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On the feasibility of direct hydrogen utilisation in a fossil-free Europe

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HIGHLIGHTS

- Hour-by-hour energy system analysis for direct green hydrogen utilisation in Europe.
- Hydrogen for industrial demands can lower biomass consumption.
- Power production applications are costly and limited for hydrogen.
- Hydrogen for heating is more expensive than heat pumps and district heating.
- E-fuels should be the main application for hydrogen in the transport sector.

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ABSTRACT

Hydrogen is often suggested as a universal fuel that can replace fossil fuels. This paper analyses the feasibility of direct hydrogen utilisation in all energy sectors in a 100% renewable energy system for Europe in 2050 using hour-by-hour energy system analysis. Our results show that using hydrogen for heating purposes has high costs and low energy efficiency. Hydrogen for electricity production is beneficial only in limited quantities to restrict biomass consumption, but increases the system costs due to losses. The transport sector results show that hydrogen is an expensive alternative to liquid e-fuels and electrified transport due to high infrastructure costs and respectively low energy efficiency. The industry sector may benefit from hydrogen to reduce biomass at a lower cost than in the other energy sectors, but electrification and e-methane may be more feasible. Seen from a systems perspective, hydrogen will play a key role in future renewable energy systems, but primarily as e-fuel feedstock rather than direct end-fuel in the hard-to-abate sectors.

Introduction

Hydrogen is the simplest molecule. It is a combustible gas that has attracted the interest of many due to its potential to replace fossil hydrocarbons without emitting CO_2 and is often suggested as a future zero-emission solution for decarbonising energy and transport systems [1–4]. Hydrogen is capable of integrating renewable electricity. Already in 1891, Poul la Cour used wind turbines to create hydrogen in northern

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Denmark, albeit on a very small scale [5]. A simple search for the term "*hydrogen economy*" in title, abstract and keywords on Scopus reveals over 3200 publications analysing this topic, with the oldest ones published in the early 1970s. Among the most cited papers in the subject area of energy, we find authors that discuss hydrogen production pathways and technologies for a complete or partial transition from oil products to hydrogen, but also papers that highlight some of the challenges of hydrogen economies. Barreto et al. [6] find that hydrogen economies are plausible and hydrogen-based technologies are flexible, despite the uncertainty if such solutions can mitigate climate change. Abe et al. [7] find hydrogen as a clean, sustainable and 'ideal' cost-efficient fuel, but identify storage as its main hurdle. Conversely, other researchers [8,9] identify that hydrogen economies must bring guarantees of fulfilment to reduce CO_2 emissions and come together with strong technological developments [8,10]. Similarly, Crabtree et al. [11] explain that the difficulty for transitioning to hydrogen lies within safety issues but identifies practical and commercial appeal. Beyond market interest, hydrogen uptake would require state support, as highlighted by Dunn [12].

Another aspect to clarify when discussing hydrogen economies is the colour of hydrogen; should it be green, i.e., produced from renewables and electrolysis or blue, obtained from fossil fuels and carbon sequestration? The majority of the authors discuss hydrogen economies from the latter's perspective [13–16], while renewable hydrogen seems to be given either a niche or a rather emerging role for the long term, in particular, due to the large electricity demand [14]. Other authors are more pragmatic, clarifying that the use of blue hydrogen is no better than the use of fossil fuels in the first place if the objective is decarbonisation, and economies can benefit more from direct power utilisation, energy storage and smart grids [17], in particular, if the price of oil is high and battery technologies do not develop sufficiently [18]. Hydrogen economies concepts are accused by other authors of lacking consistency and only propose visions and opinions, with some authors dismissing hydrogen outright [19]. The lack of consistency in appraisal is not surprising since McDowell et al. [20] find in their review that the hydrogen economy is a mix of hydrogen economies in various niche areas, with contested visions rather than shared visions on what will be the sources of hydrogen and how the hydrogen should be used.

From a purely technical perspective, hydrogen can be used in all energy applications and sectors: electricity, heating, industry, or transport. For electricity production, hydrogen can either be combusted or used in stationary fuel cell applications. The combustion can occur in specifically designed or modified gas turbines with zero carbon emissions and potentially reduced NOx emissions [21]. A 12 MW combined-cycle gas turbine using reformed hydrogen has been operational in Italy since 2009, but the project appears to be a demonstration exercise rather than a commercial solution [22]. Fuel-cell power generation has seen demonstration projects since the beginning of the last decade [23]. Hydrogen in fuel cells can offer additional flexibility by using reversed operation (merely with solid oxide cells) in power-to-hydrogen-to-power applications [24].

In the heating sector, hydrogen can be used in boilers for space heating, hot water production, and cooking purposes, and in some assessments, it is seen as a potential alternative to other renewable-based heating solutions [25,26]. This application has not been the subject of many academic studies but has been proposed for the Netherlands and the UK, where demonstration projects already exist [27–30], despite this being a more expensive solution than heat pumps or district heating in both countries [31–33]. The primary attractiveness of hydrogen is to make use of a large part of the existing gas infrastructure, especially in regions where natural gas is currently used for this purpose, although many components will still require replacements or component upgrades, such as piping, metering, burner heads and seals [34].

In the industry sector, hydrogen is an attractive fuel for the hard-to-abate processes in the production of non-metallic minerals (e.g., cement), iron and steel, non-ferrous metals or as an ingredient for the chemical industry. Unlike power and district heat production, industrial processes are more selective in the type of fuels they can use due to the operation in controlled high-temperature environments [35]. Existing research on steel production via the hydrogen route has found significant potential [36,37] and has already seen some practical examples in Sweden [38] and Austria [39]. Hydrogen for cement production has limited technical applications and needs to be combined with other renewable alternatives, but cement kilns could, for instance, run on hydrogen [40,41]. On the other hand, the chemical industry can benefit the most from this fuel since hydrogen and carbon (sourced from carbon capture systems) are essential elements [42].

One of the most well-known uses for hydrogen is in the transport sector, where it is compressed or liquefied [43–45]. Hydrogen vehicles are a method for replacing petrol and diesel fuels and achieving zero emissions, but to date, very few vehicles of this sort exist on the roads, at least compared to electric vehicles. Their primary issues are the high production cost, limited longevity and refuelling infrastructure, also hampered by safety issues and high costs, even though in time, the investment cost in related technology may decrease [46,47]. Hydrogen is also touted as promising for aviation, but dependent on low-cost green hydrogen infrastructure [48] while Horvath et al. [49] identify liquid hydrogen as most suited to replace fossil fuels in deep ocean shipping. Therefore, hydrogen propulsion may remain a possibility and may find acceptance within heavy-duty road, sea and air transport or as a range extender for electrified vehicles.

Various technical opportunities involve direct hydrogen utilisation and are the reasons for proposing hydrogen as a solution to decarbonise energy systems, although without much clarity. The debate around hydrogen is strong at the international level [50–53], and the European Commission published a strategy for hydrogen upscaling across Europe [1], while other gas stakeholders push for extended use and repurposing of their transmission and distribution grids [2,54–56], suggesting that hydrogen can be suitable for the hard to abate sectors, such as steel production, chemical industry but also as fuel for some types of transport, as trucks and busses. In its full scale, each energy sector benefits from a variety of technical solutions, available or upcoming, and can contribute to achieving the same decarbonisation goals as with direct hydrogen utilisation. These may be electrification, district heating, heat pumps, bioenergy or carbon capture combined with e-fuel production. Each of these technical solutions can be alternatives to direct hydrogen use and may be preferred depending on the comparative advantages. But to progress from technically viable solutions to feasible solutions, these must also be evaluated from a system perspective and be economically attractive, socially acceptable and environmentally friendly.

The system perspective for hydrogen has been analysed to limited extents when considering future scenarios of a sector-coupled and carbon-neutral European energy system. Pickering et al. [57] show a diversity of near-cost-optimal scenarios where hydrogen is used as a feedstock for synthetic fuel production and for utility-scale storage, without considering its direct end-use. On the other hand, more specific cross-sectorial energy system analysis of the role of hydrogen in a decarbonised Europe have included only a long-term modelling horizon rather than hourly system modelling [58], which is otherwise needed to account for the fluctuations of renewable supply and end-use demands in the energy system. Not least, Fischedick et al. [59] call for energy system analysis regarding the role of hydrogen, highlighting the need for the efficient allocation of limited renewable energy sources and the reduction of energy demands as prerequisite for any renewable energy system. To deal with the uncertainty of direct hydrogen applications, this paper explores its applications in a fossil-free and sector-coupled European energy system to identify if this fuel can be a feasible alternative to other renewable fuels and technologies, all analysed from a system perspective with an hourly representation of the energy system. The aim is to determine if direct hydrogen use, in any quantities and sectors, can be more economic and efficient than an energy system without direct hydrogen utilisation.

Methodology

To model the large-scale implementation of hydrogen, suitable tools are needed that can include the system effects of different technological options across all energy sectors. For this analysis, we use the energy system analysis tool EnergyPLAN [60,61]. EnergyPLAN is a deterministic energy system analysis tool that can model entire energy systems or groups of energy systems, such as the European energy system and can deal with simulating both 100% renewable and carbon-neutral energy systems. The tool operates on an hour-by-hour basis and offers a high level of resolution on capacities and energy production in the entire supply chain, from the production of renewable energy to the utilisation across each energy sector. These characteristics make it particularly well-placed to simulate the effect of hydrogen economies.

We use a 100% renewable energy system model for EU27 + UK as a starting point, also referred to as the "*Reference*" model. The model has been developed by Thellufsen et al. [62] as an alternative to a decarbonised European energy system developed by the European Commission [63]. The Reference model is 100% renewable, meaning it does not include nuclear energy nor carbon capture and storage, uses sustainable amounts of biomass and includes of national and international transport demands within European borders. The model is designed with energy efficiency aspects and integration of variable renewable energy in mind, focusing on district heating and heat pumps for the heating sector and large levels of direct and battery electrification for industry and transport.

The Reference model produces large amounts of green hydrogen as feedstock for e-fuels. In the transport sector, the choice is based on the particularly efficient hydrogen-to-methanol conversion and the simple storage requirements of this fuel, less costly than for gaseous and liquefied fuels [47,64]. Commercial aviation still requires jet fuels, so the proposed solution is e-kerosene, which can be produced from methanol or Fischer-Tropsch synthesis, depending on the maturity of the technologies [65]. In the case of industry, e-methane is the fuel of choice since it can replace natural gas for industrial processes where electrification is not possible. In this Reference model, for these two energy sectors, the total hydrogen demand reaches approximately 3000 TWh, supplied by a mix of over 700 GW of electrolyser technologies, which ensure, together with the four-day hydrogen storage, an energy system with a high level of flexibility.

For the alternative scenarios, direct hydrogen consumption is considered for each of the following energy sectors: electricity, heating, industry and transport. Hydrogen production is balanced by adjusting upwards or downwards offshore wind, for which the same level of electrolysis flexibility is maintained across all scenarios, i.e., over 5000 full load hours and four days of hydrogen storage. All the models restrict VRES (Variable Renewable Energy Sources) curtailment to 50 TWh/year for the whole of Europe on an annual basis (1% of the total electricity consumption). Table 1 details the main capacities and production in the reference model.

Table 1 – Main parameters in the reference model [62].

	Unit	Reference model
Primary energy supply		
Onshore wind	PWh/year	5.05
Offshore wind	PWh/year	0.69
PV	PWh/year	1.67
Biomass	PWh/year	3.09
Conversion capacities		
Onshore wind	GWe	1800
Offshore wind	GWe	290
PV	GWe	1155
Combined heat and power	GWe	144
Power plants	GWe	481
Electrolysis	GWe	759
Energy demands		
Domestic electricity	PWh/year	2.12
Industry electricity	PWh/year	1.20
Transport electricity	PWh/year	0.88
District heating	PWh/year	1.09
Individual heating	PWh/year	1.02
Transport electrofuels	PWh/year	1.46
Industry electrofuels	PWh/year	0.82
Biofuels	PWh/year	0.07

Analysis and results

The analysis and the results are organised for each energy sector, as different approaches had to be used for each sector in the modelling of direct hydrogen utilisation. Each sub-section in this chapter explains how the analysis takes place. In addition, the first sub-section presents an overview of the main cost assumptions in the model, including for hydrogen-related infrastructure.

Cost assumptions

An important component of the alternative hydrogen scenarios is the cost of the new hydrogen infrastructure and the assumptions behind the model, particularly the cost of hydrogen transmission, distribution and fuelling stations. One of the top-selling points for large-scale direct hydrogen utilisation is the possibility of utilising existing natural gas infrastructure [26,34,66], such as the extensive gas network across Europe and the large underground storage facilities, among which some can be converted to hydrogen. The reconversion of this infrastructure is estimated to be significantly less expensive than building new pipes and avoids the setbacks of stranded assets if such an infrastructure is prematurely decommissioned [2,56]. However, not all pipes can be reconverted to hydrogen due to the types of materials used or because of the practicality of the conversion, e.g. if gas supply must be maintained while conversion occurs, or because of safety limitations, since transmission grids are typically operated at pressures of 50–80 bars [2,56]. It is difficult in this top-down approach to determine how much and which parts of the existing natural gas grid are viable for hydrogen conversion; therefore, we use a conservative approach, which assumes that all direct hydrogen grid is subject to new infrastructure costs. In all scenarios, we isolate the hydrogen infrastructure costs to determine their influence on the total annual costs of the energy system. We use an annual cost of 16 M€/TWh of hydrogen transmitted, as well as an annual cost of 68 M€/TWh for distributed hydrogen following the costs estimated for 2050 by the European Commission [67]. Hydrogen distribution is more expensive than transmission since the gas needs to be transported at lower pressures; thus, the energy content is lower per volume of gas. Not all scenarios require a hydrogen distribution grid, as a hydrogen transmission line would be sufficient to link several large power plants or large consumers in the industry. However, when simulating hydrogen for heating and transport purposes the assumption is that a distribution grid would have to be in place, to supply the different households and buildings and respectively, to supply the numerous hydrogen refuelling stations across the main European roads networks.

Hydrogen transmission is also often compared to electricity transmission as a less expensive method for transporting large amounts of energy over long distances since the cost of new transmission lines can be up to 4 times more expensive than new hydrogen transmission pipes [55,56,68]. But unlike hydrogen infrastructure, the electricity infrastructure is already in place and in use and will remain so regardless of the decarbonisation pathway, as it is an indispensable infrastructure for all energy sectors. Electricity transmission is also often oversized, already providing room for manoeuvring significant amounts of renewable energy if done more efficiently [69]. However, with high levels of electrification and e-fuels, a certain level of expansion will be necessary. Egerer et al. [70] estimate that the total investment cost of expanding the electricity transmission to accommodate a highly renewable scenario can be up to 75 B€, including interconnectors, which annualised amounts to 1–2 B€. Even doubling the initial investment still leaves a low annual cost, making it only a fraction of the overall energy system, where the supply and demand account for the highest costs. For these reasons, and because it is difficult to estimate the future placement of hydrogen production and the need for transmission grid expansion, the cost of the electricity transmission is not included in the analysis. On the other hand, the cost of electricity distribution is included and adjusted across all scenarios, as this is significantly larger than that of the transmission grid, and it is also where the grid needs reinforcements to cope with electrification. Table 2 presents an overview of this cost and other infrastructure costs used throughout this analysis. Furthermore, Table 3 presents other key cost assumptions.

Hydrogen for power production

Hydrogen is first simulated for the electricity production sector. The assumption here is that part of the electricity production in Europe is supplied by hydrogen. The power plants do not use blended gas (hydrogen + methane), but we consider that several combined cycle power plants across Europe convert to using hydrogen only, with the same efficiency as the plants using green methane. Hydrogen is thus intended to replace the green methane in the reference scenario in three incremental scenarios (1-2-3) with 300, 600 and 900 TWh H_2. Additionally, we include scenarios 4 and 5, further explained in the next paragraphs.

The results in Fig. 1 show that direct hydrogen utilisation can reduce the overall biomass consumption throughout the energy system, with the largest effects in scenario 1. Then. in

Table 2 – Key assumptions for the infrastructure costs.

Infrastructure	Investment	Lifetime	O&M (% of investment)	Reference
Electricity distribution	3.3 M€/MW	50	–	[71]
DH grids	363 M€/TWh	40	–	[72]
DH Substations	92 M€/TWh	25	2.5%	[72]
Hydrogen transmission	16 M€/TWh	50	5%	Based on [67]
Hydrogen distribution	68 M€/TWh	50	5%	Based on [67]
Hydrogen refuelling stations	0.7–1.7 M€/station	25	3%	Based on [67,73,74]

Table 3 – Other key cost assumptions based on [23,62,75,76].

	Unit	Capacity factors/ efficiency	Investment (M€/unit)	Lifetime (years)	O&M (% of investment)
Electricity and heat production					
Onshore wind	MWe	32%	0.96	27	1.3
Offshore wind	MWe	54%	1.78	27	1.9
PV	MWe	16%	0.35	30	2.5
DH Heat Pumps	MWe	400%	2.13	25	0.3
Combined heat and power plants	MWe	45% heat 45% electricity	1.35	25	3.3
Power plants	MWe	60%	1.35	25	3.3
Fuel conversion					
Electrolysers	MWe	70%	0.50	25	4.0
Hydrogen storage	GWh	–	8.15	79	1.0
Biogas plant	TWh/year	–	196	20	15.0
Biogas purification plant	MWfuel	–	0.25	15	2.5
Gasifier (power gen.)	MWfuel	83%	1.33	20	3.0
Methanol synthesis	MWfuel	84%	0.30	25	4.0
Methanol-to-kerosene	MWfuel	74%	0.50	20	4.0
Post-combustion carbon capture	tCO_2/year	–	200	20	4.3

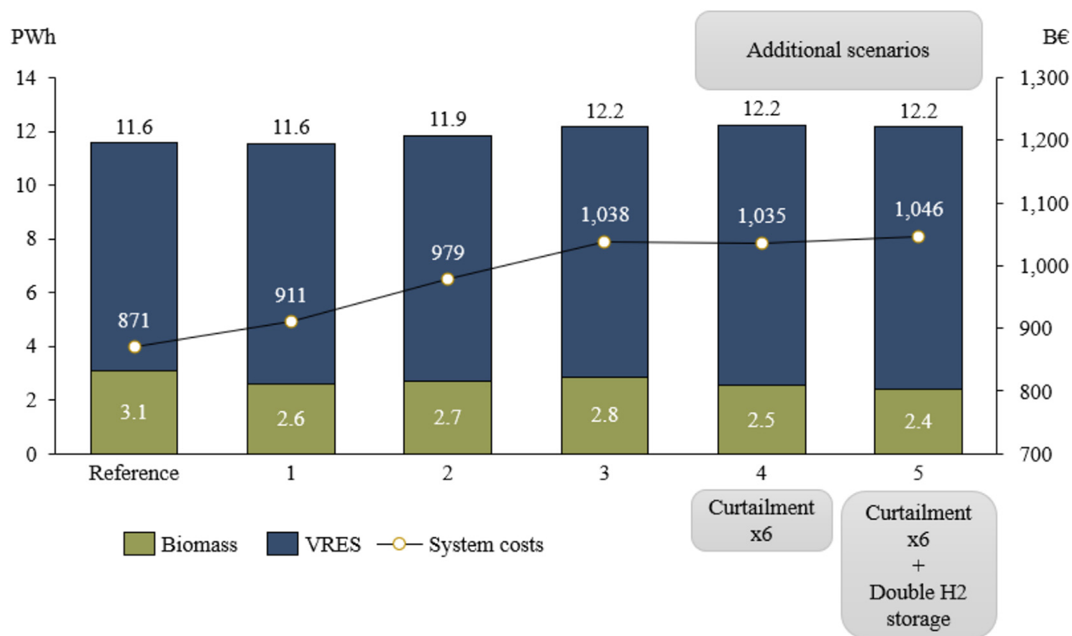

Fig. 1 – Primary energy consumption and annual energy system costs (excluding transport) for the reference and the alternative hydrogen scenarios for power production.

scenarios 2 and 3, the more power plants convert to hydrogen, the more biomass the system uses and the higher the energy system costs. The results for scenario 1, where biomass consumption decreases, can be further observed in Fig. 2, which shows that 300 TWh of hydrogen can replace 200 TWh of green methane. But the more hydrogen power plants are made available (which require more hydrogen), the less green methane is replaced, up to the point in scenario 3 where the overall power plant fuel consumption doubles compared to the reference scenario.

The cost increase naturally relates to the necessity for new renewables and electrolysis capacities. In scenario 1, the production and use of 300 TWh of hydrogen can keep the overall fuel levels in power plants at a fairly similar level to the reference scenario while also reducing green methane consumption because the system can absorb the additional hydrogen demands. But in scenarios 2 and 3, increasing the number of hydrogen power plants drives an overall higher fuel consumption because the energy system cannot sustain the additional hydrogen production while keeping the same level of curtailment, i.e., 1% of the total electricity production. Fig. 2 illustrates how the average utilisation in power plant capacity increases as more hydrogen is demanded by the system, which also means that inland produced hydrogen, as proposed in this analysis, cannot fully replace methane in power plants unless the energy system increases VRES

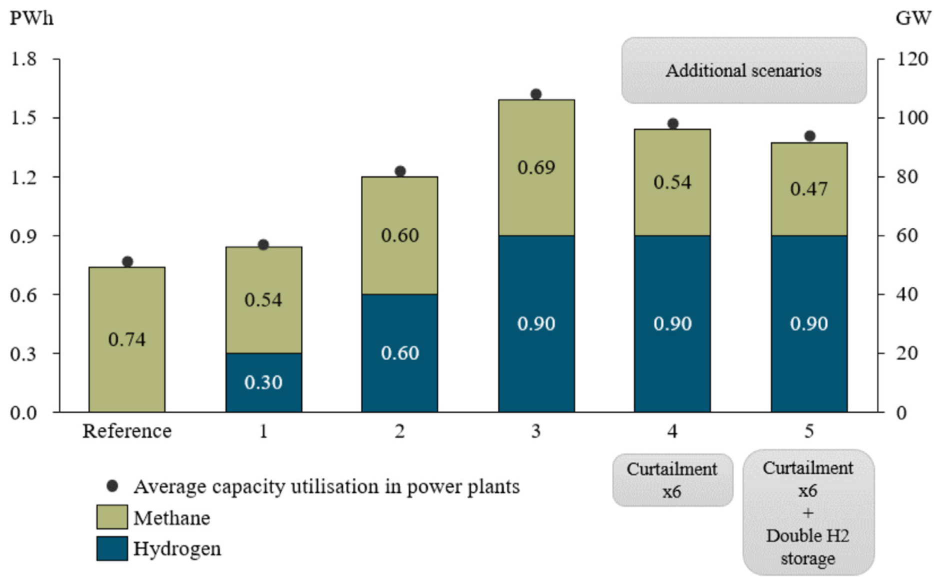

Fig. 2 – Fuels used in power plants and their average capacity utilisation.

capacity and curtailment. Overall, this means that at certain hours of the year, power plants need to operate the electrolysis due to either insufficient wind production, lack of hydrogen in the storage or both.

If more wind capacity is added and the level of curtailment is allowed to increase (six times higher as in scenario 4), this means that wind can cover more of the demands, while power plants operate less, at lower capacities, but at the expense of wasted renewable electricity. Adding more hydrogen storage (scenario 5) can increase the system flexibility, but since the total amount of hydrogen in the energy system remains the same, albeit, with higher flexibility, the effects are limited and costs further increase (Fig. 1). Therefore, as shown in Fig. 2, it becomes clear that the increased hydrogen in the energy system is restricted by its low round-trip efficiency (*electricity-to-hydrogen* and *hydrogen-to-electricity*) and only balances itself by increasing power plant utilisation and capacities. Hydrogen infrastructure has a small share of the total cost (~2% of the total), and it is not responsible for the more expensive energy system costs.

Consequently, for the power sector, using limited amounts of hydrogen has a small effect on the energy system and can be a solution for reducing biomass consumption if that is the goal, but it will make the energy system more expensive, with the cost of saving 1 TWh of biomass calculated at 85 M€. Such results are, of course, influenced by the system boundaries chosen for these models. If curtailment is no longer a limitation and hydrogen storages are very large and flexible (able to absorb large hourly variations for charge and discharge), then hydrogen can replace more green methane. However, this leaves a large production of renewable electricity unused.

Hydrogen for industry

In the next set of analyses, hydrogen is used to replace industry sector fuels in the Reference model, namely biomass and e-methane from carbon capture and utilisation. Hydrogen does not replace more efficient measures as the electrification of industrial demands, but only focuses on the solid and gaseous fuels intended for that part of the industry that cannot be electrified. The replacement of biomass and electromethane is done in steps of 300 and 600 TWh for each fuel and is illustrated in Fig. 3.

The results show that replacing e-methane in any quantity with direct hydrogen results in small changes in the energy system in the amount of biomass and renewable electricity, or the energy system costs, so the results are similar to the Reference model. However, replacing biomass has larger system effects. The results indicate that hydrogen can replace biomass at a ratio of 1:1, by integrating larger capacities of VRES without the negative system effects observed in power production. They also show that the more biomass is replaced, the lower the cost of replacing a TWh of biomass. That is, as the overall cost of the energy system increases by adding hydrogen, the cost per TWh of biomass saved is lower. Therefore, it is important to understand the system effects of which fuels hydrogen replaces, e.g. if hydrogen replaces methane from biogas – a cheaper fuel – then the results would be similar to replacing biomass.

All biomass replaced by hydrogen in industry is reflected in an overall lower biomass consumption in the energy system, with marginally higher power plant utilisation due to the increased hydrogen demands. This also entails that direct hydrogen utilisation can integrate more renewable electricity into the energy system fairly efficiently but will also require an additional 90–180 GW of offshore wind for the two biomass scenarios. Considering a biomass price 50% higher for all scenarios does not change the results significantly, as producing hydrogen will always be a more expensive solution than using biomass. Therefore, like in the analysis for the power sector, the replacement of bioenergy with direct hydrogen remains an expensive solution, but at 42 M€/TWh of biomass saved, it is also two times less expensive than direct hydrogen utilisation in power plants.

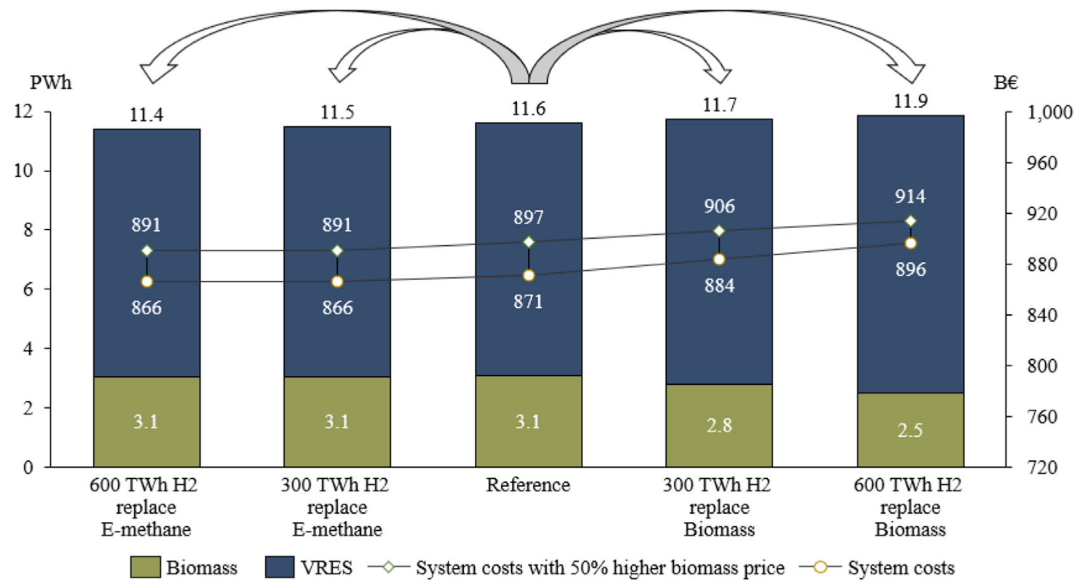

Fig. 3 – Fuel consumption and annual energy system costs (excluding transport) for the reference and alternative hydrogen scenarios in the industry sector.

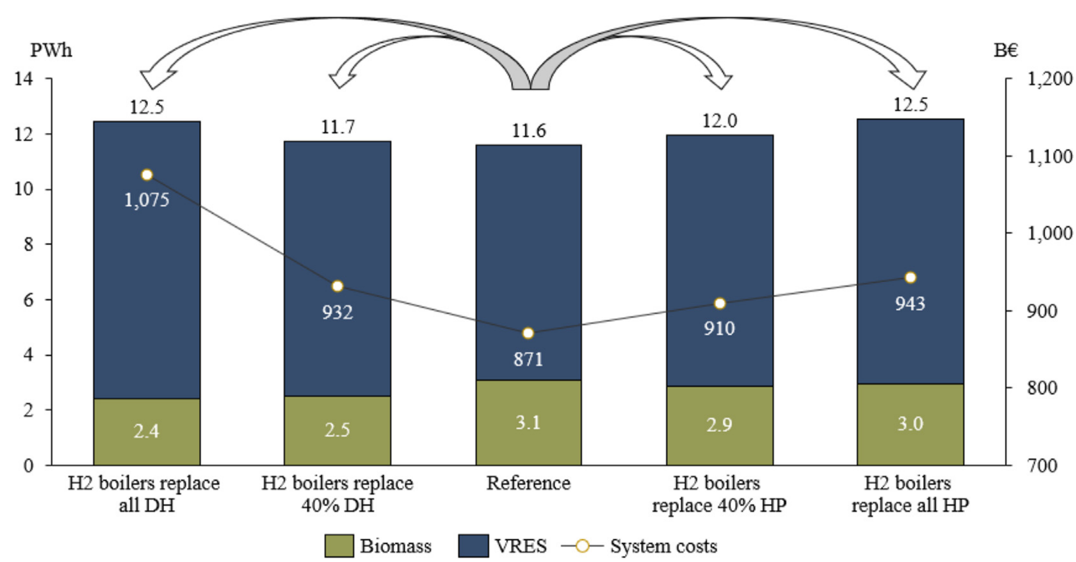

Fig. 4 – Fuel consumption and annual costs (excluding transport) for the reference and alternative hydrogen scenarios in the heating sector.

Hydrogen for heating

The next part of the analysis deals with the heating sector. Here, the hydrogen scenarios involve replacing district heating and household heat pumps from the Reference scenario with individual hydrogen boilers in four alternative scenarios, as illustrated in Fig. 4. The reference scenario has a total heat demand of 2110 TWh, with high levels of district heating and household heat pumps, where district heating supplies more than 50% of the total heat demand, while over 40% is supplied by heat pumps and a small share is dedicated to biomass boilers. All alternative scenarios include costs for the distribution of hydrogen, while in the case of replacing heat pumps with hydrogen boilers, the investments in the electricity distribution are reduced accordingly.

On the left-hand side of Figs. 4 and 5, hydrogen replaces district heating in two steps. In the first step, hydrogen replaces 40% of the district heating heat demand with hydrogen boilers using 440 TWh of hydrogen, or in other words, district heating expansion in the Reference model is reverted to today's level. The second step is an extreme scenario, where hydrogen boilers replace all heat demand for district heating (1090 TWh of hydrogen). On the right-hand side of the figure, hydrogen boilers first replace a comparative share of the heat demand for individual heat pumps, resulting in 430 TWh of hydrogen consumption, while the second scenario replaces all

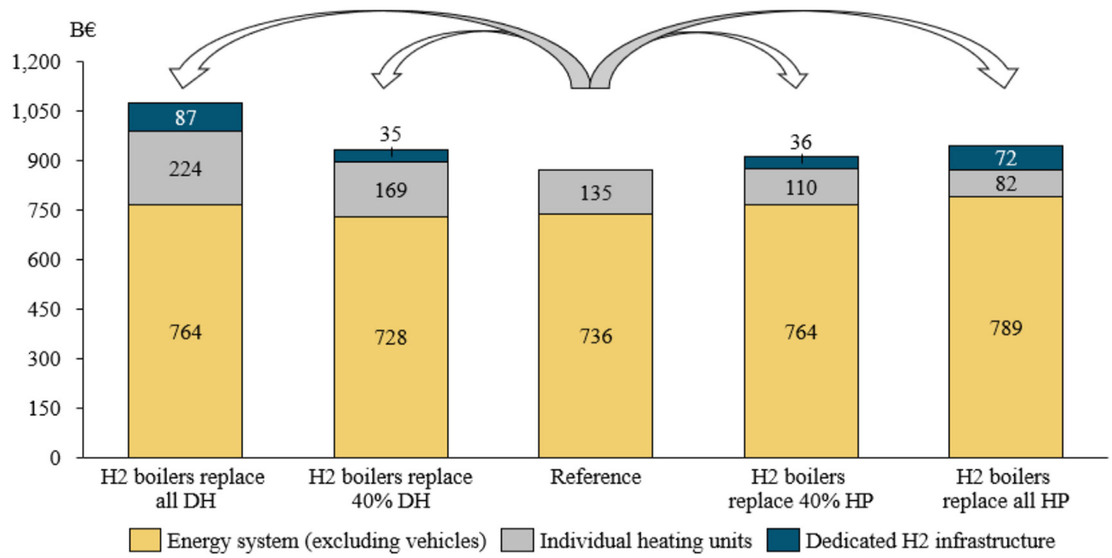

Fig. 5 – Annual cost split between key system components in the reference and alternative hydrogen scenarios.

individual heat pumps with hydrogen boilers, representing 900 TWh of hydrogen. All scenarios include hydrogen transmission and distribution costs.

As in the electricity and industry sectors, the results for the heating sector present a similar story: that direct hydrogen utilisation can save biomass, but that the cost of such an approach is high in terms of economy and energy efficiency. Replacing part of the district heating supply with hydrogen boilers comes at a high cost and primary energy supply increase, but can save significant amounts of biomass because it replaces district heating boilers and combined heat and power plants operating on green methane. Additionally, hydrogen boilers manage to integrate more VRES in the energy system, but the extreme where hydrogen boilers replace all district heating presents poor biomass savings compared to the previous scenario. The inefficiency of not utilising waste heat from electricity production, industrial processes and electrolysis is pronounced, as illustrated by the primary energy supply increase. Most significantly, using hydrogen for space and hot water heating increases the energy system costs by 7% and 23% compared to the reference scenario, costing between 60 B€ to 200 B€ more annually, making it one of the most abrupt cost increases among the scenarios investigated. Large amounts of biomass can be saved this way, but the overall biomass savings are comparable with replacing biomass in industry, as shown in the previous section. Therefore, by comparing the cost for each TWh of biomass saved, replacing all district heating with hydrogen boilers is five times costlier than replacing biomass in industry, while replacing a smaller share of district heating with hydrogen boilers, is two times costlier.

Illustrated in Fig. 5, the cost difference between the reference and alternative scenarios to the left comes from the more expensive individual boilers units and related hydrogen infrastructure and less from the energy system, at least in the case of the scenario with limited district heating replacement. Replacing individual heat pumps with hydrogen boilers can only save low amounts of green methane in power plants, significantly lower than in the case of replacing district heating. Consequently, despite the lower investments in heating units (hydrogen boilers are considered cheaper than heat pumps), the replacement of the more efficient heat pumps with hydrogen boilers makes the energy system use more VRES but at the expense of lower efficiency and higher system costs.

Overall, the use of hydrogen for heating, especially in urban contexts where district heating can be a viable alternative, radically increases the costs of the energy system. Between 120 and 320 GW of additional offshore wind will be necessary to handle the decrease in system efficiency. The application of hydrogen for heating purposes does not present the same advantage for reducing biomass in the energy system compared to the other applications in industry or power production.

Hydrogen for transport

In the transport sector, all types of fuels in the reference scenario are replaced by hydrogen, including electric and e-fuels transport. To display the energy system effects of such an alternative, Table 4 illustrates the changes in the alternative hydrogen scenarios compared to the Reference model. There are eight alternative hydrogen scenarios, four deal with replacing BEV (battery-electric vehicles) and the other four deal with replacing e-fuels. Hydrogen fuel cells replace the electrified HDV (heavy-duty vehicles), LDV (light-duty vehicles), bus, rail and cars on one side, while e-fuels are replaced by hydrogen in HDV, LDV, bus, rail, navigation and aviation. All scenarios include the costs of vehicles and BEV charging infrastructure, while the alternative hydrogen scenarios also include costs for new hydrogen distribution and fuelling stations for all road transport. Due to the lack of data, no fuelling costs are assumed for non-road transport (as for rail, navigation and aviation). Furthermore, when hydrogen replaces battery-electric transport, the costs of BEV charging stations and electricity distribution grid are adjusted accordingly but

Table 4 – Propulsion type shares between different vehicles in the reference and alternative hydrogen scenarios.

		Replacing BEV		Reference scenario		Replacing electrofuels
1	HDV	40% H_2 fuel cells 60% methanol ICE	⟵	40% BEV 60% methanol ICE	⟶	40% BEV 60% H2 fuel cells
2	LDV	50% H_2 fuel cells 50% methanol ICE	⟵	50% BEV 50% methanol ICE	⟶	50% BEV 50% H_2 fuel cells
3	Buses	50% H_2 fuel cells 50% methanol ICE	⟵	50% BEV 50% methanol ICE	⟶	50% BEV 50% H_2 fuel cells
	Rail	50% H_2 fuel cells 37% direct electric 13% methanol ICE	⟵	87% direct electric 13% methanol ICE	⟶	87% direct electric 13% H_2 fuel cells
4	Navigation			100% methane ICE	⟶	50% methane ICE 50% H_2 fuel cells
	Aviation			100% jet fuel turbine	⟶	50% jet fuel turbine 50% H_2
5	Cars	50% H_2 fuel cells 50% BEV	⟵	100% BEV		

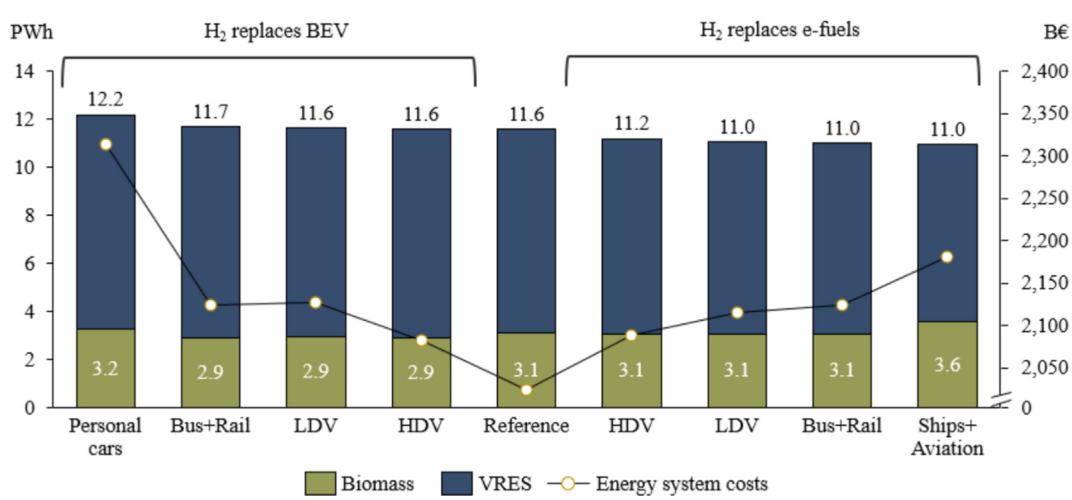

Fig. 6 – Fuel consumption and energy system annual costs in the reference and the alternative hydrogen scenarios in the transport sector.

not when hydrogen replaces e-fuel vehicles since these can reuse the existing liquid fossil fuel infrastructure at negligible costs.

The results of the transport analysis are illustrated in Fig. 6. One general observation is that hydrogen for transport (through fuel cell propulsion) does not reduce biomass consumption in any of the scenarios as it does for power production, district heating and industry; nor does it help reduce the costs in the energy system.

The right side of Fig. 7 shows that the primary energy consumption decreases when hydrogen replaces e-fuels since the former is more efficient to produce and utilise than e-fuels. The general reduction in VRES production compared to the Reference model is coupled with higher biomass consumption when it replaces electrofuels in ships and aviation. Left of the Reference model, where hydrogen replaces electrified transport, increases the primary energy consumption since hydrogen fuel cell vehicles are less efficient than electrified transport. This is driven by the higher use of VRES with similar biomass consumption across the scenarios, except for the conversion of large parts of personal transport to hydrogen, which does not integrate more renewable

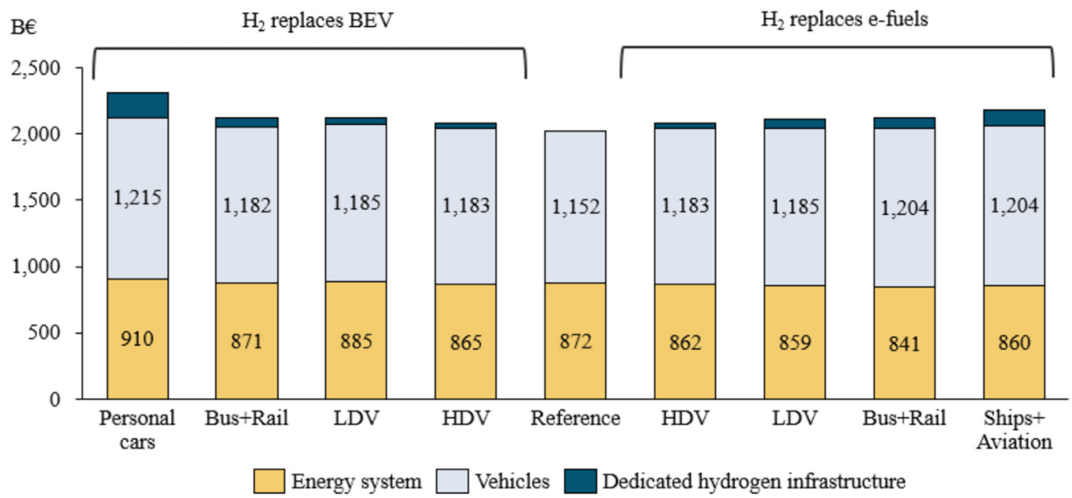

Fig. 7 — The annual cost split between the energy system, vehicles and hydrogen infrastructure in the reference scenario and the alternative scenarios for the transport sector.

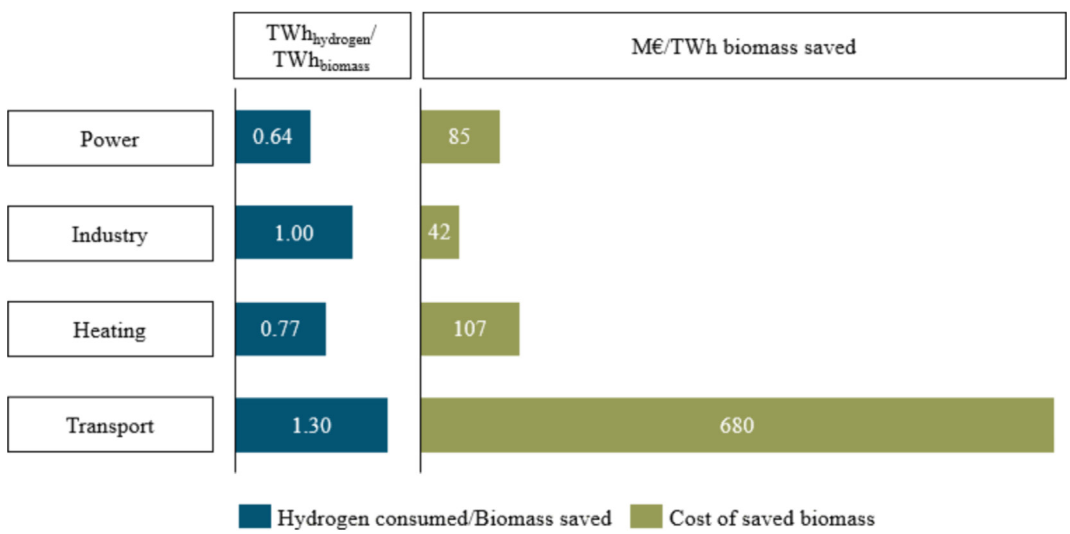

Fig. 8 — Total amount of biomass saved and the cost of saving this biomass with hydrogen extracted from the most biomass efficient scenario in each energy sector analysis.

electricity but is reliant on using more biomass in power plants to sustain the new demand for hydrogen.

Cost-wise, significant differences occur between the Reference model and the alternative scenarios, but in general, the use of hydrogen end-fuel for transport is more expensive than not using hydrogen for this purpose. Depending on the type of transport analysed, as illustrated in Fig. 8, cost differences occur due to the higher investment in the energy system (wind turbines, electrolysis), higher cost of vehicles (FC vehicles are generally considered more expensive than ICE or BEV), and hydrogen infrastructure, which makes up for a significant share of the overall annual costs since, in this case, it includes hydrogen distribution grids and fuelling stations.

For HDV, the higher costs are primarily caused by the larger investments in new vehicles since hydrogen fuel cell HDVs are more expensive than ICE HDVs. Secondly, a large dedicated pan-European H_2 fuelling station network will have to be established to handle the 5–8 million trucks using this fuel. On the other hand, the conversion of LDV to hydrogen will not necessarily incur larger vehicle costs, but the increase in overall system costs caused by the additional hydrogen infrastructure is high for over 20 million vans that would be running on this fuel. For bus, rail, shipping and aviation, it is unclear how much can the cost of new propulsion systems tilt the balance towards higher vehicle costs, which is the reason no additional costs for hydrogen fuelling were added to these scenarios, except the hydrogen distribution, which is a substantial part of the increase. Finally, replacing battery-electric transport in personal cars with hydrogen fuel cells is a very expensive solution not just for the energy system but also in terms of vehicle costs and infrastructure. Even with only 50% of the personal cars replaced with hydrogen fuel cell alternatives, the overall system costs increase by 290 B€ compared to a Reference model dominated by BEVs.

Discussion

Across all scenarios, direct hydrogen utilisation is identified as a more expensive option compared to the alternatives that provide full decarbonisation. While it could lower biomass consumption or further increase system flexibility, hydrogen will always tip the scale towards higher system costs. Replacing bioenergy with direct hydrogen may contribute to solving some of the concerns with sustainable biomass consumption. However, if biomass consumption is an issue, then such demands may also be settled more cost-effectively with higher electrification rates, energy efficiency measures or e-fuels. The use of hydrogen in hard-to-abate sectors is important, but rather than direct utilisation, often the more feasible approach is via e-methane or e-kerosene.

The Reference model in this analysis has high levels of energy efficiency, including energy savings and efficient technological solutions (electrification, heat pumps, district heating and waste heat integration), plus e-fuels in industry and transport. Even though e-fuels are less efficient to produce and utilise than direct hydrogen, they are often more practical and cheaper to implement. Therefore, based on this analysis, it is difficult to identify a role for direct hydrogen utilisation other than its potential to reduce biomass consumption.

If that is the case, then hydrogen should be used in the energy sectors that can save biomass at the lowest cost. Fig. 8 illustrates the sector that scores the best on these indicators, i.e., industry. The use of hydrogen for power production or heating purposes has more than double the costs, despite that more hydrogen is needed for the industrial sector than for electricity and heating. This can be explained through the system effects, where even though more hydrogen is required to dislocate bioenergy, it does not incur more power plant operation and can integrate VRES more efficiently than when used for power or heating, due to the specific demands that can align better to the hydrogen production. In the same regard, hydrogen for transport does not incur any cost-efficient biomass savings, and more hydrogen is needed to replace biomass.

Although replacing biomass can appear as a resourceful application for hydrogen, one should also understand that replacing biomass comes with the necessity of deploying more VRES capacity. In the present analysis, the variation in hydrogen demand is adjusted with offshore wind, so increasing the hydrogen demands above the one in the Reference model requires more offshore wind in a system with already high installed capacity, which will inevitably require more investments that can manage the new demands.

Hydrogen infrastructure is demonstrated to have a low impact on the overall costs, but only when it comes to large centralised consumers, like power plants or industry, that may make use of repurposed natural gas transmission lines. Conversely, the use of hydrogen for heating and transport would require a distribution network that can reach various private and public consumers, which would not just incur high costs with reconverting and building new pipes but would also raise practicality issues. The reconversion of natural gas pipes would involve ceasing the natural gas supply until pipes are reconverted unless new ones are built at a higher cost. On the building side, costs will also incur with the reconversion of metal pipes to polyethylene pipes [26,34] that can handle the smaller hydrogen molecules, which is not just expensive, but would also involve significant discomfort and lack of gas supply until reconversion is done. It is a valid point that district heating would also involve the construction of new pipes, but the disadvantages tend to end here. Moreover, hydrogen combustion in boilers and cooking stoves will emit nitrous oxide, a gas with high global warming potential [77], which would still not solve the problem of emissions from the heating sector. Emission control may be a solution at the boiler level, however, at a higher cost and lower fuel efficiency, and is not an option for open-flame cooking [78]. Not least, the safety of operating hydrogen boilers in buildings may also pose issues, with a recent report estimating an increase in the chances of explosions by four times compared to using methane [79]. These issues contradict the idea of a like-for-like substitution of domestic gas use with hydrogen for heating and cooking as practical, in addition to their higher cost.

The practicality of hydrogen as a transport fuel is also questionable, besides its high cost. First, hydrogen vehicles will likely remain more expensive than BEV or ICE, on the one hand, since they will involve more complex parts than a BEV (storage tank, fuel cell, balance of system, besides battery and electric drivetrain), and on the other hand because ICE is a much more mature and low-cost technology. But the largest hurdles come with the distribution and refuelling of these vehicles, which can only be done in specialised stations, unlike BEV, which can be charged at home. Liquid e-fuels also require specialised fuelling stations but benefit from an existing, well-known fuel handling infrastructure. Before it reaches the fuelling stations, hydrogen would first have to be distributed in pipes (or trucks) to strategic locations, along important motorways and urban areas, in repurposed natural gas grids or new distribution grids, depending on availability. The distribution grids and fuelling stations would also have to be dimensioned to be able to supply the millions of hydrogen vehicles on the European roads, so sufficient throughput will have to be ensured. Today, known designs of fuelling stations can handle 100–200 kgH_2/day, but in the future, this capacity would have to increase to several tons per station [80] to deal with a large number of vehicles and larger tanks (such as in trucks), but also to achieve profitability [81]. Hydrogen fueling stations are investment intensive. A 200 kgH_2/day fuelling station costs today 1.5–2.0 M€ [82] and can serve a maximum of 30–40 vehicles a day at full capacity. In terms of throughput, this can be compared with a typical 150 kW BEV charger that can serve the same number of vehicles. However, fast electric car chargers today cost between 50,000 and 75,000 €, including grid connection [83,84], so for the cost of one hydrogen fuelling station, 20–40 fast chargers can service one location with a theoretical maximum throughput of 900–1900 cars/day (one car every 30 min). Even with a cost of 1 M€/hydrogen fuelling station, an equivalent of 600–900 BEVs can recharge at such a station compared to 30–40 fuel cell vehicles. BEVs may have to recharge more often but can also use slow destination chargers, unlike fuel cell vehicles. It can be expected that with larger capacities and economies of scale, such hydrogen stations may service more vehicles at lower investment costs, but it will be difficult to match electric car chargers that will also benefit from cost reductions in the future.

Existing petrol stations may be converted to use liquid e-fuels, as the infrastructure is already in place. The throughput of such stations can vary depending on their size, assuming the station is used at maximum and may be similar to large BEV fast-charging stations but much higher than future hydrogen stations.

Thus, hydrogen for transport and heating has high societal costs and may struggle in the future to reach any significant shares due to the limitations of the technologies they involve, in particular when compared to competing technologies such as district heating, heat pumps, BEV and electrofuels. In the electricity sector, thermal power plants will remain a player in the energy system to balance the supply and demand, and here hydrogen has shown potential positive effects on biomass consumption only when limited amounts are used. Even with limited quantities, the effect of this approach will mean higher electricity prices, which will also make it more difficult to compete with electricity produced from thermal plants on biogas or biomethane, which are less expensive fuels than green hydrogen. However, if reducing biomass consumption is the goal, then hydrogen can play a small role. Existing natural gas combined cycle power plants can, in some cases, be retrofitted to hydrogen, or new ones can be designed to accommodate hydrogen, and in general, the technical difficulties with hydrogen combustion can be overcome [85].

Hydrogen combustion can be implemented in several industry sub-sectors after the retrofit and redesign of the production. Such industry sectors include cement production, iron and steel, and non-ferrous metals or chemicals. But the same sub-sectors can also use green methane or bioenergy, making the choice of fuels very dependent on their price, the industry involved and location. Hydrogen does not bring major cost or biomass reductions when it replaces e-methane, as both are expensive fuels produced from electricity, but methane can bridge the conversion from natural gas at lower investment costs than hydrogen, at least in the industries that currently use it. Our analysis does not include the cost of converting industries to using hydrogen, nor that more hydrogen energy may be necessary to achieve the same effect as the replaced fossil fuels, which may reduce the feasibility of such an alternative. Therefore, the only real benefit of hydrogen is to replace fuels of biogenic origin so that these fuels can be used in other sectors of the energy system more efficiently or simply to limit overall biomass consumption. These sectors are in particular power production, which will require low-cost fuels to balance the energy system and bio-electrofuels, fuels produced from electrolysis combined with biomass conversion technologies such as gasification, pyrolysis and hydrothermal liquefaction that can be less costly alternatives than e-fuels from carbon capture [65].

Despite the poor results for direct hydrogen utilisation in almost all energy sectors, hydrogen utilisation is high across all scenarios analysed, with the reference scenario alone producing 3000 TWh H_2 to supply the European transport and industry demands. Such large demands also mean that over 4000 TWh of electricity are needed solely for this purpose, clearly discarding the idea that hydrogen can be produced on excess electricity at a low cost [86]. Despite this, hydrogen will be an important energy carrier, not as an end-fuel, but rather as feedstock for the production of e-fuels. For these reasons, resources must be prioritised towards those parts of the energy system that need it most and not wasted where other technological solutions strike a better balance between energy efficiency and costs. Furthermore, even though their round-trip energy efficiency is lower, e-fuels can reuse existing infrastructure for fuel distribution and storage and are more adaptable to existing propulsion systems and transport demands, in particular aviation, heavy-duty long-distance road transport or shipping. Unless hydrogen vehicles and infrastructure, in general, become cheaper than internal combustion engines and liquid fuel storage, then it will be very difficult to motivate the choice of hydrogen as an end-fuel.

Conclusion

In this paper, we analysed the feasibility of direct hydrogen use for each sector of the energy system: electricity, heating, industry and transport. Hydrogen replaced other renewable fuels, district heating and electrified heating and transport in a fossil-free energy system for Europe in 2050. The results show that direct hydrogen technologies always increase the cost of the energy system. While biomass consumption can be reduced on a system level to satisfy more stringent interpretations of sustainable biomass consumption levels, this does not support deeper decarbonisation and comes at the expense of larger investments for offshore wind, electrolysis, hydrogen storage or thermal electricity production.

Hydrogen-related infrastructure bears a small cost in the analysed scenarios, except when accounting for distribution networks, individual hydrogen boilers and hydrogen fuelling stations for heating and respectively for transport. For these reasons, the high societal costs and practicality issues with the implementation of such scenarios, hydrogen cannot be considered a large-scale solution for heating and transport. The power production sector can only save limited amounts of biomass at relatively high costs, leaving the industry as a potential beneficial destination for hydrogen, where it can replace bioenergy without the negative system effects observed in the other energy sectors.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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