production and Import

4.2.1. Electricity Generation

Figure 14 shows the electricity generation in Europe for different scenarios in 2030 and 2050. In 2030, the total electricity generation shows similar levels in all scenarios at around 4100 TWh. Renewables dominate the generation mix, with onshore wind being the most widely deployed technology ranging from 1182 to 1244 TWh in scenarios S1 to S5. Onshore wind generation increases in line with higher hydrogen demand, possibly due to the favorable full load hours of wind, allowing for more efficient hydrogen production. The total installed capacity of both onshore and offshore wind ranges from 628 to 644 GW in 2030 compared to 255 GW total installed wind capacity in 2022.[53] To reach these capacities by 2030 around 48 GW would need to be installed annually - a substantial increase compared to the newly installed quantity in 2022 of about 19 GW. Photovoltaic (PV) generation increases substantially to about 790 TWh by 2030 in all scenarios. Nuclear generation is set exogenously in the model. These demands translate to a PV capacity that ranges from 679 to 690 GW in the EU compared to about 209 GW in 2022.[54] The annual installed capacity required to reach this value is about 60 GW per year, which is about 1.5 times the newly installed capacity in 2022.

In 2050, the scenarios exhibit larger differences. Similar to the 2030 case onshore wind is the dominant technology, ranging from 2300 to 3279 TWh, in response to the growing hydrogen demand. PV generation also shows a significant spread from 1617 TWh (S1) to 2752 TWh (S5). Wind offshore generation increases again following model constraints. As hydrogen demand increases from scenarios S1 towards S5, wind generation shows smaller increases compared to PV generation, possibly because the best wind onshore potentials have already been exploited. Both technologies show a significant increase compared to 2030. The required annual capacity expansions range from 37 to 87 GW for PV and from 25 to 42 GW of wind until 2050.

The results underline that in all scenarios whether including extensive or restricted use of hydrogen - a significant expansion

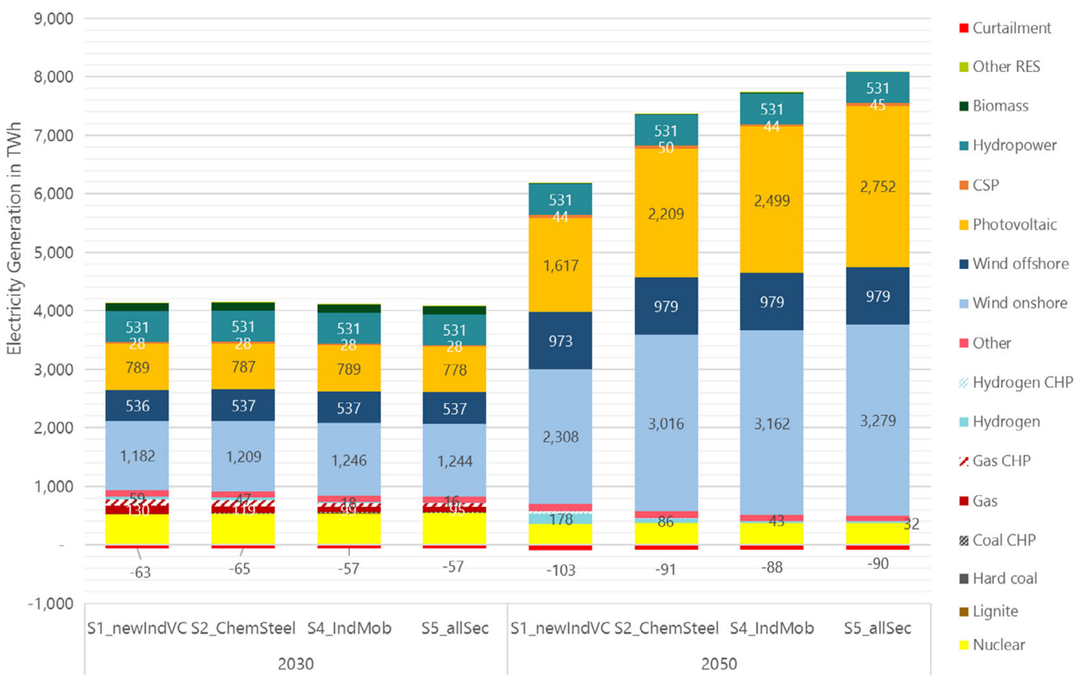

Figure 14. Electricity Generation in Europe for the different scenarios in 2030 and 2050.

of current wind and PV capacity is needed to meet the expected future increase in electricity demand.

4.2.2. Hydrogen Balance

Figure 15 shows the hydrogen balance for Europe in both 2030 and 2050. The demand comprises demands from industry, buildings and transport, along with endogenously calculated demand from the conversion sector, i.e., electricity and district heating generation. The supply consists of domestically produced electrolysis and imports from non-European sources. The details about the hydrogen demand are given in Section 4.1.

In all scenarios, electrolysis within the EU dominates the production of hydrogen. Imports from outside of Europe contribute only marginally in 2030, with S4 and S5 requiring ≈38TWh. However, by 2050, their role becomes more significant, particularly in S4 and S5, accounting for 112 and 290 TWh, respectively. Even in scenario S1, where the lowest exogenous demand is present, imports from outside of Europe still play a role with 29 TWh. All imports are supplied via pipeline from North Africa. The model can also choose ship imports to various locations, but these are only available at higher costs (see Section 3.4.2). In addition to the imports of hydrogen, we assume that all hydrogen derivatives like synfuels and syngas are imported (see quantities in Section 4.1). By 2050, these range from 600 (S2) to 1400 TWh (S1) across the scenarios.

The hydrogen demand for the conversion sector (electricity and central heat generation) is endogenously included within the system optimization. Interestingly, the resulting hydrogen demand from the conversion sector is higher in scenarios with lower exogenous hydrogen demand from industry, buildings and transport. Scenario S1 has the highest demand from the conversion sector in both 2030 and 2050, reaching 100 and 391 TWh respectively. This is explained by the fact that scenarios with lower hydrogen demand also have a lower total demand for electricity and, thus, there is a greater abundance of low-cost renewable electricity available for hydrogen production in the conversion sector. In addition, there is a high system value of hydrogen as seasonal energy storage, which also drives the high use in the conversion sector in S1.

4.2.3. Electrolyzer Locations

Figure 16 shows the installed electrolyzer capacity within each Enertile region for the year 2030 in different scenarios. The total installed capacity follows an upward trend, starting at 54 GW in S1 and reaching 107 GW in S5. In all scenarios the locations of electrolyzers follow the resource countries which have a lot of wind. In particular, Northern Germany has a significant installed capacity ranging from 14 GW in S2 to 23 GW in S5. This exceeds the given restriction for Germany of a minimum of 10 GW of electrolyzers by 2030. The UK and Ireland (15 GW in S1 and 21 in S5), France (6 GW in S1 and 16 in S5) and Norway (4 GW in S1 and 15 GW in S5) likewise have significant installed capacities.

By 2030, hydrogen demand is mainly met by electrolyzers located in regions with low wind levelized cost of electricity (LCOE) in all scenarios (see the wind-specific cost map in the Supporting Information). According to our calculations (Figure 10), PV electricity has the lowest LCOE in Europe, however, the high full load hours (FLH) of wind in Europe result in a lower levelized cost of hydrogen (LCOH).

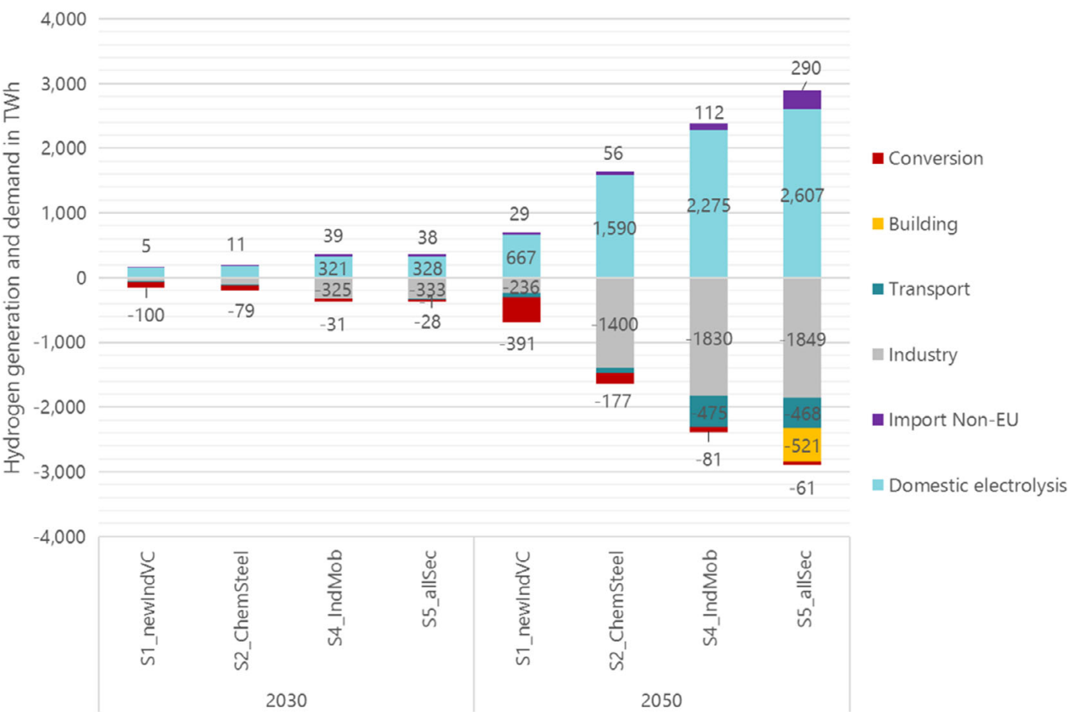

Figure 15. Demand and supply of hydrogen in Europe for 2030 and 2050 by scenario.

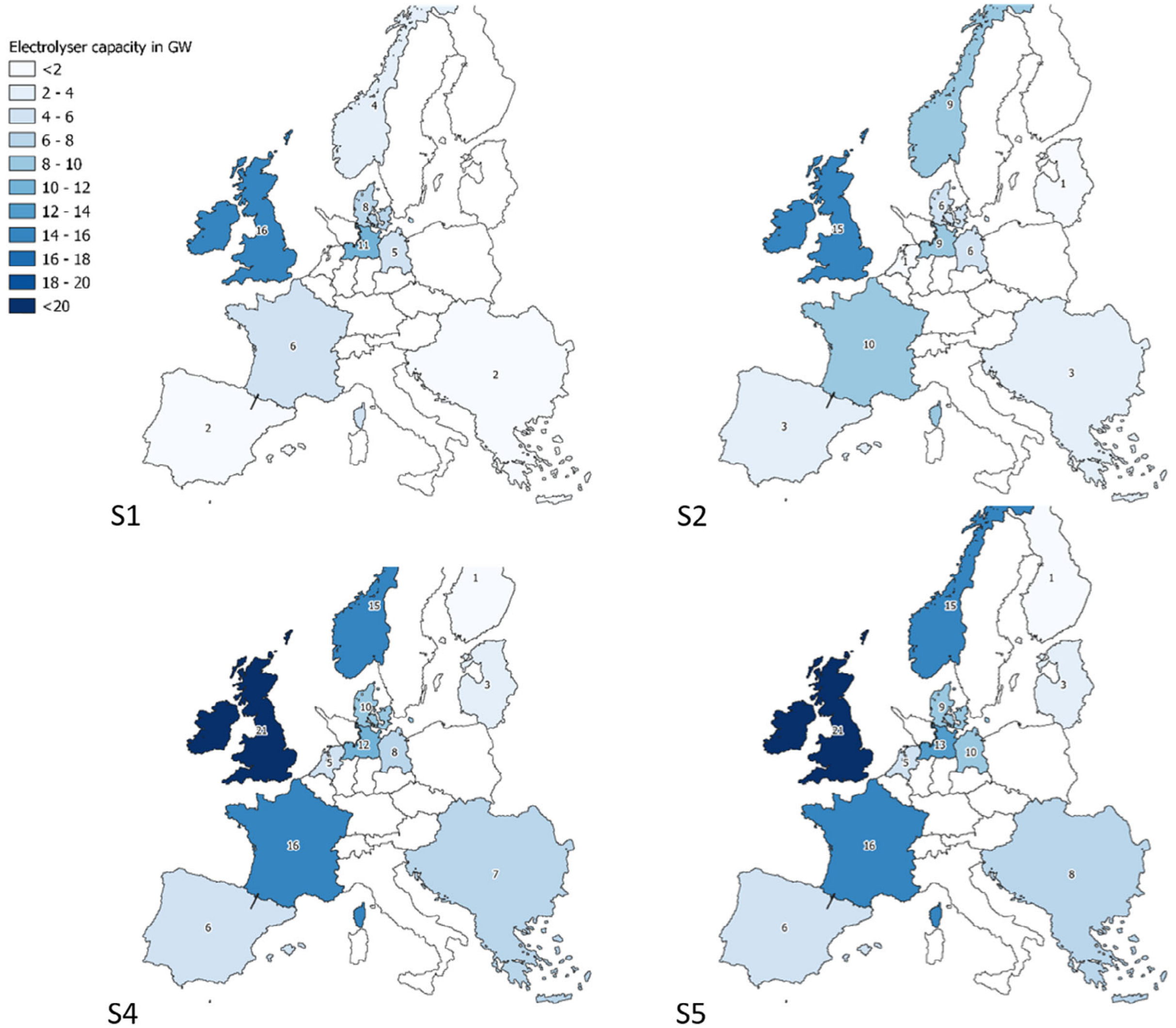

Figure 16. Electrolyzer installed capacity within each Enertile region in 2030 in GW (data available in Supporting Information).

Figure 17 shows the installed electrolyzer capacity in GW for the year 2050. A significant increase is observed in all scenarios compared to 2030. In S1, the largest electrolyzer capacities are presently installed in France, the UK, Ireland, and Northern Germany, regions identified for their abundant wind resources. However, as the demand for hydrogen rises in scenarios S2 to S5, there is a notable increase in electrolyzer installations, particularly in southern Europe. This expansion is primarily observed in the Iberian Peninsula, the Balkans, and Italy.

This shift indicates a transition toward utilizing solar resources, as new PV installations become necessary in southern Europe to meet the growing hydrogen demand. This trend is particularly pronounced in the Iberian Peninsula, where electrolyzer capacity escalates from 29 TWh in S1 to 207 TWh in S5, and in Italy, where it rises from 13 TWh to 87 TWh between S1 and S5. Both regions have large potentials for utility-scale PV.

In all scenarios, electrolyzer capacities follow the overall picture that they are mainly deployed on the outskirts of Europe and only to a small degree in the center of Europe. Mainly driven by attractive RES potentials but also by high energy densities from industry and population density in central Europe.

4.3. Cross-Country Hydrogen Transport

Pan-European hydrogen pipeline networks can effectively compensate for regional variations in both hydrogen demand and the production on a supra-national level. **Figure 18** shows the cost-optimal pan-European transport of hydrogen under different scenarios by 2030. In scenario S1, the main hydrogen flow originates from the UK and Ireland, supplying central Europe with 40 TWh. In general, the main hydrogen flows originate in Northern Europe and reach the demand centers in Central Europe. The amount of hydrogen transported from Norway to central Europe increases from 13to 50 TWh in response to the increased demand for hydrogen from scenarios S1 to S5. In contrast, the hydrogen supply from the UK and Ireland decreases from 40 TWh in S1 to 22 TWh in S4, probably due to increased

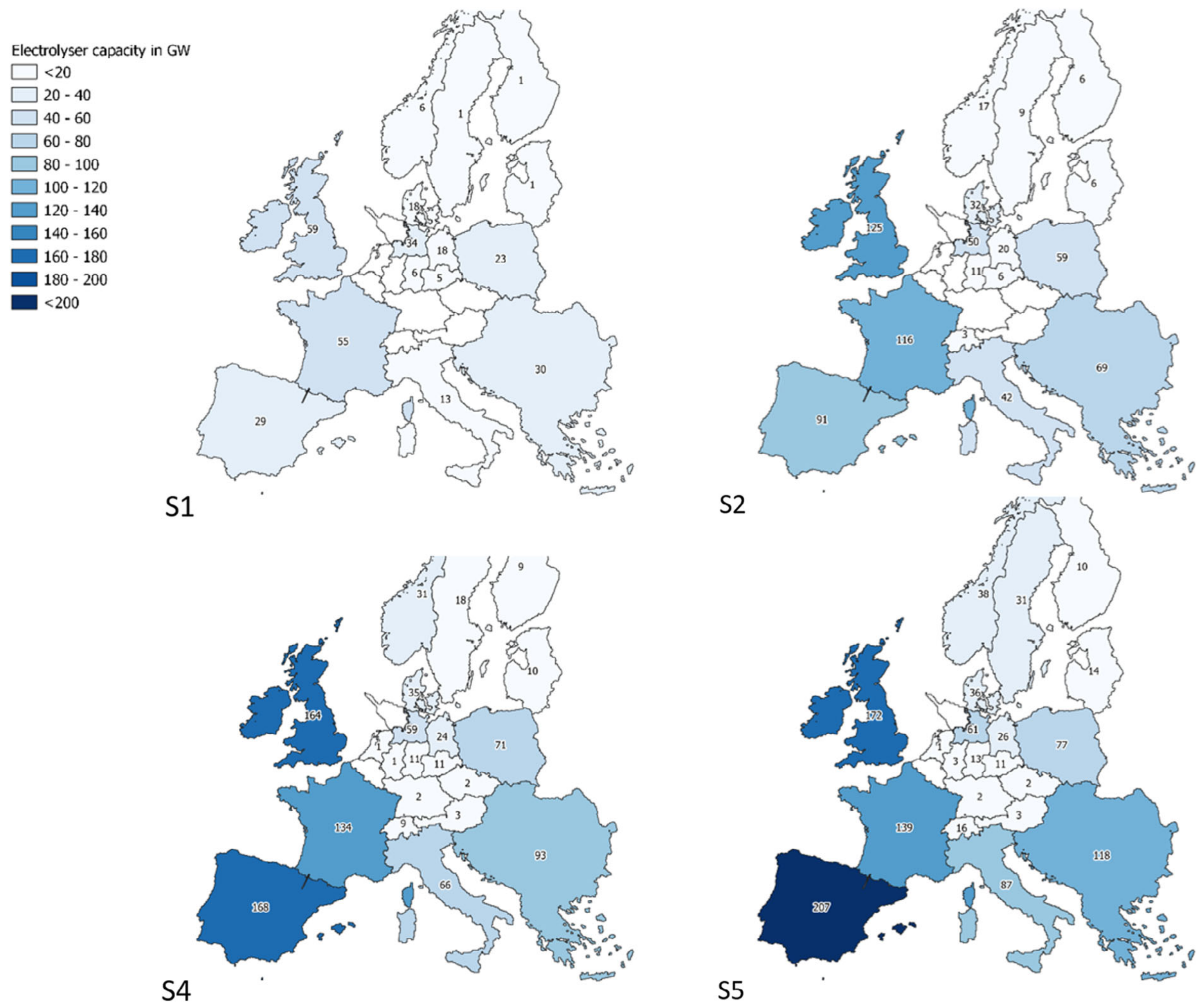

Figure 17. Electrolyzer installed capacity in 2050 in GW (data available in supplementary material).

domestic hydrogen demand. However, the flow of hydrogen increases again in scenario S5, reaching 24 TWh.

The larger arrows in the figure indicate pipeline imports from the MENA region through the Iberian Peninsula and Italy. In all four scenarios, some hydrogen import is part of the cost-optimal system, mainly through the Italian pipeline link. Hydrogen imports peak at 39 TWh in scenario S4. A table with the trade flows between all regions is included in the Supporting Information.

Figure 19 presents the intra-European transport of hydrogen in 2050. Similar to the situation in 2030, hydrogen flows from both northern and southern regions of Europe to central Europe, where the demand centers are located. In S1, the Iberian Peninsula is initially an importer of hydrogen. In S2, however, it becomes an exporter, supplying 72 TWh to France. France in turn acts as a hub for the distribution of hydrogen to various Central European countries. This pattern continues in S4 and S5, but with higher volumes of hydrogen flows. In S5, hydrogen flows from the Iberian Peninsula to France peak at 235 TWh using its high PV potential. The UK and Ireland are consistently large hydrogen exporters in all scenarios. Their exports range from 76 TWh in S1 to 267 TWh in S4 and decrease slightly to 191 TWh in S5, despite having a higher electrolyzer capacity due to larger domestic hydrogen use.

Hydrogen imports from outside Europe remain part of the cost-optimal energy system in all cases. They range from 29 TWh in S1 to 290 TWh in S5. The main transport route is through the Italian pipeline link, except in S5 where 16 TWh are directed to the Iberian Peninsula A table with the trade flows between all regions is included in the Supporting Information. Note that in additional substantial imports of hydrogen derivatives are assumed to range from 600 (S2) to 1400 TWh (S1) by 2050.

4.4. Hydrogen Production and Demand Comparison

The hydrogen trade between countries is directly driven by the demand and supply balance in each country. **Figure 20** compares the hydrogen generation and demand in the different regions. In scenario S1, regions such as the UK and France have the largest hydrogen surpluses (the difference between production and demand). Despite increasing demand, the UK maintains a significant surplus due to its expanding production capacity. However, this surplus decreases in relative terms as demand

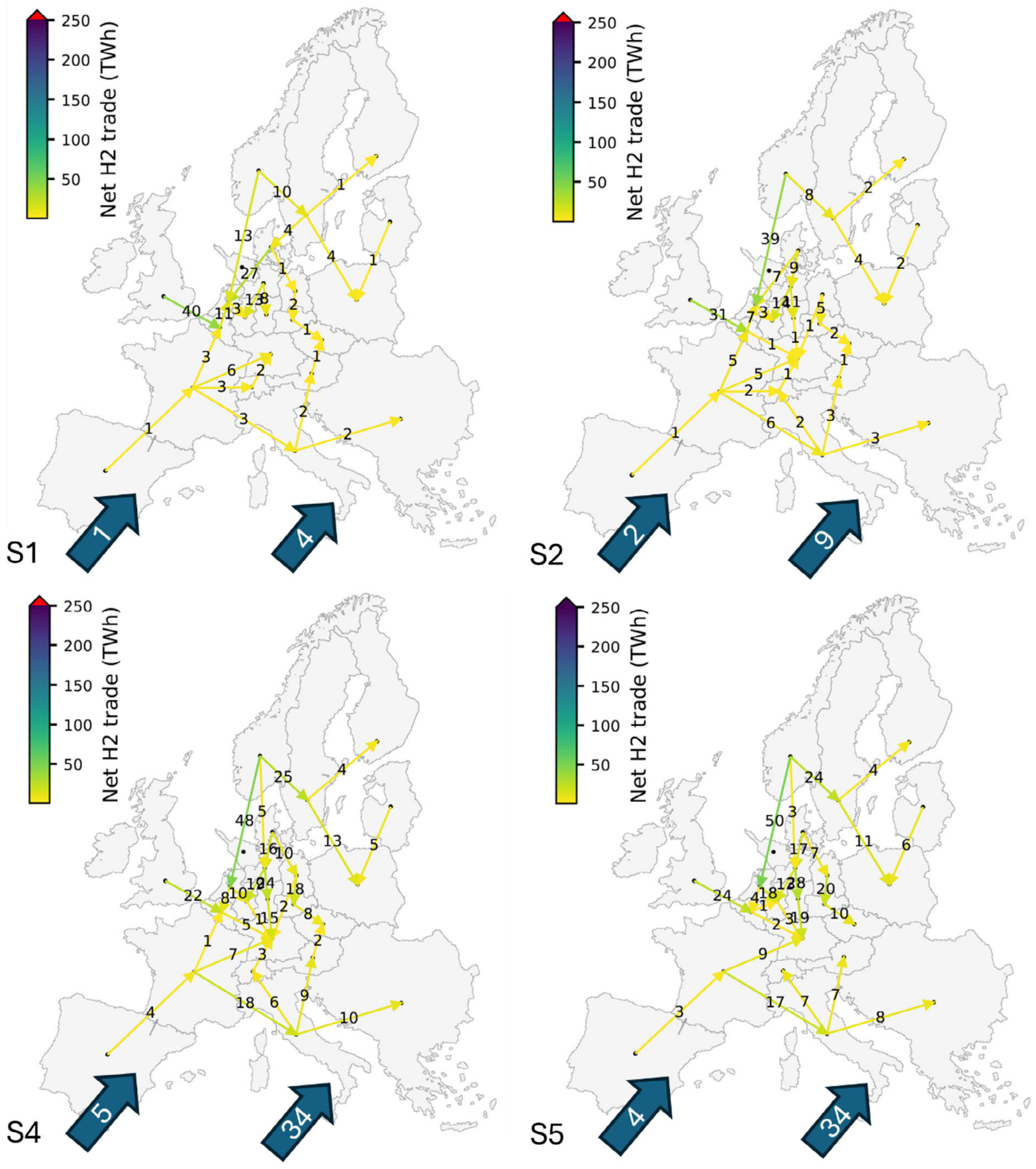

Figure 18. Net hydrogen flows between countries in 2030 including imports from non-European countries.

outstrips production growth. Similarly, France has a significant surplus in S1, which decreases significantly as demand grows faster than production.

In all scenarios, production also increases in the outer regions of Europe, especially in Norway, as demand increases. In contrast, Central Europe shows a clear hydrogen deficit, with most countries showing a deficit with demand exceeding domestic generation, especially Germany, the Netherlands, Belgium and Luxembourg. Italy also has a significant hydrogen deficit.

Comparing electrolyzer capacity in Scenario S5, Spain has the largest electrolyzer capacity of 207 GW (Figure 17), but produces less hydrogen than the UK and Ireland. This difference is due to the lower full load hours of photovoltaic technologies, the main renewable energy source in the Iberian Peninsula, compared to the wind capacity used in the UK. Similarly, Italy has a significant number of electrolyzers installed in S5, but the predominance of utility-scale PV limits the hydrogen production capacity. Overall, in 2030, the flows

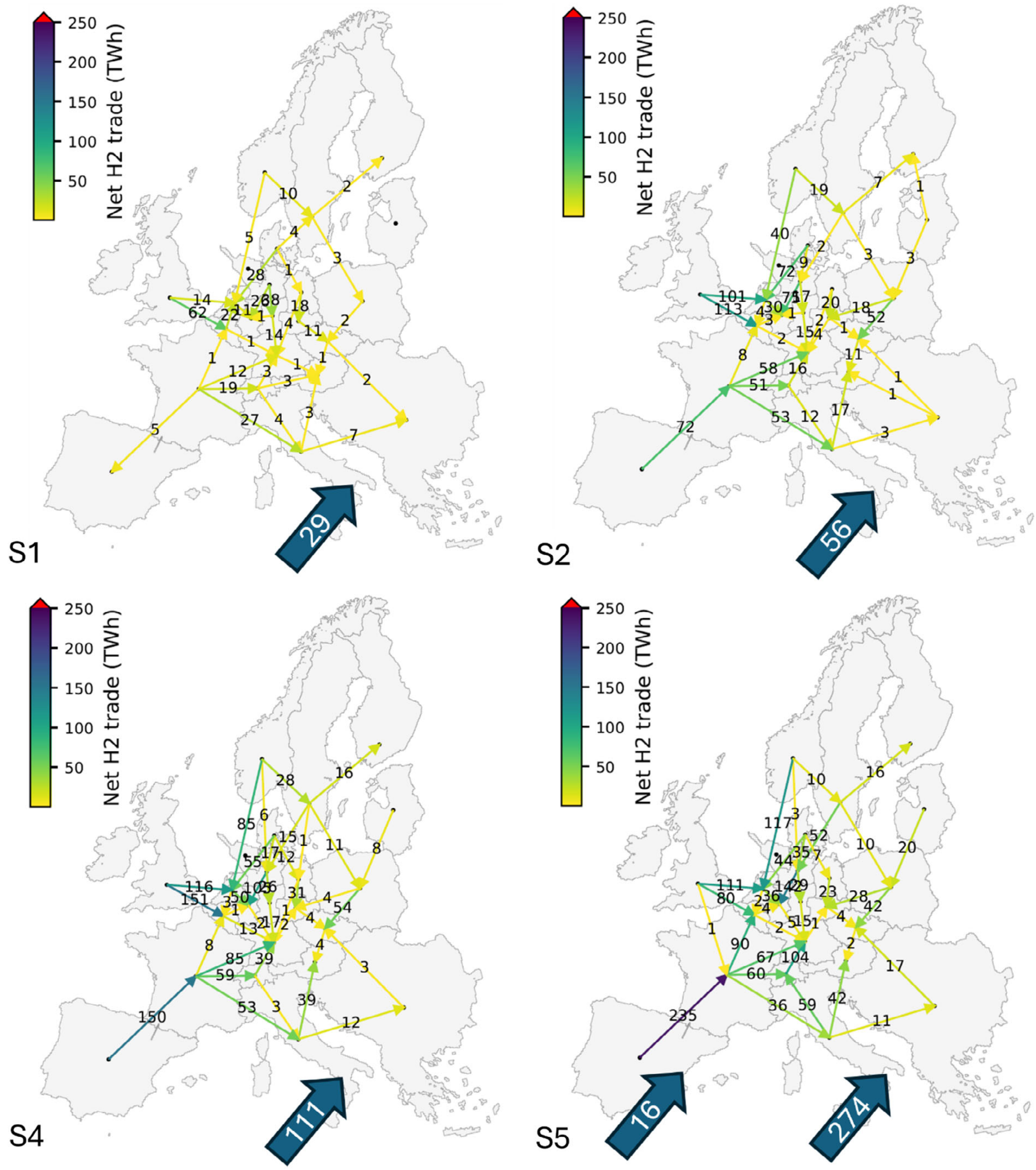

Figure 19. Net hydrogen flows between countries in 2050 including imports from non-European countries.

of hydrogen go from wind-rich regions to the demand centers. In 2050 as the amount of hydrogen demand increases, the PV-rich Iberian Peninsula becomes the main hydrogen exporter to the demand centers.

4.5. Hydrogen Storage

Figure 21 shows the projected hydrogen storage cycle for Europe in 2050. In all scenarios, there is a single storage cycle per year, correlating with the availability of wind in the fall and PV in summer. This cycle ensures the availability of hydrogen for winter use but also exhibits short-term reactions to balance wind and PV generation. Interestingly, among the scenarios, S1 has the highest storage requirement of 297 TWh, followed by S2 with 269 TWh. Conversely, S4 has the lowest storage requirement of 215 TWh. S5, which takes into account the seasonal demand of the buildings sector, shows an increase in hydrogen storage to 232 TWh compared to S4.

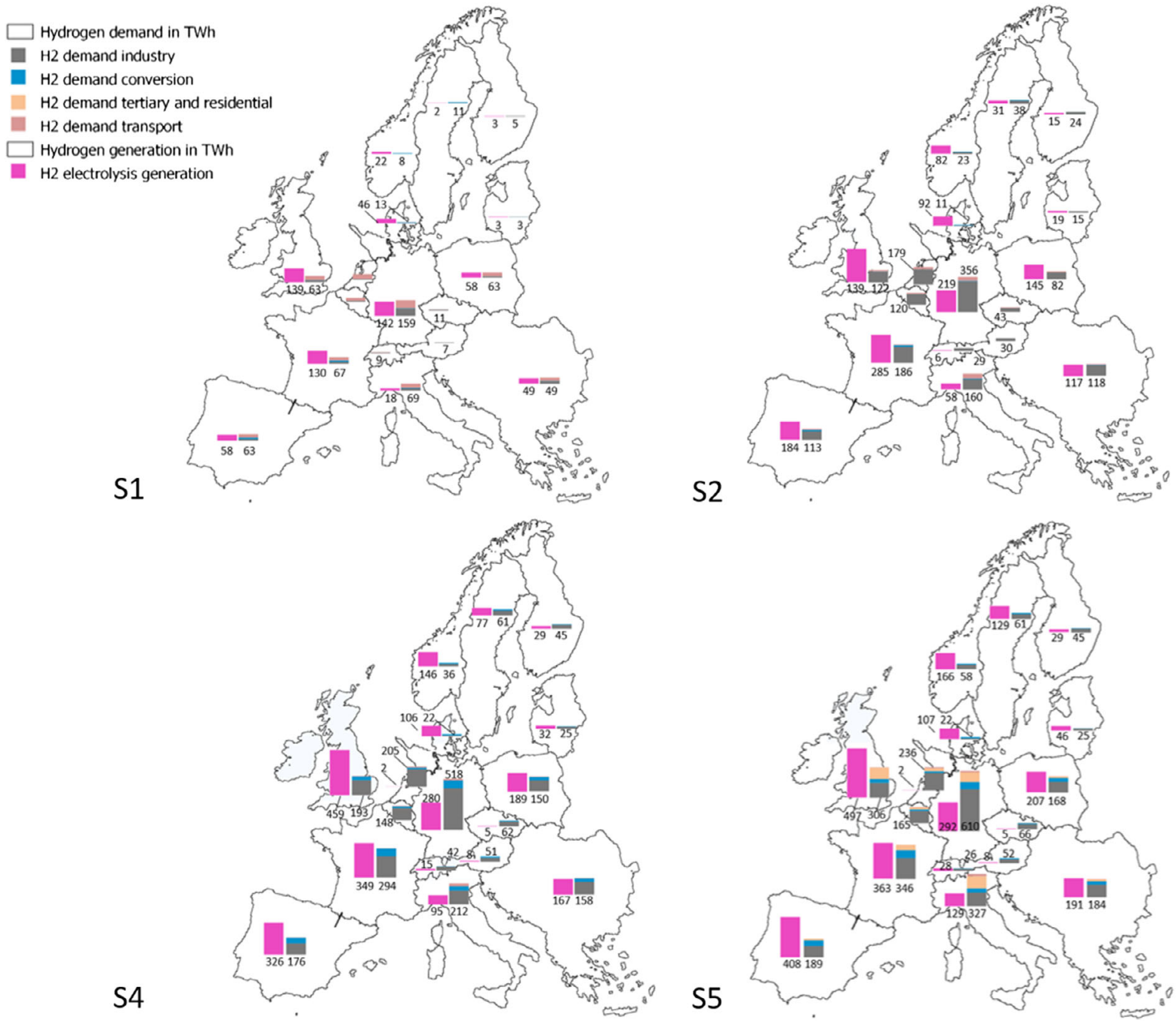

Figure 20. Resulting hydrogen demand and generation by region and scenario in the year 2050.

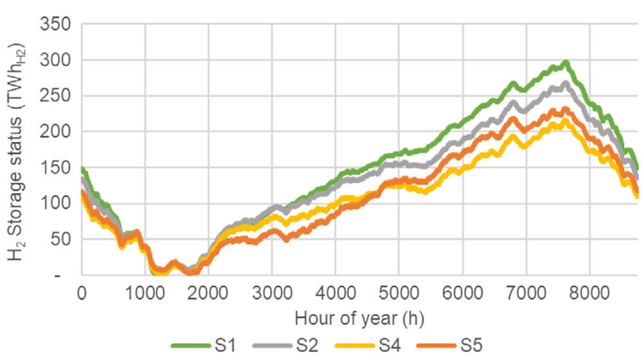

Figure 21. Hydrogen storage cycle for the different scenarios and the entire European system in 2050.

In 2022, the European Union and the UK had a total natural gas capacity of 1,130 TWh.[54] The storage facilities may be reconverted to store hydrogen; however, due to different energy density and compression characteristics, the storage capacity of hydrogen is about 20% compared to natural gas. This means the existing gas storages can be used to store about 225 TWh of hydrogen if fully converted. This capacity is lower than the required capacity in all scenarios except S4 where 95% of the existing capacity would be needed. Therefore, a conversion of existing natural gas storage to hydrogen is a robust strategy across all scenarios. Even more, it is very likely that additional new hydrogen storage capacities are an efficient element of the European hydrogen system.

The regional distribution of storage is shown in **Figure 22**. In all scenarios, Germany has the highest storage capacity, followed by the UK and Ireland. There is a decrease in storage capacity from scenario 1 (S1) to scenario 4 (S4), reflecting the observed decrease in demand within the conversion sector. Scenario 5 (S5) includes hydrogen demand from the building sectors, taking into account variables such as outdoor temperature and heating demand, as modeled by Enertile. Consequently, the seasonality of this additional demand in S5 adds additional storage requirements.

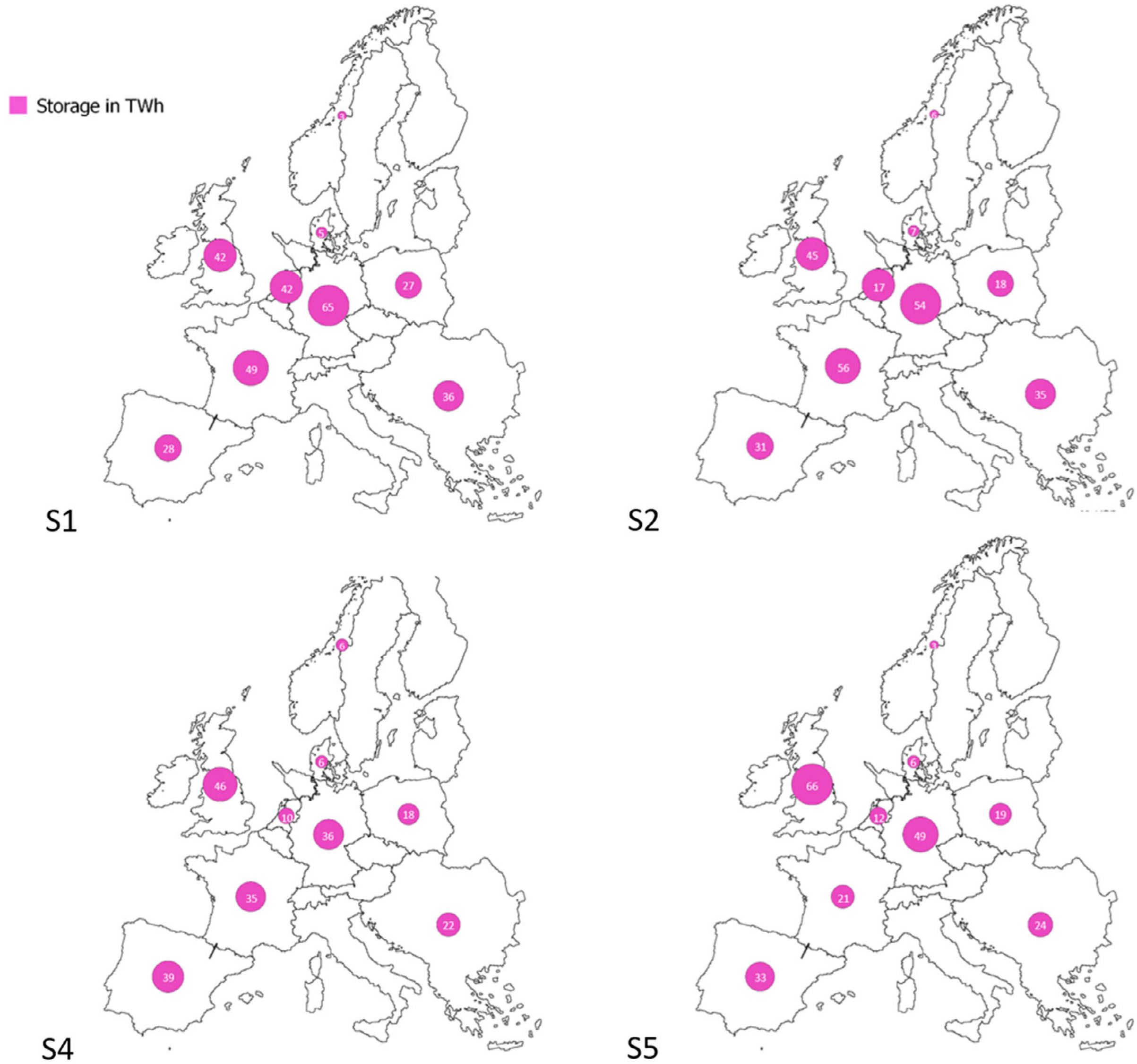

Figure 22. Storage capacity by scenario for the different Enertile regions in 2050.

In addition to storage capacity, the flow of hydrogen in and out of the storage units is another important factor. Enertile uses power plants that use hydrogen as needed to meet demand, such as H2 turbines, combined cycle, and CHP. These power plants draw hydrogen from storage primarily for electricity generation and also for heat. Using Germany's total storage as an example, the withdrawal capacities for scenarios S1, S2, and S5 are about 122 GW, while scenario S4 has a lower capacity of 98.4 GW by 2050. Enertile prioritizes filling the storage with the lowest cost electricity available for hydrogen production. The injection capacities range from 39 GW in S1 to 68 GW in S5, with smaller capacities overall compared to the outflow.

4.6. Summary of the Hydrogen System

Table 10 summarizes the main indicators of the resulting hydrogen system including demand, production, imports, trade, and storage. It shows how the huge range of hydrogen demand across scenarios drives system components like transport of hydrogen, imports, and production via electrolyzers. Only the need for hydrogen storage does not increase with increasing demand. On the contrary, storage needs are highest in scenario S1 with the lowest demand for hydrogen. The Supporting Information material contains more detailed results on country level for these individual components of the hydrogen system.

5. Discussion

These scenarios define a broad range of future hydrogen demand to capture the associated uncertainty. While this study illuminates the role of hydrogen in a system that is strongly driven by hydrogen production via electrolysis and a low use of CCS and biomass, alternative futures are possible. Scenarios

Table 10. Indicators summarizing the elements of the hydrogen system and comparing them across scenarios. (H2 traded is the sum of all net trades from the regions considered including intra-german trade).

Indicator	2030				2050				Regional Scope
	S1	S2	S4	S5	S1	S2	S4	S5	
H2 demand [TWh]	161	196	361	367	697	1.646	2.386	2.897	EU27 + UK + NO + CH + Balkan
H2 derivatives demand [TWh]	145	42	42	42	1607	723	838	819	EU27 + UK
H2 production [TWh]	156	185	322	328	667	1590	2275	2607	EU27 + UK + NO + CH + Balkan
H2 imports [TWh]	5	11	39	39	29	56	111	290	EU27 + UK + NO + CH + Balkan
H2 imports (% of total demand)	3%	6%	11%	11%	4%	3%	5%	10%	
H2 derivatives imports [TWh]	145	42	42	42	1607	723	838	819	EU27 + UK
H2 imports including derivatives (% of total demand)	49%	22%	20%	20%	71%	33%	29%	30%	
Electrolyzer capacity [GW]	54	63	104	107	299	662	922	1067	EU27 + UK + NO + CH + Balkan
Electrolyzer average fullloadhours	2895	2930	3091	3069	2232	2402	2467	2443	
H2 storage total capacity [TWh]	16	12	9	9	297	269	216	233	EU27 + UK + NO + CH + Balkan
Storage outflow capacity [GW]	19	20	25	27	122	123	98	124	Germany
Storage inflow capacity [GW]	8	8	12	13	39	44	52	68	Germany
H2 traded within Europe [TWh]	162	176	318	315	365	917	1289	1562	EU27 + UK + NO + CH + Balkan

assuming the strong use of biomass and CCS could impact the results substantially. For example, ref. [20] shows that blue hydrogen produced from natural gas using steam reforming and CCS is cost competitive to some degree, although it also results in lock-in effects. Generally, a greater demand-side use of CCS or biomass would lower the demand for hydrogen and electricity, easing the pressure on renewables, grids and the hydrogen system. At the same time, this would be accompanied by other issues like sustainability problems for biomass or a slowed energy transition in the case of CCS. In this context, direct air carbon capture and storage (DACCS) could be another option that is not considered in the modeling but would potentially impact the results and substitute the most expensive mitigation options. However, the future costs of DACCS are also highly uncertain.[56] How robust the hydrogen system presented here is against such impacts requires further analysis.

Finally, it should be noted that although some imports from outside Europe are part of the cost-optimal solution in both 2030 and 2050 for all scenarios, these are low compared to domestic hydrogen production. These results are in line with the research by Lux et al.[44] which showed that local hydrogen production is more cost effective than importing hydrogen from the MENA region, despite the fact that the MENA region has a lower LCOE due to its low-cost renewable potentials. However, the additional transport costs associated with bringing hydrogen from the MENA region or other world regions to Europe more than offset the LCOE cost advantages in in those regions. At the same time, there are substantial imports of hydrogen derivatives. Exploring further options to transport hydrogen in different forms, such as ammonia, could be beneficial and was not within the scope of this study.

6. Conclusions

This article presents the results of a comprehensive energy system study that first calculates the demand for energy using dedicated sector models for industry, buildings, and transport and then calculates the resulting cost-optimal energy system for Europe to supply this demand. Five scenarios differ with regard to the importance of hydrogen in the sectors examined and help to clarify the impact of this uncertainty on the energy system and in particular the future potential hydrogen system in Europe. The results allow numerous conclusions and recommendations in this regard.

The results show that uncertainty about the future demand for hydrogen is still high, and demand ranges between about 700 and 2800 TWh by 2050 in the EU27 + UK countries. Totally, 700 TWh can be considered the minimum and includes robust options for industrial process heating, electricity and district heat generation, as well as domestic flights. Across all scenarios, industry will be the main hydrogen consumer, although the use of hydrogen for feedstocks in chemical products is still very uncertain. This depends on how global value chains are restructured when the production of ammonia, methanol, ethylene, and other olefins become CO_2-neutral. These chemical feedstocks have a potential hydrogen demand of up to 1000 TWh, and their uncertain future is a major challenge for the development of any hydrogen system.

The regional pattern of hydrogen demand across Europe also depends heavily on how industry is structured in the future. The basic chemical and steel industries constitute major centers of demand. Assuming that complete value chains for climate-neutral basic chemicals are established in Europe and today's sites continue to be the locations for future production, North-Western Europe will be a major center of hydrogen demand. The three regions with the highest consumption in Europe are the western Netherlands (139 TWh), North-Rhine Westphalia in Germany (124 TWh), and northern Belgium (Flanders) (103 TWh).

The resulting total demand for hydrogen including its derivatives ranges between 204 (S1) and 383 TWh (S5). This is substantially below the 2030 target announced by the EU in its

REPowerEU[1] plan of about 665 TWh demand for hydrogen and its derivatives (equals 20 million tons of H_2). We conclude that it is very unlikely that the REPowerEU target can be met.

The energy system model Enertile calculates the cost-optimal energy system based on the respective demand assumptions in S1–S5. The results reveal numerous robust elements of a European hydrogen infrastructure including transport corridors, seasonal storage, and domestic electrolyzers. Our results indicate that a European hydrogen transport system is part of a cost-optimal energy system, even under different demand scenarios. Electrolyzer locations should ideally be located close to the most favorable sites for renewables and energy should be transported in the form of hydrogen to the respective demand centers. Wind locations should be prioritized over PV locations, although the latter can become competitive at a higher demand for hydrogen in the overall system. High priority should be given to developing large-scale underground storage of hydrogen to enable the efficient use of electrolyzers at times of high wind and solar electricity generation. As such, the hydrogen system facilitates the deployment of least-cost renewables potentials in Europe by combining flexible production, long-distance transport, and large-scale storage to provide seasonal and short-term flexibility.

In all scenarios, the future energy system will be dominated by solar and wind energy and the required annual expansion exceeds the values from 2022 for both wind and solar. Domestic hydrogen production via electrolysis within Europe plays a major role in a cost-optimal solution. Electrolysis locations are clustered close to the most competitive wind potentials in Northern Europe, while scenarios with a high demand for hydrogen demands add large capacities at locations in Southern Europe with low-cost solar potentials after 2030. This illustrates how solar and wind resource potentials shape the energy and in particular the hydrogen system. Overall, the installed electrolyzers' capacities in European countries range between 54 and 107 GW by 2030 and between 300 and 1067 GW by 2050.

Hydrogen imports play only a marginal role. These stem from North Africa via pipelines, underlining the high competitiveness of the domestic wind and solar energy potentials. Scenarios with higher hydrogen demand tend to have slightly higher imports, but they only supply about 10% of overall hydrogen demand with a maximum import quantity of 290 TWh in 2050. If, however, the energy system deviated substantially from the cost-optimal solution, e.g., in terms of RES deployment or transmission capacities, imports would become more competitive and play a larger role. On the other hand, there are substantial imports of hydrogen derivatives ranging from 600 to 1400 TWh across the scenarios by 2050.

All the scenarios indicate the important role for pan-European hydrogen transport infrastructure. Large-scale transport is in place by 2030 from Northern European countries with the best wind potentials, while the Southern European countries and especially the Iberian Peninsula with the best PV potentials produce large quantities of hydrogen by 2050 that are transported to the industrial clusters in Central Europe. Even if the energy-intensive chemical and steel industries do not require large quantities of hydrogen and import intermediate products instead, there is still a substantial need for cross-border hydrogen transport.

Large-scale hydrogen storage also features in all scenarios, with a maximum capacity between 215 and 300 TWh by 2050. This is more than could be provided by converting all the current natural gas storages into hydrogen storages. The storages are operated in one single cycle per year and use the availability of wind in autumn and PV in summer to produce hydrogen for winter use. Greater use of hydrogen for heating will increase the storage required. In addition, the hydrogen storages can also be used to provide shorter-term flexibility as a reaction to fluctuations in renewable power due to weather changes.

Further research can provide a better understanding of the robustness of the hydrogen system in the light of other uncertain parameters, like the deployment of RES across Europe or import prices. A different picture would result if blue hydrogen, biomass, DACCS, and CCS were assigned a stronger role, and this should also be the subject of future research. The energy demand data are published at a very high level of detail making them available for use in future systems studies.

Appendix

A1. Enertile Model Definitions and Assumptions

Table A1. Land utilization factors for the considered technologies.

Land use category	Rooftop PV	Utility-scale PV	CSP	Wind onshore	Wind offshore
Barren	–	16%	20%	20%	–
Cropland natural 20	–	0.9%	0%	0%	–
Croplands	–	0.9%	0%	16.9%	–
Forest	–	0%	0%	4.32%	–
Grassland	–	1.2%	1,5%	5.79%	–
Savannah	–	0.5%	10%	12.36%	–
Shrub land	–	0.5%	10%	12.36%	–
Water	–	0.05%	–	–	30%
Urban	6.0%	–	–	–	–

Figure A1. Definition of Enertile regions as used for the supply modeling.

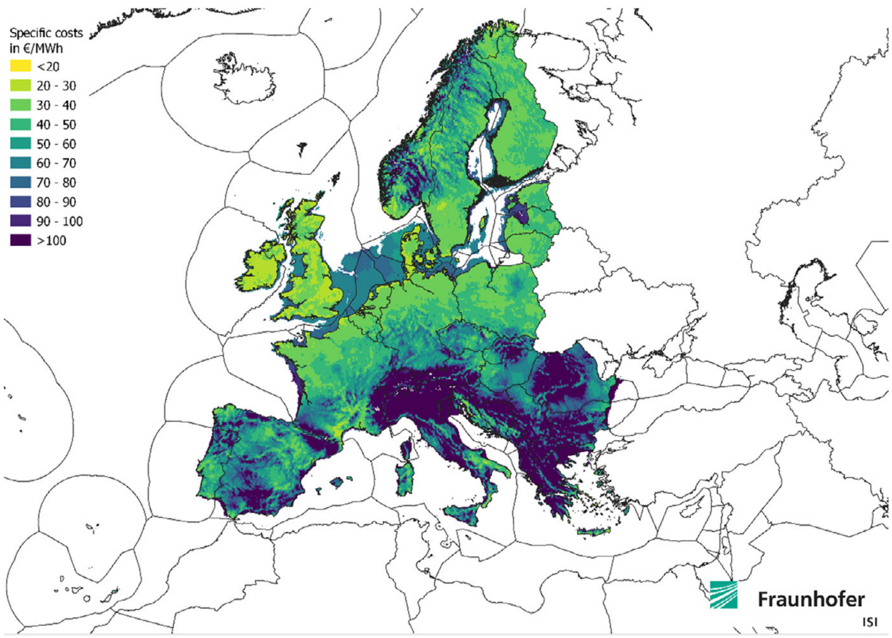

Figure A2. Specific costs for wind generation in 2050.

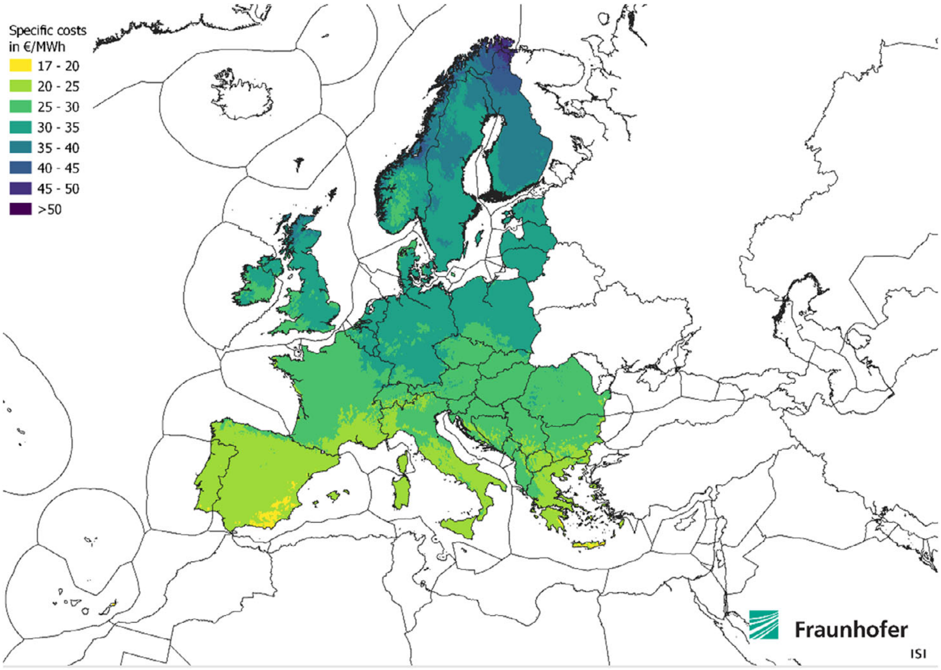

Figure A3. Specific costs for PV generation in 2050.

A2. Renewable Technologies Parameters

Table A2. Minimum installed capacities for wind offshore per region in GW.

Region	2030	2050
FR	10.0	30.0
BAT	2.4	2.4
BEU	4.3	4.3
DK	12.9	12.9
FI	2.2	2.2
IBEU	0.3	0.3
NL	14.7	14.7
NO	4.5	4.5
PL	6.1	6.1
RO	0.3	0.3
SE	3.8	3.8
UKI	50.0	100.0

Table A3. Maximum installed capacity for wind onshore per region in GW.

Region	2030	2050
FR	40	70
IBEU	50	NR
NO	20	65
PL	25	NR
UKI	40	70

Table A4. Specific cost assumptions in Euro/kW for the different solar technologies.

Technology	2030	2035	2040	2045	2050
Utility-scale PV	430	392	369	356	347
CSP	4025	3472	3013	2657	2400
Rooftop PV	901	851	809	774	742

Table A5. Specific costs assumptions in Euro/kW for the different wind offshore configurations.

Technology configuration wind offshore	2030	2035	2040	2045	2050
120 m Tower height, 330 W m^{-2}	0	2746	2702	2664	2627
120 m Tower height, 400 W m^{-2}	2625	2588	2546	2511	2474
160 m Tower height, 340 W m^{-2}	2911	2866	2820	2781	2742
160 m Tower height, 350 W m^{-2}	2887	2844	2797	2759	2720
180 m Tower height, 330 W m^{-2}	0	2960	2912	2872	2833

Table A6. Specific costs assumptions in Euro/kW for the different wind onshore configurations.

Technology configuration wind onshore	2030	2035	2040	2045	2050
100 m Tower height, 350 W m^{-2}	1041	1012	994	983	976
120 m Tower height, 350 W m^{-2}	1114	1083	1064	1053	1045
130 m Tower height, 300 W m^{-2}	1267	1232	1211	1197	1188
140 m Tower height, 280 W m^{-2}	0	1313	1290	1276	1266

Table A6. Continued.

Technology configuration wind onshore	2030	2035	2040	2045	2050
140 m Tower height, 350 W m^{-2}	1187	1154	1134	1122	1114
150 m Tower height, 270 W m^{-2}	0	0	0	1332	1323
150 m Tower height, 280 W m^{-2}	1387	1348	1325	1310	1301
150 m Tower height, 350 W m^{-2}	0	1190	1169	1156	1148
160 m Tower height, 270 W m^{-2}	0	0	0	1367	1357

Supporting Information

Supporting Information is available from the Wiley Online Library or from the author.

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Conflict of Interest

The authors declare no conflict of interest.

Data Availability Statement

The data that support the findings of this study are available in the supplementary material of this article.

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