One Earth

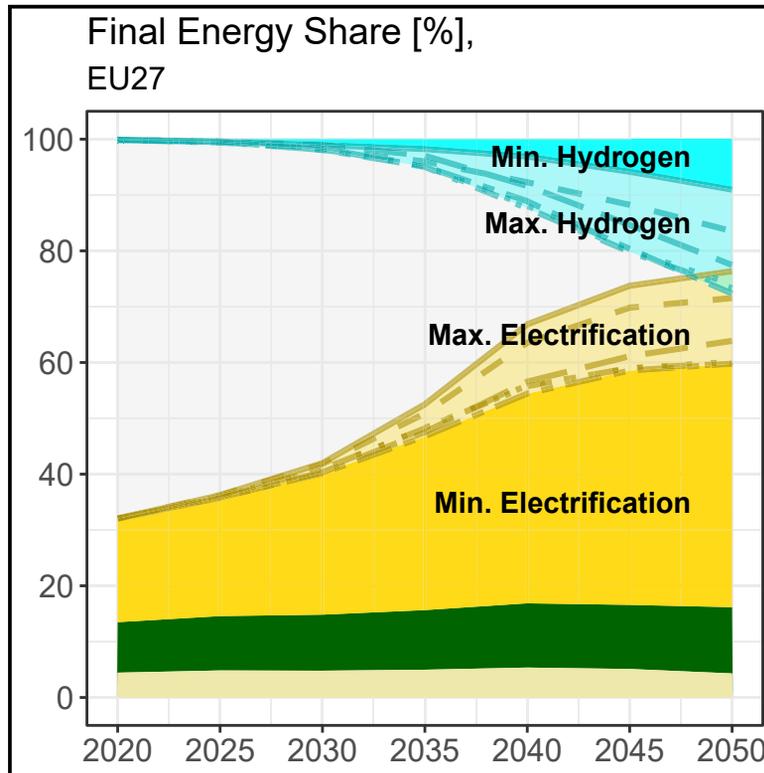# Distinct roles of direct and indirect electrification in pathways to a renewables-dominated European energy system

Graphical abstract

Final Energy Share [%], EU27

Highlights

- Deriving plausible multi-scenario ranges for electrification and hydrogen

- Complementary roles: electrification dominant, hydrogen for hard-to-electrify sectors

- EU scenarios show 42%–60% electricity and 9%–26% hydrogen-based energy share in 2050

- EU electricity demand increases across scenarios by 80%–160% in 2050

Authors

Felix Schreyer, Falko Ueckerdt, Robert Pietzcker, ..., Michaja Pehl, Robin Hasse, Gunnar Luderer

Correspondence

felix.schreyer@pik-potsdam.de

In brief

Energy system transformation in buildings, industry, and transport can be achieved by the direct use of renewable electricity or deployment of hydrogen-based fuels. However, it remains unclear how these two strategies should be planned and leveraged to enable a cost-effective and fast transformation for reaching the EU climate neutrality goal. Here, we investigate plausible combinations of direct and indirect electrification strategies in EU climate neutrality scenarios using the REMIND model and find the direct electrification route to be the dominant strategy, while hydrogen-based energy is necessary in hard-to-electrify sectors.

CellPress

Article

Distinct roles of direct and indirect electrification in pathways to a renewables-dominated European energy system

Felix Schreyer,[1,2,3,*] Falko Ueckerdt,[1] Robert Pietzcker,[1] Renato Rodrigues,[1] Marianna Rottoli,[1,2] Silvia Madeddu,[1] Michaja Pehl,[1] Robin Hasse,[1,2] and Gunnar Luderer[1,2]

[1]Potsdam Institute for Climate Impact Research, Member of the Leibniz Association, Potsdam, Germany
[2]Global Energy Systems Analysis, Faculty Process Science, Technische Universität Berlin, Berlin, Germany
[3]Lead contact
*Correspondence: felix.schreyer@pik-potsdam.de
https://doi.org/10.1016/j.oneear.2024.01.015

SCIENCE FOR SOCIETY Our energy systems are the primary emitter of greenhouse gases and require rapid transformation. Although mitigation strategies in the power sector have been well researched and the EU is in the middle of a transformation to mostly renewable electricity, the question arises how this electricity can be used to abate emissions across sectors. The two primary approaches—direct electrification via electric technologies (e.g. heat pumps) or indirect electrification via an intermediary fuel (e.g. electricity-based hydrogen)—each have shortcomings, which can elevate costs, require the construction of new energy facilities, and slow progress towards climate targets. A computational model that considers multiple EU energy system transformation pathways has shown that the best way to achieve the EU climate neutrality target is for policymakers to prioritize direct electrification for passenger cars and low-temperature heating and indirect electrification via hydrogen and synthetic fuels for aviation, shipping, chemical industry, and electricity storage. An adaptive and flexible approach should be taken for truck transport and high-temperature heating.

SUMMARY

Renewable electricity can facilitate climate change mitigation in the buildings, industry and transport sector via direct electrification or indirect electrification, that is, converting electricity to hydrogen-based fuels. While direct electrification is generally energy efficient, indirect electrification can partially build upon existing applications and infrastructure. However, their roles and relative importance have not been well researched in mitigation scenarios. Here, we derive plausible ranges for both strategies based on EU climate neutrality scenarios using the REMIND model. We find that by 2050 direct electrification is the dominant strategy with an electricity share of 42%–60% in final energy, while indirect electrification is necessary in hard-to-electrify sectors and contributes a share of 9%–26%. Our analysis highlights that policy makers should respect the distinct sectoral roles of both strategies by fostering an end-use transformation towards direct electrification while prioritizing hydrogen and synthetic fuels for applications where they are indispensable.

INTRODUCTION

In its efforts to address climate change mitigation, the European Union (EU) has established and ambitious and legally binding goal to reach greenhouse gas (GHG) neutrality by 2050.[1] This requires a deep transformation to a low-carbon economy at unprecedented speed.

The energy sector is at the heart of this transformation, contributing about three-quarters of the current European GHG emissions. At present, the transformation is at different stages with respect to electric and non-electric energy use. While the power sector has seen a substantial increase of renewable electricity from 14% in 1990 to 38% in 2020,[2,3] non-electric energy use in buildings, industry, and transport has hardly reduced its dependence on fossil fuels. For reaching the strengthened 2030 climate target of 55% emissions reductions relative to 1990 and the GHG-neutrality target in 2050, a trend break is needed urgently in these sectors.

Recent technology developments and assessments point to rapid shifts in the economics of low-carbon technologies. Solar photovoltaics and wind power have shown extraordinary cost declines and quasi-exponential growth over the past decade.[4,5] In addition, given their comparatively low life-cycle GHG emissions and environmental impact, variable renewable electricity (VRE) technologies are an attractive option to become the backbone of the future low-carbon energy system.[6–9] However, rapid technological change is not limited to renewable supply technologies. Batteries exhibit steep cost reductions due to learning, and technology assessments point to considerable scope for further innovation in electricity-based demand-side technologies, such as battery-electric vehicles (BEVs) or heat pumps.[10–14]

In contrast, alternative low-carbon options such as nuclear power or a carbon capture and storage (CCS) with fossil-based technologies come with substantial drawbacks given economic and sustainability criteria.[15,16] Despite the global efforts to mitigate climate change, these options have not gained much traction in the last decade.[17,18] Furthermore, large-scale use of bioenergy is subject to sustainability concerns due to its impact on land and biodiversity,[19–21] which impairs its role in the transition to climate neutrality.

These developments make a transition to a renewables-dominated energy system that links the power sector to all energy end-use sectors the most viable and plausible pathway toward climate neutrality. However, coupling of the power sector to the other energy sectors can be done via two different strategies: direct and indirect electrification. Direct electrification refers to a switch to electric end-use technologies such as BEVs or heat pumps. Indirect electrification refers to the conversion of electricity to hydrogen or hydrogen-based synthetic fuels that can be used as low-carbon fuels in existing (e.g., internal combustion engines [ICEs], gas boilers) or alternative energy end-use technologies (e.g., fuel-cells, hydrogen-based steel making). The scopes and trade-offs of direct and indirect electrification as different strategies of realizing a VRE-based energy system are less well researched.

Technology reviews and sectoral modeling studies established the technological characteristics and potentials of direct and indirect electrification for specific sectors of the energy system.[11,13,14,22–24] Generally, direct electrification makes more efficient use of scarce renewable electricity while requiring a transformation of end-use technologies and processes away from combusting fuels. There are limits to the diffusion rate and long-term depths of direct electrification for certain applications. Indirect electrification does not have these limitations and can supply electricity-based low-carbon fuels to a broad range of partially existing end-use technologies and infrastructures.

However, the production of electricity-based hydrogen and synthetic fuels involves conversion losses, and associated end-use technologies are less efficient (e.g., efficiency of combustion engines versus electric engines). The available amount of electricity-based hydrogen and synthetic fuels, moreover, is substantially confined in the near term due to barriers of ramping up electrolysis capacity from the currently low EU production levels of less than 10 TWh/y.[25,26] Finally, there are specific challenges to transporting hydrogen and different possible supply chains are under discussion. Hydrogen imports via ship are expensive and hydrogen pipelines require international coordi-

nation and extensive building times.[27–29] Given the associated uncertainties and diverging implications for infrastructure and end-use transformation, policy making requires robust quantitative assessment of the roles of direct and indirect electrification in transformation scenarios.

There is a lack of scenario studies analyzing the scopes and trade-offs of direct and indirect electrification with an up-to-date technology parameterization and cautious assumptions about bioenergy and CCS. Generally, the existing scenario literature often assumes optimistic CCS potentials and unsustainable levels of bioenergy deployment resulting in substantial residual emissions by 2050.[30] While there are a couple of EU scenario studies specifically on the role of hydrogen,[31–35] important research gaps remain. There is a lack of sectoral detail in present modeling studies, which is a critical limitation as the potential and challenges of direct and indirect electrification differ substantially across sectors. Evangelopoulou et al. do not appear to analyze sectoral results and present a wide scenario space with strong inclinations toward either direct or indirect electrification. Blanco et al. and Seck et al. both use linear energy system models (ESMs), which, in comparison to integrated assessment models (IAMs), generally have limitations in representing energy-demand transformations, temporal transformation dynamics, and the full portfolio of GHG sources. Blanco et al. focus on the long-term state in 2050, while Seck et al. see a substantial near-term and long-term deployment of hydrogen. However, this is questionable in light of recent technology developments supporting direct electrification and the required time to scale up green hydrogen production. Seck et al., moreover, model scenarios with high CCS deployment, which come with the mentioned sustainability issues. Tarvydas presents a review study on hydrogen in EU scenarios from the gray literature, which is an ex-post evaluation without harmonized scenario assumptions on technology and climate policies. Hence, there is a gap between detailed sectoral studies and full-system scenario modeling that we aim to close with this study.

Here, we present a new set of EU scenarios in line with the GHG-neutrality target and recent technology trends, using the Regional Model of Investments and Development (REMIND) IAM with improved sectoral detail to quantify plausible future ranges of direct and indirect electrification and their implications on energy supply. We find that, across scenarios, 73%–78% of the final energy in the European Union with 27 member states (EU27) is provided either by electricity or electricity-based hydrogen and synthetic fuels in 2050. Direct electricity use in final energy increases from 20% in 2020 to at least 42%–60%, while 9%–26% are provided by electricity-based hydrogen and synthetic fuels. Direct electrification dominates the passenger car and low-temperature heating applications, while hydrogen and synthetic fuels are needed in long-distance transport, chemicals, and for electricity storage. Hence, both strategies are largely complementary and compete only in a segment of up to 15% of final energy (trucks and high-temperature industrial heat). Furthermore, we estimate total EU-wide demand for hydrogen and synthetic fuels in 2050 to be between 1,000 and 2,600 TWh/y and electricity demand to increase by 80%–160% relative to current levels depending on the scope of direct and indirect electrification as well as hydrogen imports. Based on robust elements of our scenario analysis, we identify three
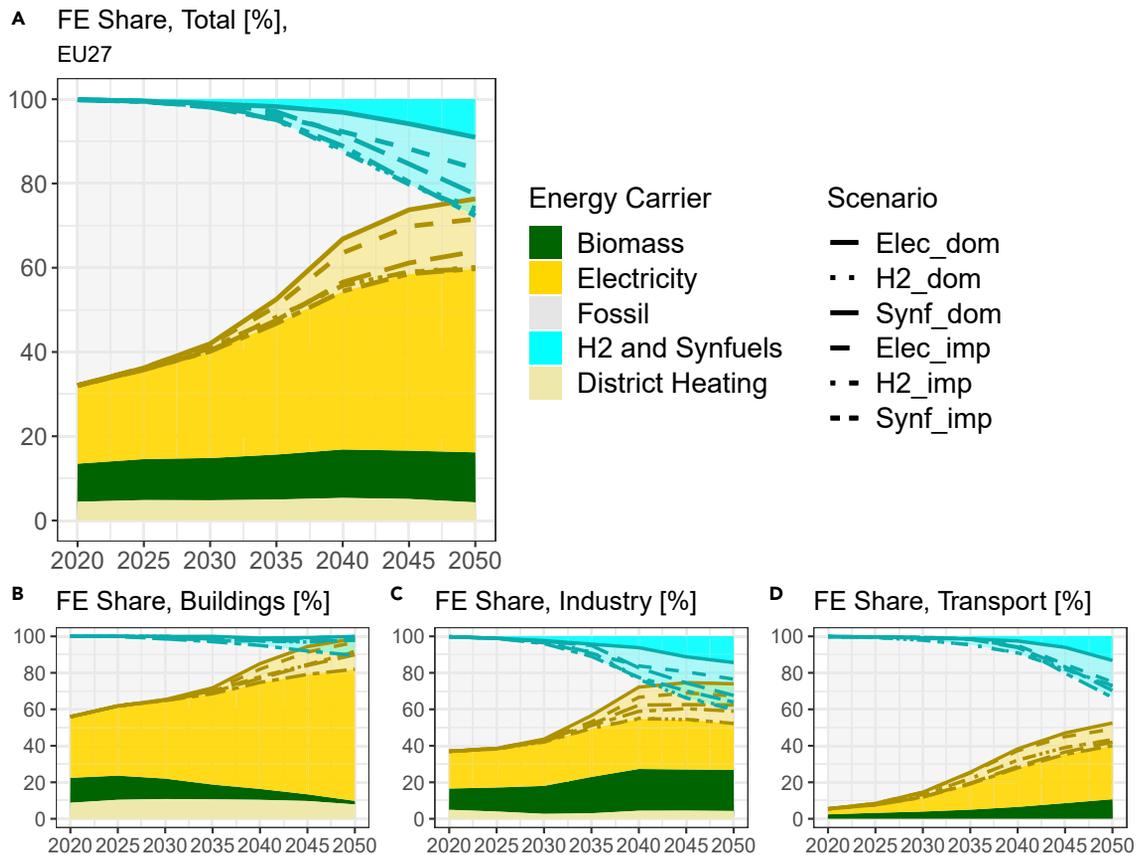
A FE Share, Total [%], EU27

Figure 1. Scenario ranges of direct and indirect electrification
Final energy mix integrating scenario ranges for direct electrification (yellow) and indirect electrification (light blue) across our scenarios. Shares are compiled for total final energy (A), final energy in buildings (B), industry (C), and transport (D). The plots show the range of shares for electricity and hydrogen-based carriers across scenarios with different color shadings and lines. The (yellow/blue) areas in full color depict the respective segment of final energy in the scenario with the minimum share of electricity/hydrogen-based energy and the (yellow/blue) areas in transparent color depict the additional increase to the scenario with the maximum share. Moreover, the contours of the segments for electricity and hydrogen-based carriers in the final energy mix of the individual scenarios are shown as lines. The lines for electricity (yellow) and hydrogen-based carriers (blue) overlap in certain cases as they represent different scenarios. Biomass and district heating shares do not significantly vary across scenarios and are taken from the Elec_dom scenario in the plot. Final energy includes bunker fuels and non-energy use.

cornerstones to guide EU policy. Policy making should (1) focus direct and indirect electrification on the outlined no-regret sectors first, namely sectors in which one strategy is preferred across all scenarios; (2) remove barriers to renewable power expansion; and (3) incentivize the scale-up of hydrogen supply chains. For the end-use sectors with more uncertainty about the roles of direct and indirect electrification, an adaptive policy strategy needs to remain flexible about respective infrastructure and technology choices.

RESULTS

Ranges of direct and indirect electrification
Our scenario analysis finds that direct electrification is the key strategy for transformation, while indirect electrification is indispensable for some sectors (Figure 1). Electricity and hydrogen-based fuels together provide the bulk of final energy (including bunkers fuels and non-energy use) required in 2050 with a share of 73%–78% (including district heating produced from electricity). Electricity dominates the final energy demand in 2050

with a share of at least 42% (yellow area in Figure 1), while a minimum share of 9% needs to be provided by hydrogen-based energy carriers (light blue area in Figure 1). Under favorable technology conditions for electrification, the electricity share increases to 60%, while hydrogen-focused scenarios show a maximum share of 26% of hydrogen-based energy carriers. Hence, only about 15% of final energy is generally flexible between direct and indirect electrification in our scenarios, which represents a relatively narrow range for a potential competition between the two options.

Enabled by existing infrastructure, commercially available technology, and carbon pricing, electrification unfolds already in the 2020s and early 2030s (electricity share increases to 31%–37% in 2035). In some sectors, the required technologies are already mature, such as battery-electric light-duty vehicles and low-temperature heat pumps. As the carbon intensity of electricity is rapidly reduced over the next 10–15 years (Figure S1) and the price of fossil energy steadily increases, efficient electric technologies become competitive, in particular for the buildings and passenger car sectors.
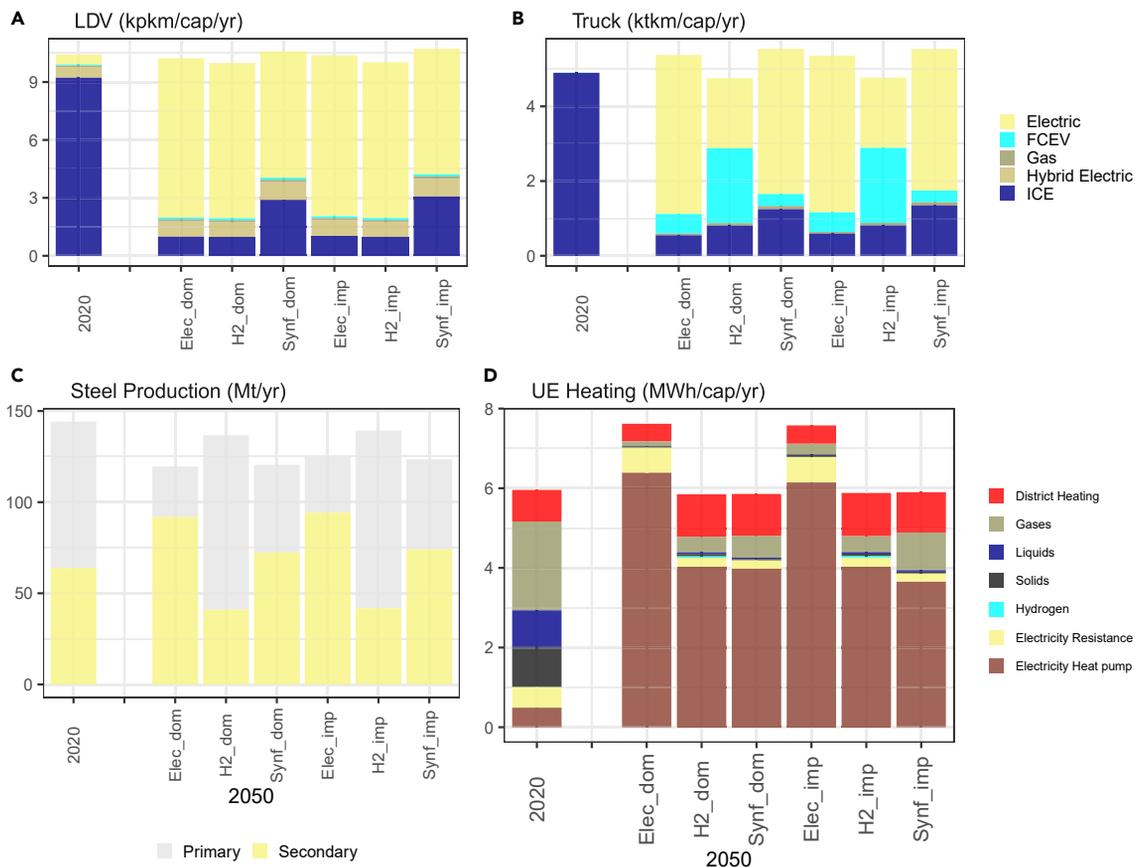
Figure 2. Demand of key energy services across scenarios

Key energy services in the end-use sectors in 2050 across scenarios and 2020.

(A) Annual passenger kilometers traveled by LDVs *per capita*.

(B) Annual freight ton kilometers delivered by trucks *per capita*.

(C) Annual steel production.

(D) Annual *per capita* useful heating energy demand in buildings. Values shown for 2020 are model values calibrated to historical data representing 2018–2023 averages.

In contrast, relevant amounts of hydrogen-based energy can only be expected from the mid-2030s onward (Figure 1). The near-term scarcity of green hydrogen is due to the time it takes to ramp up electrolysis capacity[26] and to go through the required technological innovation cycles. In addition, most hydrogen applications are not yet cost-competitive. Moreover, distribution infrastructure (hydrogen pipelines) and end-use technologies (fuel-cell vehicles, direct reduction steel plants) are partially still in demonstration phase and require buildup and development for at least a decade. On top of the hydrogen supply challenges, additional bottlenecks are the development and up-scaling of carbon capture (especially direct air capture) and the associated CO_2 transport infrastructure. Therefore, relevant synthetic fuel production based on hydrogen and atmospheric carbon must be expected to evolve even later than elementary hydrogen.

We find that the variations of imports of hydrogen-based energy (dom/imp scenarios) have a rather small impact on energy service demand (transport fleet, heating systems, industrial production) and the final energy mix in comparison to the technology focus (Elec/H$_2$/Synf, see Table 1 for scenario definitions) of the scenarios (Figures 2 and S2). Producer prices for hydrogen

and synthetic liquids decrease up to 10%–20% as a result of the higher import assumptions (Figure S3). However, this is a comparatively small factor given the dependence of energy service dynamics and energy carrier substitution on the end-use side on other cost factors (taxes, transmission and distribution, end-use technologies) or behavioral aspects. Higher imports of synthetic liquids, though, lead to a slightly increased share of this carrier in the final energy mix (6%–7% increase in share) since they are modeled as perfect substitutes to fossil liquids and therefore react more strongly to producer price changes.

Sectoral view: Buildings

In the buildings sector (Figures 1B and 2D), we can distinguish between electric energy used for non-heating purposes (appliances, lighting, space cooling) and energy used for heating in buildings (space and water heating). For the transformation of heating, electrification is the dominant strategy: the share of electricity-based heat provision (in terms of useful energy) increases from 17% in 2020 to 65%–92% by 2050. This is driven mainly by the widespread use of on-site electric heat pumps that make efficient use of electricity. In situations where no efficient ambient heat

source is available, resistive electric heating can complement heat pumps. In some densely populated areas, buildings can be connected to district heating grids, where heat provision is largely shifted to centralized electric heating, too. As the overall cost of heating decreases in the Elec scenarios relative to hydrogen-focused scenarios, a higher demand of heating services can be observed in our modeling (Figure 2D).

In the H_2 and Synf scenarios where heat pump diffusion is assumed to be limited, the remaining non-electric heating systems are gas boilers or district heating. Gas boilers can be run on either fossil gas, biogas, or synthetic gas in the model but synthetic gas only becomes competitive for a small share (7%) of useful energy in the Synf_imp scenario. Direct hydrogen heating is not competitive even under favorable technology conditions. Significant efficiency losses and (in the case of direct hydrogen) new grid infrastructure make hydrogen-based heating hardly attractive in comparison to electric heating.[14]

Sectoral view: Industry

In the industry sector, both electrification and the use of hydrogen-based energy carriers play an important role in the transformation depending on the manufactured good and its production process. We find the electricity share in final energy (including non-energy use) to increase from 23% in 2020 to 28%–47% by 2050, while the 2050 share of hydrogen-based carriers varies between 14% and 44% (9%–31% share of synthetic fuels) across scenarios (Figures 1C and S2). In addition, a significant share of final energy comes in the form of biomass-based carbonaceous fuels (16%–22%), which are used for energetic and feedstock purposes.

Our scenarios are characterized by different assumptions on the minimum share of primary steel in total EU steel production that lead to different transformation routes (Figures 2C and S4–S6). Total steel production remains similar to current levels by 2050 across our scenarios, yet, in the Elec scenarios, our model shows a shift from primary to secondary steel driven by favorable economics of the less energy-intensive recycling route. This shift is limited exogenously in the H_2 (and partially in Synf) scenarios where we impose larger minimum shares of primary steel, which would be in line with an industrial policy that deliberately aims at building low-carbon primary production in Europe. The production of primary steel shifts from coal-based blast furnaces predominantly to hydrogen-based direct iron reduction (DRI) and electric arc furnaces (EAFs).

High-temperature processes in other industrial sectors pose limits to electrification as the required technologies are highly uncertain.[11,36] In the non-metallic minerals sector (cement, glass, and ceramics), electrification is limited and some hydrogen is used in cement kilns in the H_2 scenarios (Figures S4 and S5). CCS is an important option in the cement sector since it is required also for abating process emissions from calcination. Similarly, the chemicals sector sees little electrification and maintains a significant share (60%–70%) of carbonaceous energy (mainly liquids). This is because some share of carbonaceous carriers is required to provide feedstocks for chemical products (mostly plastics), which creates synergies with the use of those carriers for energetic purposes. Here, emissions abatement happens by a partial shift to carbonaceous carriers from non-fossil origin (biogenic or synthetic) and industrial CCS.

The remaining industrial sectors (e.g., non-ferrous metals, food, pulp and paper, machinery) can reach high levels of electrification via resistive heating or heat pumps as many applications involve the generation of low- or medium-temperature heat (Figures S4 and S5). Without the availability of significant hydrogen networks close to industrial centers (as in H_2 scenarios), direct hydrogen use for heating only plays a marginal role in those sectors.

Sectoral view: Transport

In transport, electrification and hydrogen-based carriers are both relevant as battery-electric solutions come with high efficiency but face limitations for long-haul applications (aviation, shipping, and potentially parts of truck transport). This is because, although energy densities of batteries are still expected to improve, they are unlikely to reach levels required for those applications. Across our scenarios, the 2050 share of electricity in final energy (including international aviation and shipping) is between 28% and 41% and the share of hydrogen-based carriers between 13% and 32% (Figure 1D). On energy service level, the shares of electric technologies are again higher due to their increased efficiencies (Figures 2A and 2B).

Passenger cars switch almost entirely to BEVs by 2050 in all scenarios with the exception of the Synf, where some ICE cars remain (Figure 2A). Given recent improvements of battery energy density and costs as well as the current uptake of electric vehicles, a nearly full electrification of the light-duty vehicle (LDV) sector is plausible due to the favorable economics of BEVs.[22,37] The Synf scenarios represent a case where the EU-wide ban on new ICE vehicles by 2035 is not enacted and a residual share of conventional cars of about a third remains. In these scenarios, we assume a lack of public charging infrastructure and that some consumers maintain a preference for combustion vehicles despite their unfavorable economics.

Truck transport shows a strong variation across scenarios reflecting uncertainty about future technology development and policy support (Figure 2B). In the Elec scenarios, a high share of BEVs is reached in 2050 based on an improvement of battery energy densities sufficient for most segments and a roll-out of megawatt charging.[13] Other scenarios assume limits in these technological developments and thus show about a third to half of the freight tons delivered by either fuel-cell trucks (H_2 scenarios) or conventional trucks (Synf scenario), in particular for long-haul applications.

Finally, long-distance transport modes can hardly be electrified.[38] The model therefore only considers liquid carbonaceous fuels (fossil, bio-based, or synthetic) for aviation and shipping. A mix of residual oil-based fuels and carbon-neutral fuels (synthetic fuels or biofuels) provides the supply of the remaining liquid transport fuel in 2050. The emissions from residual fossil fuels are compensated by CO_2 removal to reach the GHG-neutrality target (Figure S7).

Total hydrogen supply and demand

Total demand for hydrogen-based energy carriers (hydrogen and synthetic fuels) in the EU27 is between 1,000 and 2,600 TWh/y by 2050 across our scenarios (Figure 3). In 2030, the ranges are small as all scenarios show a demand around
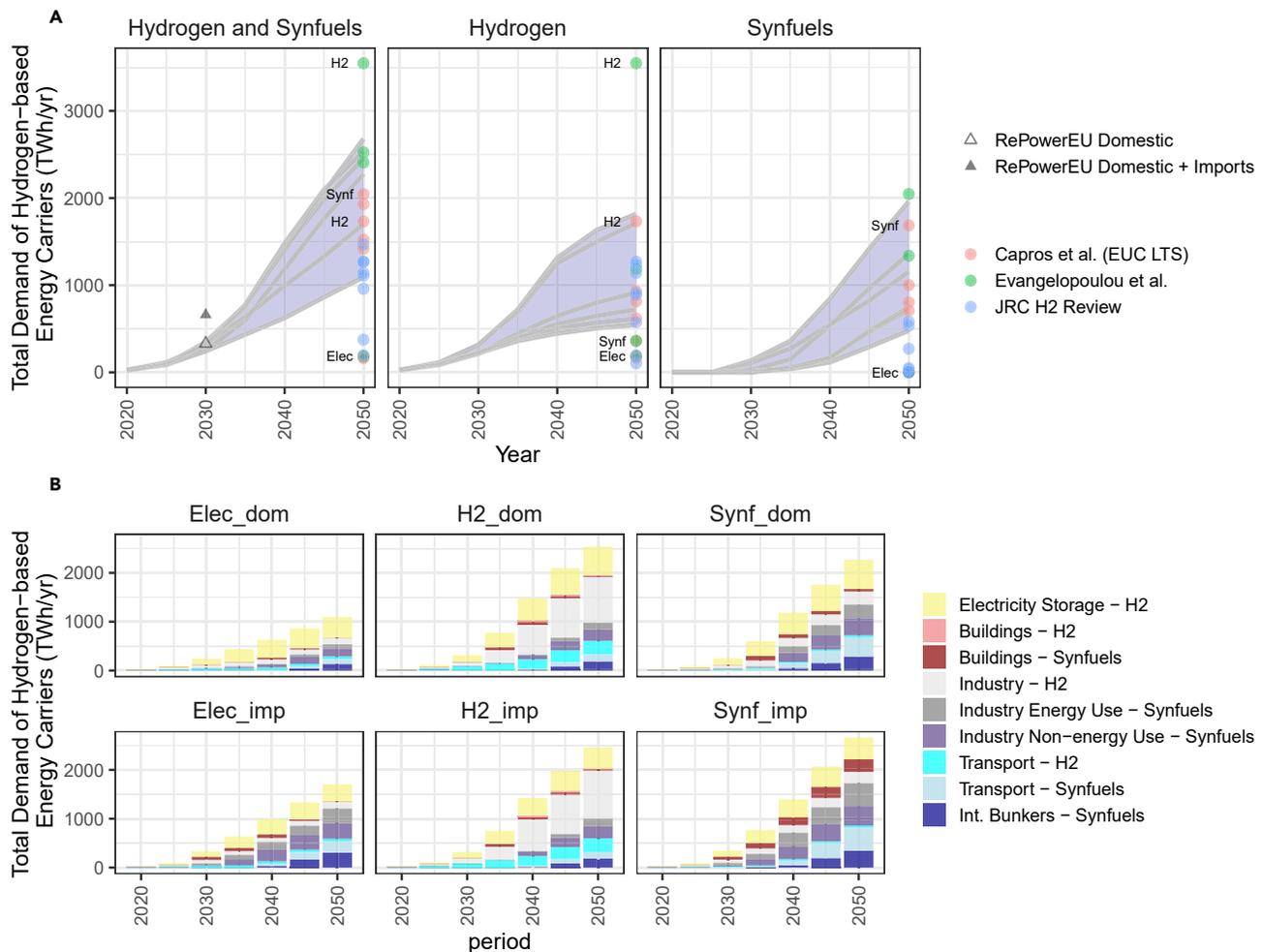
Figure 3. Total hydrogen demand across sectors
Total demand for hydrogen-based energy carriers across scenarios and sectors.
(A) Range of total demand for the aggregate of hydrogen and synthetic fuels as well as hydrogen and synthetic fuels separately (funnel) across scenarios (lines). Triangles show targets of the RePowerEU plan for domestic production and imports of green hydrogen. Colored dots show scenarios from comparison studies[33,35,40] where labels indicate scenarios with narratives similar to this study. One study[33] did not report synthetic liquids, so their numbers for synthetic fuels refer to synthetic gas only.
(B) Total demand for hydrogen and synthetic fuels across sectors. Bunker fuels (dark blue bars) are split from the transport sector and non-energy use (purple bars) is split from the industry sector.

250–350 TWh/y, which mainly comes in the form of direct hydrogen consumption in industry and as electricity storage. The 2030 demand for hydrogen-based energy is about the level of the green domestic production target and significantly lower than the total consumption target of green hydrogen in the RePowerEU plan (triangles in Figure 3A). The 2030 production level of green hydrogen, in particular, is clearly below the RePowerEU production target across our scenarios (Figure S8). Given the current state and near-term trends of electrolysis projects in Europe,[26,39] this indicates that the RePowerEU targets for green hydrogen have moved out of reach.

By 2050, a minimum amount of at least 500 TWh/y synthetic fuels is needed in all scenarios to provide non-fossil carbonaceous energy carriers for long-distance transport (aviation, shipping) and the chemical industry (non-energy use). In the Synf scenarios where parts of industrial heating and road transport

still use combustion technologies in 2050, demand for synthetic fuels strongly increases to 1,300–1,900 TWh/y. Direct usage of hydrogen is between 500 and 1,800 TWh/y. Here, the minimum amount (Elec scenario) is determined mainly by the need for seasonal electricity storage, while the maximum amount (H$_2$ scenario) is driven by additional demand for hydrogen in primary steel making and industrial heat generation.

On the supply side, our scenarios feature low-emissions production of hydrogen and synthetic fuels. Across scenarios, hydrogen is predominantly produced via electrolysis run in a fully decarbonized power system (Figures S1 and S9). Electrolysis becomes competitive driven by carbon prices, decreasing capital cost, and temporally flexible operation benefitting from wind and solar electricity at lower-than-average prices. Moreover, production of hydrogen from natural gas with CCS, the main competitor, would require geological carbon storage, which is
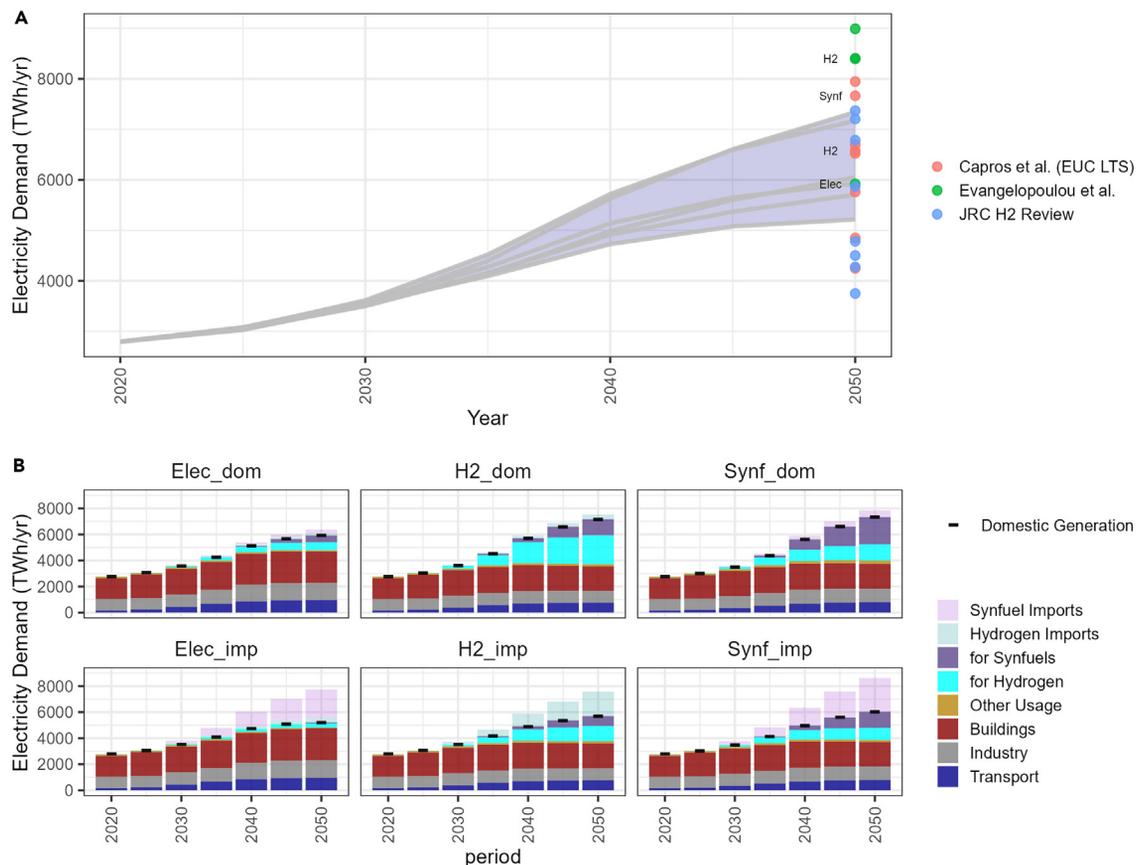
Figure 4. Total electricity demand across sectors
Gross electricity demand across usages and scenarios (including transmission losses and energy system consumption).
(A) Total electricity demand across scenarios. Lines refer to scenarios shown in bottom part. Colored dots show scenarios from comparison studies[33,35,40] where labels indicate scenarios with narratives similar to this study. One study only provided electricity generation data and not electricity demand.[35]
(B) Gross electricity demand across sectors. The solid bars represent domestic electricity generation in the EU27. Electricity used outside of the EU for the production of imported hydrogen and synthetic fuels is depicted in transparent bars on top of the solid bars.

almost entirely needed for negative emissions to reach climate neutrality in our scenarios (Figures S7 and S10). Synthetic fuels are predominantly produced using non-fossil captured carbon where the more expensive direct air capture comes into play only in the H_2 and Synf scenarios once the potential of biogenic carbon sources is fully used (Figure S10).

Total electricity supply and demand
We find total domestic electricity generation to reach 5,200–7,300 TWh/y in 2050 (Figure 4A). That is an increase by 2,400–4,500 TWh/y, which is 80%–160% of 2020 levels. Note that electricity generation corresponds to electricity demand in our model since we do not include electricity trade. The H_2 and Synf scenarios require significantly more electricity than Elec scenarios due to lower efficiency of end-use applications (BEVs, heat pumps vs. fuel cells, boilers, ICEs) and considerable electricity used for domestic hydrogen production (Figures 4B and S1). High hydrogen and synthetic fuel imports can reduce the requirements for renewable electricity expansion in the EU (note that H2_imp features lower generation than Elec_dom). However, these import scenarios outsource the electricity generation as electricity demand including electricity used for imported

hydrogen carriers is consistently higher in the H_2 and Synf scenarios (see transparent bars in Figure 4B).

In all scenarios, the increase in electricity demand comes with substantial VRE expansion and integration requirements until 2050 (Figure S11). Average EU-wide capacity installations in 2025–2050 are 60–110 GW/y for solar photovoltaics (PV) and 40–60 GW/y for wind power. Historically, installation rates in 2015–2019 were at about 8 GW/y for PV and 10 GW/y for wind.[3] Maximum installation rates in the EU27 were about 22 GW/y for solar PV (2011) and 11 GW/y for wind (2015). Hence, the scenario requirements translate roughly into a 3- to 5-fold acceleration of VRE expansion compared to past record years, and a 4- to 10-fold acceleration compared to recent years. Scenarios with more electrification and hydrogen imports (Elec_imp) are at the lower end of the range, while hydrogen-focused pathways with limited imports (Synf_dom) require the highest VRE expansion rates.

DISCUSSION

Comparison to EU scenario literature
Comparing our results on an aggregate level to previous studies, there are some notable differences. Most of the comparison
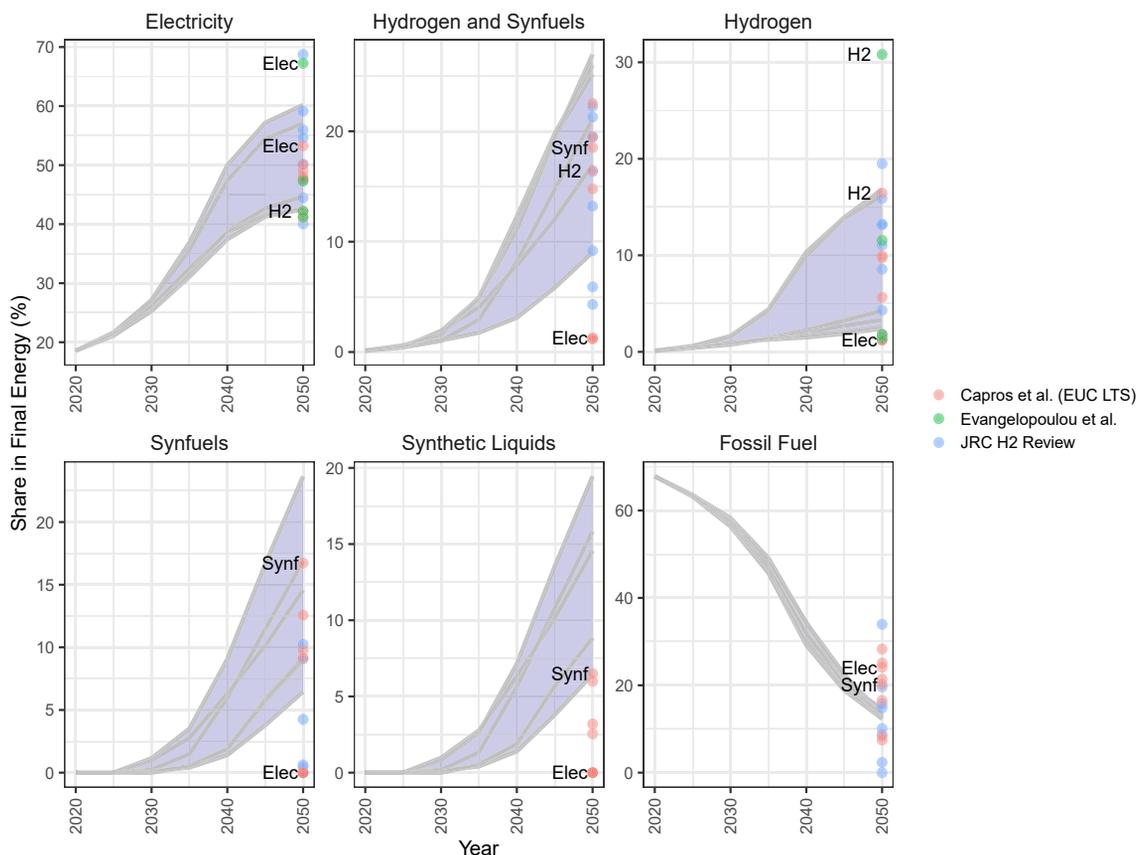
Figure 5. Comparison of final energy shares to EU scenario literature
Share of electricity, hydrogen-based energy carriers, and fossil fuels in final energy across the scenarios of this study (blue funnel). Colored dots show scenarios from comparison studies[33,35,40] where labels indicate scenarios with narratives similar to this study. Synfuels refer to the sum of hydrogen-based synthetic liquids and synthetic gases.

scenarios where final energy data were available[33,35,40] show electricity shares of final energy in 2050 toward the lower end our scenario range (Figure 5). Moreover, several of those scenarios feature very low shares of hydrogen-based energy below 10% outside of our scenario range. This may be partially explained by a larger share of residual fossil fuels due to less ambitious climate targets or more negative emissions or a more pronounced role of bioenergy. In addition, it is not clear whether all scenarios have full sectoral coverage and include, for instance, non-energy use and bunker fuels.

Again, other studies show a much higher total demand for hydrogen and synthetic fuels at the upper end or above our range of 1,000–2,600 TWh/y. Seck et al., for example, present scenarios with a total demand for hydrogen above 3,000 TWh/y (including hydrogen for synthetic fuels) and Blanco et al. feature a range of about 1,600–5,000 TWh/y for 95% CO_2 reduction scenarios in 2050.[31,34] One notable difference is that their scenarios always see a significant role for direct hydrogen usage in fuel-cell vehicles, which is questionable given recent trends in BEV adoption and expected improvements in battery technology.[13] In addition, these studies tend to see a smaller reduction in total final energy demand by 2050 relative to 2020 (about 10%–20%) compared to our scenarios (about 35%–40%).

Finally, most scenarios in the literature show a larger demand for direct hydrogen than for hydrogen-based synthetic liquid fuels.[31,33–35,40] However, outside of the H_2 scenarios, we find direct hydrogen use in final energy (i.e., excluding hydrogen used for the power sector) with up to 350 TWh/y to only play a minor role, while synthetic liquids are important across all scenarios by replacing fossil fuels in the long-distance transport and chemicals sector (at least 500 TWh/y). This is a plausible result since there are only few applications (e.g., primary steel production) that cannot be electrified but feature a promising solution based on direct hydrogen without conversion to a carbonaceous fuel.

Limitations and outlook
While our scenarios vary the key uncertainties regarding the competition between direct and indirect electrification, there are limitations, which should be kept in mind when interpreting our results. First, the ranges we derive need to be assessed in the context of our scenarios assumptions, which we sought to set sufficiently broad but could have been chosen more or less extreme (degree of cost or tax changes, behavioral changes in transport etc.). Second, we did not explore variations in lifestyle changes, material or energy efficiency, or relocation of industry

to outside the EU. This could reduce the total energy demand and could slightly shift the roles of electrification and hydrogen depending on which sectors are affected.

Third, there is considerable uncertainty about bioenergy and CDR potential. This would mainly affect how much residual fossil fuels remain at the point of climate neutrality. A key assumption in this study is the land carbon sink of about 300 MtCO$_2$/y that the EU Commission aims to maintain in 2050. In fact, there is conceptual disagreement about whether these carbon removals can be accounted as anthropogenic.[41] Omitting these negative emissions would further increase the mitigation pressure to substitute the residual fossil fuels and could further increase the demand for hydrogen-based synthetic fuels.

Fourth, we did not take into account a global warming impact of hydrogen leakage, whose magnitude is still uncertain and will depend, in particular, on leakage rates of the future hydrogen infrastructure.[42,43] A non-negligible climate impact of hydrogen leakage and its consideration in the EU climate-neutrality target would affect our results and might lead, in particular, to a smaller role of direct hydrogen use.

Fifth, our results are based on an integrated energy-economy modeling framework that takes a full-system perspective but cannot represent the detail of sectoral bottom-up modeling. In particular, future modeling of energy substitutions in the buildings and industry with a technology-based approach instead of a production function would further bridge the gap to sectoral models. To investigate this gap and, more generally, the extent of the scenario spread discussed above, multi-model comparisons with harmonized scenario assumptions and model vetting would be needed on this subject. Furthermore, our analysis was focused on the European context but could be extended to a global analysis that takes into account different transformation capacities and requirements of the Global North and Global South.

Lastly, our model cannot provide an hourly or spatially explicit picture of sector coupling or analyze different transport and usage forms of hydrogen-based energy (ammonia, methanol, dimethyl ether, or liquid organic hydrogen carriers) that are discussed in the literature.[44,45] This is the strength of ESMs that could be coupled to IAMs to spell out these implications for specific time steps and investigate region-specific infrastructure requirements.

Conclusions and policy implications

We model EU transformation scenarios to quantify plausible future ranges of direct and indirect electrification for a transition to climate neutrality by 2050 under limited availability of bioenergy and CCS. We find that 73%–78% of final energy in 2050 can be provided by direct use of electricity or electricity-based hydrogen and synthetic fuels. This electrification potential is dominated by direct electrification (42%–60% of final energy), while hydrogen-based energy (9%–26% of final energy) is needed in hard-to-electrify sectors such as long-distance transport and chemicals. Hence, direct and indirect electrification are largely complementary, while they compete for a minor share of about 15% of final energy. These uncertain segments include freight road transport (trucks) and parts of industrial process heat, where their respective roles will depend on policy support, technology development, and infrastructure availability. The

focus on either direct or indirect electrification and assumptions about future hydrogen imports have a significant impact on the required average installation rates of solar PV and wind power in 2025–2050, which range from a 4- to 10-fold acceleration compared to recent years. In contrast to previous studies, our scenarios come with greater sectoral detail and show a larger potential for direct electrification, a more confined deployment range for hydrogen-based energy, as well as a more pronounced role for synthetic liquid fuels as opposed to direct hydrogen use.

Based on the robust and uncertain elements of our scenario analysis, we see three cornerstones of a successful policy strategy on direct and indirect electrification. In the following, we will discuss each of them and comment on their status in the ongoing EU policy processes under the Fit-for-55 package.

Sectoral roles of direct and indirect electrification

EU policy should be guided by the insights from scenario modeling and bottom-up studies on the respective sectoral roles of electric and hydrogen-based solutions. There are several elements in the ongoing policy process that already support such roles, while further measures can be recommended:

First, carbon pricing is a core element of a successful EU sector coupling strategy. To start with, the EU emissions trading scheme (ETS) is a key driver of power sector decarbonization,[46] which is a prerequisite for both direct and indirect electrification to actually abate emissions. Moreover, a carbon price in the end-use sectors increases the transformation pressure and helps reveal the competitiveness and sectoral roles of electric or hydrogen-based solutions as a technology-neutral instrument. Completing the coverage of carbon pricing on the energy sector by the introduction of the ETS2 for buildings and transport from 2027 has therefore been an important step.[47] However, since consumer decisions, especially in the buildings and transport sector, are often myopic and subject to non-monetary factors,[48–50] it is sensible to complement carbon pricing by additional policies that are technology specific.

Second, for technology-specific regulation, it is crucial to align with, or at least not contradict, the respective roles of electrification and hydrogen. An EU-wide target of 10 million heat pump installations until 2027, support programs, as well as subsidies in some member states are promising for the buildings sector.[51,52] Moreover, the EU-wide energy efficiency target for 2030 generally encourages a near-term scale-up of direct electrification as it offers efficiency gains.[53] However, in the absence of widespread phase-out policies for gas heating systems[54] and mixed signals on the repurposing of infrastructure for low-carbon gases or hydrogen,[55] there is still the risk of an expensive lock-in into heating systems based on natural gas.[56] Similarly, the adopted ban on new ICE cars by 2035 in transport makes an exception for cars that run on synthetic fuels, which leaves uncertainty for vehicle manufacturers and owners. This can lead to a fossil lock-in that either requires an expensive lock-out later or threatens to miss climate targets. However, the e-fuel (and biofuel) drop-in quota in the aviation sector (Aviation Fuels Directive) as well as regulations for maritime transport (inclusion in ETS and emissions standards via FuelEU maritime regulation) are important cornerstones to start the uptake of hydrogen-based carriers in those sectors.[57,58] A corresponding element for industry is the

state-level target of 42% green hydrogen in total industrial hydrogen use by 2030 implemented in the current reform of the Renewable Energy Directive.[59] It encourages the transformation of hydrogen production, which so far is based on steam methane reforming, for existing use cases in industry that will continue to demand hydrogen in the long term (e.g., ammonia, methanol in the chemicals sector).

The remaining uncertainty regarding the competition between hydrogen and electricity (heavy-duty long-haul transport and high-temperature industrial heat) can be addressed with an adaptive policy approach. As long as the future availability and prices of low-carbon hydrogen are uncertain, direct electrification options such as battery-electric trucks and industrial heat pumps could also be prioritized for these sectors, while hydrogen options can be further developed, tested, and demonstrated. Generally, a high-electrification energy system is preferable in terms of power generation and hydrogen import requirements. It supports energy independence of the EU, which is one of its primary goals since the energy crisis following the Russian invasion of Ukraine (REPowerEU plan). However, if hydrogen turns out to become clearly cost-competitive against electrification in those applications, this approach should be adapted toward a greater role of hydrogen. Infrastructure deployment with long lead times such as hydrogen pipelines could account for these uncertainties and be oversized to prepare for the optimistic end of hydrogen scenario ranges. In general, policy makers have to strike a balance between redundancy required to hedge against risks and cost efficiency, which is key for the acceptance of the energy transition as a whole. High carbon prices can help to reduce the need for technology-specific regulation and shift responsibility to market actors.

Scale-up of green hydrogen-based fuels

The substantial long-term demand for hydrogen-based energy shown by our scenarios reemphasizes the need for an EU strategy on the scale-up of green hydrogen production, which currently stands at less than 10 TWh/y.[60] To support financing in this early stage, the European Hydrogen Bank has been established and is set to auction subsidies for renewable hydrogen production and imports from outside the EU.

However, a main challenge will be to foster a rapid expansion of electrolytic hydrogen supply, without diverting substantial renewable electricity from the more efficient electrification. First, it is important to stimulate demand in sectors where, in the long term, hydrogen-based energy is definitely needed. Subsidizing only the hydrogen supply side poses the risk of crowding out investment into electrification in sectors where direct electrification is superior in the long term. As discussed above under the first point, emergence of sector-specific hydrogen demand is already supported to some extent by renewable energy targets or mandatory quotas. Second, electrolytic hydrogen production should primarily use wind and solar electricity in hours when abundant electricity from renewables is in the grid and electricity prices are low. This ensures a low-carbon hydrogen supply chain, provides synergies with grid balancing measures, and respects prioritization of renewable electricity for direct electrification. In the medium term, an increasing carbon price in the ETS would incentivize the use of VRE electricity for electrolysis as electricity prices in hours of the low remaining fossil generation will soar. In the near term where fossil generation still plays a

role, the recent Delegated Act on the definition of renewable fuels[61] is helpful as it formulates criteria on additionality as well as spatial and temporal correlation of renewable electricity generation for accounting electrolytic hydrogen as renewable. However, in this early stage, too-strict regulation can be detrimental to the market and it needs to be seen how projects will respond to the requirements. Finally, the design of the European electricity market will be a crucial factor in the medium term that needs to incentivize electrolysis operations to follow short-term price signals from fluctuating renewable supply.

As a significant amount of green hydrogen will be needed for the production of carbon-neutral synthetic fuels, timely planning of future CO_2 infrastructure as well as consistent accounting and regulation of fossil and non-fossil carbon flows in the economy are required. EU policy on sustainable carbon cycles is still in its infancy. The European Commission formulated "aspirational objectives" for this decade, among them the implementation of a systematic monitoring of carbon flows and a minimum share of non-fossil carbon in the chemical industry.[62] Importantly, consistent integration of carbon capture and utilization (CCU) into the emission trading schemes without loopholes or double counting is crucial given the importance of carbon pricing and the potential complexity of future carbon cycles. Planning of CO_2 networks and regulation, moreover, needs to avoid lock-ins into synthetic fuel production based on fossil carbon sources as scenario results suggest that production chains using predominantly non-fossil CO_2 are required in the long term to reach the climate-neutrality goal.

Accelerating renewable power installation

Accelerating installation and integration of renewable power to the grid should be of high priority for EU policy making regardless of the uncertainty about low-carbon energy imports to be expected. While the recent levels of ETS carbon prices and levelized cost of electricity for new wind and solar plants generally make renewable electricity competitive, there still is substantial investment uncertainty. Among the reasons for the recent slow-down of renewable installations in some member states during the second half of the last decade were long permitting processes, resistance from local communities, and roll-back or reform of support policies.[63] Transmission grid expansion has faced similar challenges, which need to be overcome for harnessing benefits of a geographically distributed VRE-based generation and balancing across Europe.[64,65] Faster permitting frameworks and designation of acceleration areas for renewables as implemented by the latest reform of the Renewable Energy Directive could solve part of these problems.[59]

However, a capital-intensive cost structure, regulatory uncertainty (e.g., market design debates[66]), and uncertain electricity prices continue to pose risks to renewable investment. There is substantial literature on the necessity, merits, and risks of different types of renewable support policies in the ongoing transition process.[67–71] Maintaining carefully designed auctions of renewable subsidies (contracts for differences) in line with nationally defined installation targets can help in securing the required renewable growth in the near term.

In summary, the ongoing EU policy process under the Fit-for-55 package includes a number of elements that support a transformation in line with the results of this study and the broader literature. As transformations to either electric or

Table 1. Summary of scenario assumptions used in this study

Scenario Assumption[a]	Electrification (Elec_dom/Elec_imp)	Hydrogen (H2_dom/H2_imp)	Synfuel (Synf_dom/Synf_imp)
Energy end-use	lower cost associated with electricity used for heating in buildings and industry (e.g., heat pumps, resistive heating), subsidies and behavioral assumptions support BEVs in transport	lower cost associated with hydrogen used for heating in buildings and industry, support for hydrogen-based steel making, subsidies and behavioral assumptions support fuel-cell electric vehicles (FCEVs)	lower cost of conventional combustion technologies in buildings and industry, support for gas-based DRI steel making limited subsidies for BEV/FCEV, consumer behavior favors ICEs
Steel production	at least 20% primary steel by 2040	at least 70% primary steel by 2040	at least 40% primary steel by 2040
Infrastructure[b]	high cost for hydrogen network, accelerated buildup of BEV charging infrastructure	lower cost/policy support for hydrogen network, accelerated buildup of FCEV refueling infrastructure	high cost for hydrogen network, slower up-scaling of BEV/FCEV infrastructure
Energy taxes[b]	EU-wide decrease of electricity taxes, increase taxes on other fuels	EU-wide decrease of hydrogen taxes, increase of taxes on other fuels	EU-wide decrease of taxes on carbonaceous fuels, increase of taxes on other fuels
Electrolysis operation[b]	flexible electrolysis runs on about $3/4$ average electricity prices at $1/2$ capacity factor	power market design to favor flexible electrolysis to run on about $1/2$ average electricity prices at $1/2$ capacity factor	power market design to favor flexible electrolysis to run on about $1/2$ average electricity prices at $1/2$ capacity factor
Emissions target	2030 −55% total GHG emissions (rel. 1990), 2050 −100% total GHG emissions		
Agriculture	optimistic abatement: 280 MtCO$_2$eq/yr residual emissions (non-CO$_2$) in 2050 (2019 value: 385 Mt CO$_2$eq/yr)		
Geological carbon storage	conservative: max. injection 270 MtCO$_2$/yr		
Land-use change	land carbon sink based on EU Commission assumptions of about 330 MtCO$_2$/yr		
Bioenergy supply	limited supply due to high sustainability requirements: domestic production max. about 2,000 TWh/yr in 2050, based on low scenario of Ruiz et al.,[72] high import tax		
Imports hydrogen-based fuels[b]	each scenario run in a variant with low and high imports		

[a]Description of scenario assumptions behind the technology dimension (Elec/H$_2$/Synf scenarios) and the import dimension (dom/imp scenarios) as well as common assumptions across scenarios.
[b]See Table S1 in supplemental information file for more detailed information.

hydrogen-based solutions involve substantial path dependency, it will remain crucial for policy making to play an active role and align regulation with the insights from energy systems research.

EXPERIMENTAL PROCEDURES

Resource availability
Lead contact
Further information and requests for resources should be directed to and will be fulfilled by the lead contact, Felix Schreyer (felix.schreyer@pik-potsdam.de).
Materials availability
This study did not generate new unique materials.
Data and code availability
Model output data and the scripts used to analyze them for this article are publicly available and deposited at Zenodo: https://doi.org/10.5281/zenodo.10522863 (https://zenodo.org/records/10522864). The code of the REMIND model version used to produce the data is publicly availability under https://github.com/fschreyer/remind/tree/ElecH2_prod. Any additional information required to reanalyze the data reported in this paper are available from the lead contact upon request.

Scenario setup
We construct a set of scenarios with consistent technology and policy assumptions that foster either electrification, direct use of hydrogen or the use of

hydrogen-based synthetic fuels in the EU-wide energy transition (Tables 1 and S1). This takes into account recent assessments from bottom-up analyses and latest trends in technology development with respect to electrification and hydrogen use,[11,13,14,23,36] which were not available to prior scenario modeling studies. We derive the technology scenarios primarily by adjusting cost components associated with energy end use that also include inconvenience cost and policy subsidies. We use those cost components to align sub-sectoral model behavior with the mentioned technology assessments and our scenario narratives.

Each of the scenario types is run in two variants, assuming a focus on either domestic production with low imports (dom) or high imports (imp) of hydrogen-based carriers to the EU. Low import scenarios assume EU-wide imports of 280 TWh/y in 2050, while import scenarios assume 1,400 TWh/y (Figure S12). This corresponds to about 4% and 20% of combined gas and oil imports in 2019, respectively.

The electrification scenarios (Elec_dom/Elec_imp) assume favorable development and policy support for electric end-use technologies such as BEVs and heat pumps. Energy tax reforms are implemented to lower electricity taxes and increase the taxes on other fuels across the EU. Furthermore, secondary (recycled) steel, which can be based on electricity only, is assumed to play an increasingly dominant role in steel production.

The hydrogen scenarios (H2_dom/Elec_imp) feature support for hydrogen-based technologies such as fuel-cell vehicles. Energy taxation is assumed to favor hydrogen over other energy carriers. Moreover, we impose a high minimum share (70%) of primary steel in total steel production. This is plausible if, for instance, the EU aims to become a technology leader for the world market

in low-carbon primary steel with a dedicated industrial policy strategy. There is strong push to build hydrogen-grid infrastructure and the power market design favors green hydrogen to be produced via flexible operation of electrolysis at lower-than-average electricity prices from VRE generation.

The synthetic fuel scenarios (Synf_dom/Synf_imp) assume a continued relevance of combustion technologies in many end-use applications and a stagnant transformation to electric or hydrogen-based appliances. Energy taxes benefit carbonaceous energy carriers and hydrogen-grid expansion encounters significant obstacles. Still, green hydrogen production from electrolysis is supported as in H_2 scenarios to foster a clean transition to synthetic fuels.

There are some assumptions that are common to all our scenarios (Table 1). For non-CO_2 emissions from agriculture, our exogenous trajectory decreases to about 280 $MtCO_2eq/y$ residual emissions in 2050. This is an optimistic assumption in the range of technical and lifestyle mitigation scenarios developed by the Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) model for the EU Commission.[73] Moreover, we make conservative assumptions about realizable CCS (maximum 270 $MtCO_2/y$) and include the EU Commission's goal on enhancing the land carbon sink (330 $MtCO_2/y$), which provides a total carbon dioxide removal (CDR) potential of about 600 $MtCO_2/y$ in 2050. Finally, we assume limited supply of bioenergy (domestic and imported) to decrease the pressure on agricultural land and water use.

Modeling methods

We use the multi-regional IAM REMIND 3.0 that allows investigating cost-efficient transformation pathways with respect to global or regional climate targets under various scenario assumptions.[74,75] The model conducts an intertemporal welfare optimization linking a Ramsey-type economic growth model with a technology-based bottom-up energy system model. The specific model version we employ uses a setup of 21 world regions where the 27 EU member states are grouped into eight distinct model regions of the EU to better resolve regional transformation dynamics[76] (see Figure S13 for final energy plots across model regions; Table S2 for region definitions). The strength of the REMIND framework is its hybrid approach, which is crucial for investigating the dynamics around electrification and hydrogen use. It combines a technology-rich energy-supply system with price-elastic and increasingly detailed energy-demand modeling, which are both linked to a macroeconomic welfare optimization.

While REMIND could generally be applied for a global analysis, we focus this study on EU transformation scenarios. This is because there is better availability of data and literature on end-use sectors in the EU, which serves as an input to our modeling. Moreover, the EU has an ambitious climate-neutrality goal in 2050 such that clarifying the roles of direct and indirect electrification is a timely issue. This is linked to an important debate on the need to import hydrogen-based energy, which is not as relevant in the US, for example, where abundant renewable power potential is available.

Relative to prior versions, REMIND 3.0 has been augmented by an improved representation of the energy-demand side and the hydrogen supply chain. Specifically, this is the first study to apply REMIND with more detailed industry and transport modules and the option of producing hydrogen-based synthetic fuels for analyzing EU transformation scenarios. Here, we provide a summary of the main model features relevant for this study:

REMIND broadly consists of three core parts: a linear energy-supply system, sector-specific energy-demand representations and a macroeconomic growth model (Figure S14). These systems are all linked via an intertemporal optimization of economic welfare, which provides the model with a high degree of endogeneity across all sectors.

REMIND is coupled to the detailed transport model Energy Demand Generator-Transport (EDGE-T), which simulates consumer choices between different transport modes and technologies via a logit function approach. This detailed transport modeling is featured in the latest configuration of the REMIND model[77] and has been used in a number of studies.[7,22,78] However, the present study is the first to apply it to cross-sectoral EU-level analysis in conjunction with the new detailed industry representation (see below). The coupling works as documented in Rottoli et al.[22,79]: REMIND provides EDGE-T with aggregate energy service demand (in passenger kilometers and freight ton kilometers) from the macro system and with energy prices from the energy-supply system. EDGE-T then simulates the choice between transport modes (e.g., LDV versus bus transport), vehicle types (e.g., large

versus compact vehicles), and powertrains (e.g., battery electric, fuel cell, or ICEs). EDGE-T provides REMIND with energy demand per carrier and capital cost of the transport fleet. REMIND and EDGE-T are iteratively coupled to converge such that the feedback of the transport system on the full-system optimization is integrated. The decision between transport modes and technologies involves monetary (fuel cost, vehicle ownership cost, value of time) as well as non-monetary components, or inconvenience costs (e.g., range anxiety, risk aversion, vehicle model availability). The latter are implicitly represented for all transport modes except for LDVs. For non-LDVs, their historical value is derived from past trends and their future development is driven by a set of assumptions in each of the three technology scenarios (Elec, H_2, Synf). In the case of LDVs, inconvenience cost components are explicitly modeled for each powertrain: the powertrain adoption results from an endogenous market where inconvenience cost components vary as a function of the powertrain market share.

In addition, this model version uses an improved representation of the industry sector developed by Pehl et al.[80] The industry sector is modeled by an extension of the constant elasticity of production (CES) function to the industrial subsectors of steel, cement, chemicals, and (an aggregated) other industry (Figure S15). The industry representation is linked at the bottom to the energy system, which provides it with different energy carriers (electricity, heat, hydrogen, carbonaceous solids, liquids, and gases). These inputs come in energy units. The output of the industry sectors comes in physical units for the steel and cement industry (tons of material produced) and in monetary values for the chemicals and other industry sector. The industrial outputs are nodes of the CES function, which are themselves inputs to the macroeconomic part of the CES function that eventually has gross domestic product (GDP) as its output. The elasticity of substitution in each nest of the CES function (σ in Figure S15) is a parameter to define the responsiveness changes in the quantity of the inputs to price changes, i.e., the substitutability of inputs when moving away from a baseline scenario without climate policy that REMIND is calibrated to (see below for details). There is some substitutability between energy and capital input in each of the industry sectors; i.e., the same amount of aggregate energy input per industry sector can produce more industrial output by increasing the energy efficiency capital input. For the steel sector, there are two subsectors, primary and secondary production routes, where both steel types are treated as highly substitutable for the economy, while the production of secondary steel is limited by the availability of scrap steel.

The fuel-switching dynamics in CES function of the industry sector are determined by the elasticity of substitution, the final energy price from the energy-supply system, and a mark-up cost for end-use transformation. The substitution of energy inputs for industrial heat starts with a low elasticity in the near term and is increased to high levels of substitutability until 2040. This is because technological options for the different energy carrier substitutions (e.g., power-to-heat or hydrogen-based heating) exist but still need to be fully developed or scaled up. Moreover, to account for the higher upfront investment and integration cost of introducing new technologies to industrial processes, we add a cost mark-up on electricity and hydrogen inputs in the heat nest. This serves to represent the additional non-fuel cost of power-to-heat (e.g., heat pumps, electric furnaces) or hydrogen-based technologies (e.g., direct iron ore reduction, hydrogen infrastructure and boilers) relative to conventional operations based on carbonaceous energy. We decrease or increase the mark-up cost on those inputs in our technology scenarios to represent electrification or hydrogen support policies or a lack thereof and to correct for too structurally conservative substitution behavior of the CES function.

The buildings sector is also represented by an extension of the CES function (Figure S16). It features a distinction between energy input used for heating and electricity use for all other end uses (e.g., appliances, lighting, or cooling) with a very low substitutability (low elasticity σ) between the two as they are used for different energy services. Heating energy can be provided by different energy carriers and technologies, including carbonaceous solids (biomass or coal), liquids, gases, district heating, restive electric heaters, and electric heat pumps. Similar to the heating input in industry, the elasticity between those increases over time and converges to high levels in 2040. Gases can be provided either by carbonaceous gas (methane) or hydrogen. There is a high substitutability in the long term between gas and hydrogen since hydrogen could use the gas distribution infrastructure. However, there is a cost mark-up at low

levels of hydrogen penetration to capture the additional cost of rededicating the gas grid and preparing heating systems for hydrogen in the scale-up period. In addition, heat pump electricity is imposed with a cost mark-up to capture both higher investment cost and higher efficiency of heat pumps relative to conventional technologies such as oil and gas boilers. Additional costs are charged as well on district heating to represent higher cost relative to industrial consumers of district heating.

REMIND is calibrated to energy-demand (final energy and energy services) trajectories in buildings, industry, and transport in the baseline scenario assuming absence of climate policy. These trajectories are derived from the bottom-up energy-demand models EDGE-Buildings, EDGE-Industry, and EDGE-Transport.[79–81] A key input to all three demand-projection models are population and GDP trajectories from the shared socio-economic pathways (SSPs) used in the integrated assessment modeling community.[82] The trajectories in this study are based on the SSP2 scenario.

In this study, we focus on comparing different policy scenarios that reach the EU-level net-zero goal in 2050. These runs are all derived from the same baseline run where no climate policy is present. The policy scenarios shift away from the baseline scenario driven by price changes from climate policy. Figure S17 shows this effect on the aggregate final energy level between baseline and policy runs.

Hydrogen can be produced via different technologies in the linear energy system model, including electrolysis, steam methane reforming of natural gas (with and without carbon capture) as well as based on coal or biomass. Hydrogen can be demanded not only as a fuel by the end-use sectors (buildings, industry, and transport) but can also be used for balancing of variable renewables in the power system or to produce synthetic gas or liquids using captured CO_2 generated by technologies with carbon capture. The inclusion of hydrogen-based synthetic fuels is a new feature of our study that has not been available in previous versions of REMIND.

Another a new feature is that we make scenario assumptions about how power market design affects the electricity price for electrolysis. In the H_2 and Synf scenarios, we assume that electrolysis is run flexibly at a lower-capacity factor and can benefit from hours of low electricity prices once there is a sufficiently high VRE share in electricity generation. Our parameterization linearly reduces the electricity price seen by electrolysis relative to the annual average price as a function of VRE share. We vary the maximum possible reduction of this mechanism across our scenarios (Table S1) to represent different ways of how electrolysis can operate in the power market. Finally, we specifically introduced endogenous learning with respect to the capital cost of electrolysis and direct air capture in this study, which are important drivers for the competitiveness of synthetic fuels.

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.oneear.2024.01.015.

AUTHOR CONTRIBUTIONS

Conceptualization, F.S., F.U., and G.L.; methodology, F.S., F.U., R.P., R.R., M.R., M.P., and R.H.; software, F.S., R.R., M.R., and M.P.; validation, F.S., R.P., M.R., S.M., and R.H.; formal analysis, F.S.; investigation, F.S.; writing – original draft, F.S.; writing – review and editing, F.S., F.U., R.P., S.M., R.H., and G.L.; visualization, F.S.; supervision, F.U. and G.L.; funding acquisition, F.U., R.P., and G.L.

REFERENCES

1. EU (2021). Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 Establishing the Framework for Achieving Climate Neutrality and Amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law').

2. Agora, and Ember. (2021). The European Power Sector in 2018: Up-To-Date Analysis on the Electricity Transition*18*. https://ember-climate.org/insights/research/eu-power-sector-2018/.

3. Eurostat (2018). Database. http://ec.europa.eu/eurostat/de/data/database.

4. Clarke, L., Wei, Y.-M., De La Vega Navarro, A., Garg, A., Hahmann, A.N., Khennas, S., Azevedo, I.M.L., Löschel, A., Singh, A.K., Steg, L., et al. (2022). Energy Systems. In Climate Change 2022: Mitigation of Climate Change. Working Group III Contribution to the IPCC Sixth Assessment Report, P.R. Shukla, J. Skea, R. Slade, A. Al Khourdajie, R. van Diemen, D. McCollum, M. Pathak, S. Some, P. Vyas, and R. Fradera, et al., eds. (Cambridge University Press). https://doi.org/10.1017/9781009157926.008.

5. IRENA (2022). Renewable Power Generation Costs in 2021. https://www.irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021.

6. Hertwich, E.G., Gibon, T., Bouman, E.A., Arvesen, A., Suh, S., Heath, G.A., Bergesen, J.D., Ramirez, A., Vega, M.I., and Shi, L. (2015). Integrated life-cycle assessment of electricity-supply scenarios confirms global environmental benefit of low-carbon technologies. Proc. Natl. Acad. Sci. USA *112*, 6277–6282. https://doi.org/10.1073/pnas.1312753111.

7. Luderer, G., Madeddu, S., Merfort, L., Ueckerdt, F., Pehl, M., Pietzcker, R., Rottoli, M., Schreyer, F., Bauer, N., Baumstark, L., et al. (2021). Impact of declining renewable energy costs on electrification in low-emission scenarios. Nat. Energy *7*, 32–42. https://doi.org/10.1038/s41560-021-00937-z.

8. Luderer, G., Pehl, M., Arvesen, A., Gibon, T., Bodirsky, B.L., de Boer, H.S., Fricko, O., Hejazi, M., Humpenöder, F., Iyer, G., et al. (2019). Environmental co-benefits and adverse side-effects of alternative power sector decarbonization strategies. Nat. Commun. *10*, 5229. https://doi.org/10.1038/s41467-019-13067-8.

9. Pehl, M., Arvesen, A., Humpenöder, F., Popp, A., Hertwich, E.G., and Luderer, G. (2017). Understanding future emissions from low-carbon power systems by integration of life-cycle assessment and integrated energy modelling. Nat. Energy *2*, 939–945. https://doi.org/10.1038/s41560-017-0032-9.

10. IRENA (2022). Renewable Solutions in End-Uses: Heat Pump Costs and Markets (International Renewable Energy Agency). https://www.irena.org/Publications/2022/Nov/Renewable-solutions-in-end-uses-Heat-pump-costs-and-markets.

11. Madeddu, S., Ueckerdt, F., Pehl, M., Peterseim, J., Lord, M., Kumar, K.A., Krüger, C., and Luderer, G. (2020). The CO2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat). Environ. Res. Lett. *15*, 124004. https://doi.org/10.1088/1748-9326/abbd02.

12. Mauler, L., Duffner, F., Zeier, W.G., and Leker, J. (2021). Battery cost forecasting: a review of methods and results with an outlook to 2050. Energy Environ. Sci. *14*, 4712–4739. https://doi.org/10.1039/D1EE01530C.

13. Plötz, P. (2022). Hydrogen technology is unlikely to play a major role in sustainable road transport. Nat. Electron. *5*, 8–10. https://doi.org/10.1038/s41928-021-00706-6.

14. Rosenow, J. (2022). Is heating homes with hydrogen all but a pipe dream? An evidence review. Joule *6*, 2225–2228. https://doi.org/10.1016/j.joule.2022.08.015.

15. Anderson, K., and Peters, G. (2016). The trouble with negative emissions. Science *354*, 182–183. https://doi.org/10.1126/science.aah4567.

16. Haywood, L., Leroutier, M., and Pietzcker, R. (2023). Why investing in new nuclear plants is bad for the climate. Joule *7*, 1675–1678. https://doi.org/10.1016/j.joule.2023.07.006.

17. Global CCS Institute (2022). The Global Status of CCS: 2022 (Global CCS Institute). https://status22.globalccsinstitute.com/wp-content/uploads/2022/10/Global-Status-of-CCS-2022-Report-Final-compressed.pdf.

18. Schneider, M., and Froggatt, A. (2022). The World Nuclear Industry Status Report 2022. https://www.worldnuclearreport.org/-World-Nuclear-Industry-Status-Report-2022-.html.

19. Calvin, K., Cowie, A., Berndes, G., Arneth, A., Cherubini, F., Portugal-Pereira, J., Grassi, G., House, J., Johnson, F.X., Popp, A., et al. (2021). Bioenergy for climate change mitigation: Scale and sustainability. GCB Bioenergy *13*, 1346–1371. https://doi.org/10.1111/gcbb.12863.

20. Hanssen, S.V., Steinmann, Z.J.N., Daioglou, V., Čengić, M., Van Vuuren, D.P., and Huijbregts, M.A.J. (2022). Global implications of crop-based bioenergy with carbon capture and storage for terrestrial vertebrate biodiversity. GCB Bioenergy *14*, 307–321. https://doi.org/10.1111/gcbb.12911.

21. Merfort, L., Bauer, N., Humpenöder, F., Klein, D., Strefler, J., Popp, A., Luderer, G., and Kriegler, E. (2023). State of global land regulation inadequate to control biofuel land-use-change emissions. Nat. Clim. Chang. *13*, 610–612. –3. https://doi.org/10.1038/s41558-023-01711-7.

22. Rottoli, M., Dirnaichner, A., Pietzcker, R., Schreyer, F., and Luderer, G. (2021). Alternative electrification pathways for light-duty vehicles in the European transport sector. Transport. Res. Transport Environ. *99*, 103005. https://doi.org/10.1016/j.trd.2021.103005.

23. Ueckerdt, F., Bauer, C., Dirnaichner, A., Everall, J., Sacchi, R., and Luderer, G. (2021). Potential and risks of hydrogen-based e-fuels in climate change mitigation. Nat. Clim. Chang. *11*, 384–393. https://doi.org/10.1038/s41558-021-01032-7.

24. Weidner, T., and Guillén-Gosálbez, G. (2023). Planetary boundaries assessment of deep decarbonisation options for building heating in the European Union. Energy Convers. Manag. *278*, 116602. https://doi.org/10.1016/j.enconman.2022.116602.

25. IEA (2023). Global Hydrogen Review 2023 (International Energy Agency). https://www.iea.org/reports/global-hydrogen-review-2023.

26. Odenweller, A., Ueckerdt, F., Nemet, G.F., Jensterle, M., and Luderer, G. (2022). Probabilistic feasibility space of scaling up green hydrogen supply. Nat. Energy *7*, 854–865. https://doi.org/10.1038/s41560-022-01097-4.

27. Genge, L., Scheller, F., and Müsgens, F. (2023). Supply costs of green chemical energy carriers at the European border: A meta-analysis. Int. J. Hydrogen Energy *48*, 38766–38781. S0360319923030847. https://doi.org/10.1016/j.ijhydene.2023.06.180.

28. Hampp, J., Düren, M., and Brown, T. (2023). Import options for chemical energy carriers from renewable sources to Germany. PLoS One *18*, e0262340. https://doi.org/10.1371/journal.pone.0281380.

29. IRENA (2022). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part II – Technology Review of Hydrogen Carriers. https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II.

30. European Scientific Advisory Board on Climate Change (2023). Scientific Advice for the Determination of an EU-wide 2040 Climate Target and a Greenhouse Gas Budget for 2030–2050. https://climate-advisory-board.europa.eu/reports-and-publications/scientific-advice-for-the-determination-of-an-eu-wide-2040.

31. Blanco, H., Nijs, W., Ruf, J., and Faaij, A. (2018). Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization. Appl. Energy *232*, 617–639. https://doi.org/10.1016/j.apenergy.2018.09.216.

32. Blanco, H., Nijs, W., Ruf, J., and Faaij, A. (2018). Potential of Power-to-Methane in the EU energy transition to a low carbon system using cost optimization. Appl. Energy *232*, 323–340. https://doi.org/10.1016/j.apenergy.2018.08.027.

33. Evangelopoulou, V., Zazias, Capros, and Capros. (2019). Energy System Modelling of Carbon-Neutral Hydrogen as an Enabler of Sectoral Integration within a Decarbonization Pathway. Energies *12*, 2551. https://doi.org/10.3390/en12132551.

34. Seck, G.S., Hache, E., Sabathier, J., Guedes, F., Reigstad, G.A., Straus, J., Wolfgang, O., Ouassou, J.A., Askeland, M., Hjorth, I., et al. (2022). Hydrogen and the decarbonization of the energy system in europe in 2050: A detailed model-based analysis. Renew. Sustain. Energy Rev. *167*, 112779. https://doi.org/10.1016/j.rser.2022.112779.

35. Tarvydas, D. (2022). The Role of Hydrogen in Decarbonisation Energy Scenarios: Views on 2030 and 2050 (Publications Office). https://publications.jrc.ec.europa.eu/repository/bitstream/JRC131299/JRC131299_01.pdf.

36. IEA (2020). Energy Technology Perspectives 2020. https://www.iea.org/reports/energy-technology-perspectives-2020.

37. Krause, J., Thiel, C., Tsokolis, D., Samaras, Z., Rota, C., Ward, A., Prenninger, P., Coosemans, T., Neugebauer, S., and Verhoeve, W. (2020). EU road vehicle energy consumption and CO2 emissions by 2050 – Expert-based scenarios. Energy Pol. *138*, 111224. https://doi.org/10.1016/j.enpol.2019.111224.

38. Sharmina, M., Edelenbosch, O.Y., Wilson, C., Freeman, R., Gernaat, D.E.H.J., Gilbert, P., Larkin, A., Littleton, E.W., Traut, M., van Vuuren, D.P., et al. (2020). Decarbonising the critical sectors of aviation, shipping, road freight and industry to limit warming to 1.5–2°C. Clim. Pol. *21*, 455–474. https://doi.org/10.1080/14693062.2020.1831430.

39. IEA (2022). Hydrogen Projects Database. https://www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database.

40. Capros, P., Zazias, G., Evangelopoulou, S., Kannavou, M., Fotiou, T., Siskos, P., De Vita, A., and Sakellaris, K. (2019). Energy-system modelling of the EU strategy towards climate-neutrality. Energy Pol. *134*, 110960. https://doi.org/10.1016/j.enpol.2019.110960.

41. Grassi, G., House, J., Kurz, W.A., Cescatti, A., Houghton, R.A., Peters, G.P., Sanz, M.J., Viñas, R.A., Alkama, R., Arneth, A., et al. (2018). Reconciling global-model estimates and country reporting of anthropogenic forest CO2 sinks. Nat. Clim. Chang. *8*, 914–920. https://doi.org/10.1038/s41558-018-0283-x.

42. Arrigoni, A., and Bravo Diaz, L. (2022). Hydrogen Emissions from a Hydrogen Economy and Their Potential Global Warming Impact (Publications Office of the European Union).

43. Sand, M., Skeie, R.B., Sandstad, M., Krishnan, S., Myhre, G., Bryant, H., Derwent, R., Hauglustaine, D., Paulot, F., Prather, M., and Stevenson, D. (2023). A multi-model assessment of the Global Warming Potential of hydrogen. Commun. Earth Environ. *4*, 203. https://doi.org/10.1038/s43247-023-00857-8.

44. Dieterich, V., Buttler, A., Hanel, A., Spliethoff, H., and Fendt, S. (2020). Power-to-liquid via synthesis of methanol, DME or Fischer–Tropsch-fuels: a review. Energy Environ. Sci. *13*, 3207–3252. https://doi.org/10.1039/D0EE01187H.

45. Stöckl, F., Schill, W.-P., and Zerrahn, A. (2021). Optimal supply chains and power sector benefits of green hydrogen. Sci. Rep. *11*, 14191. https://doi.org/10.1038/s41598-021-92511-6.

46. Pietzcker, R.C., Osorio, S., and Rodrigues, R. (2021). Tightening EU ETS targets in line with the European Green Deal: Impacts on the decarbonization of the EU power sector. Appl. Energy *293*, 116914. https://doi.org/10.1016/j.apenergy.2021.116914.

47. EU (2023). Directive of the European Parliament and of the Council Amending Directive 2003/87/EC Stablishing a System for Greenhouse Gas Emission Allowance Trading within the Union and Decision (EU) 2015/1814 Concerning the Establishment and Operation of a Market Stability Reserve for the Union Greenhouse Gas Emission Trading System.

48. Gillingham, K., and Palmer, K. (2014). Bridging the energy efficiency gap: Policy insights from economic theory and empirical evidence. Rev. Environ. Econ. Pol. 8, 18–38.

49. McCollum, D.L., Wilson, C., Pettifor, H., Ramea, K., Krey, V., Riahi, K., Bertram, C., Lin, Z., Edelenbosch, O.Y., and Fujisawa, S. (2017). Improving the behavioral realism of global integrated assessment models: An application to consumers' vehicle choices. Transport. Res. Transport Environ. 55, 322–342. https://doi.org/10.1016/j.trd.2016.04.003.

50. Wekhof, T., and Houde, S. (2023). Using narratives to infer preferences in understanding the energy efficiency gap. Nat. Energy 8, 965–977. https://doi.org/10.1038/s41560-023-01303-x.

51. European Commission (2022). Communication from the Commission to the European Parliament (the European Council, the Council, the European Economic and Social Committee of the Regions REPowerEU Plan).

52. European Heat Pump Association (2023). Subsidies for Resiential Heat Pumps in Europe. https://www.ehpa.org/wp-content/uploads/2023/03/EHPA_Subsidies-for-residential-heat-pumps-in-Europe_FINAL_April-2023.pdf.

53. EU (2023). Directive of the European Parliament and of the Council on Energy Efficiency and Amending Regulation (EU) 2023/955 (recast).

54. Braungardt, S., Tezak, B., Rosenow, J., and Bürger, V. (2023). Banning boilers: An analysis of existing regulations to phase out fossil fuel heating in the EU. Renew. Sustain. Energy Rev. 183, 113442. https://doi.org/10.1016/j.rser.2023.113442.

55. European Commission (2021). Proposal for a Directive of the European Parliament and of the Council on Common Rules for the Internal Markets in Renewable and Natural Gases and in Hydrogen.

56. Gross, R., and Hanna, R. (2019). Path dependency in provision of domestic heating. Nat. Energy 4, 358–364. https://doi.org/10.1038/s41560-019-0383-5.

57. European Commission (2021). Proposal for a Regulation of the European Parliament and of the Council on Ensuring a Level Playing Field for Sustainable Air Transport.

58. European Commission (2021). Proposal for a Regulation of the European Parliament and of the Council on the Use of Renewable and Low-Carbon Fuels in maritime transport and amending Directive 2009/16/EC.

59. European Council (2023). Proposal for a Directive of the European Parliament and of the Council Amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652 and Proposal for a Directive the European Parliament and of the Council amending Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources, Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency 2021/0218(COD).

60. European Commission (2023). Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee of the Regions on the European Hydrogen Bank.

61. European Commission (2023). Commission Delegated Regulation (EU) of 10.2.2023 Supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin.

62. European Commission (2021). Communication from the Commission to the European Parliament and the Council Sustainable Carbon Cycles.

63. Kędzierski, M. (2019). German wind power sector in crisis Energiewende under further threat. OSW Commentary, 1–8.

64. Neumann, F., Zeyen, E., Victoria, M., and Brown, T. (2023). The potential role of a hydrogen network in Europe. Joule 7, 1793–1817. https://doi.org/10.1016/j.joule.2023.06.016.

65. Tröndle, T., Lilliestam, J., Marelli, S., and Pfenninger, S. (2020). Trade-Offs between Geographic Scale, Cost, and Infrastructure Requirements for Fully Renewable Electricity in Europe. Joule 4, 1929–1948. https://doi.org/10.1016/j.joule.2020.07.018.

66. Chen, T., and Vandendriessche, F. (2023). Evolution of the EU legal framework for promoting RES-E: A market compatible paradigm shift? Util. Pol. 83, 101608. https://doi.org/10.1016/j.jup.2023.101608.

67. Hu, J., Harmsen, R., Crijns-Graus, W., Worrell, E., and van den Broek, M. (2018). Identifying barriers to large-scale integration of variable renewable electricity into the electricity market: A literature review of market design. Renew. Sustain. Energy Rev. 81, 2181–2195. https://doi.org/10.1016/j.rser.2017.06.028.

68. Held, A., Ragwitz, M., Del R-Resch, G., Klessmann, C., Hassel, A., Elkerbout, M., Rawlins, J., and Rawlins, J. (2019). Do Almost Mature Renewable Energy Technologies Still Need Dedicated Support Towards 2030? EEEP 8. https://doi.org/10.5547/2160-5890.8.2.ahel.

69. Özdemir, Ö., Hobbs, B.F., van Hout, M., and Koutstaal, P.R. (2020). Capacity vs energy subsidies for promoting renewable investment: Benefits and costs for the EU power market. Energy Pol. 137, 111166. https://doi.org/10.1016/j.enpol.2019.111166.

70. Liebensteiner, M., and Naumann, F. (2022). Can carbon pricing counteract renewable energies' cannibalization problem? Energy Econ. 115, 106345. https://doi.org/10.1016/j.eneco.2022.106345.

71. Anatolitis, V., Azanbayev, A., and Fleck, A.-K. (2022). How to design efficient renewable energy auctions? Empirical insights from Europe. Energy Pol. 166, 112982. https://doi.org/10.1016/j.enpol.2022.112982.

72. Ruiz, P., Nijs, W., Tarvydas, D., Sgobbi, A., Zucker, A., Pilli, R., Jonsson, R., Camia, A., Thiel, C., Hoyer-Klick, C., et al. (2019). ENSPRESO - an open, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials. Energy Strategy Rev. 26, 100379. https://doi.org/10.1016/j.esr.2019.100379.

73. European Commission (2018). In-depth analysis in support of the Commission Communication COM (2018) 773. A Clean Planet for all. A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy.

74. Baumstark, L., Bauer, N., Benke, F., Bertram, C., Bi, S., Gong, C.C., Dietrich, J.P., Dirnaichner, A., Giannousakis, A., Hilaire, J., et al. (2020). REMIND2.1: Transformation and Innovation Dynamics of the Energy-Economic System within Climate and Sustainability Limits.

75. Luderer, G., Bauer, N., Baumstark, L., Bertram, C., Leimbach, M., Pietzcker, R., Strefler, J., Aboumahboub, T., Abrahão, G., Auer, C., et al. (2022). REMIND - REgional Model of INvestments and Development (Zenodo)). https://doi.org/10.5281/zenodo.6794920.

76. Rodrigues, R., Pietzcker, R., Fragkos, P., Price, J., McDowall, W., Siskos, P., Fotiou, T., Luderer, G., and Capros, P. (2022). Narrative-driven alternative roads to achieve mid-century CO_2 net neutrality in Europe. Energy 239, 121908. https://doi.org/10.1016/j.energy.2021.121908.

77. Baumstark, L., Bauer, N., Benke, F., Bertram, C., Bi, S., Gong, C.C., Dietrich, J.P., Dirnaichner, A., Giannousakis, A., Hilaire, J., et al. (2021). REMIND2.1: Transformation and innovation dynamics of the energy-economic system within climate and sustainability limits. Geosci. Model Dev. Discuss. (GMDD), 1–50. https://doi.org/10.5194/gmd-2021-85.

78. Dirnaichner, A., Rottoli, M., Sacchi, R., Rauner, S., Cox, B., Mutel, C., Bauer, C., and Luderer, G. (2022). Life-cycle impacts from different

decarbonization pathways for the European car fleet. Environ. Res. Lett. *17*, 044009. https://doi.org/10.1088/1748-9326/ac4fdb.

79. Rottoli, M., Dirnaichner, A., Kyle, P., Baumstark, L., Pietzcker, R., and Luderer, G. (2021). Coupling a Detailed Transport Model to the Integrated Assessment Model REMIND. Environ. Model. Assess. *26*, 891–909. https://doi.org/10.1007/s10666-021-09760-y.

80. Pehl, M., Schreyer, F., and Luderer, G. (2023). Modelling Long-Term Industry Energy Demand and CO2 Emissions in the System Context Using REMIND (Version 3.1.0). Geosci. Model Dev. Discuss. (GMDD), 1–29. https://doi.org/10.5194/gmd-2023-153.

81. Levesque, A., Pietzcker, R.C., Baumstark, L., De Stercke, S., Grübler, A., and Luderer, G. (2018). How much energy will buildings consume in 2100? A global perspective within a scenario framework. Energy *148*, 514–527. https://doi.org/10.1016/j.energy.2018.01.139.

82. Riahi, K., van Vuuren, D.P., Kriegler, E., Edmonds, J., O'Neill, B.C., Fujimori, S., Bauer, N., Calvin, K., Dellink, R., Fricko, O., et al. (2017). The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview. Global Environ. Change *42*, 153–168. https://doi.org/10.1016/j.gloenvcha.2016.05.009.

Supplemental information

Distinct roles of direct and indirect electrification in pathways to a renewables-dominated European energy system

Felix Schreyer, Falko Ueckerdt, Robert Pietzcker, Renato Rodrigues, Marianna Rottoli, Silvia Madeddu, Michaja Pehl, Robin Hasse, and Gunnar Luderer

Supplemental Information

Supplemental Figures
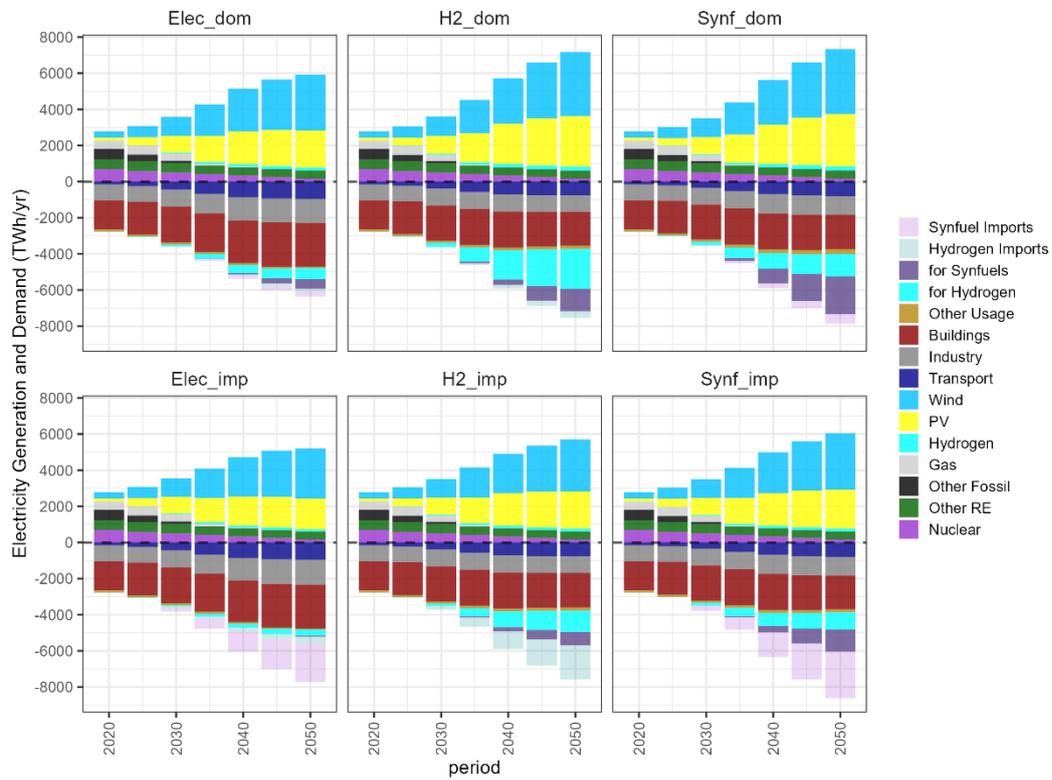
Figure S1: Electricity supply (positive bars) and demand (negative bars) across scenarios in the EU27.
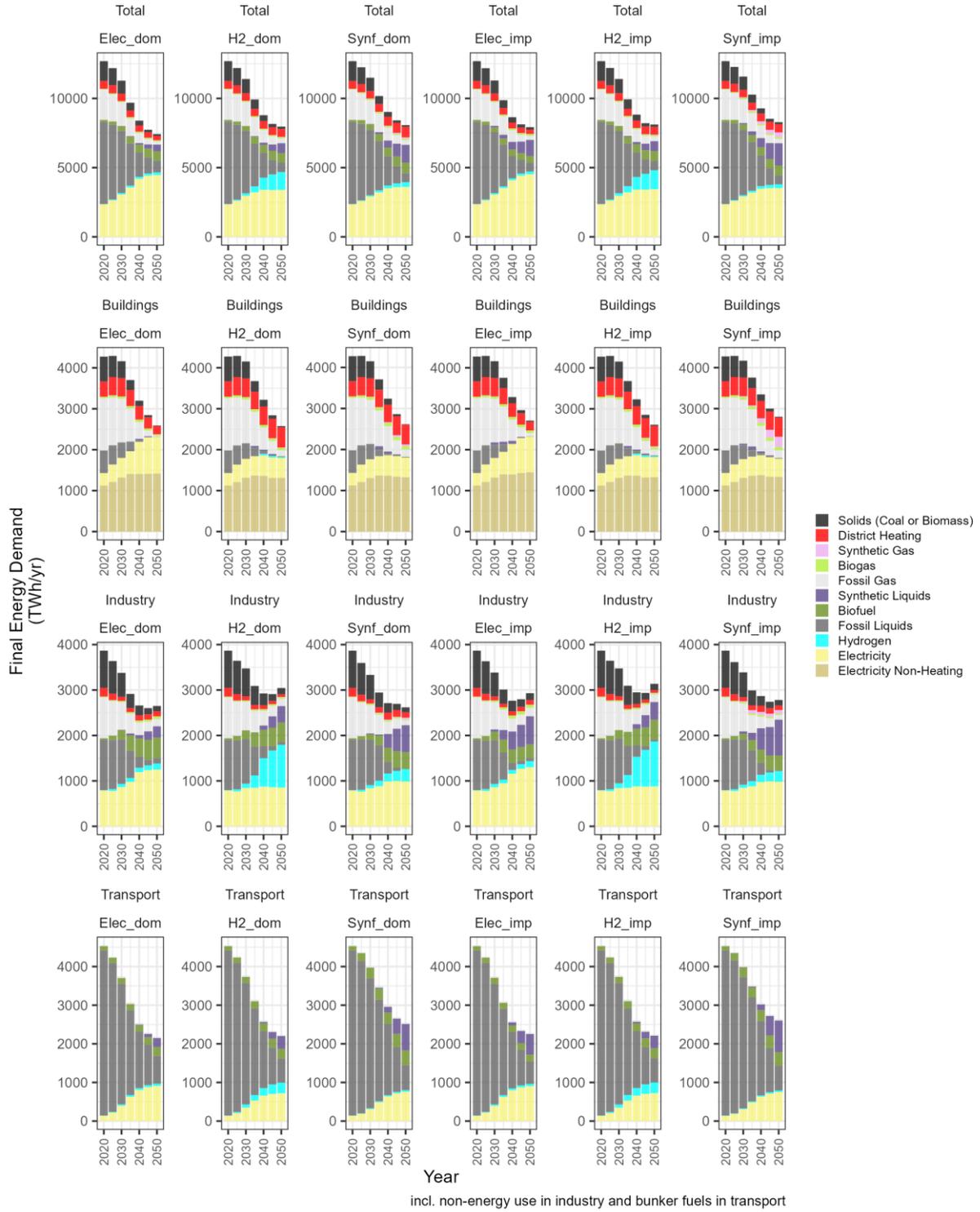
Figure S2: Final energy mix in the EU27 across sectors and scenarios from 2020 to 2050.
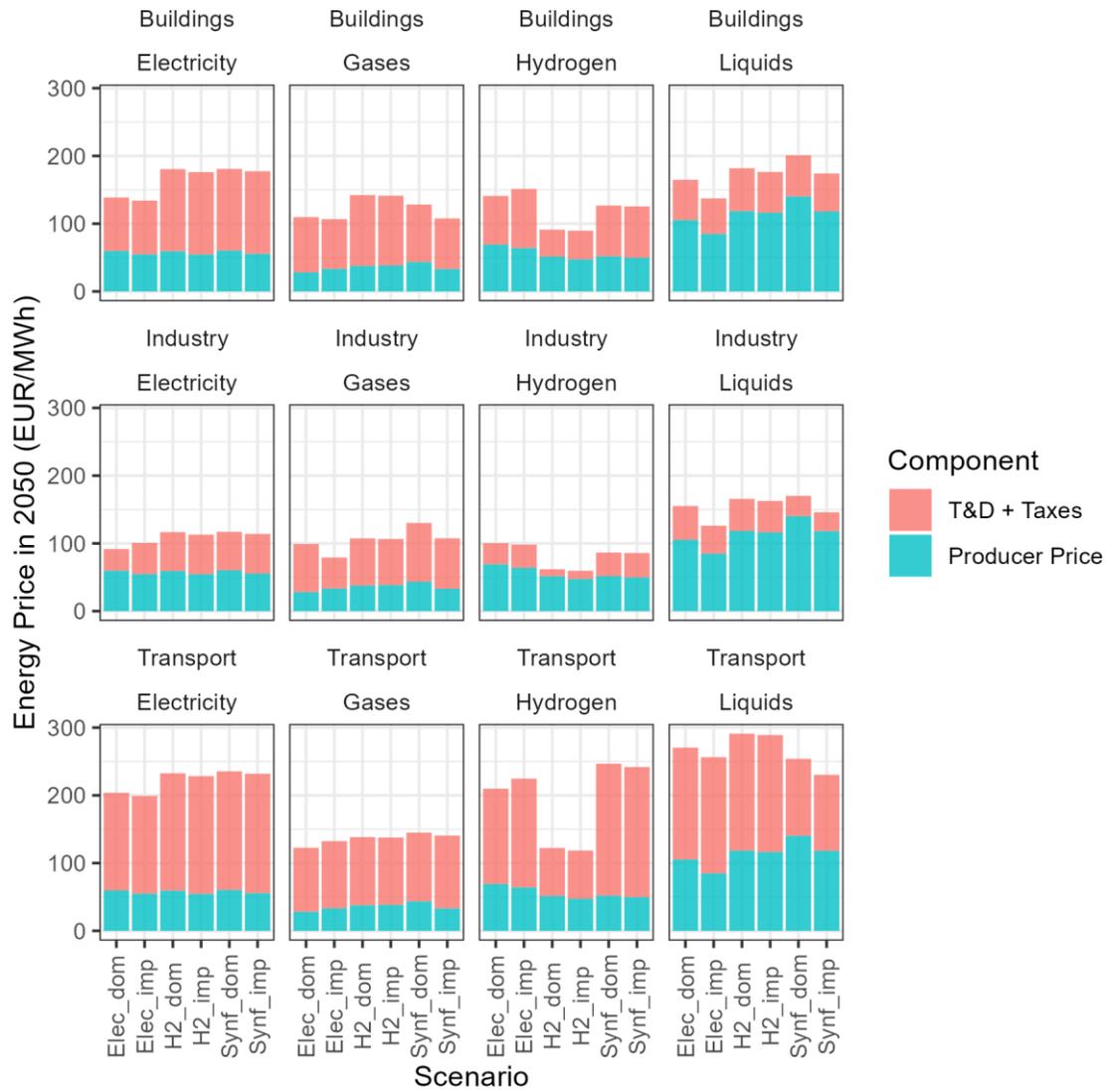
Figure S3: Modeled final energy prices in 2050 across scenarios and sectors for electricity, hydrogen, liquids and gases in the EU27 (regional averages weighted by energy demand). Secondary energy prices (blue component) correspond to the producer price. Final energy prices include taxes (carbon tax and general energy taxes) as well as transmission and distribution cost (red component). The depicted prices are based on model output, that is, on the shadow price of the secondary and final energy balance equations respectively.
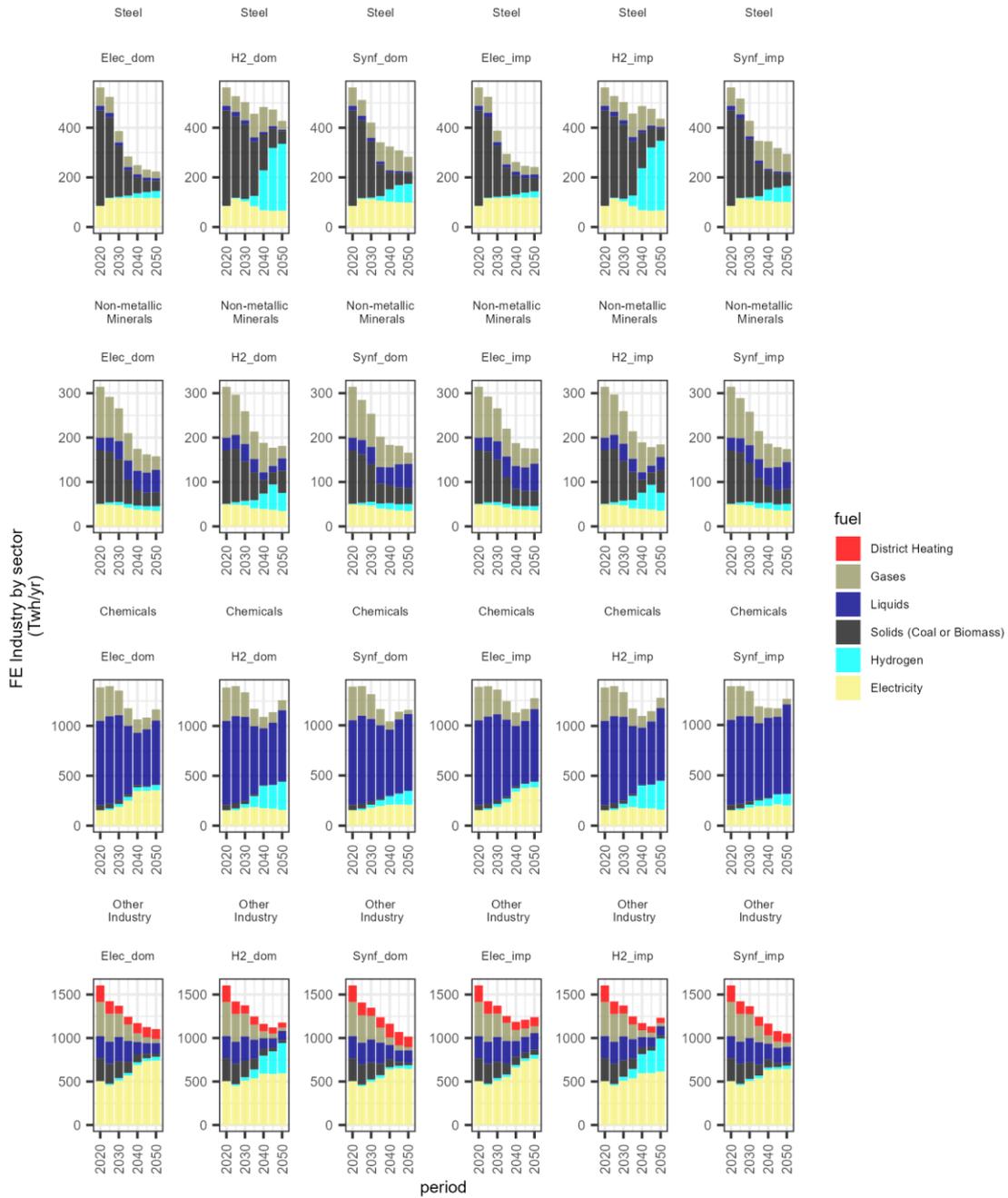
Figure S4: Final energy demand in industry sectors by energy carrier across scenarios in the EU27. Solids, liquids and gases subsume carbonaceous energy of fossil, biogenic and synthetic origin. The steel sector includes production of primary as well as secondary steel. The non-metallic minerals sector includes manufacturing of cement, glass and ceramics. The chemical sector includes non-energy use (feedstocks).
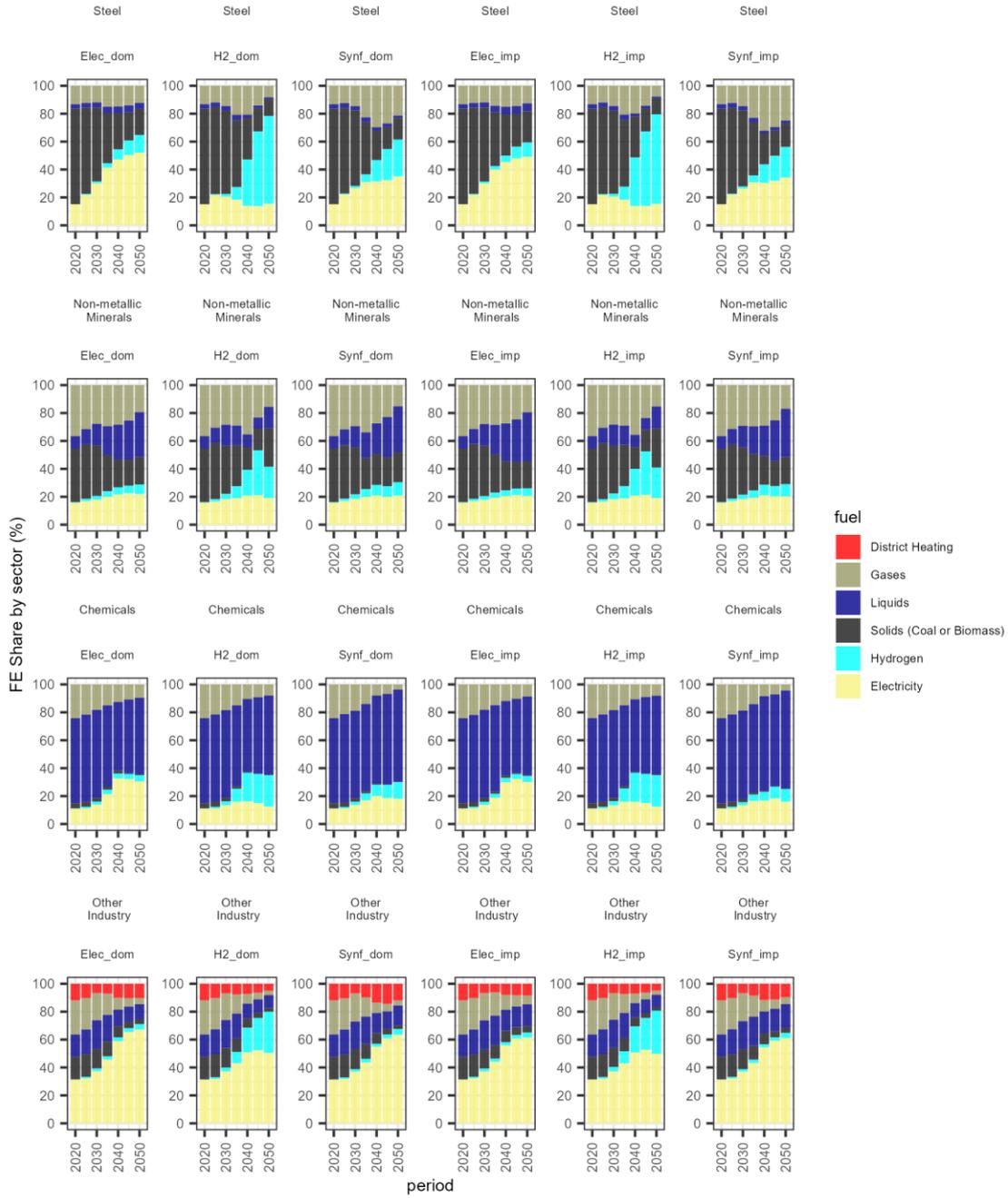
Figure S5: Shares of final energy demand in industry sectors by energy carrier across scenarios in the EU27. Solids, liquids and gases subsume carbonaceous energy of fossil, biogenic and synthetic origin. The steel sector includes production of primary as well as secondary steel. The non-metallic minerals sector includes manufacturing of cement, glass and ceramics. The chemical sector includes non-energy use (feedstocks).
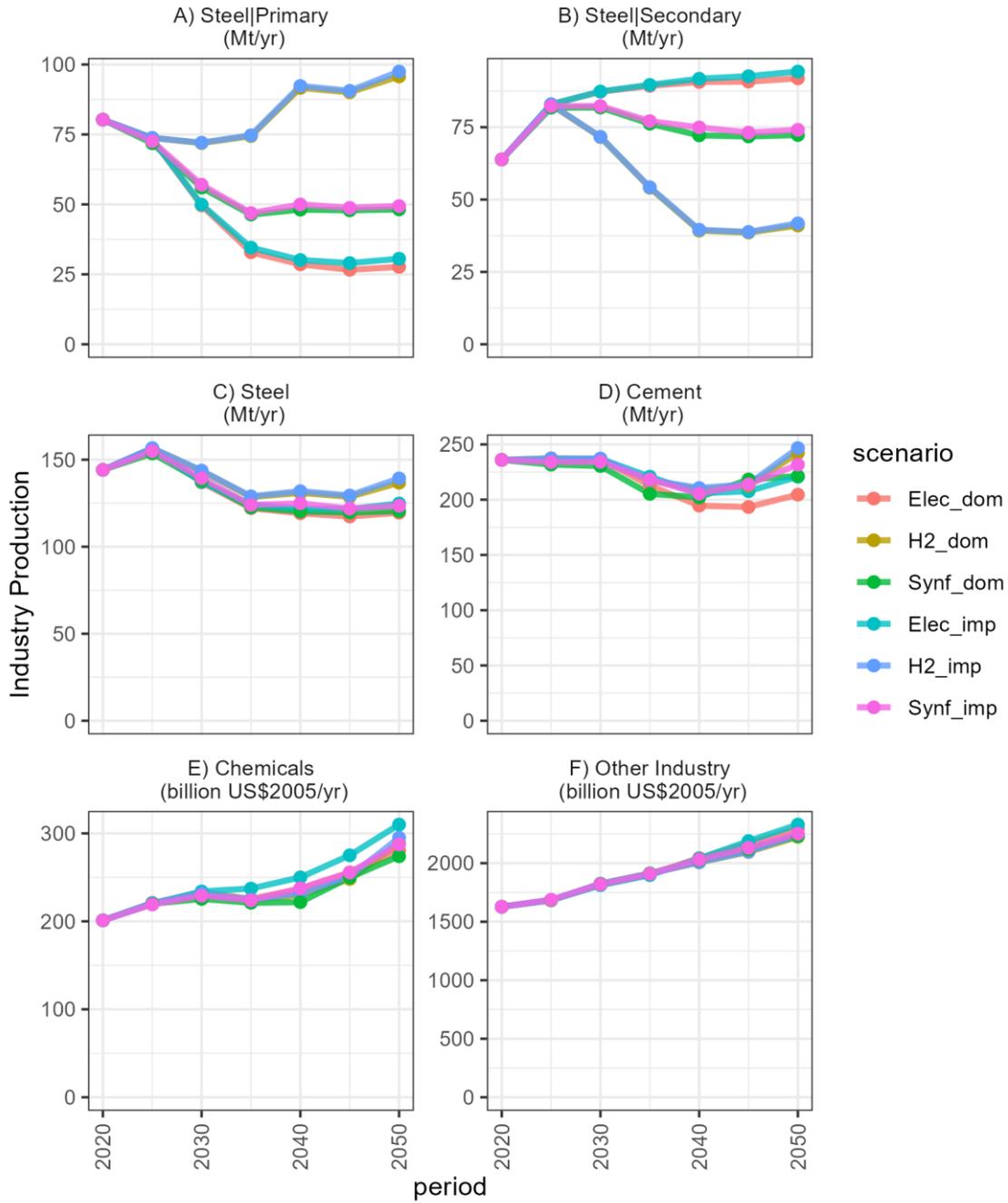
Figure S6: Production of industrial subsectors resolved in the model across scenarios in the EU27. Panels refer to different outputs: A) Primary steel production, B) Secondary steel production, C) Total steel production, D) Cement Production, E) Chemicals Production, F) Aggregate production of other industrial sectors. Steel and cement are given in metric tons, while chemicals and other industry (e.g. non-ferrous metals, food, pulp and paper, machinery) are accounted as value added in monetary units.
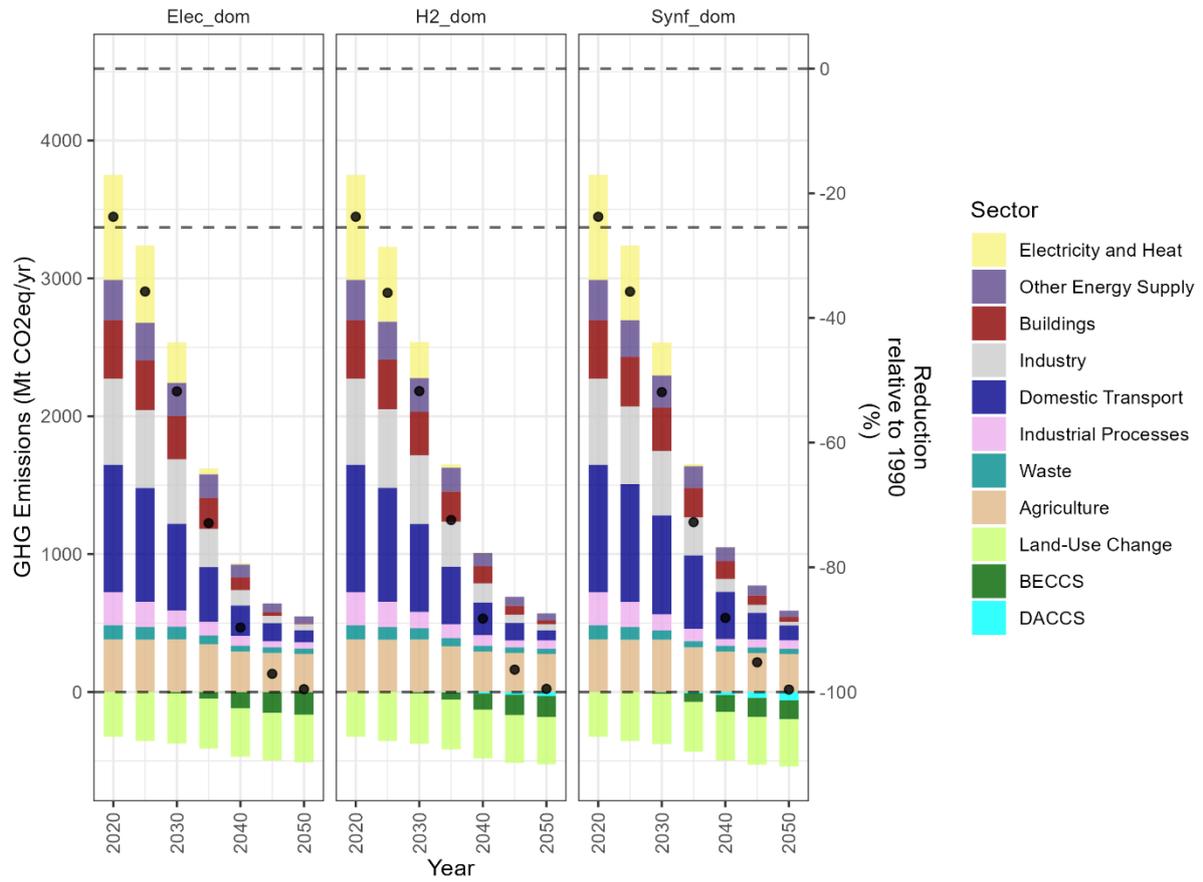
Figure S7: Greenhouse gas emissions pathways across sectors and scenarios with domestic focus. Horizontal lines show 1990 emissions, 2020 emissions and 2050 target emissions of the EU27.
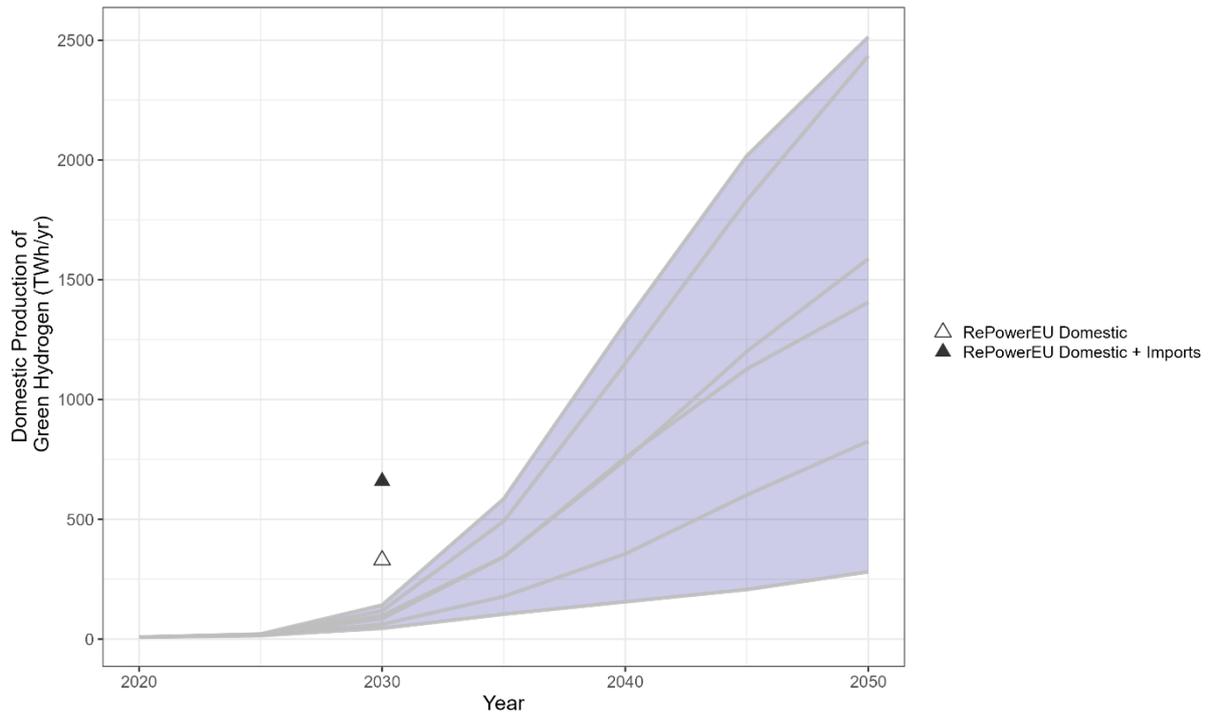
Figure S8: Production of green hydrogen via electrolysis across scenarios in the EU27. Triangles denote the green hydrogen production and consumption targets defined by the RePowerEU plan[1].
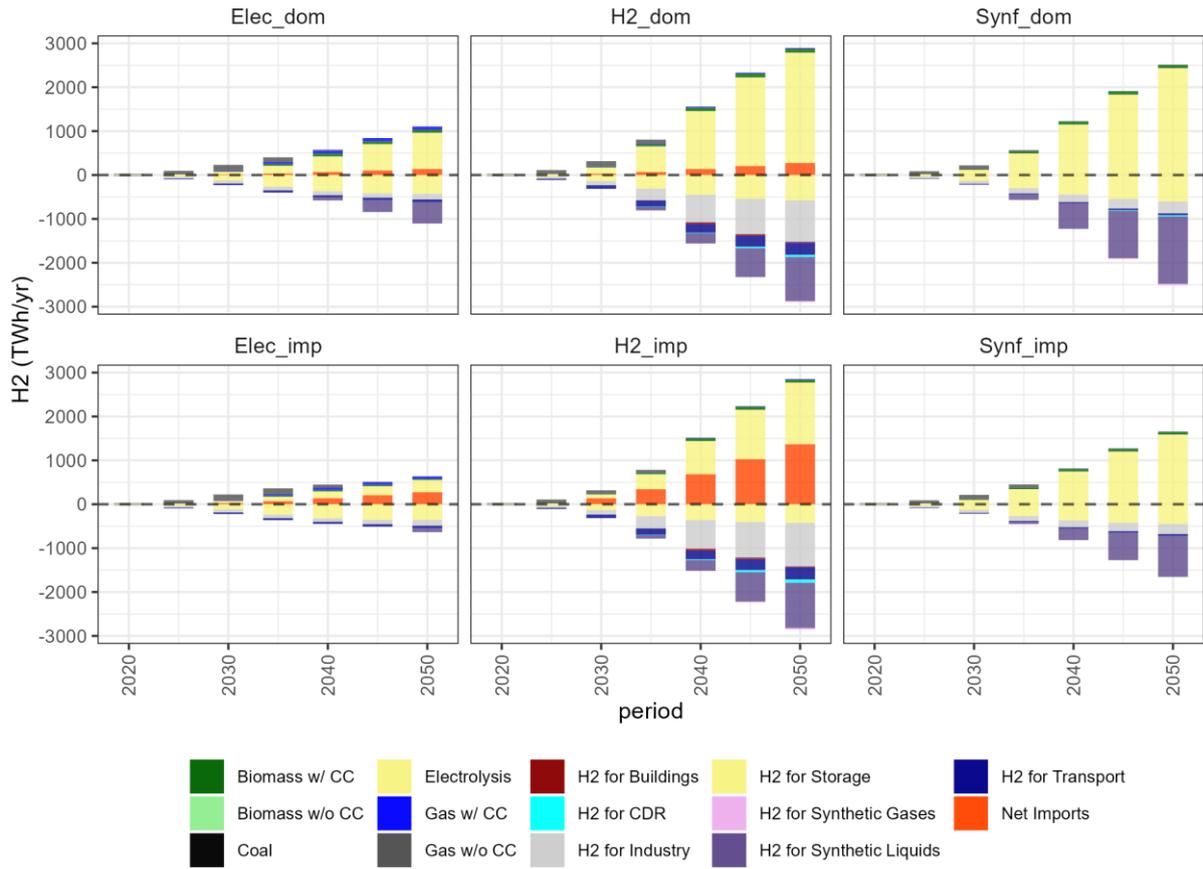
Figure S9: Hydrogen supply by source (positive bars) and hydrogen demand by sector (negative bars) across scenarios in the EU27.
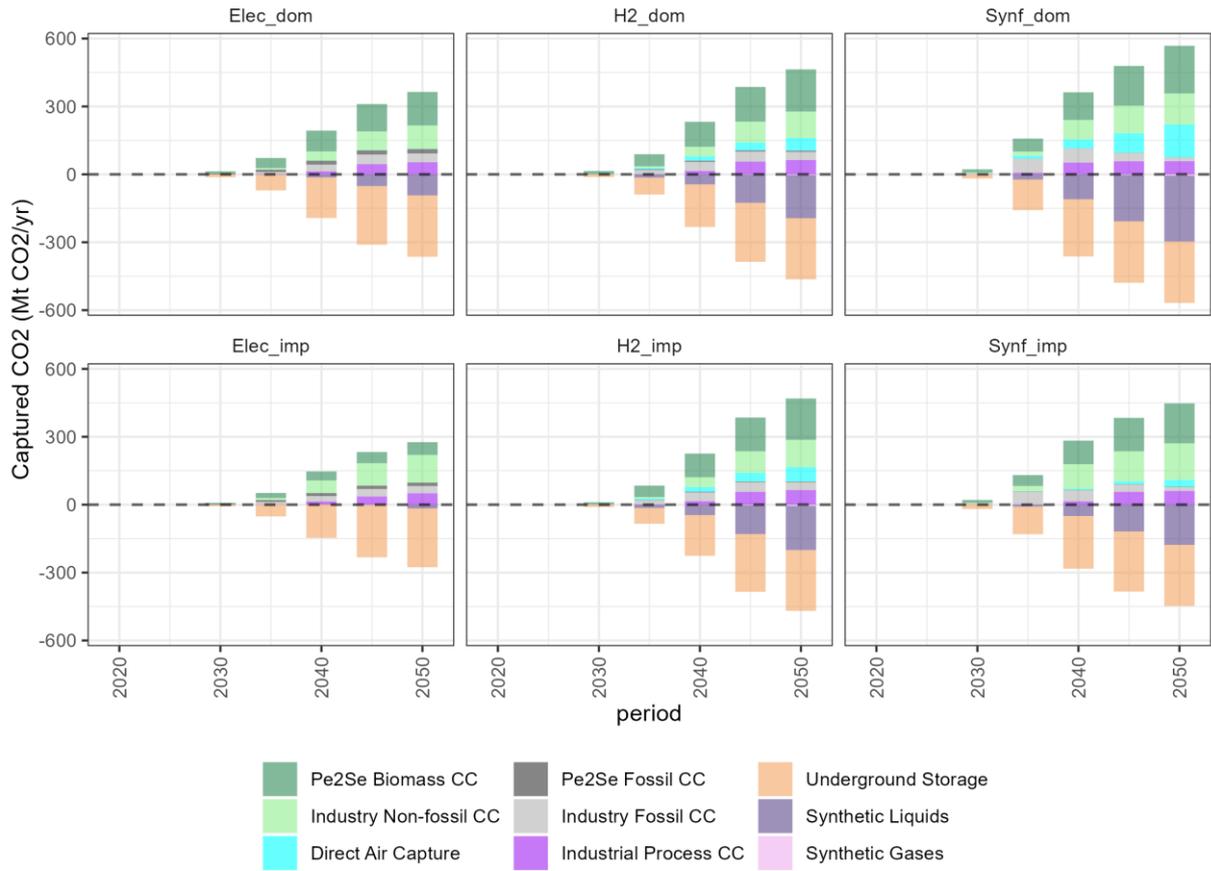
Figure S10: Sources and sinks of captured CO2 across scenarios for the EU27. In the legend, Pe2Se refers to captured carbon (CC) from energy conversion technologies (e.g. from power plants). Industrial process CC refers to carbon from calcination in cement production.
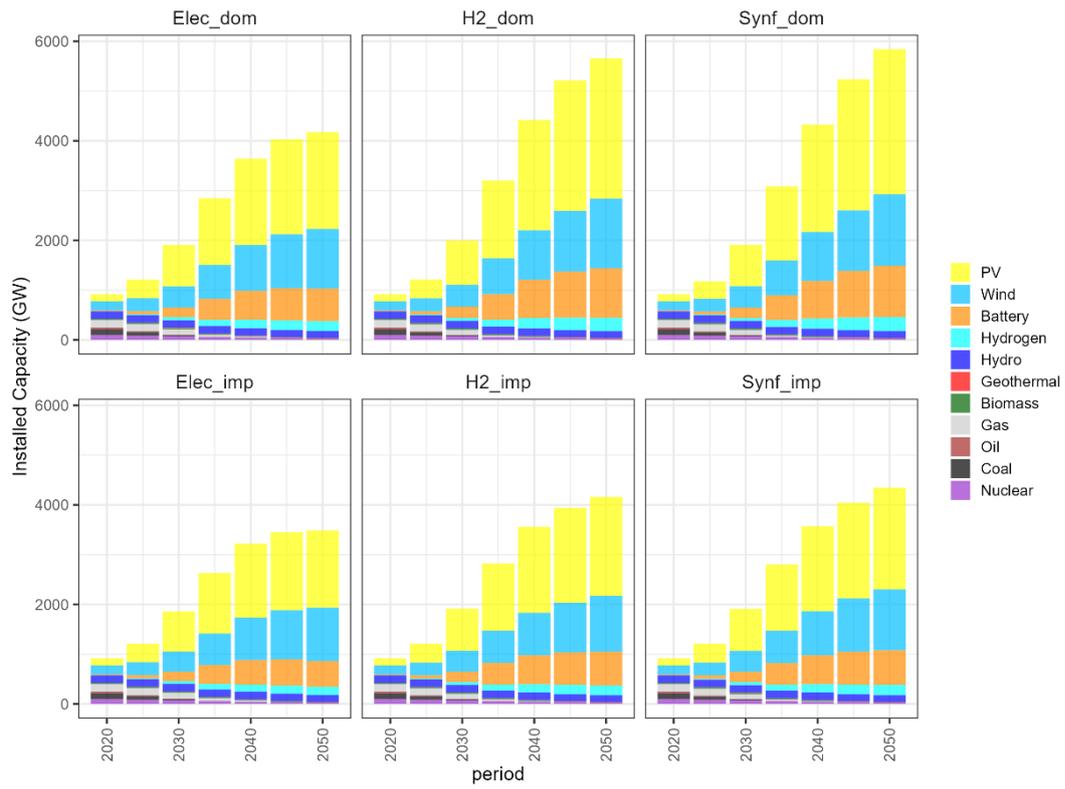
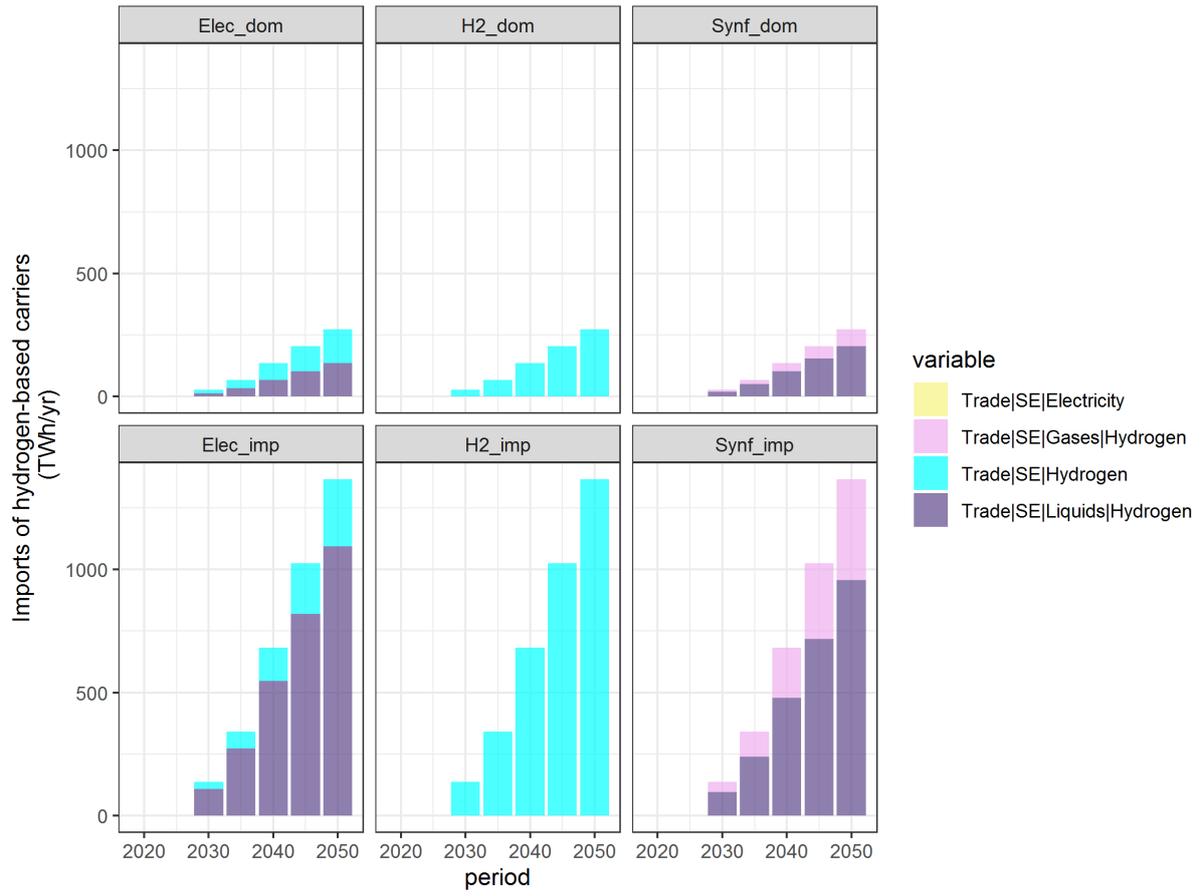*Figure S11: Capacities of electricity generation by technology in the EU27 across scenarios.*

Figure S12: Exogenous assumptions on hydrogen and synthetic fuels imported to the EU27 in TWh/yr. Imports are distributed across EU regions by share of GDP.
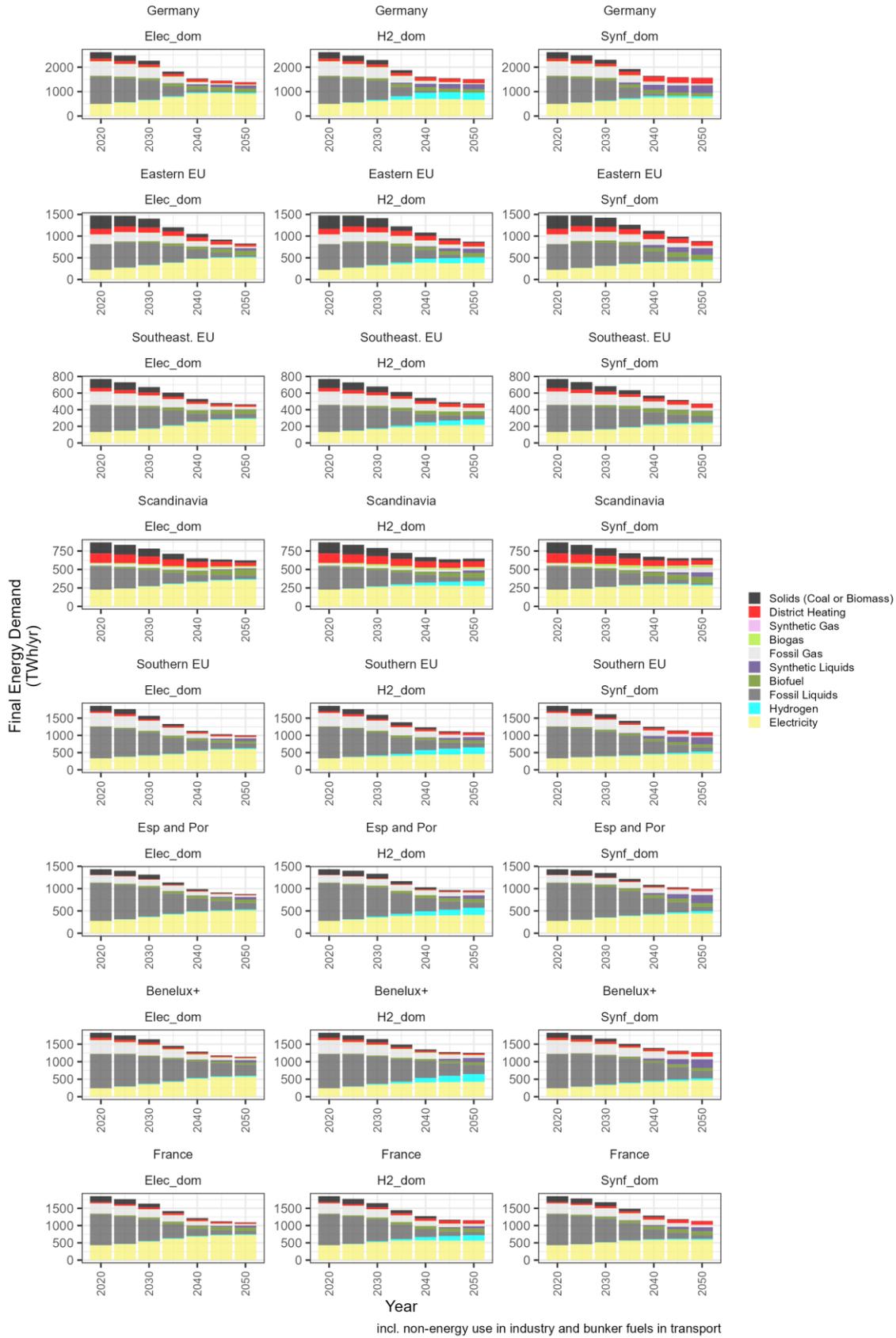
Figure S13: Final energy mix from 2020 to 2050 across the three domestic scenarios and the 8 European regions that were modelled within the EU27 region. Please see Table S1 for the countries included in each of the regions.
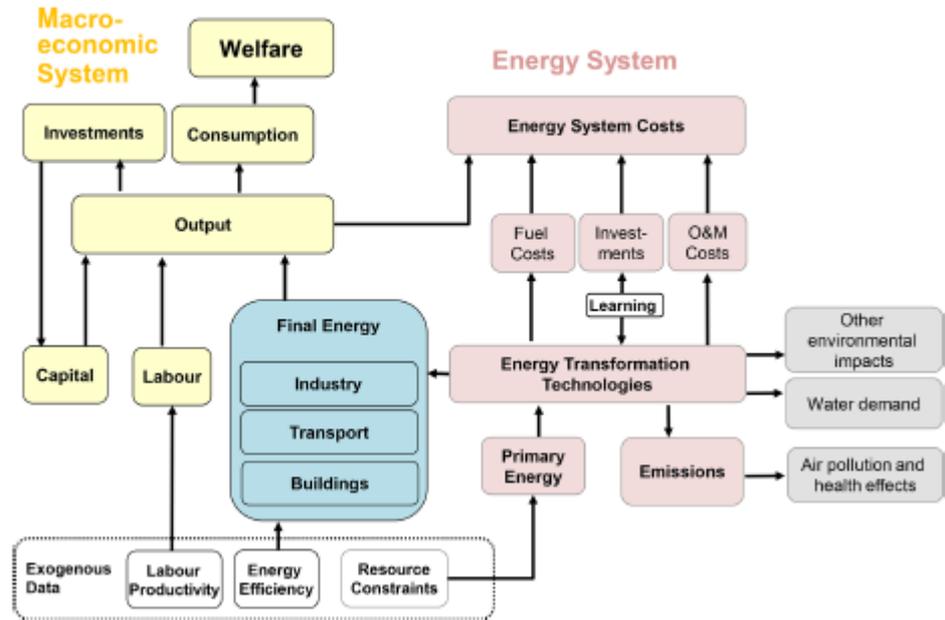
Figure S14: Structure of the REMIND model. REMIND is an integrated assessment modeling framework to explore energy-economy transformation dynamics by linking linear energy supply system (red) to sector-specific energy demand representations (blue) and a macroeconomic growth model (yellow). These systems are coupled and subject to an intertemporal optimization of macroeconomic welfare. The Figure is taken from Baumstark et al[2].
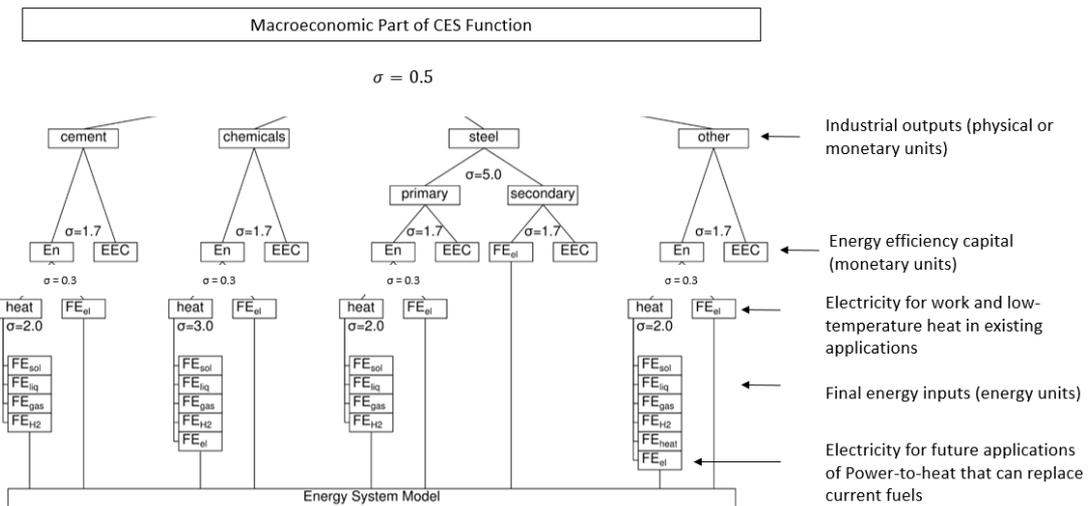

Figure S15: CES function of the industrial sector in REMIND. At the bottom, the CES function is linked to the energy system via the provision of final energy carriers. At the top, it is linked to the macroeconomic part of the CES function. The figure is adapted from Pehl et al[3].
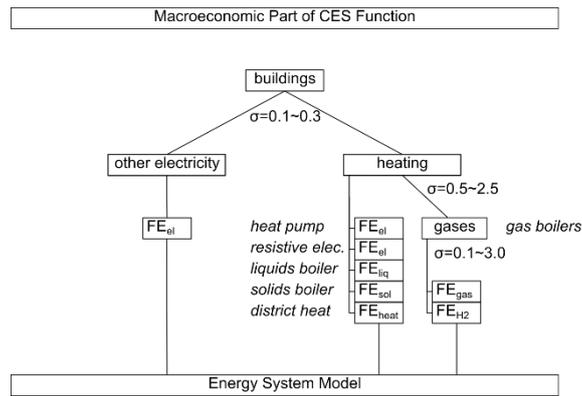
Figure S16: CES function of the buildings sector in REMIND. At the bottom, the CES function is linked to the energy system via the provision of final energy carriers. At the top, it is linked to the macroeconomic part of the CES function.
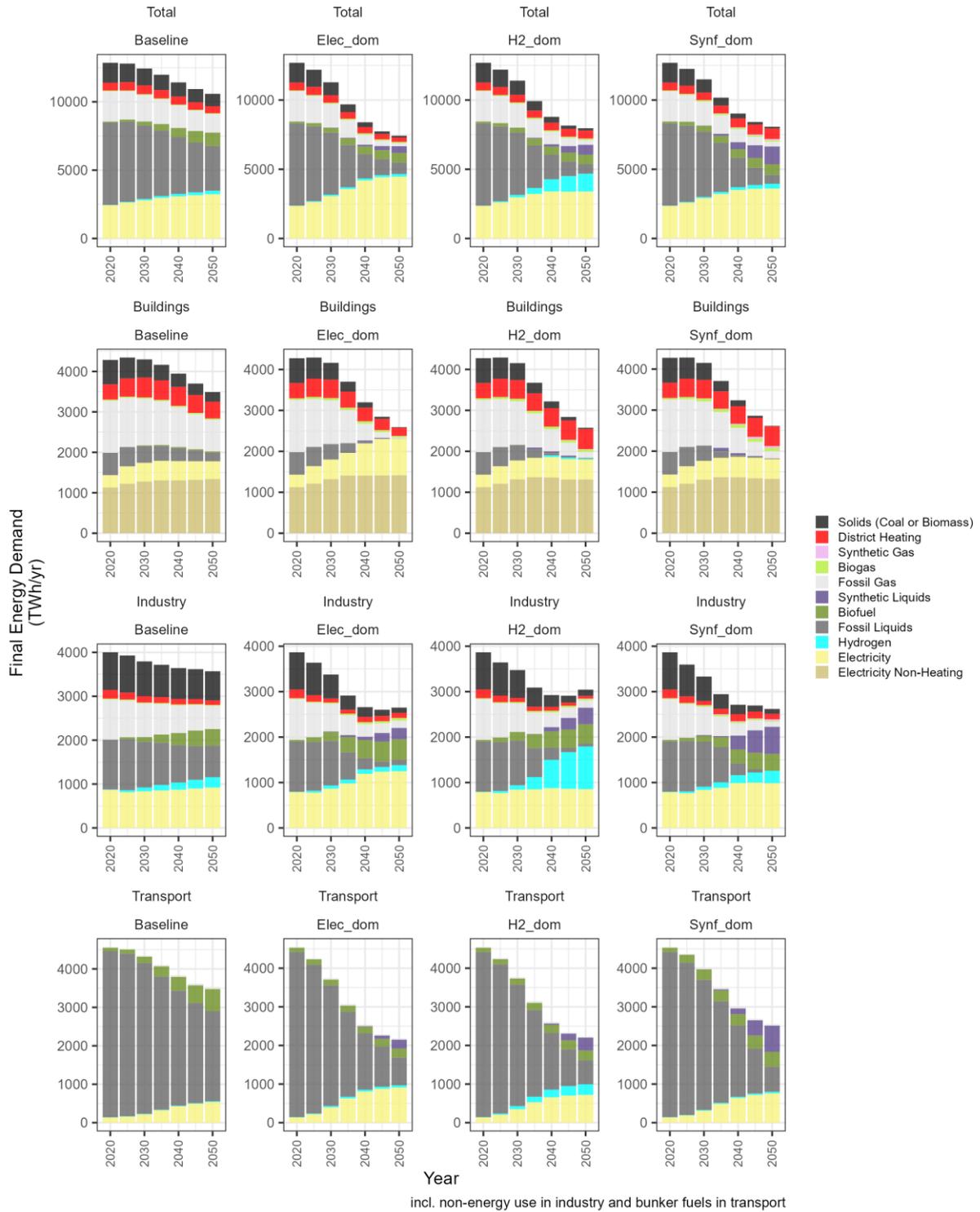
Figure S17: Final energy demand for the EU27 region across sectors for the baseline scenario and the three domestic technology scenarios presented in this study. The baseline scenario is a scenario without climate policy that serves as a reference to derive our six scenarios introducing climate targets and technology policies on top (see Table 1, Table S1).

Supplemental Tables

Table S1: Details on Cost Assumptions Across Scenarios

Assumption	Baseline	Elec	H2	Synf	Comment
Energy Taxes (without carbon tax)					
Electricity	Constant at current levels (default [a])	-30% decrease	+30% increase	+30% increase	
Hydrogen	Constant at current levels of natural gas (default)	default	-30% decrease	+30% increase	Tax changes only affect transport sector as tax is small in other sectors.
Gas (carbonaceous)	Constant at current levels (default)	+30% increase	+30% increase	-90% decrease	
Liquids (carbonaceous)	Constant at current levels (default)	+30% increase	+30% increase	-90%/-30% decrease	Strong decrease in industry/buildings of 90%, only -30% in transport since transport fuel taxes are high and major source of income for some regions.
Transmission and Distribution Cost					
Hydrogen Grid (CAPEX in USD/kW(H2))	900 (default)	1800	450	1800	Synf scenario represents a case where H2 grid is deliberately held back despite low-cost H2 production for synthetic fuels.
Energy Supply					
Maximum reduction in electricity price for electrolysis due to flexible operation (capacity factor 0.5)	-20%	-32%	-62%	-62%	This reduction in electricity price is approached at a VRE share of 100%. Below, linear increase from 0% reduction at 0% VRE share.

Table S1: Details on the cost assumptions in the energy system for baseline and technology scenarios.

[a] default energy taxes on all carriers vary by EU region and sector based on historic tax levels.

Table S2: Definition of Model Regions for the EU27

Region	Countries
Germany	Germany
Eastern EU	Czech Republic, Estonia, Latvia, Lithuania, Poland, Slovakia
Southeastern EU	Bulgaria, Croatia, Hungary, Romania, Slovenia
Scandinavia	Aland Islands, Denmark, Faroe Islands, Finland, Sweden
Southern EU	Cyprus, Greece, Italy, Malta
Esp and Por	Spain, Portugal
Benelux+	Austria, Belgium, Luxembourg, Netherlands
France	France

Table S2: EU27 model regions with member states included.

Supplemental References

1. European Commission (2022). Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee of the Regions REPowerEU Plan.

2. Baumstark, L., Bauer, N., Benke, F., Bertram, C., Bi, S., Gong, C.C., Dietrich, J.P., Dirnaichner, A., Giannousakis, A., Hilaire, J., et al. (2020). REMIND2.1: Transformation and innovation dynamics of the energy-economic system within climate and sustainability limits. https://doi.org/10.5194/gmd-14-6571-2021.

3. Pehl, M., Schreyer, F., and Luderer, G. (2023). Modelling Long-Term Industry Energy Demand and CO2 Emissions in the System Context Using REMIND (Version 3.1.0). Geoscientific Model Development Discussions, 1–29. 10.5194/gmd-2023-153. https://doi.org/10.5194/gmd-2023-153.