Resource requirements and consequences of large-scale hydrogen use in Europe

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As European countries transition to fuels with lower climate change impact, distinct challenges may arise. Electrolytic hydrogen is central to planned developments in transportation and industry, but large-scale hydrogen production could have energy and environmental consequences. Here we simulate site-specific hydrogen demand distribution for Europe in 2050, to assess possible effects on local water use risks, regional electricity generation composition and cost, and total land use. Results show that around 20% of annual water use for hydrogen production is simulated to happen in areas with 'extremely high' projected risk of water stress, and local water stress caused by hydrogen production could become severe. Widespread electrolytic hydrogen use requires large investments in electricity generation, but the impacts on the marginal electricity cost to consumers could be small. The electricity generation system required for producing hydrogen or e-fuels would require less land than cultivating biomass for biofuels. The findings highlight the need for coordinated policy action to ensure that hydrogen deployment aligns with local water availability, regional electricity system development, land constraints and broader sustainability goals.

To avoid catastrophic effects of climate change, emissions contributing to global warming need to decrease[1]. As a response, European countries have implemented a range of policies targeted at reducing emissions to net zero by 2050[2]. A large part of the strategy to reduce CO_2 emissions relies on the production and use of renewable electricity. However, direct electrification of heavy vehicles travelling long distances, such as trucks, ships and aircraft[3], is difficult. In these segments, indirect electrification through the use of electrolytic hydrogen has emerged as an option pursued around Europe[4]. Hydrogen can provide a long range, short refuelling times and low weight and can be produced using renewable electricity to split water molecules into hydrogen and oxygen. Hydrogen might thus, in the future, be used widely in transportation. Either, it could be used directly or in a hydrogen-based energy carrier, such as a hydrocarbon, an alcohol or ammonia, which often have better storage and transportation properties than pure hydrogen. When produced synthetically using electrolytic hydrogen, these energy carriers are called e-fuels[5]. Hydrogen might also be used in some industrial applications, for example, high value chemicals (HVC), ammonia and steel production[6], replacing fossil feedstock.

However, electrolytic hydrogen has never been produced on a large scale in Europe before and increased production might be constrained by societal and environmental impacts. Such impacts include (1) local increase in water use at the site of hydrogen production, (2) electricity costs effects due to higher electricity demand and (3) additional land use needed for electricity and fuel production. More research is needed to better understand consequences of increased production of electrolytic hydrogen under the many potential future energy transition pathways.

Many studies have investigated potential impacts of large-scale hydrogen production. Notably, Kountouris et al.[7] studied different

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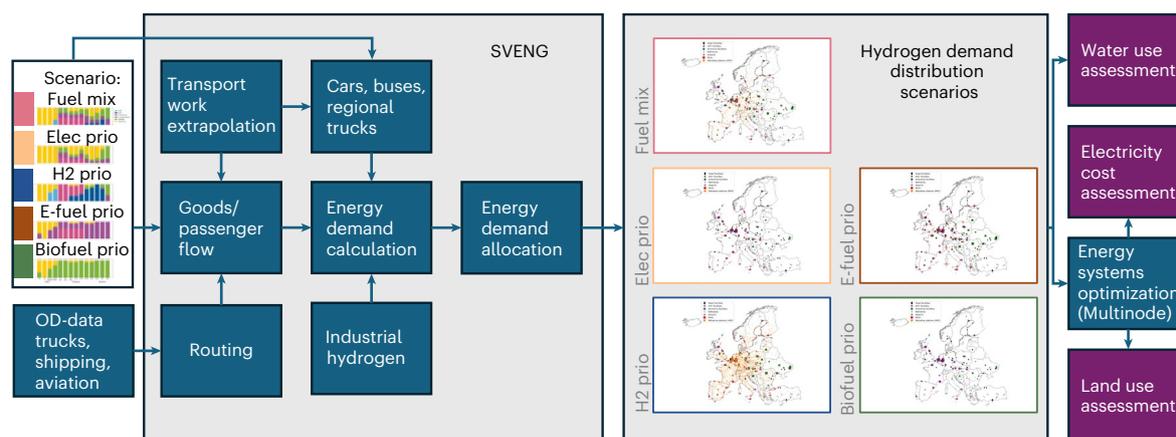
Fig. 1 | Model overview. Maps of hydrogen demand distribution shown here for each of the five scenarios are given in full size in Extended Data Figs. 1–5. Scenario fuel adoption, shown to the left in the figure, is elaborated on in Methods.

Blue boxes indicate calculation modules, purple boxes indicate analysis results. OD (data input to SVENG) is short for Origin-Destination, denoting goods or passenger volumes between two locations.

hydrogen supply strategies for Europe and Neumann et al.[8] investigated the impact of developing the electricity and hydrogen grids in a future European hydrogen energy system. Both studies provide valuable insights on different costs for establishing a European hydrogen supply chain. With a broader environmental impact perspective, Gabrielli et al.[9] looked at consequences on cost, water and land use of different global energy demand pathway scenarios in the chemicals sector. Land use and water-related risks, particularly related to hydrogen production, were also studied by refs. 10,11. They all conclude that no European country should expect considerable risk for water scarcity from production of hydrogen alone. However, their country-by-country assessments misrepresent the highly local aspects of these issues; especially concerning water.

Throughout previous studies, there is a lack of detail in representing different transportation modes and segments, fuel types, operating routes and their respective potential transition pathways, when discussing hydrogen technology. Input data and results are often given on the country or regional levels, even though it has been shown that when modelling hydrogen supply chain development the results can be strongly affected by the spatial scale of the model itself[12]. Additionally, local factors are important: cost vulnerability can vary between regions when developing a renewable electricity system[13,14] and effects from increased water use depend on local water availability[15,16].

Optimization studies often recommend trading hydrogen between regions from a total system cost perspective[7,8], but being a small, volatile molecule, with low volumetric density and high risk for leaks[17], hydrogen is technically challenging and costly to transport. Planning for a hydrogen supply chain is thus difficult in practice and producing hydrogen where it is used could be cheaper for the individual off-taker[18]. Studying a system where hydrogen is used and produced in the same location could provide perspectives on whether hydrogen transportation is necessary.

The aim of this study is to better understand consequences of water scarcity risk, electricity generation composition and cost and land use, from increased electrolytic hydrogen production under different European energy transition scenarios in transportation. To investigate these impacts with better local representation, we have built a model for projecting future site-specific demand for hydrogen and other fuels in the transportation and industrial sectors, at the point of energy use (for example, refuelling stations or industrial consumption).

The data generated represent geographical positions and hourly hydrogen demand, published alongside this article[19]. The model is called SVENG (simulating vehicle energy needs geospatially) and is

introduced for heavy-duty road transportation by Löfving et al.[20]. For this study, we have added modules for simulating the energy demand distribution for aviation, shipping and the remaining road transportation segments; as well as industries producing ammonia, steel, HVCs (in this case, ethylene) and refinery products.

To represent different possible energy transition pathways, we run the model for five scenarios (Fig. 1). One, called 'fuel mix', represents zero emissions transportation with a mix of solutions. In the other four, one pathway is prioritized (even if it is not the only used option): 'elec prio' (for direct electricity use), 'H2 prio', 'e-fuel prio' (for e-fuels) and 'biofuel prio'. All scenarios include industrial actors transitioning to hydrogen use. The scenarios are further described and motivated in Methods. All hydrogen is considered to be produced using electrolysis at the site of use, while electricity and e-fuels can be transported longer distances. This means that there is a more geographically distributed energy demand for transportation in three of the scenarios (fuel mix, elec prio and H2 prio) with a more extensive use of electricity and/or hydrogen in the transport sector. Conversely, the electricity and water use for transportation in the e-fuel prio scenario is more centralized to liquid fuel production hubs, since fewer vehicles need electricity or hydrogen along the road, or in ports and airports. In the biofuel prio scenario, less electricity and hydrogen are used altogether.

Water stress and depletion are modelled at the local water sub-basin level, for 751 sub-basins across all Europe, considering additional hydrogen production locally. Cost for electricity generation is calculated by importing demand for hydrogen from SVENG to the electricity optimization model Multinode. Multinode is a European optimization model that invests in electricity generation and storage technologies, as well as decentralized hydrogen production, to meet a regional electricity demand; for details see ref. 21. Land use for the different scenarios is compared for the entire electricity generation system as modelled in Multinode, including biomass cultivation for biofuels.

Results
Water supply risk
Figure 2 shows the water use for hydrogen production, aggregated by risk category for water stress (Fig. 2a) and water depletion (Fig. 2b) in the respective sub-basin. The total quantity exceeding the capacity in its sub-basin (also considering the 'regular' projected freshwater use) is indicated by stripes on the bars. The risk categories go from 'low' to 'extremely high' and represent annual water use relative to the available water considered for the two metrics, modelled for the year 2050[22].
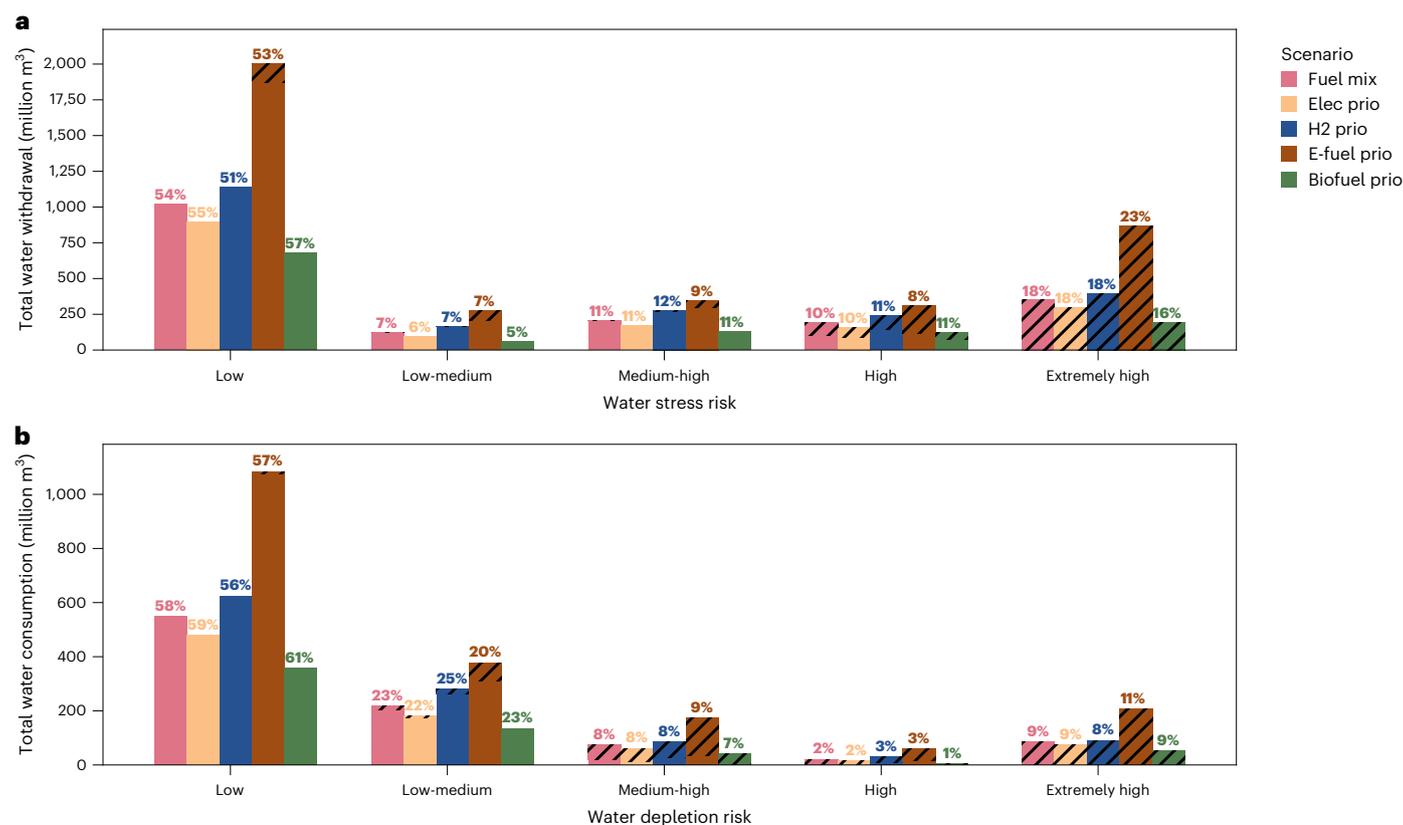
Fig. 2 | Water use for hydrogen production per water sub-basin risk category. a, Water withdrawal for each water stress risk category. **b**, Water consumption for each water depletion risk category. The dashed part represents water used in excess of projected basin capacity. Percentages show the share of water demand for the scenario in the respective risk category.

The largest share of hydrogen is produced in regions with a low water supply risk factor. More concerning is that the second largest share of water withdrawal for hydrogen production, around 20% in all scenarios, happens in basins in the extremely high water stress category. Furthermore, these results are modelled on an annual basis, which means that impacts could be even more severe as a result of seasonal or interannual variation[16].

While all hydrogen production in extremely high water stress areas contributes directly to overextraction, Fig. 2 also shows that sub-basins with lower projected risks can suffer overextraction, especially in the e-fuel prio scenario. This result is contrary to ref. 11, which states that no country in Europe risks water overextraction due to hydrogen production (assuming a similar total European hydrogen demand as in scenarios fuel mix and H2 prio). Since the assessment of ref. 11 compares country-wide demand to country-wide water availability, local water access is disregarded, which means risks are underestimated, as shown here.

This is further supported by Figs. 3 and 4, illustrating the modelled water stress (Fig. 3) and water depletion (Fig. 4) risk in Europe for 2050. It shows where individual sub-basins could see their available water resources exhausted. Annual sub-basin capacity is exceeded as a result of water use for hydrogen production in regions marked with stripes. Black sub-basins were projected to be overusing their annual water resources already before adding modelled hydrogen production. Notably, some regions with low projected risk suffer overextraction in the e-fuel prio scenario: the areas around Cologne (Germany) and Bohuslän (Sweden) are both projected to withdraw (affecting water stress, Fig. 3) more than their annual available water and southern Finland is projected to consume (affecting water depletion, Fig. 4) more water than is available.

Other regions may not see their entire annual basin capacity exceeded but still suffer a dramatic change in water-related risk. Regions marked with blue dots in Figs. 3 and 4 have their water withdrawal or water consumption increased by 50% or more. While overextraction impacts in lower-risk basins are fewer in the H2 prio scenario compared with e-fuel prio, the relative increase in risk is more widespread, due to the more prevalent use of direct hydrogen in transportation. Even though many of these regions are projected to have low water stress risk, such a change could still have a substantial environmental impact depending on the local ecosystem composition and resilience[15], especially if considering water availability variations within a year as mentioned above.

The option to trade water between sub-basins, which is left out of this assessment, could potentially alleviate local water stress. That total water use for hydrogen production in this assessment is very small compared with other end-uses, such as agriculture (which aligns with other studies[23,24]), would support this assumption. However, many sub-basins suffering from water stress would not be able to import enough water to decrease their water stress risk to acceptable levels, without imposing undue stress on the water resources of neighbouring regions. Calculations supporting this are elaborated and discussed further in Supplementary Note 1. Also, see this note for a brief discussion on alternative technologies such as seawater desalination and wastewater purification[25]. Long-distance water transportation requires a lot of energy and large infrastructure investments[15] and might face resistance as a result of the risk of exacerbating water stress problems for other industrial, social and cultural end uses[16,26,27]. In light of the results presented in Figs. 2, 3 and 4, we thus want to underline the importance of considering local water availability in planning hydrogen production.
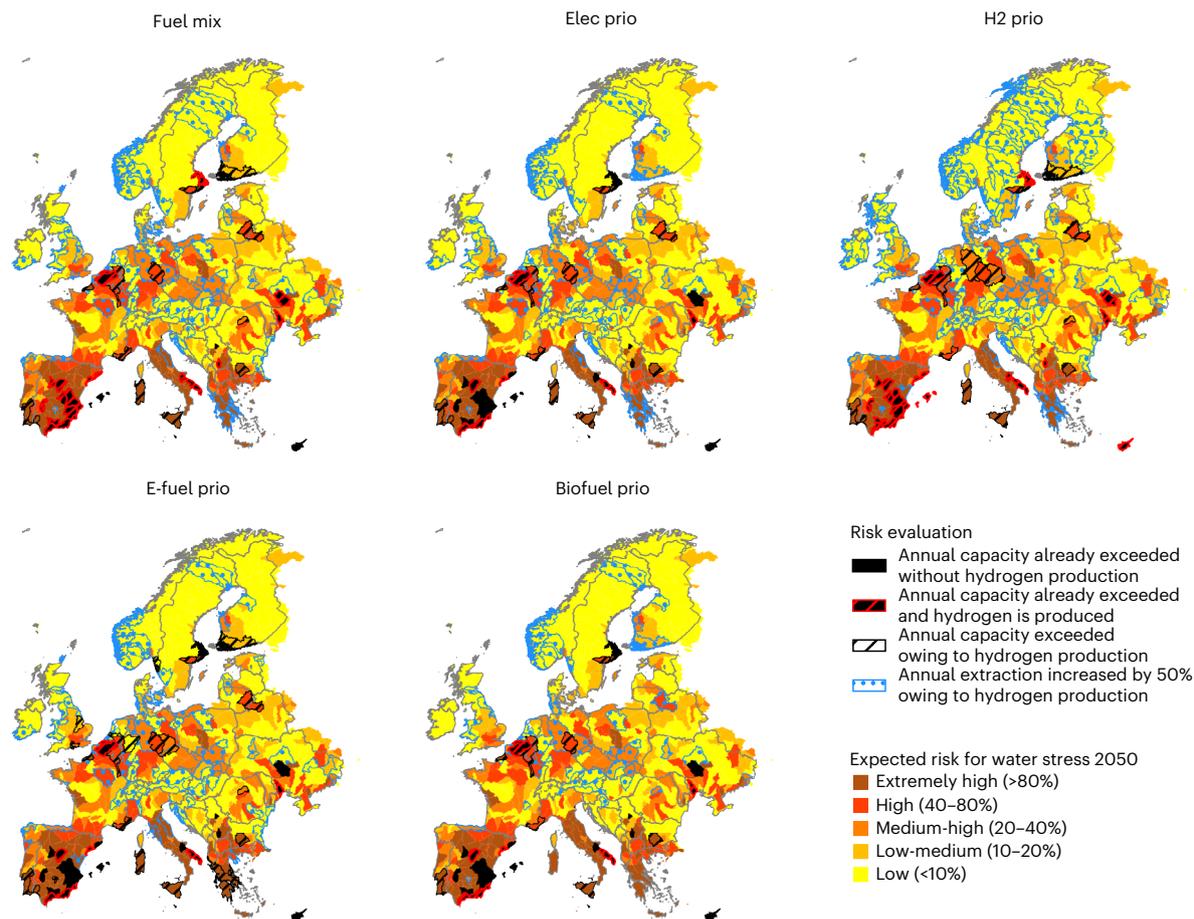
Fig. 3 | Map of water stress risk for different sub-basins in Europe. Baseline risk (indicated by background colours) is modelled in Aqueduct 4.0 (ref. 59). Dashes indicate where annual water use exceeds available resources as a result of hydrogen production. Dots indicate extraction increased by more than 50%. Basemap data from Eurostat[68].

Electricity cost impacts

Figure 5a presents the load weighted marginal electricity costs for the 50 modelled regions, along with the European average, across the different scenarios investigated for year 2050. These results can be compared with the annualized investment costs for electricity generation, transmission and storage, shown in Fig. 5b. Further details on total electricity generation, total annualized costs and the corresponding hydrogen demand in each scenario are in Supplementary Note 2.

As expected, scenarios with the greatest electricity demand—which increases with hydrogen use in transportation and industry—entail the largest investments costs and, in general, the highest marginal electricity costs. However, while the annualized investment costs in the e-fuel prio scenario are almost double those in the biofuel prio scenario, the European average marginal electricity costs only differ by 18%, indicating a relatively weak relationship between those costs. This can primarily be explained by two factors. First, although higher demand may necessitate more investment in costly bulk generation technologies (such as nuclear power or coal with CCS) compared with a scenario with lower overall demand, the marginal cost of electricity is still likely to be set by gas turbines during high net-load periods regardless of whether the demand is high or low. Gas turbines are used because of their operational flexibility and low capital costs, but entail high operating costs. Second, although higher hydrogen demand may necessitate the use of more costly generation technologies (given the limited potential and declining quality of wind and solar resources as deployment expands), flexible hydrogen production can provide temporal demand shifting. However, realizing this flexibility requires

additional investments in electrolyser capacity and hydrogen storage. These costs are considered in Multinode. In previous studies, it has been shown that such flexibility can enhance the cost-competitiveness of wind and solar power[28], thereby limiting the electricity cost increase imposed by higher demand.

At the country level, Belgium, the Netherlands and Germany exhibit some of the highest electricity costs and are among the most strongly affected by the additional demands in the scenarios investigated. This can be attributed to their limited wind and solar potential relative to their high industrial demand. Conversely, Sweden, Norway and Finland are characterized by low electricity costs and are only marginally affected by additional demand. This can be explained by their substantial wind (and solar) potential, combined with large volumes of hydropower that facilitate a cost-effective integration of variable renewable energy, particularly wind power[29].

When comparing across scenarios, more than half the regions (regions are defined in ref. 60) exhibit only minor variations in average electricity costs (for example, BE, BG, CH, CZ, DE5, DK1–2, ES4, FI, FR2–5, HU, IE, LT, NO1–3, PO3, PT, RO, SE3–4, SK and UK1–3), despite substantial differences in electricity demand and the associated investments in many of these regions. By contrast, some regions are considerably affected by the choice of energy carriers in the transportation sector. In several regions (for example, AT, DE1, DE4, EE, ES2, FR1, GR, IT2, IT3, LV), the marginal electricity cost in the e-fuel prio scenario is notably higher than in the other scenarios. In most of these regions, this outcome is linked to the deployment of thermal power technologies not used in any other scenario, such as nuclear (DE4, IT2), coal with
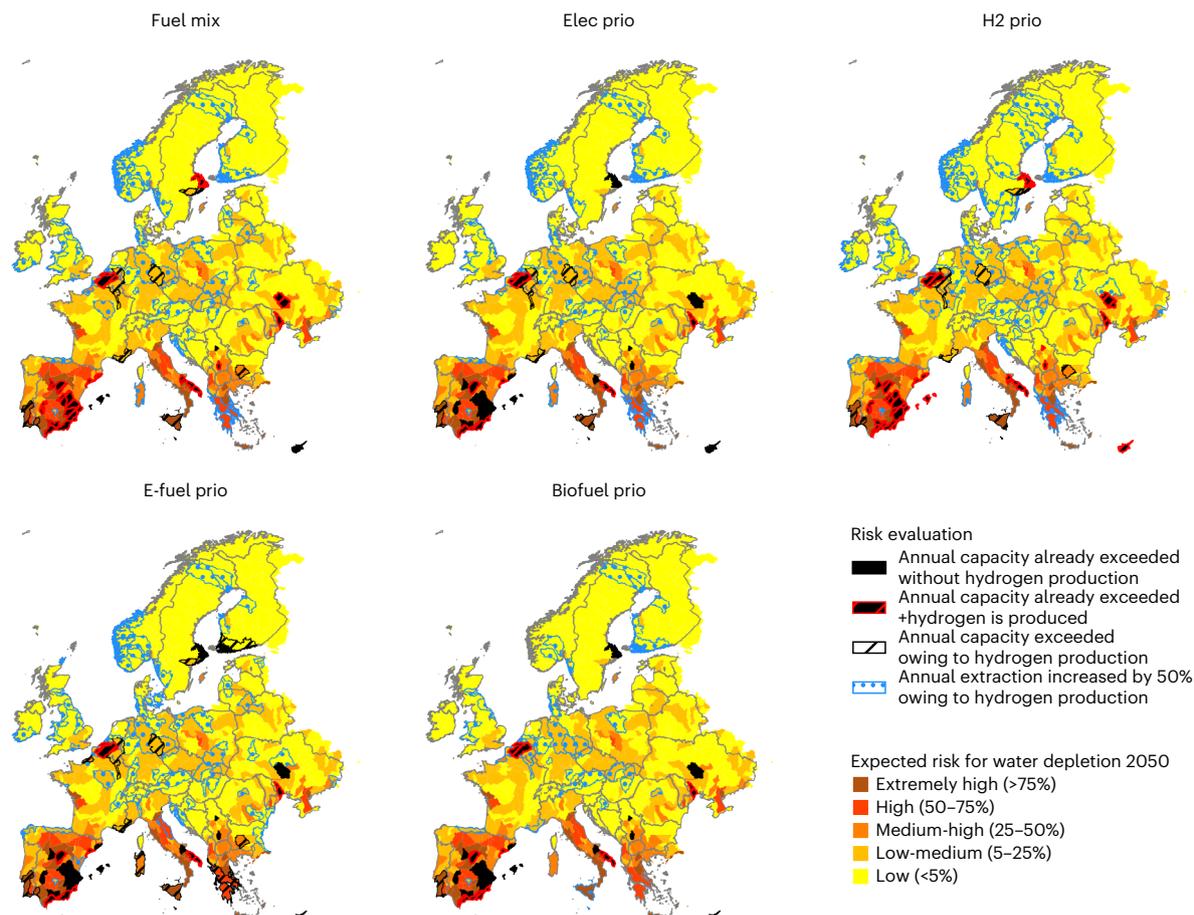
Fig. 4 | Map of water depletion risk for different sub-basins in Europe. Baseline risk (indicated by background colours) is modelled in Aqueduct 4.0 (ref. 59). Dashes indicate where annual water use exceeds available resources as a result of hydrogen production. Dots indicate extraction increased by more than 50%. Basemap data from Eurostat[68].

CCS (FR1, IT2, IT3) and waste-to-energy plants (DE4, GR, IT2, IT3). In AT, DE1 and ES2, these technologies are used in other scenarios as well, but make up a larger share of the electricity mix in the e-fuel prio scenario. Some regions, conversely, see the lowest average electricity costs in the biofuel prio scenario (DE1, FR1, IT1–3, NL, PO2). The reduced electricity demand in these regions allows them to avoid building new thermal power capacity altogether (DE1, FR1, IT1–3) or to rely on much less of it (NL, PO2), while also requiring less solar deployment (FR1, IT1–3, PO2).

The key point indicated by these results is that using hydrogen (instead of direct electrification or biofuels) could require larger investments in the electricity system, but that these investments would not necessarily directly translate to a large electricity cost increase for the end-user. This suggests that from a societal perspective, the larger electricity system warranted by using more hydrogen could be less of an obstacle than could be concluded from only looking at the total investment cost. However, we should acknowledge the potential challenges associated with getting these investments in place. Additionally, adding more hydrogen demand affects marginal electricity costs differently between regions. In many regions, these costs are particularly high in scenarios with hydrogen usage, compared with those in the 'no transition' case. This points to regional differences in potential to manage more hydrogen demand, which needs to be considered together with factors like differences in vulnerability to electricity cost variations[13,14].

Land use impacts

Figure 6 illustrates the land requirements for electricity generation technology (as modelled using Multinode) and biofuel crop cultivation

for the five scenarios. This can be compared with the total arable land in Europe, at 2.73 Mkm² (ref. 30). The shaded part of biomass land use represents areas that could be offset by using alternative feedstock streams. Feedstock from biomass residue, defined in the Renewable Energy Directive, is shown for one conservative estimate of availability in 2050[31]. Additionally, certain crop rotation practices could allow the co-production of biofuel feedstock with food and feed crops while promoting other ecosystem values[32], such as increased soil organic carbon and decreased greenhouse gas emissions, without decreasing the output of food and feed.

The electricity system land use is barely discernible, regardless of the amount of hydrogen used, compared with that for producing biofuel feedstock. However, land use footprint can vary a lot depending on definition[33], especially for renewable electricity. It also varies as a result of local conditions, such as solar irradiation and wind variation and the ability to co-generate other values such as forestry or agricultural products on the same land[34,35], meaning aggregate results are uncertain. The values used in this comparison represent infrastructure footprint[33], which does not account for space between, for example, wind turbines that could be used for other purposes, such as farming. This assessment is compared with higher and lower values, under other definitions, in Supplementary Note 3.

Looking at Fig. 6, there is an indication that using a larger share of hydrogen or hydrogen-based fuels to power heavy transportation segments decreases the total energy system land use footprint, when substituting biofuels. Even the elec prio scenario, compared with the fuel mix scenario, requires an additional area for biomass cultivation
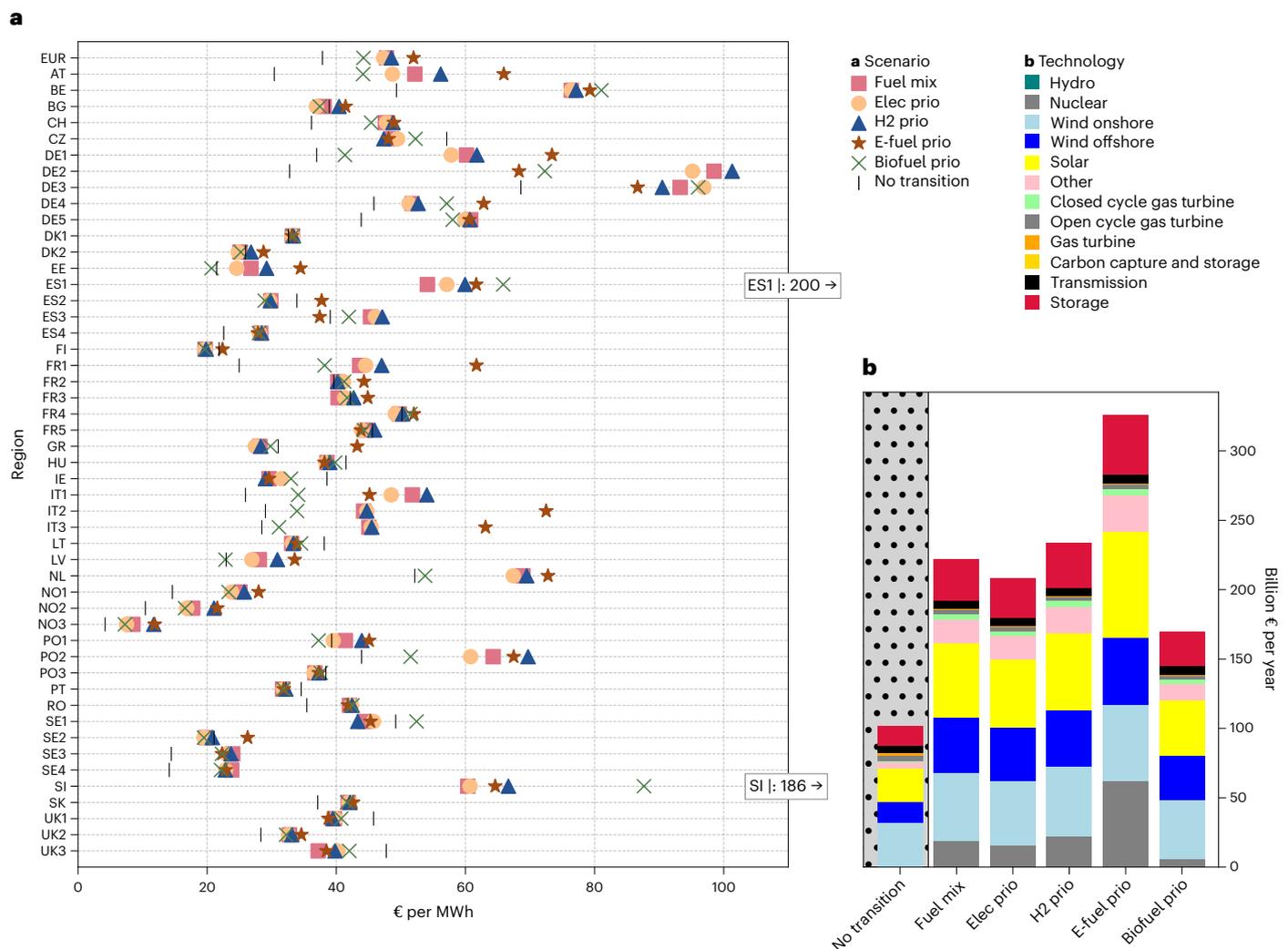
Fig. 5 | Electricity generation cost results from Multinode, for each scenario. a, Load weighted average marginal electricity cost per region. **b**, Total annualized investment costs in electricity generation, storage (including heat, hydrogen and batteries) and transmission. Regions are defined in ref. 60. The special case labelled 'no transition', in the dotted section, shows Multinode results for a model run with no hydrogen use and very little transportation electrification. In this case, two regions (ES1 and SI) present outlying average cost, as shown in panel (**a**), due to low solar deployment and extended use of gas turbines.

approximately the size of Iceland, as a result of its slightly higher use of biofuel in aviation. In the biofuel prio scenario, biomass cultivation would require a very large area, as seen in Fig. 6.

Apart from using hydrogen and direct electrification, alternative biomass feedstocks that are not in competition with food and feed show a potential to alleviate land use requirements. Large-scale use of residual biomass feedstock might, however, become challenging, since the establishment of such a supply chain involves many obstacles; such as adjusting farm or forestry operations and establishing new and stable biomass supply chains and logistics solutions[36]. The potential of using residual feedstocks is thus uncertain. Still, since renewable electricity production may be constrained by acceptance issues[37], coordinating efforts for residue collection, while also leveraging smart crop rotation practices to increase the biomass output and seeking other solutions like co-producing biomass and electricity on the same land[38], could provide complementary energy generation for the transportation sector.

Discussion

There are many obstacles to overcome to achieve a sustainable, Europe-wide, hydrogen economy. With this work, we provide

geospatially specific data that can be used to assess the development of a supply chain for electrolytically produced hydrogen, for the whole continent. On the basis of these data, we provide analyses on local water risk, electricity cost and land use for an energy system building on decentralized hydrogen production.

Contrary to previous findings, we show that large-scale hydrogen production could cause (or suffer, depending on the viewpoint) serious local water stress or water depletion. European countries are considered 'highly adaptable' to water-related risks[39], but mitigating problems before they arise is probably both cheaper and more convenient. Being proactive suggests a need to develop water and energy policy together, instead of separately[40]. Our assessment also shows that country-level conclusions on water availability could paint a misleading picture, since water constraints are defined on the sub-basin level. With the detailed geospatial dataset published alongside this paper, we hope to enable further exploration on the connection between macro energy systems and local environment.

When examining the marginal electricity cost results, some regions exhibit patterns that appear counterintuitive—for example, higher electricity costs in scenarios with lower overall demand compared with those with higher demand. This can partly be explained by the objective
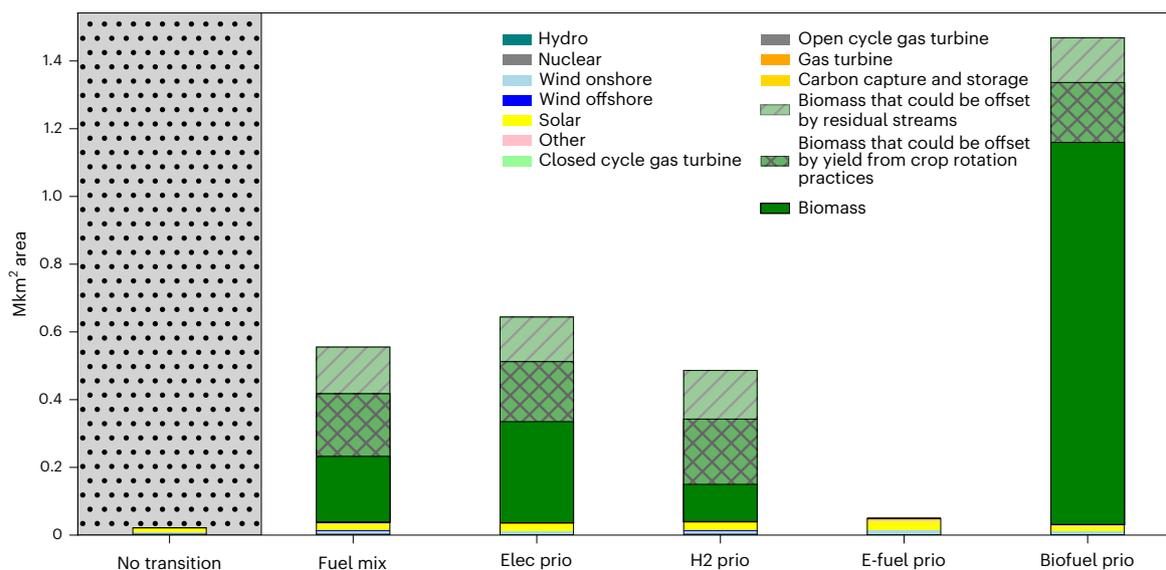
Fig. 6 | Land use for electricity generation and biofuel feedstock cultivation. The special case labelled 'no transition', in the dotted section, shows land use for a model run with no hydrogen use and very little transportation electrification. Many of the electricity generation technologies listed in the legend aren't visible in the bars, due to their small total land use footprint.

function of the model, which minimizes total system costs without explicitly optimizing for regional cost minimization. However, since electricity markets are not necessarily organized along the regional boundaries applied in this study, variations in regional electricity costs could also indicate bottlenecks in the transmission and distribution grids, which could be subjected to high stress under the investigated scenarios. Both these aspects highlight the importance of considering regional differences[13] when planning the deployment of hydrogen systems.

We also show that the future portfolio of energy carriers for transportation will affect the amount of land that is required for electricity and fuel production. That bioenergy uses more land than other types of energy has been found in several other studies[9,11,41] and is seen also here. Understanding the land use impact from one technology over another is difficult, however, because of differences in production potential and the possibility to use the land for several purposes. Additionally, both biofuel crops and electricity generation are subject to social acceptance issues[15], making the deployment potential uncertain. Our results (complemented with the discussion in Supplementary Note 3) suggest that using direct or indirect electrification or alternative biofuel feedstocks, could provide considerable relief from land use pressure.

Which strategies are preferable for producing and distributing hydrogen are subject to debate. For the individual off-taker, decentralized production close to the point of use could be cheaper than transporting hydrogen from somewhere else[18], but many optimization studies (for example, refs. 7,8) recommend transporting hydrogen when considering total system costs. Although omitting options for transporting hydrogen is a limitation of this study, it also allowed us to show that in some locations, either importing water or the hydrogen itself will be necessary, since hydrogen production can have a severe impact on water scarcity and electricity cost. Establishing such supply chains is very complex and we urge that future planning considers local effects beyond total cost.

Other limitations include uncertainty about whether the assumed deployment levels of drivetrains and energy technologies will be feasible[10,42] and the assumption that all modelled industries will remain in present facilities rather than building new sites. While outside the scope of this study, investigations into suitable locations for new facilities, considering access to water and renewable electricity, or other values such as access to CO_2-distribution channels and storage sites,

could be done using the data presented in this paper. Since we assume all off-takers to produce their own hydrogen, we do not model any micro-level hydrogen distribution network, which could be needed if many close off-takers share production facilities.

Another limitation is that political and cultural opinions may be at odds with the economically optimizing rationale represented by an electricity system model. The results from scenarios run in Multinode and the following analyses, could also be affected by opposition to, or preference for, one or more of the electricity generation technologies[15,37] (see also Supplementary Notes 2 and 3).

While this work points to some of the problems and opportunities that should be considered in planning a hydrogen economy, many topics for investigation remain. The hydrogen demand datasets published alongside this article could be used to assess: other technology options for hydrogen production and distribution; local environmental impacts and land availability for technology deployments; resilience evaluations and other additional capacity requirements; highly resolved infrastructure optimization; and required policy measures to realize the potential of a future hydrogen economy.

Methods
Scenario definition
The four prio-scenarios are designed to test the impacts of using the respective energy carriers at a very large scale (within the limits of what the authors deem theoretically possible) by 2050. This is intended to represent 'extreme' cases where society decides to prioritize certain energy carriers in transportation. The fuel mix scenario, as the name suggests, represent a future with a low emission transportation system using a mix of energy carriers. The shares for each fuel type remain constant across all vehicles in each transportation segment for each scenario. The transportation segments are listed in Supplementary Note 4 and the assumed energy mix in the five designed scenarios is presented visually, for each transportation segment, in Supplementary Fig. 4. In all scenarios, the included industries (ammonia, steel, HVC and refineries) are considered to transition completely to processes based on hydrogen. Scenario designs represent exploratory narratives[43] based on a qualitative-to-quantitative approach[44], using discussions with industry and author assumptions based on more than 20 years of research in the field, motivated below.

For some of the analyses, a special case labelled 'no transition' is also included. In this case, no hydrogen usage has been included for transportation or industry and the only transport segments using direct electricity are 50% of cars and buses. We do not provide any details on whether or how the energy transition takes place in transportation and industry in this case. It is included to clarify the impact of hydrogen usage across all sectors. Since the biofuel prio scenario includes almost no hydrogen for transportation (only a small amount of hydrogen in refineries for production of biogenic jet fuel), this could be compared with the no transition case to examine the effect of only using hydrogen in industry.

Fuel mix represents a future where many types of fuels coexist. E-fuel is used for aviation corresponding to the Refuel EU Aviation regulation and electricity and hydrogen is used on some shorter distances. Shipping uses a mix of fuels, with a slight preference for ammonia, in all segments except passenger transportation due to its toxicity. The four remaining scenarios represent futures where one energy carrier is prioritized. Elec prio has a high share of directly electrified vehicles using batteries. In this scenario, direct hydrogen use is avoided and it is only used to some extent 'indirectly' through e-fuels. Where battery electric propulsion might not be possible because of technical limitations, this scenario uses a mix similar to fuel mix. H2 prio has a high share of indirect electrification. Gaseous hydrogen is used in heavy road transport and liquid hydrogen is used for shipping and aviation, considering projections that hydrogen may be able to serve medium-distance flights[45]. This scenario emphasizes carbon-free energy carriers and the segments of shipping where direct liquid hydrogen might be technically insufficient, ammonia is used instead. E-fuel prio has a high share of vehicles and vessels running on e-fuels and biofuel prio has a high share of vehicles and vessels running on biofuels. In all scenarios, a large part of road traffic, as well as a minor share of some shipping segments operating on short distances, are electrified. This is also intended to account for some onboard energy use being offset by onshore power.

Hydrogen demand is distributed to specific geospatial node locations for each scenario. There are 10,077 nodes in H2 prio and 4,312 nodes in fuel mix, since hydrogen is used directly in trucks, shipping and aviation. There are 276 nodes in the remaining scenarios.

Modelling methods

This study is primarily based on two models: the SVENG model for simulating energy demand from transportation in 2050 (presented for trucks in ref. [20]) and the Multinode model for modelling electricity system investments and dispatch year 2050. Outputs from the Multinode model are, for example, electricity generation and investments from different technologies and marginal electricity costs for different regions around Europe[21]. Hydrogen demand for industry was modelled separately using the SVENG model, as well as water use and land use. Maps of demand nodes are given in Extended Data Figs. 1–5 and a summary of total relative electricity system costs per scenario is given in Supplementary Note 2.

Demand modelling

The main modules of SVENG build on origin–destination data for calculating energy demand for individual trips and allocating this demand to specific geographical sites. This is used for long-haul trucks, shipping and aviation. Energy demand from short-distance transportation modes, such as cars, buses and regional trucks, is estimated on the basis of average distance regional transportation work. All industries considered in this study, steel, ammonia and HVC production, are considered to transition completely to hydrogen-based processes. Their hydrogen demand is determined in relation to their output. Detailed descriptions of demand modelling are given in following sections, complemented by further detail in Supplementary Note 4.

We used logistics origin–destination data from ref. [46] to represent individual trips in heavy-duty road transport, shipping and

aviation. Short-distance trucks were modelled separately on the basis of aggregate transport work, which is described further in Supplementary Note 4. Transportation work, when calculating demand for liquid fuels and electric propulsion for cars and buses, was also handled differently. Liquid fuel demand was calculated using the total Europe transportation work from the JRC IDEES Europe-dataset[47] and, for transportation electricity, data from Multinode were used, see ref. [21].

For the long-distance transportation segments covered in SVENG, individual linear regression models were built for each country, for national and international road transport, all different shipping segments and aviation. These correlate outgoing transportation work from Eurostat[48–52] with gross domestic product based on purchasing power parity (GDP_PPP) from the World Bank[53,54]. A growth factor for transportation work in each country and segment is determined by applying this model to a value for projected GDP_PPP in 2050 under the shared socioeconomic pathway scenario 2 (SSP 2), modeled by IIASA[55]. Further details on the linear regression modes are given in Supplementary Note 4 (with descriptions of some exceptions). Car and bus transport, considered in bulk when calculating liquid fuel demand, is projected onto 2050 using the same methodology on total values for all Europe. For transportation work growth and its influence on electricity demand for cars and buses, see ref. [21].

Direct electricity for battery electric vehicles and electricity for hydrogen production, was allocated to the geographical location of charging points and hydrogen refuelling stations, respectively. Electricity for hydrogen production for further conversion into e-fuels is modelled according to geographic points for European refineries and fuel production is considered to be distributed to fuel production sites according to EU-ETS reported emissions as described in Supplementary Note 2. Production of e-ammonia is distributed onto current ammonia plants around Europe, according to current ammonia production, listed with references in Supplementary Data.

Road energy demand is allocated for electricity and direct hydrogen to truck stop locations from ref. [56], using the SVENG model as described in ref. [20]. The SVENG model has for this work also been adapted to model geospatial charging distribution for long-haul trucks using electric drivetrains, in addition to hydrogen refuelling that is modelled in ref. [20]. In addition, we have added local and shorter-distance regional freight. Road passenger transportation (cars and buses) has also been added, calculated in bulk for all Europe. These additions to the SVENG model are explained further in Supplementary Note 4.

Shipping energy demand is calculated individually for all ship routes starting in Europe. Electricity demand and hydrogen demand, for the entire route, is allocated back to the starting port. We used reported data from EU MRV[57] to calculate energy use per unit of transportation work (tkm) for the different considered shipping segments. The resulting values are given in Supplementary Tables 6 and 7.

Aviation energy demand is also calculated individually for each aviation route starting in Europe, multiplied by the modelled annual number of aircraft. Again, electricity and hydrogen demand, for the entire route, is allocated back to the starting airport. Energy uses for aircraft in the different segments have been provided in discussion with industry experts. These are described in Supplementary Table 10.

For road transport, all liquid fuels are considered to be produced through the Fischer–Tropsch process. For shipping, the biofuel pathway is represented by biomethanol and the e-fuels pathway includes both e-methanol and e-ammonia, as indicated in Supplementary Fig. 4. For aviation, the biofuel pathway is ethanol-to-jet and the e-fuels pathway is e-methanol-to-jet. Propulsion efficiency, production efficiency and hydrogen usage are given in Supplementary Tables 3, 8, 9 and 11.

Hydrogen use for steel, ammonia and HVC production is calculated in relation to facility output, with further details and data given in Supplementary Note 4. Ammonia production, specifically, has been

gathered from several sources, each of which is listed in Supplementary Data. After calculating the annual energy demand for each node (representing, for example, a hydrogen refuelling station or a steel plant), this demand was combined with an hourly operational profile. The profile represents demand as a full-year 8,760-h time-step series in each node, with profiles varying between node type. These data are supplied along with the article for each scenario, to allow modelling the energy system with an hourly resolution. The details around these data are explained further in Supplementary Note 4.

Water stress modelling

Water resources are subject to different kinds of pressure. Water stress risk relates available water to total withdrawal of water, of which some is returned to the source. Water depletion risk relates available water to total consumption of water, which is the part that is embedded in the product, lost as steam and so on, and not returned[22]. For every kilogram of hydrogen produced, 30 l of water is estimated to be withdrawn from the source[58], 15 l of which is consumed and not returned to the basin[25].

These pressures are, for each scenario, calculated from the total hydrogen demand from all nodes in each sub-basin throughout Europe. The Aqueduct 4.0 dataset[59] contains data on projected future freshwater risk for each of these sub-basins[22]. Each sub-basin in that dataset is assessed according to different types of projected risks for water management under different scenarios, from low to extremely high. Their business-as-usual scenario for 2050 is used for the assessments in this study.

When comparing water stress and water depletion, respectively, to the pressures in the Aqueduct 4.0 database, the annual additional water pressure is calculated by comparing annually projected available water with annually projected water withdrawal. The water for hydrogen production is, for both comparisons, added to the water withdrawal, since projected water depletion is not included in the dataset. This is done for each sub-basin separately and compared with the Aqueduct modelled annual water availability.

Electricity system modelling

Electricity system investments and dispatch are modelled using the Multinode electricity system model. A recent description of this model is given in ref. 21. Multinode is a cost-minimizing linear optimization system built in GAMS, solved using Cplex. It is essentially a so-called 'greenfield' model, meaning that it builds an optimal electricity system 2050 from scratch without considering the current power generation fleet. However, some details such as current hydropower and transmission capacity are included as a starting point for the model. This is further elaborated in ref. 21. The model includes 50 regions on national and sub-national levels in Europe, specified geographically in ref. 60. Also, electrolyser capacity and hydrogen storage are modelled using this model. The Multinode model is run for the year 2050. A breakdown of hydrogen demand simulated in SVENG for each scenario, as well as details on electricity generation and investments, are elaborated in Supplementary Fig. 1. The baseline electricity demand, to which the hydrogen demand in this study is added, are taken from ref. 21. Technology costs for electricity and hydrogen generation and storage are largely based on data from the Danish Energy Agency[61] and are provided in Supplementary Tables 1 and 2. Like refs. 9,11,21, we consider the regions to be self-sufficient in their hydrogen production and consumption and no trade in hydrogen is done between the regions. Electricity, however, can be traded between regions, according to the transmission capacity invested.

After the annual hydrogen and transportation electricity demand has been modelled on the node level using SVENG, as shown in Fig. 1, these are aggregated region by region and added to the Multinode optimization model, on top of the baseline 2050 load. In this study we used 6-h time steps, using the baseline electricity and heat use profiles

from ref. 21. Belarus, Ukraine and the Balkans, although simulated in SVENG and thus part of the hydrogen demand dataset, are not part of the Multinode model and therefore left out of the electricity generation and cost assessment.

The average marginal electricity cost is the weighted marginal value of electricity ($€_{2024}$) in each time step, for each region. Costs do not include other costs like taxes, or local or regional electricity distribution costs. Average weighted marginal cost is calculated for each region by multiplying the average hourly marginal cost per 6-h time step with the electricity use in the same time step, summing the total value per region and dividing by the total electricity use in that region. The European average marginal cost is weighted according to electricity demand for each region. The electricity generation investment costs have been annualized considering total investment cost and technical lifetime for each technology.

Land use modelling

The land requirements for electricity production in each scenario are calculated on the basis of the electricity generation mix modelled in Multinode. Land use factors for thermal and hydropower are from ref. 34 based on UNECE[35]. Land use for offshore wind is also taken from the latter. The land use factor for onshore wind is chosen as the median infrastructural land use factor presented by Turkovska et al.[33] ($3.2 \, m^2 \, MWh^{-1}$). This is a lot smaller than the average wind farm size presented by Ritchie[34] at $99 \, m^2 \, MWh^{-1}$ and also than the average land use intensity that can be derived from the ENSPRESO dataset[62] at $55 \, m^2 \, MWh^{-1}$. The chosen value only represents land use for permanent infrastructure and technology connected to wind power generation, which means we are considering the potential for co-generation of values, such as forestry or farming, between power generation installations. Using a larger factor would thus be misrepresentative for this comparison. As in one of the ENSPRESO datasets, solar power land use intensity was calculated assuming $170 \, MW \, km^{-2}$ technology, which at a capacity factor of 0.12 requires $5.6 \, m^2 \, MWh^{-1}$. This is lower than the ground-mounted PV figures from ref. 34 and at the higher end of the spectrum for rooftop photovoltaic (PV). Since rooftop solar is the dominating kind in the EU[63], with lower acceptance issues considering deployment compared with ground-mounted solar and with a large continued potential for further deployment[64], we consider this factor to be representative of the total land use for solar power. Different land use intensities for different assumptions are presented and discussed further in Supplementary Note 3.

Total land use from biofuels production is calculated using the EU average land use intensity, 59 GJ of biofuels per hectare, modelled for a mix of crops under the ILUC directive restriction of maximum 7% conventional biofuels in the Globiom report[65]. Biomass from alternative feedstock streams (Annex IX feedstocks + miscanthus, as described below) are considered to first offset jet fuel, since this regulation requires Annex IX feedstocks to be used for biofuels to be counted towards targets in the Refuel EU Aviation legislation. Jet fuel has a higher feedstock need per unit of energy than road and shipping biofuel, due to conversion via ethanol-to-jet. Any remaining biomass from alternative streams then offset road and shipping feedstocks. The domestic availability of Annex IX feedstocks for use in the EU transportation sector in 2050 have been estimated by Soler[31] and the minimum estimate comprise the 'residue potential' case in Fig. 6. The annual miscanthus feedstock is assumed from Englund et al.[32] where they modelled annual miscanthus output in a 3-yr rotation together with 4 years of other crops. This output is recalculated to biofuels using a factor of 0.22 kg of ethanol per kilogram of miscanthus dry mass, estimated from ref. 66.

Reporting summary

Further information on research design is available in the Nature Portfolio Reporting Summary linked to this article.

Data availability

Hourly hydrogen demand data and node locations compatible with Geographical Information Systems (GIS) are provided in ref. 19. Input data for the model used in this work are given in Supplementary Notes 2 and 4, Supplementary Data and in ref. 67. All data originate from open repositories referenced in this work.

Code availability

The main code for simulating hydrogen demand can be found in ref. 67. Explanations of the Multinode equations can be found in ref. 21.

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Author contributions

J.L., S.B. and M.G. conceptualized the study. J.L. carried out formal analysis with support from S.B., M.G., S.Ö. and M.T. J.L. gathered all the data and built all new software used in the study. S.Ö. and M.T. built and provided access to the Multinode model, presented in earlier studies, and supported J.L. on integrating it with the new software. J.L. wrote the original draft and collaborated with S.B., M.G., S.Ö. and M.T. on review and editing. S.B. and M.G. acquired funding for the work and supported with project administration.

Competing interests

The authors declare no competing interests.

Additional information

Extended data is available for this paper at https://doi.org/10.1038/s41893-026-01771-5.

Supplementary information The online version contains supplementary material available at https://doi.org/10.1038/s41893-026-01771-5.

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Peer review information *Nature Sustainability* thanks Stuart Cohen and the other, anonymous, reviewer(s) for their contribution to the peer review of this work.
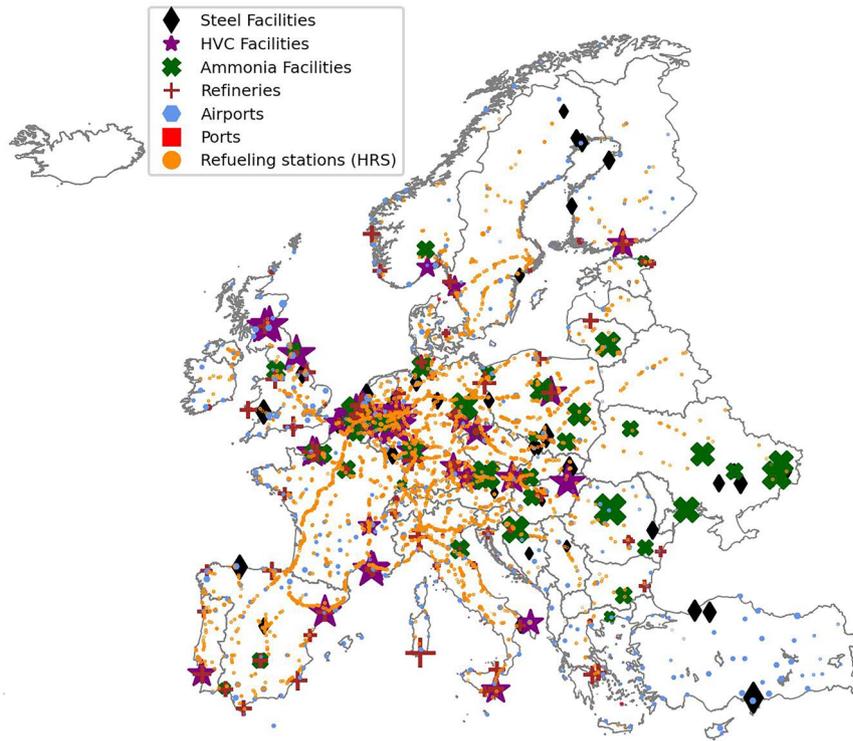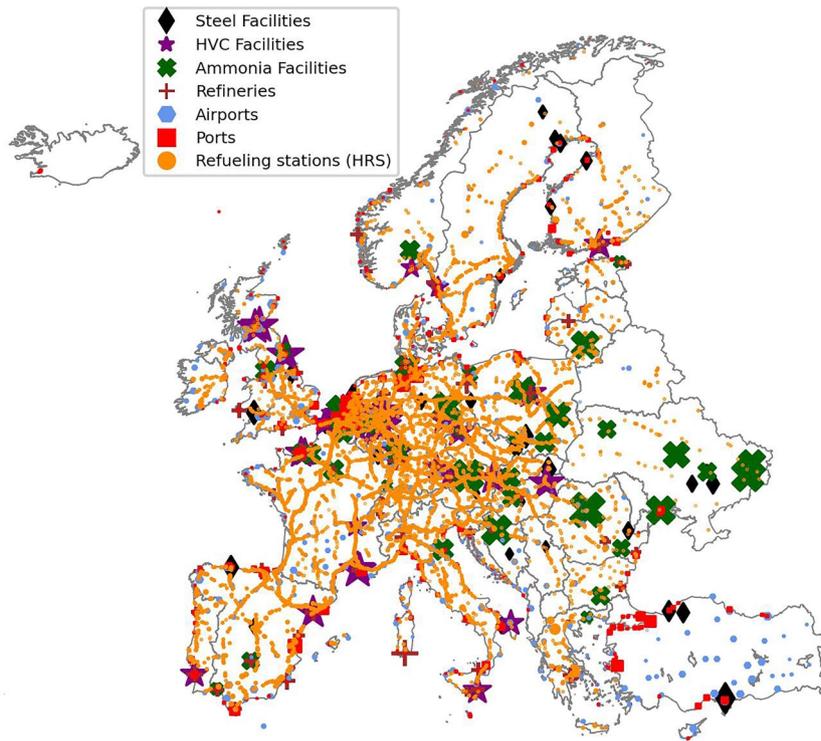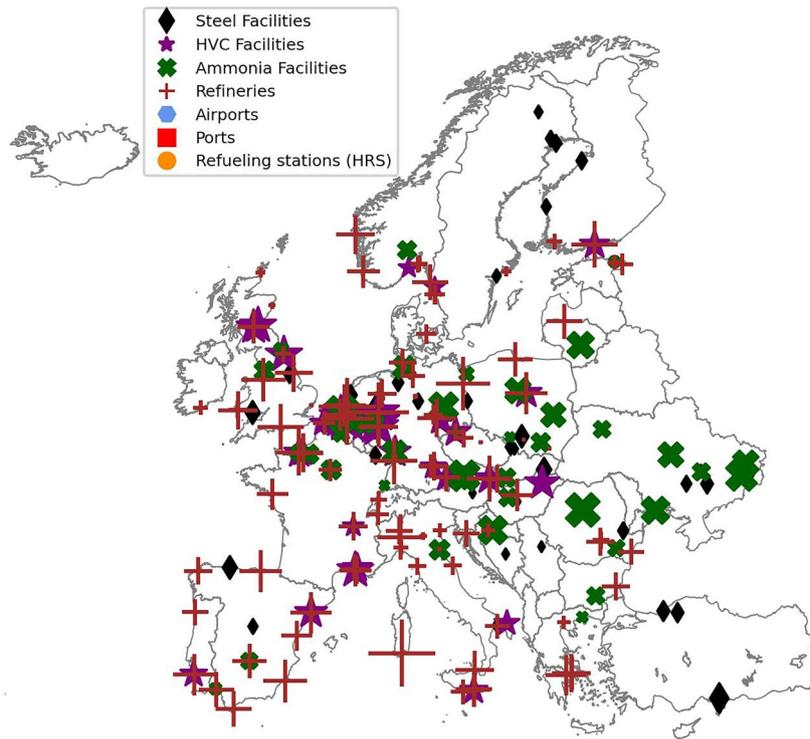
Extended Data Fig. 1 | Node locations, scenario Fuel mix. Node size indicates relative annual demand size.
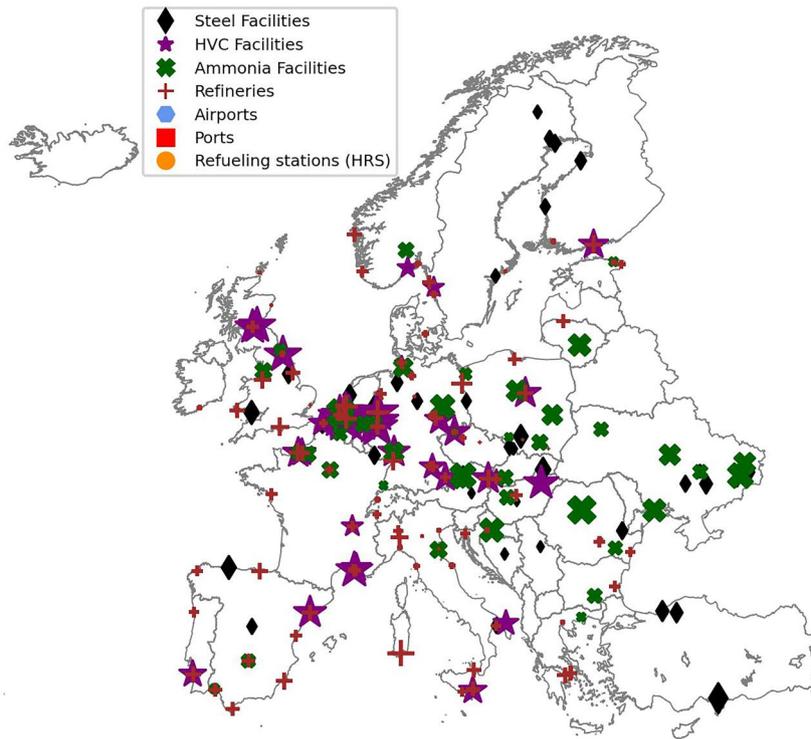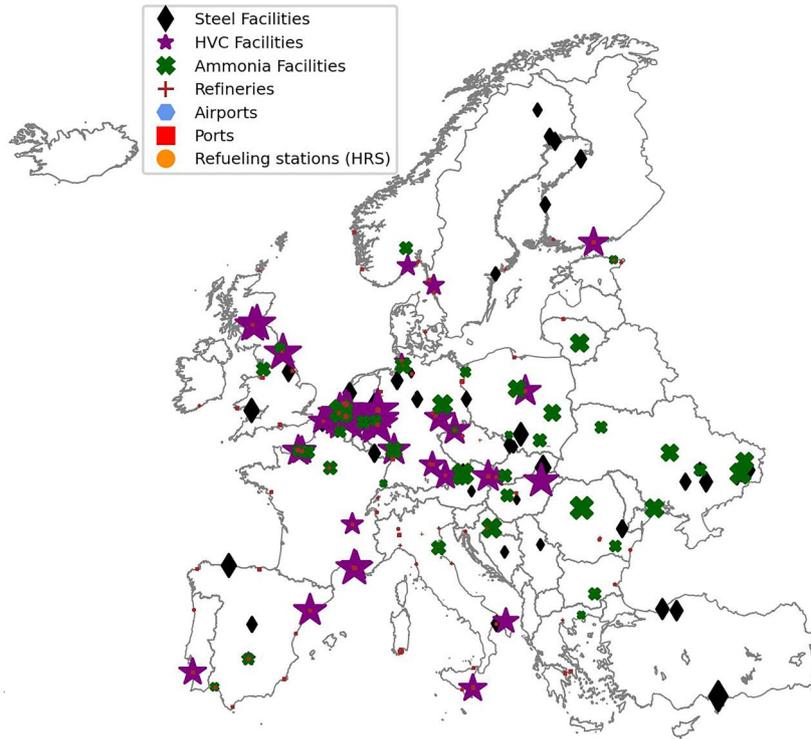
Extended Data Fig. 2 | Node locations, scenario Elec prio. Node size indicates relative annual demand size.

Extended Data Fig. 3 | Node locations, scenario H2 prio. Node size indicates relative annual demand size.

Extended Data Fig. 4 | Node locations, scenario E-fuel prio. Node size indicates relative annual demand size.

Extended Data Fig. 5 | Node locations, scenario Biofuel prio. Node size indicates relative annual demand size.

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Last updated by author(s): Dec 16, 2025

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Our web collection on statistics for biologists contains articles on many of the points above.

Software and code

Policy information about availability of computer code

Data collection	No software was used for collecting data.
Data analysis	All code used for the hydrogen demand simulation, called the SVENG model (version 3), as well as all code pertaining to the data analysis and vizualisation, is available here: doi.org/10.5281/zenodo.15223365 This also includes the scripts used to orchestrate/schedule the execution of the different analysis scripts. The SVENG model builds on GIS (Geographic Information System) data structures. it is built on python 3.9, and utilizes the geopandas, pandas, numpy, searoute, haversine, matplotlib packages. Some scripts are built using julia 1.12. The code for the Multinode model, used for electricity system optimization, is not published here. It is, however, described in e.g. https://doi.org/10.1016/j.apenergy.2017.04.018 and doi.org/10.1016/j.apenergy.2022.120233

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All manuscripts must include a data availability statement. This statement should provide the following information, where applicable:

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The data produced as results in this study can be accessed here: doi.org/10.5281/zenodo.15228269
Input data was downloaded from different open online databases, referenced in the article. Input data is provided in Supplementary Notes 2 and 4, in Supplementary Data table 1, and along with the code: doi.org/10.5281/zenodo.15223365

Research involving human participants, their data, or biological material

Policy information about studies with human participants or human data. See also policy information about sex, gender (identity/presentation), and sexual orientation and race, ethnicity and racism.

Reporting on sex and gender	There were no human subjects in this research, and as such no data on sex or gender was collected.
Reporting on race, ethnicity, or other socially relevant groupings	There were no human subjects in this research, and as such no data on groupings was collected.
Population characteristics	See above.
Recruitment	No human participants were included in this study.
Ethics oversight	No ethics oversight was deemed required for this work.

Note that full information on the approval of the study protocol must also be provided in the manuscript.

Field-specific reporting

Please select the one below that is the best fit for your research. If you are not sure, read the appropriate sections before making your selection.

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Ecological, evolutionary & environmental sciences study design

All studies must disclose on these points even when the disclosure is negative.

Study description	The study investigates effects on water resources, electricity prices, and land use under different energy transition pathways, focusing on the impacts of hydrogen use across Europe.
Research sample	No sampling of live organisms was done.
Sampling strategy	No sampling of live organisms was done.
Data collection	Data was acquired from online databases.
Timing and spatial scale	Data was acquired over the period of March 2023 - April 2025.
Data exclusions	From datasets acquired in open online databases, data has been excluded if it was considered erroneous (suspected measurement error that would skew the results in a way deemed unrepresentative) or not applicable (e.g. applying to a country outside of the scope of the study). These criteria were established prior to analyzing the data.
Reproducibility	All data and code is preserved, which enables reproducing the results, since the data has been gathered from openly accessible databases.
Randomization	No grouping/randomization was done.
Blinding	No blinding was done, since the nature of the data and analysis required all involved researchers to understand the nature of all data.

Did the study involve field work? ☐ Yes ☒ No

Reporting for specific materials, systems and methods

We require information from authors about some types of materials, experimental systems and methods used in many studies. Here, indicate whether each material, system or method listed is relevant to your study. If you are not sure if a list item applies to your research, read the appropriate section before selecting a response.

Materials & experimental systems

n/a	Involved in the study
☒ ☐	Antibodies
☒ ☐	Eukaryotic cell lines
☒ ☐	Palaeontology and archaeology
☒ ☐	Animals and other organisms
☒ ☐	Clinical data
☒ ☐	Dual use research of concern
☒ ☐	Plants

Methods

n/a	Involved in the study
☒ ☐	ChIP-seq
☒ ☐	Flow cytometry
☒ ☐	MRI-based neuroimaging

Plants

Seed stocks	No seed stocks.
Novel plant genotypes	No novel plant genotypes.
Authentication	No authentication of the above has been done, since there weren't any seeds or plants.