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How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system☆

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ABSTRACT

Hydrogen is a promising avenue for decarbonising energy systems and providing flexibility. In this paper, the JRC-EU-TIMES model – a bottom-up, technology-rich model of the EU28 energy system – is used to assess the role of hydrogen in a future decarbonised Europe under two climate scenarios, current policy initiative (CPI) and long-term decarbonisation (CAP). Our results indicate that hydrogen could become a viable option already in 2030 – however, a long-term CO_2 cap is needed to sustain the transition. In the CAP scenario, the share of hydrogen in the final energy consumption of the transport and industry sectors reaches 5% and 6% by 2050. Low-carbon hydrogen production technologies dominate, and electrolysers provide flexibility by absorbing electricity at times of high availability of intermittent sources. Hydrogen could also play a significant role in the industrial and transport sectors, while the emergence of stationary hydrogen fuel cells for hydrogen-to-power would require significant cost improvements, over and above those projected by the experts.

"Oui, mes amis, je crois que l'eau sera un jour employée comme combustible, que l'hydrogène et l'oxygène, qui la constituent, utilisés isolément ou simultanément, fourniront une source de chaleur et de lumière inépuisables et d'une intensité que la houille ne saurait avoir."

(L'Île Mystérieuse, Jules Verne, 1874)

☆ The views expressed are purely those of the authors and may not in any circumstances be regarded as stating an official position of the European Commission.

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Introduction

Energy security, competitiveness and climate change are key policy drivers for the European Union. The conclusions on the 2030 Climate and Energy Policy Framework of the European Council [1] endorse a binding target for the EU of at least 40% domestic reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 levels, coupled with a minimum of 27% renewable energy and energy efficiency improvements. The challenge remains on identifying the best way to reduce GHG emissions, while at the same time improving competitiveness, growth, and security of supply.

This has rekindled interest in the "hydrogen economy", based on hydrogen as a promising clean energy carrier for decarbonised energy systems, if produced from renewable energy sources, or coupled with carbon capture and storage (CCS) or nuclear energy. Its penetration in the energy system could help to reduce GHG emissions, in particular in sectors where decarbonisation is the hardest [2]. Moreover, flexible hydrogen production technologies, coupled with hydrogen storage options, could provide added flexibility in the face of fluctuating energy demand.

The European Union (EU) has been actively pursuing advancements in hydrogen and fuel cells since the late 80s, supporting with over EUR 500M more than 200 research projects on hydrogen production, distribution, storage, end-use technologies, and best practices to promote the update of clean hydrogen technologies.[4] In 2002, the then-Commissioners for Energy and Transport and for Research established the High Level Group for Hydrogen and Fuel Cells Technologies, tasked with developing a vision on the potential contribution of hydrogen to sustainable energy [3]. In 2008, the European Council adopted Council Regulation 521/2008 [4], establishing the Fuel Cells and Hydrogen Joint Technology Initiative, which was renewed and strengthened in 2014 [5]. This represents an important public–private partnership, aimed at accelerating the development and deployment of hydrogen and fuel cells.[5] For transport, the new EU Directive on the "deployment of alternative fuels recharging and refuelling infrastructure" [6] aims amongst others "at ensuring a sufficient number of publicly accessible hydrogen refuelling points, with common standards, in the Member States who opt for hydrogen infrastructure, to be built by end-2025".[6]

Several European countries have developed national strategies to support the penetration of hydrogen and fuel cells in their energy systems. The German National Innovation Programme for Hydrogen and Fuel Cell Technology makes 1.4 billion € available over 10 years (2007–2016), with funding from public and private sources. It aims at advancing the deployment of hydrogen based technologies in all energy/transport sectors [7]. In France, various aspects of hydrogen energy pathways are covered within the 34 roadmaps of the "New Industrial France" [8]. Despite the renewed efforts in technological research and development for hydrogen and fuel cells, the hydrogen economy is not yet developed, and several technological and non-technical barriers persist. France Stratégie [9], for example, questions the role that hydrogen can play in the energy transition and argues that it is a too costly alternative.

Improving our understanding of the role that hydrogen could play in decarbonising the energy system in Europe is critical in informing better targeted policies in support of the sector. In doing so, it is important to realise that assessing the role of hydrogen in isolation from the rest of the energy system may lead to biased inferences, failing to capture interactions with other drivers of the energy system, as well as competition among sectors for primary energy.

Several authors address the opportunities and challenges of hydrogen. For an early review, see Ref. [10]. More recently, Ref. [2] reviews the barriers and opportunities for the deployment of hydrogen in the transport sector. They conclude that sustained high fossil fuel costs, large deployment of renewables and CCS, limited breakthrough in vehicle batteries, as well as stringent mitigation targets for the transport sector, are pre-conditions for the transition to a hydrogen-based mobility. Ref. [11] assesses the economic attractiveness of hydrogen production technologies, and concludes that coal and natural gas remain the most attractive processes from an economic perspective. The paper, however, focuses on the current situation, without considering technological improvements, competition with other sectors for fuels, nor climate change concerns.

Bottom-up energy system models, either in isolation or coupled with additional tools, have been used to assess the role of hydrogen in overall decarbonisation, addressing trade-offs within the wider energy system, at different levels of governance. For instance, Refs. [12–15] focus on the UK, while Ref. [16] on Germany, Ref. [17] on the US, and Ref. [18] on Japan. Some studies at the sub-national level have also been undertaken (for instance, Ref. [19] looks at hydrogen use in the transport sector in the region of Madrid). The focus on the European energy system can be found in Refs. [20] and [21–23]. Capros and co-authors [21–23] show that hydrogen is cost-effective in Europe in the long-term as a means to store excess power. At the global level, Ref. [24] finds that hydrogen production shifts towards renewable sources over time, in a carbon-constrained world, while Refs. [25,26] assess the key factors influencing the deployment of hydrogen fuel cell vehicles at the global scale.

Despite the different approaches and assumptions, these studies agree in considering investment costs in hydrogen production and consumption technologies a key obstacle. Moreover, they tend to identify a critical role of hydrogen for long-term decarbonisation, with a significant deployment starting usually around 2040 in a carbon-constrained world.[7] And, without a strong carbon price signal, the role of hydrogen remains limited.

[4] http://ec.europa.eu/research/energy/eu/index_en.cfm?pg=research-fch-support [last accessed on 21.05.15].

[5] http://www.fch-ju.eu/ [last accessed on 21.05.15].

[6] http://europa.eu/rapid/press-release_IP-14-1053_en.htm [last accessed on 21.05.15].

[7] Ref. [15] shows that, applying dynamic growth constraints to take into account of the time needed for the diffusion of new powertrains leads to a smoother transition, starting earlier, around 2030.

Starting from existing literature, we assess the potential role of hydrogen in decarbonising the energy system in Europe. We extend the analysis to the energy system of the European Union as a whole, with a higher level of technological detail for hydrogen supply, for which this paper provides key techno-economic parameters. This paper also provides an up-to-date assessment of the potential role of hydrogen given current policies and expected developments in Europe, by integrating in the analysis the latest climate and energy policies of the European Commission for 2030 (Refs. [1] and [27]). Our analysis focuses on the pathways for hydrogen production and consumption, discussing in detail production technologies, delivery and storage options, and hydrogen in the end-use sectors. We explicitly allow for hydrogen electrolysers and storage to provide system flexibility, and assess the extent to which this is cost-competitive in Europe. To do so, we use the JRC-EU-TIMES, a linear optimisation, bottom-up, technology-rich model of the European energy system [28,29]. The results of such analysis can provide valuable insights and contributions to the current and revived debates on the hydrogen economy in Europe, and help prioritise research in this field.

The remainder of the paper is organised as follows. Methodology section describes the JRC-EU-TIMES model, focussing on: the main assumptions (The JRC-EU-TIMES model – main assumptions section); the improved hydrogen supply and demand pathways (The hydrogen energy system in the JRC-EU-TIMES section); and the modelled scenarios (Modelled scenarios section). Results and discussion presents and discusses the main results of this study, starting with Hydrogen production technologies section, hydrogen delivery and sectoral consumption (Hydrogen delivery and consumption section), and hydrogen storage (Hydrogen storage and system flexibilitysection). Conclusions section concludes the paper.

Methodology

The JRC-EU-TIMES model is a partial equilibrium, linear optimisation bottom-up technology model generated with the TIMES model generator from Energy Technology System Analysis Programme (ETSAP)[8] of the International Energy Agency ([28,29]). It represents the 28 EU member States (EU28) plus Switzerland, Iceland and Norway from 2005 to 2050, with each country constituting one region of the model. The JRC-EU-TIMES explicitly considers energy supply sector and transformation – primary energy supply, electricity and heat generation – and five energy demand sectors – industry; residential; commercial; agriculture; and transport. Fig. 1 depicts the structure of the reference energy system.

The objective of a TIMES model is the satisfaction of energy services demand while minimising (via linear programming) the discounted net present value (NPV) of energy system costs, subject to several constraints. Some constraints are generally applicable, such as: balance constraints for all energy forms and emissions, relations between allowed energy generation and capacities as well as constraints that guarantee that variable costs are proportional to a certain energy generation. All these generalised constraints are explained in Refs. [28,29]. Other constraints are more specific and depend on the analysed case, such as: supply limits for primary resources, technical constraints governing the creation, operation, and abandonment of each technology, and timing of investment payments and other cash flows. The most important specific constraints are discussed in Modelled scenarios section. For this, TIMES simultaneously decides on equipment investment and operation, primary energy supply and energy trade. Fig. 2 summarises the key characteristics of the JRC-EU-TIMES model.

It is important to point out that energy system optimisation is different from doing NPV calculations for analysing the business case of a certain technology. The most important difference is that in an energy system model, prices are not predefined, so endogenous. For instance the price of electricity which is an important driver for hydrogen electrolysers, is endogenous.

An extensive description of the JRC-EU-TIMES can be found in Ref. [30]. The main drivers and exogenous inputs are: (1) the "theoretical" end-use energy services and materials demand; (2) characteristics of the existing and future energy related technologies, such as efficiency, stock, availability, investment costs, operation and maintenance costs, and discount rate; (3) present and future sources of primary energy supply and their potentials; and (4) policy constraints and assumptions. These have been updated based on more recent data as well as policy developments.

The JRC-EU-TIMES model – main assumptions

The end-use energy services and materials demand projections for each country are differentiated by economic sector and end-use energy service, with 2005 historical data as the base year. The underlying macroeconomic projections and sector specific assumptions have been updated in line with Ref. [31]. In the current research framework, emission reduction can also be achieved by lowering the demand for energy services, at a cost to the energy system, depending on their price elasticity.

Country and sector-specific energy balances are derived from Eurostat data, determining the energy technology profiles for supply and demand technologies in the base year. The techno-economic parameters for technologies beyond the base year are updated, following Ref. [32]. Compared to Ref. [30], a higher level of technological detail is implemented for several renewable electricity generation technologies (photovoltaics, concentrated solar power, and ocean energy). On the demand side, the representation of energy efficiency in buildings is improved, with the explicit modelling of insulation options in residential and commercial buildings. Different to Ref. [30], we have disaggregated the car technologies further for this study, differentiating between 50 car powertrain variants including several improvement levels for conventional cars, alternative-fuel cars, battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), and hydrogen fuel cell (HFC) cars. The techno-economic assumptions for these technologies are based on Ref. [33]. Member

[8] http://www.iea-etsap.org/web/index.asp [last accessed on 17. 08.15].

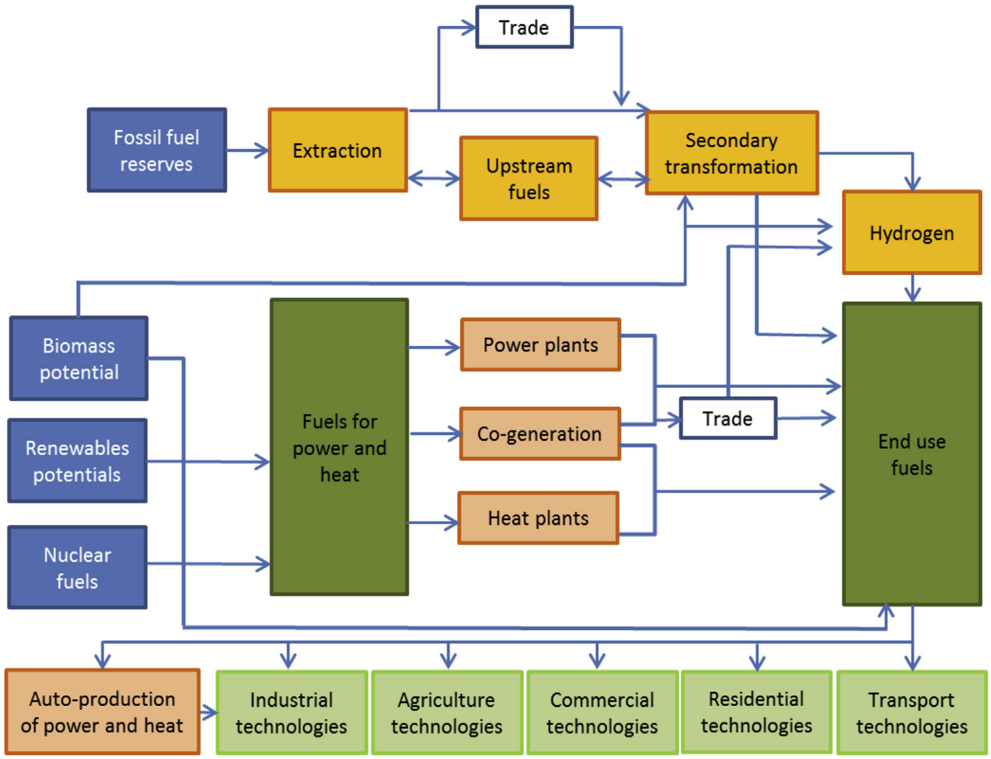

Fig. 1 – Structure of the reference energy system in the JRC-EU-TIMES.

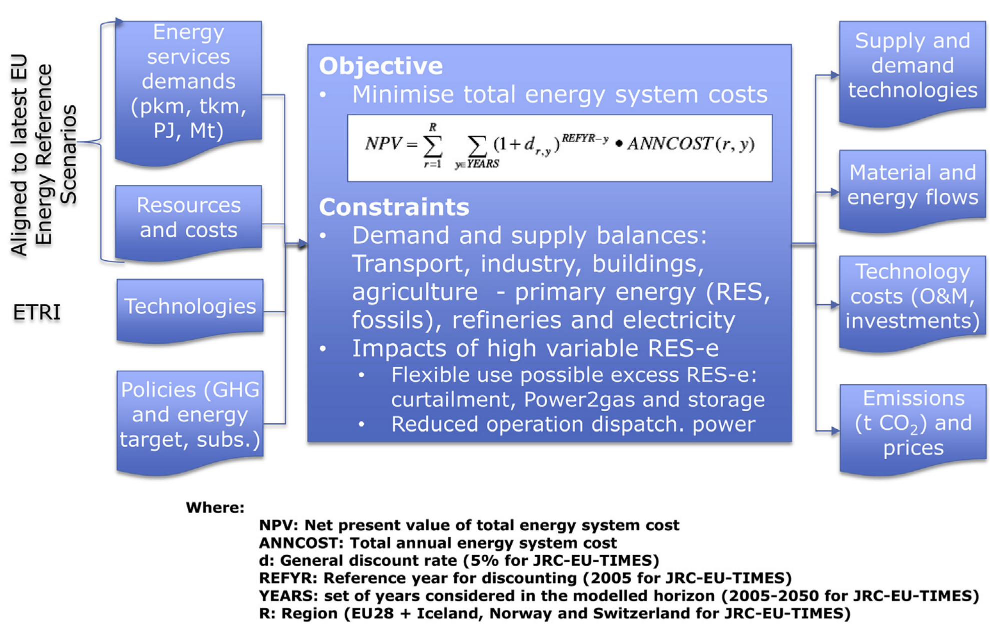

Fig. 2 – Simplified structure of the JRC-EU-TIMES model.

state specific differences in the vehicle fleet composition are implicitly considered in the model through the base year data. The modelling of hydrogen is also further refined, as described in detail in The hydrogen energy system in the JRC-EU-TIMES section.

The assumptions regarding the potential for solar, wind and marine energy have been updated, based on more recent data, studies and country-level analysis, as well as modelling features. The potentials for tidal and wave are derived from Refs. [34,35], modified based on experts' assumption for the long-term. Solar potentials are based on area availability, to better reflect competition for space.

Each year is divided in 12 time-slices that represent an average of day, night and peak demand for every one of the four seasons of the year. To address flexibility issues, each time-slice of the power sector is further split into two sub-periods. In 12 out of the 24 sub-periods, there is a possible excess generation of electricity, endogenously calculated for each country based on the installed power of photovoltaic panels, wind and wave technologies as well as on demand profiles. This allows modelling the competition amongst curtailment and different transformation and storage options in case of excessive variable renewable electricity production.

The hydrogen energy system in the JRC-EU-TIMES

The hydrogen energy system is modelled in detail, including centralised and decentralised hydrogen production technologies with the associated delivery pathways, and blending of natural gas and hydrogen; and several end-use technologies for transportation and stationary applications, as well as hydrogen-to-power stationary fuel cells. The conceptual model structure of the hydrogen supply chain is presented in Fig. 3. Bolat and Thiel [36,37] provide an extensive review of the literature on techno-economic descriptions of each stage of the chain.

This structure allows gaining insight in the role of hydrogen consumption in all end-use sectors, the primary energy vector from which hydrogen is produced, as well as storage.

Hydrogen production and delivery

Four main categories of hydrogen production technologies are considered: (i) Gasification and pyrolysis (coal or biomass)[9]; (ii) Reforming, from natural gas, ethanol, biomass or heavy fuel oil; (iii) Electrolysis; this category groups alkaline and proton exchange membrane (PEM) electrolysers, whose cost evolution is expected to be aligned over time; and (iv) Nuclear very high temperature reactor. These can be centralised and/or decentralised and of different sizes. Their techno-economic parameters are summarised in Table 1.

It is important to highlight that, in our model, biomass hydrogen production pathways coupled with CCS allows the net removal of carbon dioxide (CO_2) from the atmosphere. This is an important driver in the technology uptake, and it reflects the concept of negative emissions from bioenergy with CCS (Bio-CCS) which has been gaining increasing importance in the last decade. The possibility of Bio-CCS was recognised by the EU already in its Energy Roadmap 2050 [48] in 2011. According to the IEA Greenhouse Gases Programme, bio-CCS could remove 800 million tonnes of CO_2 annually by 2050 using available sustainable biomass in Europe alone, over and above the reduction achieved by replacing fossil fuels [49]. Bio-CCS is already deployed at industrial scale, though not in Europe [49]. According to guidelines from the Intergovernmental Panel on Climate Change ([50,51]), negative emissions from bio-CCS are allowed, coupled with measures to ensure full accounting in the land use emission inventory, and that there is no double-counting for imported biomass. While biomass sustainability issues might be an additional concern with bio-CCS, in our model, bioenergy sustainability is ensured exogenously, as the biomass available for energy is estimated taking into account sustainable harvesting levels.

In addition to dedicated supply technologies, in our model hydrogen is a by-product of ammonia and chlorine advanced production processes (advanced membrane and iron-oxide blast furnace).

Hydrogen can be delivered in liquid or gaseous forms from centralised production. For decentralised delivery pathways, shorter distribution chains are assumed. The delivery pathways considered include: delivery of hydrogen by road (short/long) in liquefied/compressed gas form ended with a refuelling process liquid to liquid, liquid to gas and gas to gas in small/large scales; delivery of hydrogen by ship of liquefied hydrogen, which can also be delivered to end use with pipelines and road transport; delivery of gaseous hydrogen by pipeline system; and blending hydrogen with natural gas within the current natural gas infrastructure, serving all sectors. We consider a maximum concentration of 15% of hydrogen by volume, as it is assumed that with this relatively low concentration it is not necessary to invest in extensive modifications of pipelines and end-use devices, following existing literature [52]. As hydrogen can be blended in the natural gas pipelines it can also be traded across regions via this route.

Table 2 summarises the techno-economic parameters of delivery processes considered in the model.

Three different storage technologies have been identified as relevant and explicitly included in the model: two centralised storage typologies (underground and tank storage) and decentralised tank storage.

The techno-economic parameters of the storage technologies and their traceable injection-withdrawals operation time resolution levels are summarised in Table 3.

End-use technologies

Hydrogen as a transport commodity can be consumed in fuel cell buses, cars and light and heavy duty trucks. In addition, hydrogen-to-power is included in the model: 100 kW proton exchange membrane fuel cell systems running on hydrogen produce electricity with efficiency at peak electrical load that increase from 44% in 2015 to 46% in 2050 (Table 4).

In the industrial sector, hydrogen direct reduction is considered a technically viable option in Europe starting from 2030 onwards. This is considered one of the innovative technologies with the highest future potential in the iron and steel sector in the long-term [54], but it is not currently considered competitive in Europe, even though it is explored in other countries [55]. In addition to existing hydrogen use technologies, our model also includes the use of hydrogen for the production of first generation biofuels, as well as carbon

[9] Supercritical water gasification is considered a promising technology for the efficient conversion of wet (high moisture content) biomass into a product gas that after upgrading can be used as substitute natural gas or hydrogen rich gas [38,39]. However, the paucity of quantitative techno-economic parameters and their evolution over time, as well as the lack of distinction in biomass moisture content in the current version of the JRC-EU-TIMES model, does not allow exploring the actual competition with other hydrogen production options.

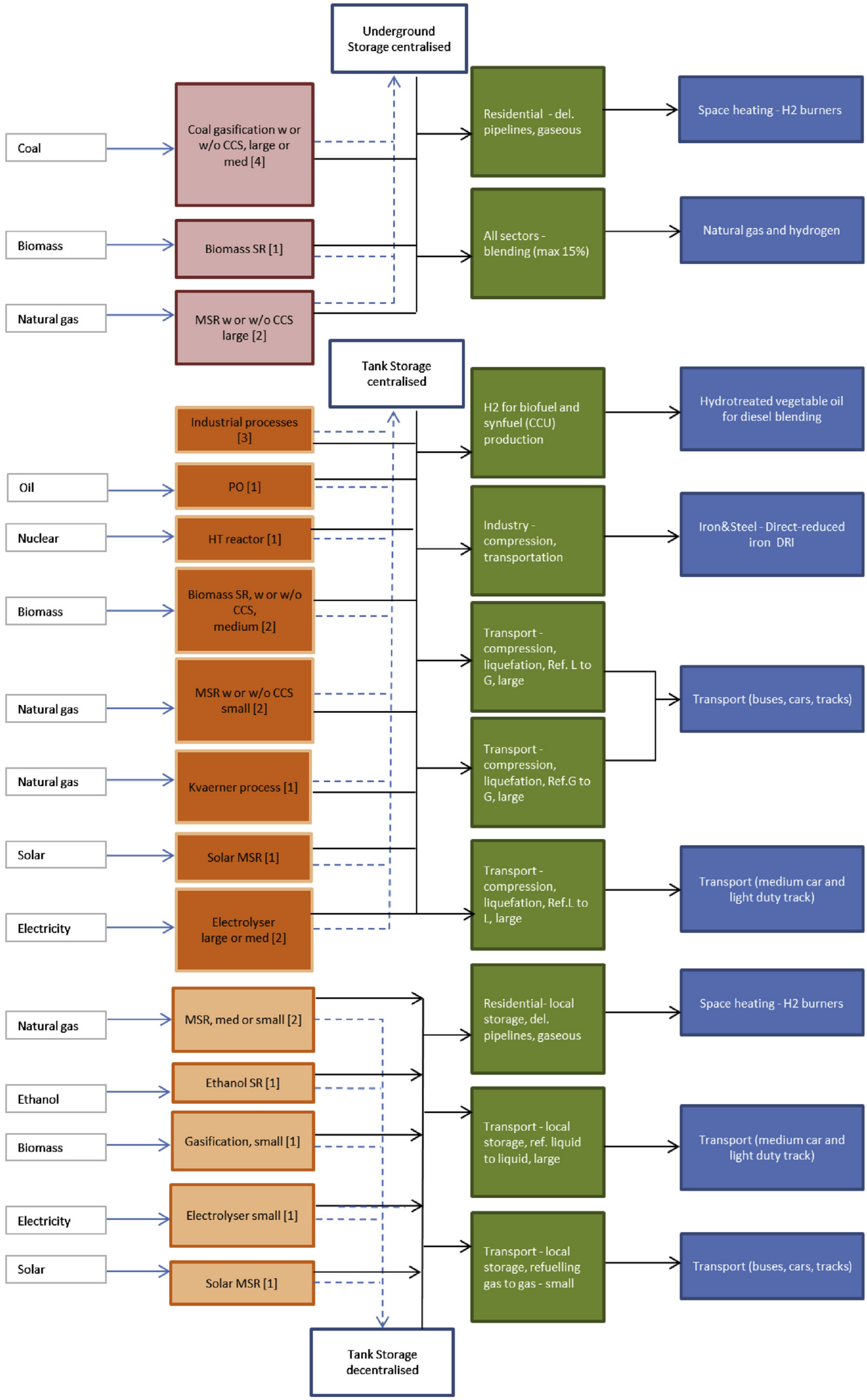

Fig. 3 – Structure of the hydrogen supply and delivery chain.

Table 1 – Techno-economic parameters of hydrogen production technologies for the years 2015 and 2030.

Technology description	Ref. Cap.	Availability factor	Investment costs [€$_{2010}$/kW]		Fixed O&M costs [€$_{2010}$/kW]		Variable O&M costs [€$_{2010}$/GJ]		Life	Source
	MW		2015	2030	2015	2030	2015	2030	Years	
Coal gasification, large size, centralised	1667	0.90	462.46	350.94	27.50	22.41	0.16	0.12	0.90	[37,40]
Coal gasification, medium size, centralised	434	0.80	573.37	573.37	14.33	14.33	0.22	0.00	0.80	[37,41]
Coal gasification + carbon capture, large size, centralised	1667	0.90	570.97	363.25	41.00	22.69	0.20	0.13	0.90	[37,40]
Coal gasification + carbon capture, medium size, centralised	442	0.80	660.83	660.83	27.45	27.45	0.26	0.00	0.80	[37,41]
Biomass gasification, small size, decentralised	0.7	0.71	4101.10	3099.11	81.94	81.94	1.83	0.00	0.71	[37,42]
Biomass gasification, medium size, centralised	33	0.90	2637.55	1290.62	131.74	64.50	0.93	0.00	0.90	[37,40]
Biomass gasification + carbon capture, medium size, centralised	33	0.90	2651.22	1309.21	111.52	65.32	0.93	0.00	0.90	[37,40]
Kvaerner process, centralised	19	0.90	1993.33	1993.33	79.81	79.81	0.70	0.70	0.90	[37,43]
Biomass steam reforming, centralised	235	0.90	519.31	519.31	20.77	20.77	0.18	0.00	0.90	[37,44]
Methane steam reforming, large size, centralised	1530	0.90	201.16	158.25	9.84	7.65	0.08	0.05	0.90	[37,40]
Methane steam reforming, small size, centralised	33	0.90	431.85	344.39	16.40	12.76	0.14	0.05	0.90	[37,40]
Methane steam reforming + carbon capture, large size, centralised	1502	0.90	284.71	191.33	14.21	11.48	0.53	0.07	0.90	[37,40]
Methane steam reforming + carbon capture, small size, centralised	33	0.90	590.37	450.75	29.52	23.84	0.20	0.07	0.90	[37,40]
Solar steam reforming of methane, centralised	150	0.87	309.92	309.92	21.67	21.67	0.11	0.11	0.87	[37,45]
Methane steam reforming, medium size, decentralised	2	0.86	485.78	376.87	28.21	28.21	0.04	0.04	0.86	[37,45]
Methane steam reforming, small size, decentralised	0.7	0.90	1847.65	1157.79	44.55	22.96	0.65	0.40	0.90	[37,40]
Ethanol steam reforming, decentralised	0.01	0.90	7379.68	7379.68			19.65	19.65	0.90	[37,46]
Solar steam reforming of methane, decentralised	0.1	0.33	851.85	851.85	17.14	17.14			0.33	[37,47]
Central PO of heavy oil (CPO3)	300	0.90	431.85	431.85	21.59	21.59	0.14	0.14	0.90	[37,43]
Alkaline/PEM electrolyser, large size, centralised	72	0.90	625.91	377.20	41.54	26.24	0.15	0.06	0.90	[37,45]
Alkaline/PEM electrolyser, medium size, centralised	33	0.90	1779.05	444.90	89.92	10.39	0.06	0.06	0.90	[37,40]
Alkaline/PEM electrolyser, small size, decentralised	0.6	0.90	1940.58	512.48	136.66	25.42	0.96	0.17	0.90	[37,40]
Very high temperature reactor, centralised	600	0.94	–	4687.31	–	304.67	–	2.60	0.94	JRC own estimate

capture and use (CCU) technology options for the production of kerosene and diesel. Such technologies are assumed to become technically available at the commercial level starting in 2025. These power-to-liquid technologies use CO_2 and hydrogen and/or electricity that are combined in a reactor to produce gases, subsequently synthesized into hydrocarbons. While the electrolysis of hydrogen can be integrated in the CCU technologies, these can also be designed to use directly hydrogen. For this analysis, therefore, we assume that the technology costs could never exceed the cost of a medium size electrolyser.

It is important to highlight that our model only indirectly covers the use of hydrogen in refineries and in some industrial processes, such as in the production of ammonia. According to Ref. [56], hydrogen consumption in Europe in 2008 was forecast at 76 billion m^3, over 80% of which used by these two sectors.

Modelled scenarios

For this study we run the model up to 2050 with the following policy scenarios: (i) a "current policy initiative" scenario (CPI), which includes the 20-20-20 policy targets of the European Union (Refs. [57–60]), and is consistent with the medium-term CO_2 emission reduction goals of the European Commission Communication on *A policy framework for climate and energy in the period from 2020 to 2030* [61]; (ii) a long-term decarbonisation scenario (CAP) that, in addition to the assumptions for 2020 and 2030 as in the CPI scenario, includes an overall emission reduction target of 80% below 1990 levels in 2050. In

Table 2 – Techno-economic parameters of hydrogen delivery technologies for the years 2015 and 2030 (source: Ref. [36], based on Ref. [43]).

Sector	Technology description	Availability factor	Investment cost [€/GJ/a]		Fixed O&M [€/GJ/a]		Variable O&M [€/GJ]		Life
		%	2015	2030	2015	2030	2015	2030	Years
From centralised production									
TRA	COMP + TR + LIQ + LSTORB + RTS + REFLL (large, with or without underground storage)	75%	38.71	27.39	2.02	1.43	0.95	0.65	20
TRA	COMP+TR + LIQ + LSTORB + RTS + REFLG (large, with or without underground storage)	75%	65.69	45.79	2.72	1.90	0.34	0.24	20
RSD and IND	COMP + TR + DP (with or without underground storage)	70%	34.04	30.29	1.78	1.57	0.36	0.32	20
TRA	COMP + TR + DP + REFGG (large, with or without underground storage)	70%	80.55	62.02	5.78	4.30	0.55	0.44	20
TRA	COMP + USTOR + TR + GSTORB + RTS + REFGG (small)	80%	66.00	47.16	5.02	3.53	0.27	0.19	20
From centralised production for hydrogen blending with gas									
All sectors	COMP + USTOR + TR + BLENDING	70%	5.87	4.92	0.37	0.30	0.08	0.06	20
From decentralised production									
RSD	LOCGSTORB + DP – residential	70%	51.84	43.58	2.50	2.11	0.28	0.25	20
TRA	LOCGSTORB + ONSITELIQ + REFLL (large)	70%	144.84	98.93	8.99	6.09	1.78	1.20	20
TRA	LOCGSTORB + REFGG (small)	70%	70.18	49.93	5.09	3.57	0.19	0.13	20

Abbreviations: RSD, residential; COM, commercial; TRA, transport; IND, industry; SUP, supply; ELC, electricity; AGR, agriculture; COMP, compression; TR, transmission pipeline; LIQ, liquefaction; ONSITELIQ, on site liquefaction; LSTORB, liquid storage bulk; LSTORS, liquid storage small; GSTORB, gas storage bulk; LOCGSTORB, local gas storage bulk; GSTORS, gas storage small (compressed); USTOR, underground storage; RTS, road transportation short; RTL, road transportation long; DP, distribution pipeline; REFLL(*size*), refuelling liquid to liquid (*size*); REFLG(*size*), refuelling liquid to gas (*size*); REFGG(*size*), refuelling gas to gas (*size*).

addition, both scenarios achieve a reduction in primary energy consumption (excluding non-energy) of 27% in 2030, aligned with the target adopted by the European Council ([1,27]). We then undertake a comparative analysis of the two scenarios for the EU28 for 2030 and 2050.

Under both scenarios electrolysers can play a role in providing flexibility to the energy system, by transforming (excess) electricity into hydrogen that can be consumed either with or without storage, as well as stored and transformed back into electricity.

Results and discussion

In our results, and in line with the findings of similar studies, as shown in Fig. 4, already in the CPI scenario the role of hydrogen in the EU28 energy system in 2050 is higher than in 2020, with a total production in the EU28 of approximately 250 PJ in 2050. With a long-term CO_2 cap, hydrogen deployment increases rapidly beyond 2030, with total production 6 times higher in 2050 with respect to the CPI scenario (1600 PJ).

With a long-term CO_2 cap, the share of hydrogen in final energy consumption grows from less than 1% in 2030 to 4% in 2050. On the other hand, in the CPI, the share of hydrogen in final energy consumption is less than 1% (Fig. 5).

While the contribution of hydrogen might still seem limited, it is important to note that the hydrogen production chain – in particular biomass + CCS – plays as critical role in the decarbonisation of specific sectors, such as industry and transport. Moreover, hydrogen becomes an important source of system flexibility. Hydrogen delivery and consumption and Hydrogen storage and system flexibility sections explore these results in more detail.

Hydrogen production technologies

A higher penetration of hydrogen in the energy system is no guarantee in itself that its carbon intensity will decrease: the advantages of using hydrogen as a fuel depend on how hydrogen is produced in the first place.

According to the literature (e.g. Ref. [2]), natural gas steam reforming, coal gasification and water electrolysers are proven technologies which are already deployed, though with a limited role. In a carbon-constrained world, it is expected that new technologies based on renewables will take over, in particular biomass-based hydrogen production. However, the extent to which biomass will be used for hydrogen production also depends on competition with other sectors. Solar steam reforming of methane is also being researched at the moment, though the technology range is limited to countries with a high solar radiation, notably Southern Europe and Northern Africa. It is also expected that coal gasification and gas reforming will only be an option in the medium to long-term if coupled with carbon capture and storage. Finally, the role for nuclear power plants in hydrogen production remains highly uncertain, and thought possible only with very high hydrogen demands.

Our results are in line with the prevailing literature in showing a marked shift of hydrogen production technologies towards renewables. As shown in Fig. 6, in both scenarios production is dominated by a handful of technologies, with the choice largely driven by a combination of techno-

Table 3 – Techno-economic parameters of hydrogen storage technologies for the years 2015 and 2030.

	Injection-withdrawals	Efficiency	Investment costs[a] [€$_{2010}$/(GJ/a)]		Fixed O&M[a] [€$_{2010}$/(GJ/a)]		Life	Source
		[%]	2015	2030	2015	2030	Years	
Centralised hydrogen underground storage	DayNight/seasonal	100	3.53	2.71	0.30	0.23	30	[53]
Centralised hydrogen gas tank storage	DayNight/seasonal	98	13.25	10.19	0.61	0.47	22	[43]
Distributed hydrogen gas tank storage	DayNight/seasonal	98	23.67	18.21	1.09	0.84	22	[43]

[a] Costs are linked to the size of the storage.

Table 4 – Techno-economic parameters of PEM hydrogen fuel cells for the years 2015 and 2030.

	Operation	Efficiency [%]		Investment costs [€$_{2013}$/kW$_e$]		Variable O&M [€$_{2013}$/MWh]		Life	Source
		2015	2030	2015	2030	2015	2030	Years	
100 kW PEM fuel cell system	DayNight	44	46	3500	2000	118	80	10	JRC

economic assumptions, climate change mitigation and energy efficiency targets, and competition for primary energy. In both cases, decentralised production technologies do not reach market competitiveness.

Competition with other sectors and a stringent CO_2 target, coupled with energy efficiency requirements, drive out almost entirely fossil-fuel based hydrogen production – with the exception of medium-size, centralised coal gasification with CCS. With a long-term emission reduction target (CAP scenario), the increasing electrification of the sector is clear: in 2050, the output of centralised electrolysers increases from 130 PJ in the CPI to 480 PJ in the CAP scenario. This points to the role of the sector in absorbing excess electricity from variable sources. Electrolysers' activity level peaks during the day (with over 90% of the production), in particular in summer and spring.

At the same time, the share of biomass-based hydrogen production reaches 44% of the total (excluding industrial hydrogen by-product) in 2050, compared to only 6% in the CPI (Fig. 7). Similarly, CCS (biomass and coal gasification) is used for almost 70% of production, compared to 25% in the CPI. While biomass gasification with CCS is not cost-competitive in the CPI scenario, it becomes the main source of hydrogen in

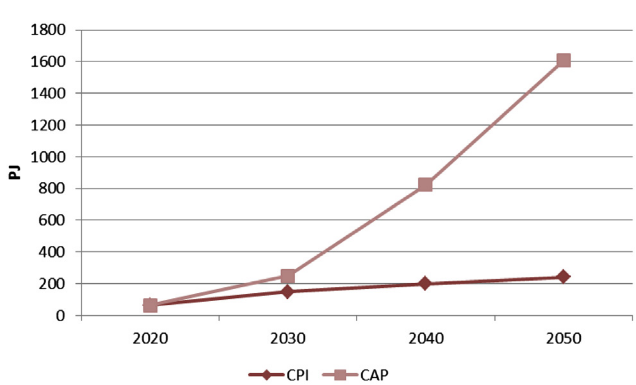

Fig. 4 – Total hydrogen production in the EU28 under the two scenarios.

absolute term by 2050 in the CAP (almost 700 PJ). This result is strongly driven by assumption that biomass use coupled with CCS allows a net absorption of emissions – under the CAP scenario, this technology is very attractive as it allows for a relaxation of the overall CO_2 emission constraint. A 30% lower CO_2 capture rate efficiency in Bio-CCS already drives biomass gasification with CCS out of the technology mix, substituted by coal gasification and methane steam reforming with CCS, and electrolysers. Interestingly, the role of hydrogen in the energy system is strengthened with the reduced options for CO_2 capturing, with total production in 2050 18% higher. A similar result is found when CCS technologies in general are assumed not to be available, as discussed later in this section.

In our scenarios, solar steam reforming of methane and very high temperature nuclear reactors for co-producing hydrogen and electricity do not become cost-competitive over the modelled horizon.[10] While the latter is driven mostly by high capital intensity compared to other hydrogen production technologies, the former is limited in its deployment by the availability of high direct solar irradiation. The analysis however does not take into account other, non-cost related, elements that might influence market deployment of technologies, such as legislative barriers or public resistance.

Finally, the production of hydrogen as a by-product of industrial processes becomes less relevant – declining from about 28–16% in 2030 to 17–3% in 2050 in the CPI and CAP respectively.

Our modelling results indicate that hydrogen production, in particular in the CAP scenario, relies heavily on a few technologies – and, more importantly, on the use of CCS to decarbonise the sector. It is important to understand whether a delay in the availability of CCS, or an increase in its cost, could jeopardise the role of hydrogen. We find that, on the contrary,

[10] New nuclear capacity – over and above the currently planned plants – is installed over the time horizon for electricity production.

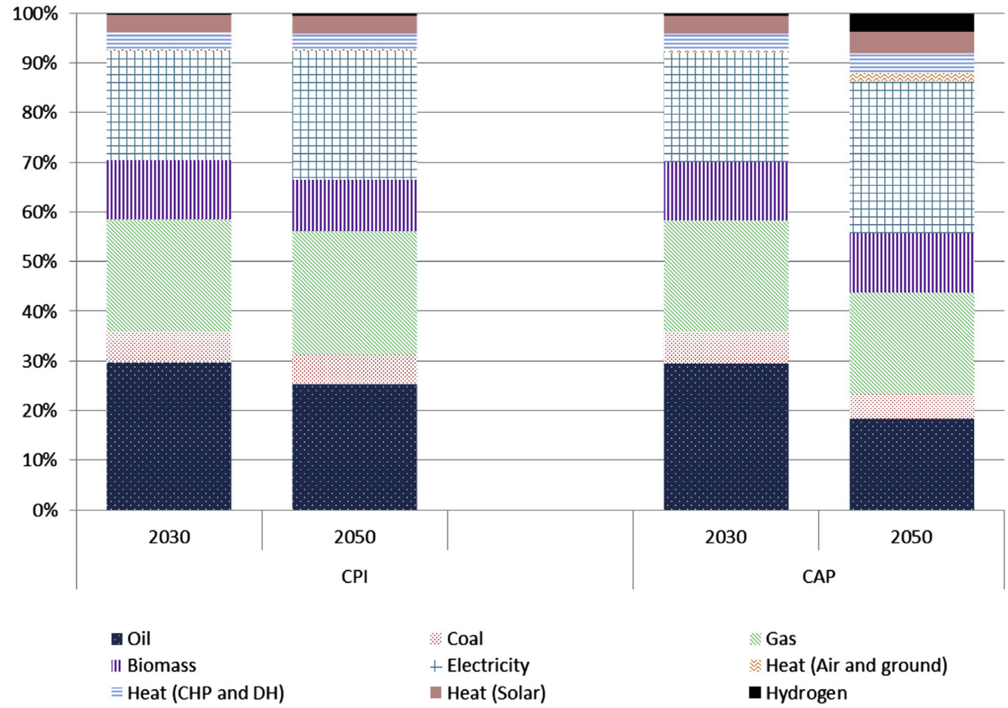

Fig. 5 – Final energy consumption by fuel in the two scenarios for 2030 and 2050.

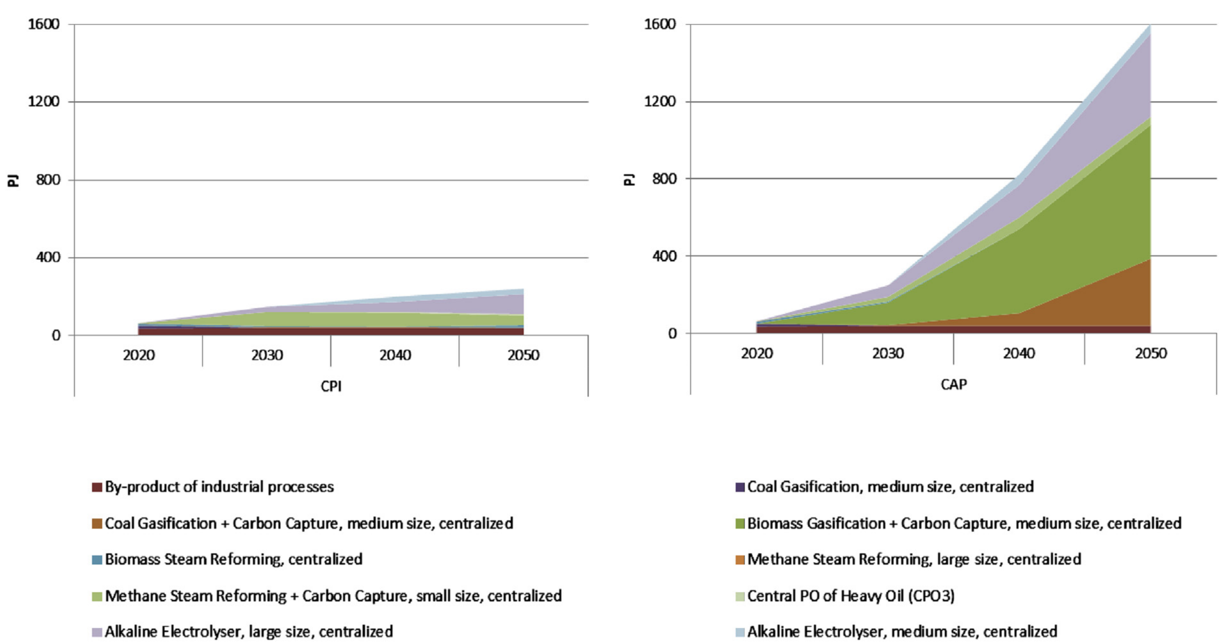

Fig. 6 – Hydrogen production technologies in the EU28 under the two scenarios, including by-product of industrial processes.

the role of hydrogen is strengthened. Assuming that CCS technologies could only be deployed with a 10 year delay, and with a 40% higher investment costs, *increases* the long-term availability of hydrogen – in the CAP scenario in 2050, hydrogen production would be 20% higher. This is because hydrogen is even more needed to help decarbonise the system in the medium-term, when the use of fossil fuels has to be further reduced. This result is even more striking if CCS is not a viable option within the modelled time frame – this could be the result, for instance, of technology failure or social and

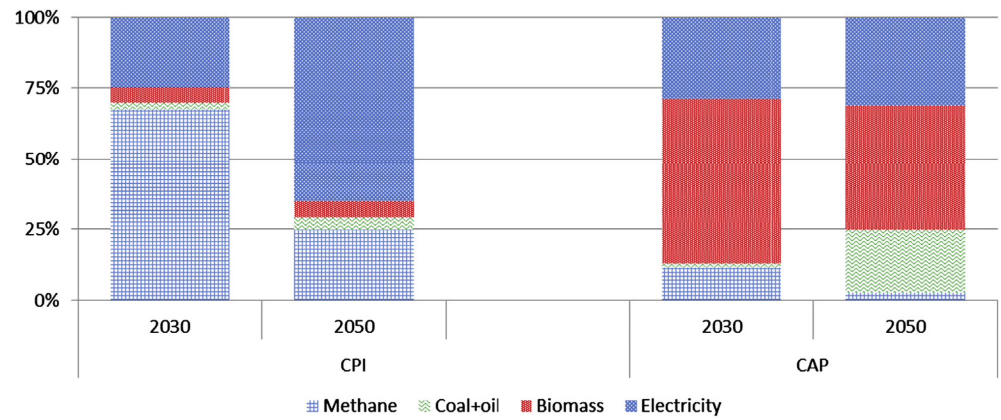

Fig. 7 – Share of feedstock and energy carriers in hydrogen production in the EU28 in the two scenarios for 2030 and 2050.

behavioural obstacles. In this case, hydrogen production in 2050 increases by 80% compared to the CAP. With costly and delayed CCS the production of hydrogen still relies heavily on CCS technologies, though only after 2040. Prior to then, it is electrolysers which fill the gap. With CCS unavailable, hydrogen production relies almost exclusively on electrolysers.

Hydrogen delivery and consumption

Under both scenarios, hydrogen is used in sectors that have limited decarbonisation options and increasing energy needs, transport and industry (Fig. 8). This trend intensifies in the long-term in the CAP scenario.

In the industrial sector, hydrogen becomes an important input as reducing agent for the iron and steel industry, contributing 6% of the total final industrial energy consumption in 2050 under the CAP scenario, as opposed to only 1% in the CPI. Industrial hydrogen use in the CAP in 2050 constitutes almost 70% of the total use in the energy system in Europe. In the CPI, iron and steel production from primary ore relies on a combination of fossil fuels with a high carbon content, in particular coke. The introduction of hydrogen as a reducing agent – in itself produced mostly from low-carbon technologies – allows halving the use of fossils, thus significantly reducing the CO_2 emissions of the sector. This is in line with our finding, and aligned with results from similar studies (see, for instance, Ref. [62]). ULCOS (Ultra-Low CO_2 Steelmaking)[11] – an EU programme launched by a consortium of 48 partners with support from the European Commission – is investigating breakthrough technologies that could help decarbonise the hydrogen and steel sector, but the consortium does not expect direct hydrogen reduction to become viable in the medium-term [63]. Fischedick et al. [54] find direct reduction more attractive than other low-carbon innovative technologies in the sector, including iron ore electrolysers, as it enables harnessing the opportunity of cheap excess renewable energy through electrolysis and hydrogen storage. This is in line with our results that see an important role of direct hydrogen reduction in the iron and steel sector in the long-term (2050).

[11] See http://www.ulcos.org/en/index.php [last accessed on 21. 05.15].

The second largest consumer of hydrogen is the transport sector. Electrification of transport is the most important avenue for decarbonising the sector: almost 30% of transport final energy consumption in 2050 is constituted by electricity, compared to less than 10% in the CPI. Given the strong decarbonisation requirements, hydrogen-fuelled vehicles also start to become competitive in 2050, though their penetration remains low: according to our result, the share of hydrogen in transport final energy consumption reaches 5% in the CAP scenario in 2050, as opposed to less than 1% in the CPI, and virtually no deployment in 2030 in both scenarios.

Under the CAP scenario, hydrogen-fuelled vehicles become competitive for passenger and freight transport. Hydrogen fuel cells cars are deployed under the CAP scenario in 2050, covering more than 6% of the total passenger per kilometre (pkm) demand, while there is no deployment in the CPI in our model. This is mostly based on carbon intensity of transportation and fuel-efficiency compared to other technologies – while EV are the main type of transport for passengers in both scenarios in 2050, in the CAP advanced gasoline cars are less attractive compared to the CPI because of the more stringent cap. The deployment in the public transport sector is even more striking: both for intercity and urban transportation, hydrogen-fuelled buses are deployed in 2050, covering 3% of passengers' demand in the CPI scenario – and nearly 40% in the CAP scenario. In the latter case, an earlier deployment (2040) is also observed compared to the CPI. It is mostly diesel-powered buses that are driven out in the longer-term, and substituted by hydrogen-fuel cells powered vehicles. Finally, in the freight transport sector, hydrogen fuel-cell heavy-duty vehicles and, to a lesser extent, light-duty vehicles satisfy more than 10% of demand in 2050 in the CAP scenario, compared to 1.6% in the CPI.[12] In conclusion, based on cost-competitiveness alone (i.e. disregarding issues such as non-

[12] It is important to point out that the final demand for transport (both pkm and tkm) is lower than the theoretical demands, because of price elasticity of the transport sector. In particular, in 2050: the demand for public transport is 4–6% lower in the CPI and CAP respectively; the demand for car transport is 2% lower in the CAP; and the demand for freight transport, the most elastic, is 4–8% lower in the CPI and CAP respectively.

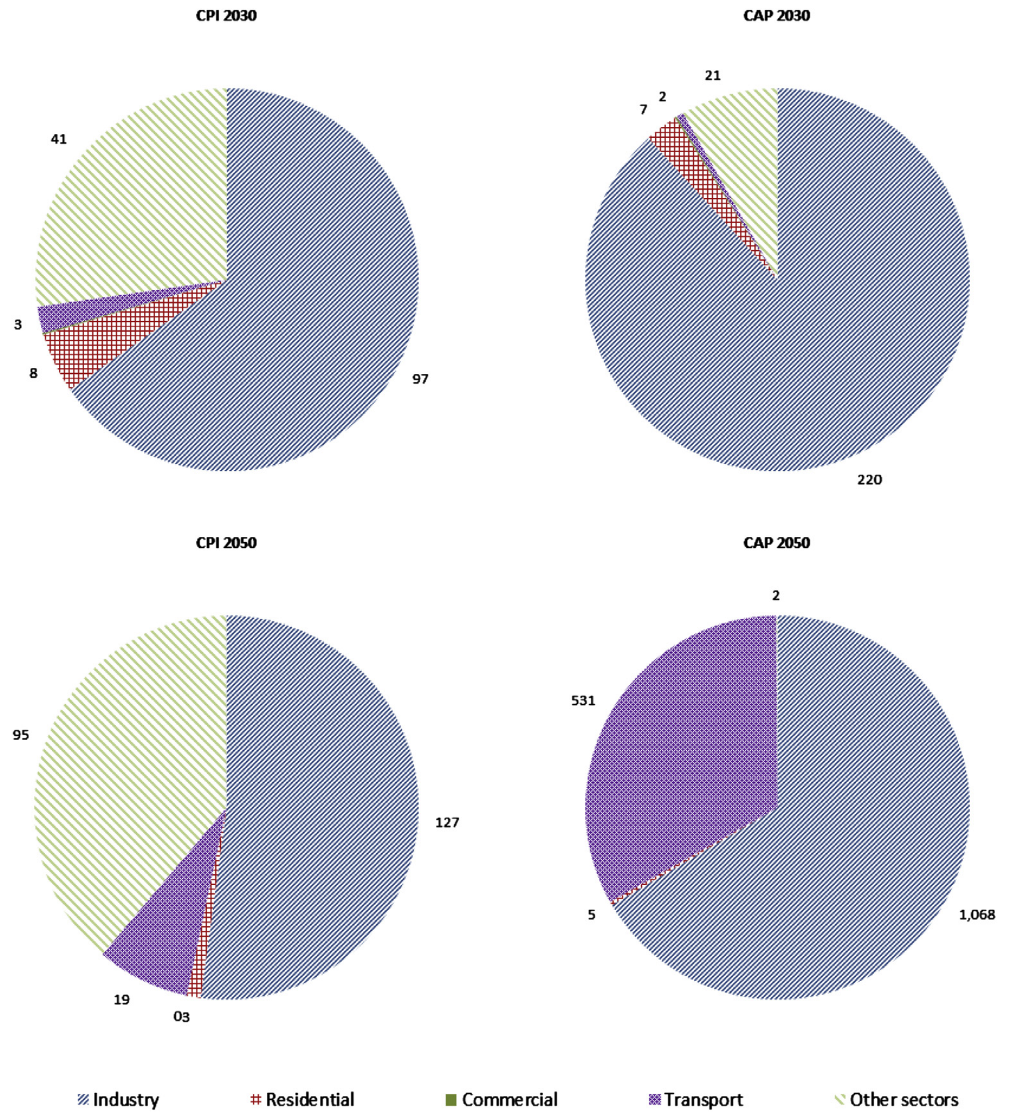

Fig. 8 – Sectoral hydrogen consumption as share of total hydrogen consumed (figure) and PJ (legend) in the two scenarios – 2030 (top) and 2050 (bottom).

linearities in infrastructure needs), according to our modelling results, there is a role to play for hydrogen vehicles by 2050 alongside other low carbon vehicles.

In addition to these two large sectoral uses of hydrogen, other uses are also emerging in the model, grouped under the "other sector" categories in Fig. 8. These include agriculture, biofuels production, and supply sectors. In 2030 and 2050, only the supply sector makes use of hydrogen in the two scenarios. This includes the production of electricity from stationary hydrogen fuel-cells, and the production of synthetic fuels via CCU technologies.

Under the CPI scenario, a large share of hydrogen (just over 30% in 2050) is used for the production of kerosene. However, with a long-term cap on emission, this technology is driven out of the energy system. While this result may seem counterintuitive, it can be understood by considering that the use of kerosene has a high cost in terms of CO_2 emissions: with a stringent GHG emission reduction target, the use of all carbon-intensive fuels has to be reduced and there is, therefore, no scope for additional production. Indeed, the consumption of kerosene in the CAP scenario is 16% lower than in the CPI by 2050.

On the other hand, hydrogen-to-power becomes cost-effective only in the CAP scenario, and only from 2040. The absorption of cheap excess electricity produced by renewables, and the low cost of hydrogen, make it cost-competitive even if the round-trip efficiency of stationary fuel-cells is low (around 44–46%, see Table 4). This technology remains however marginal – less than 1% of the total electricity produced. Significant cost reductions in hydrogen PEM fuel cells are still needed for this technology to be largely deployed. Even with a 25% reduction in investment costs compared to the input in Table 4 would lead to only marginal increases in its deployment.

Finally, with our modelling assumptions, hydrogen and natural gas blending has only a minor role to play in

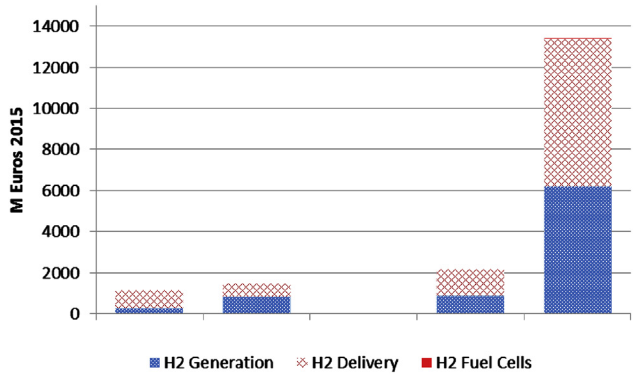

Fig. 9 – Annualised investment in hydrogen production and delivery for both scenarios in 2030 and 2050.

"greening" the gas sector. This seems to be at odds with the current thinking of the gas industry, though it is again a result of the stringency of the CO_2 emission target: hydrogen and natural gas blending brings about relatively small savings in emissions. In an energy system perspective, hydrogen is allocated to uses where it can substitute more carbon-intensive fuels, thus generating higher emission savings. Reducing the cost of cost of hydrogen and gas blending (such as compression, transportation, adjustment to end-use technologies, …) could marginally improve the prospects: a 25% reduction would only lead to a 5% increase in the hydrogen blended with natural gas in the residential sector in the CAP scenario.

The penetration of hydrogen in the energy system requires a significant increase in investment for the associated hydrogen delivery infrastructure (Fig. 9). The total annual investment for delivery by 2050 increases from 0.6bn €$_{2015}$ in the CPI to just over 7bn €$_{2015}$ in the CAP scenario. This represents over 50% of the total investment costs in the hydrogen economy. As expected, the bulk of investment is in the transport and industrial sectors. Despite this remarkable increase, the cost of hydrogen compared to the total investment needs of the energy system (supply and demand sides) remains small – less than 1% of the total – as hydrogen's share in final energy consumption remains low.

Hydrogen storage and system flexibility

Finally, with a long-term emission reduction target hydrogen becomes relevant in complementing electricity storage options, able to provide additional flexibility to the energy system. Fig. 10 shows the total annual electricity stored, as well as the total electricity used for electrolysers and being curtailed. The increasingly important role of electrolysers in using excess electricity is evident: electricity for electrolysers constitutes, in 2050, 23% and 42% of the electricity stored in the CPI and CAP scenarios – under the CAP, this is equivalent to about 4% of the total electricity produced in the EU28. Electrolysers become the most important form of absorbing excess electricity in 2050 in the CAP scenario, and the increase between 2030 and 2050 is significantly more than what is observed for storage media, in the face of a 15% increase in the total generated electricity, and a stable share of intermittent electricity.[13] These results support the value of hydrogen in providing system flexibility under a stringent climate mitigation target.

Coupled with the use of electricity to produce hydrogen with high availability of renewable sources, hydrogen is also stored, both underground and above ground. Hydrogen stored increases significantly and, in the CAP scenario in 2050, it is four times higher than in the CPI. Consequently, the capacity for hydrogen storage increases: in the CPI, capacity reaches 26 PJ and 50 PJ in 2030 and 2050, while in the CAP it increases from about 37 PJ to 150 PJ (Fig. 11, red bars). In both scenarios, centralised tanks constitute the bulk of storage capacity in 2050, coupled with centralised electrolysers (about 36–38% of the hydrogen stored in tanks comes from electrolysers). It is indeed important to point out that, as shown in Fig. 3, underground storage can only be associated with large scale coal gasification and methane steam reforming – technologies which play a minor role in the long-term under both the CPI and the CAP scenario. This partly drives the type of hydrogen storage that is chosen in our model (For interpretation of the references to color in this paragraph, the reader is referred to the web version of this article.).

Our results confirm the important role that hydrogen could play in dampening day/night (and, to a lesser extent, seasonal) variations in electricity demand by providing system flexibility via storage. It is also interesting to look at the pattern of storage (red bars)/discharge (blue bars) at the night/day level, shown in Fig. 11 for 2050. First of all, centralised tanks represent the main hydrogen storage option under both scenarios, with underground storage representing in 2050 less than 1% of the total activity level in the CAP scenario. Secondly, centralised storage of hydrogen is preferred for short-term variability, as shown by the charge and discharge pattern. And thirdly, hydrogen is stored exclusively during the day, and primarily during periods with a high level of intermittent electricity production (notably solar): this result supports the intuition that hydrogen storage, in particular electrolysers, can play a role in absorbing cheap excess electricity for release in periods with lower intermittent electricity production (For interpretation of the references to color in this paragraph, the reader is referred to the web version of this article.).

Conclusions

The JRC-EU-TIMES model – a bottom-up technology-rich model of the EU28 energy system plus Switzerland, Iceland, and Norway – is used to assess the role of hydrogen in a future decarbonised energy system in Europe. The detailed representation of the hydrogen system, including production, delivery, storage and end-use technologies make it suitable tool to address in-depth questions related to the role

[13] It is important to point out that, while the share of intermittent electricity in total electricity produced is the same in the two scenarios, in absolute terms, by 2050, intermittent electricity is 20% higher in the CAP than in the CPI.

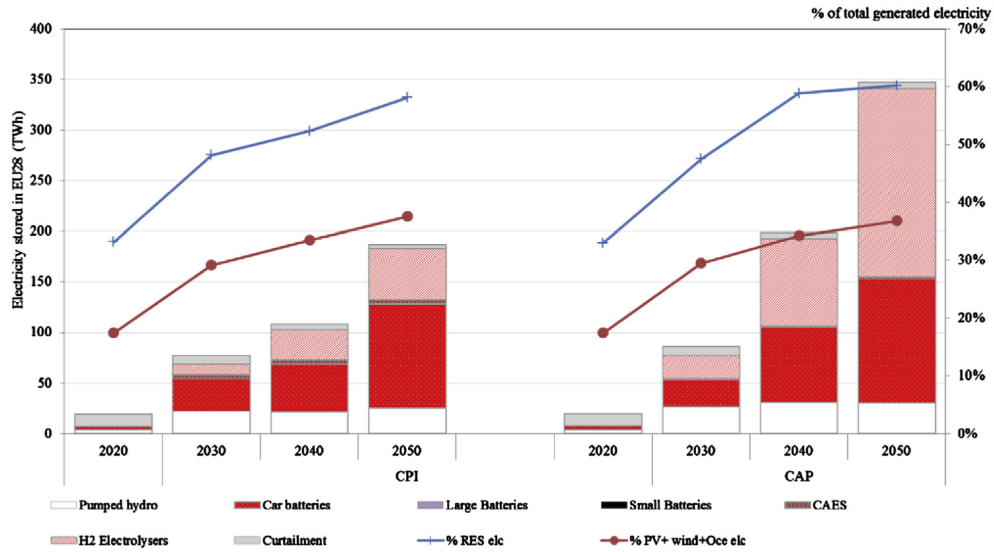

Fig. 10 – Electricity inflow into storage and electrolysers, and curtailment.

of existing as well as new and emerging technologies in decarbonising energy systems, both in the current policy initiative scenario, as well as under a long-term decarbonisation path.

While care is needed in interpreting the results of modelling exercises such as this one, as they can be sensitive to the input data and other assumptions, transparency in the input data, as well as the key drivers and exogenous assumptions, facilitate interpreting the results reported in this paper. Further improvement in the modelling framework, such as the inclusion of non-cost related technological barriers and non-rational aspects that condition investment in new and more efficient technologies, could help deepen the understanding of technological choices. With respect to

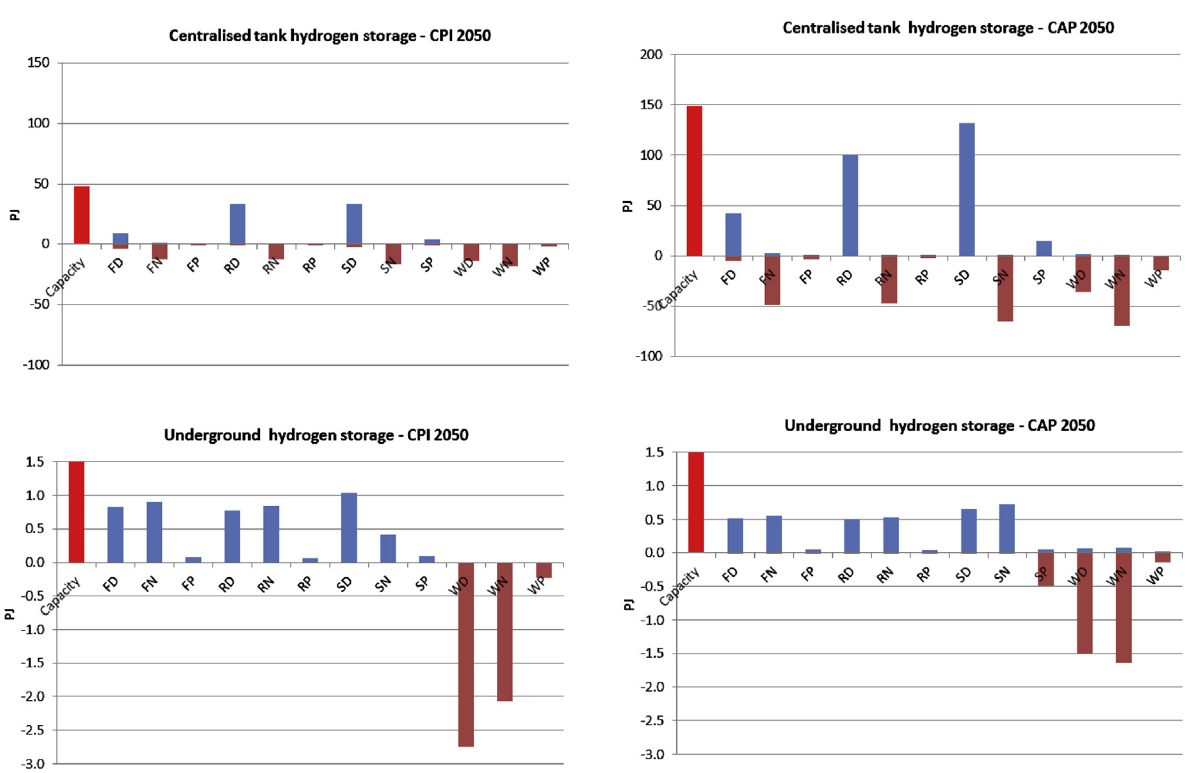

Fig. 11 – Day/night hydrogen storage in the EU in the two scenarios in 2050 for tank storage (top) and underground storage (bottom) and capacity levels (red bar) (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.).

the hydrogen pathways, an increased level of technological specification in particular on the hydrogen consumption side would allow a more in-depth assessment of hydrogen pathways. In this context, areas for further work include: further options for blending; the specification of storage technologies and their potential, both underground and above ground; Bio-CCS; a more detailed specification of the industrial-sector; the inclusion of additional frontier technologies on the supply side (such has supercritical water gasification of biomass, coal and organic waste for hydrogen production), and on the consumption side (such as hydrogen-fuelled planes). Coupling the JRC-EU-TIMES with geographically referenced information to better understand hydrogen storage would also bring enhanced realism to these results. Despite the uncertainty associated with the analysis of futures in a long-term horizon, energy system models such as the JRC-EU-TIMES can provide interesting insights on the potential role of hydrogen in Europe and beyond, as well as areas where policies could focus to further enhance it.

The results of our analysis indicate that the deployment of hydrogen in an energy system perspective is strongly and positively influenced by the presence of a stringent overall CO_2 emission reduction target. Our results depart from existing literature in indicating an earlier and faster start of hydrogen penetration in the energy system before 2040, even under the CPI scenario. This might be partly due to the "perfect foresight" nature of models such as the JRC-EU-TIMES, and by the role that hydrogen production plays in coping with variable electricity on the one hand, and with emission reduction on the other, in particular through centralised electrolysers and Bio-CCS. Moreover, our results highlight the important role that hydrogen can play in the medium- and long-term decarbonisation of the European energy system, in particular by: providing alternative energy sources in those sectors with limited low-carbon energy technology options, notably transport and industry; and providing additional flexibility, enabling the energy system to better cope with fluctuations in energy demands.

While in the long term even under the CPI scenario low-carbon production technologies are important (notably methane steam reforming with CCS), under the CAP this trend is even more accentuated, with coal and biomass gasification coupled with CCS playing an important role, followed by electrolysers. The technology portfolio is partly driven by assumptions on Bio-CCS. However, it is important to point out that the delay or absence of CCS options would not decrease or slow down the penetration of hydrogen, on the contrary: while the technology mix would be markedly different (with an even stronger role for electrolysers), hydrogen would play an even more decisive role in decarbonisation. On the other hand, and perhaps in contrast to the expectations of the gas sector, with our modelling assumptions, hydrogen has a limited role in lowering the emissions of gas use, in particular in the long-term. This is driven by the relatively small savings in emissions.

In our model, the iron and steel sector is the main consumer of hydrogen both in the medium and long-term: primary iron production processes rely for 18–50% on hydrogen in 2050 under the CPI and CAP scenario respectively. This result is contingent upon the technological specification of the iron and steel sector: the introduction of more technologies would allow a more detailed exploration of the potentials for hydrogen in the sector. The penetration of hydrogen in the transport sector is also significant. Under the CAP scenario, in our modelling results hydrogen contributes about 5% of the sector's final energy consumption (compared to virtually no deployment in the CPI). Hydrogen production and storage also have a role to play in increasing system flexibility: storage supports flexibility in consumption sectors, enabling to store hydrogen during periods of high variable electricity production, when electrolysers can benefit from cheap electricity for production. Stationary fuel cells, on the other hand, remain marginal: significant cost reductions are still needed to ensure the cost-competitiveness of this technology and its penetration in the energy system in Europe. Finally, the penetration of hydrogen in the energy system requires a significant increase in investment for the associated hydrogen production and delivery infrastructure. However, the cost of the hydrogen infrastructure compared to the total investment needs of the energy system (supply and demand sides) remains small – less than 1% of the total. This is a reflection of the relative importance of hydrogen as energy carrier in the system: despite the very high growth rates between 2030 and 2050, its share contribution remains low.

Acknowledgements

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Glossary of terms and acronyms

AGR	agriculture
ANNCOST	annual energy system costs
BEV	battery electric vehicle
CAP	long-term CO_2 cap scenario
CCS	carbon capture and storage. Set of technologies that allow the capturing of CO_2, its transportation and future storage, in order to reduce greenhouse gases emissions
CO_2	carbon dioxide
COM	commercial
COMP	compression
CPI	current policy initiative scenario
d	discount rate
DP	distribution pipeline
ELC	electricity
ETRI	energy technology reference indicators
EU	European Union
EU28	All European Union countries (including Croatia)
GHG	greenhouse gases
GJ	gigajoule, or 1 J $\times$ 10^9 (see joule)
GSTORB	gas storage bulk

GSTORS gas storage small (compressed)
GW unit of electric power equal to one billion watts, one thousand megawatts, or 1.34 million horsepower enough to supply a medium size city.
H_2 hydrogen
HFC hydrogen fuel cell
IND industry
JRC European Commission's Joint Research Centre
kW unit of power, equal to one thousand watts
kW h kilowatt/hour, or 1 W $\times$ 1 h $\times$ 10^3
LIQ liquefaction
LOCGSTORB local gas storage bulk
LSTORB liquid storage bulk
LSTORS liquid storage small
MW megawatt is a unit derived from energy, used for measuring energy capacity. It is equal to 1 million watts
NPV net present value
O&M operation and maintenance
ONSITELIQ on site liquefaction
PEM proton exchange membrane
PHEV plug-in hybrid electric vehicle
PHS pumped hydro storage
PJ petajoule. Standard unit of energy. For electricity: 1 PJ equals 277.78 million kW h
pkm passenger per kilometre
R region
REFGG refuelling gas to gas
REFLG refuelling liquid to gas
REFLL refuelling liquid to liquid
REFYR reference year
RES renewable energies
RSD residential
RTL road transportation long
RTS road transportation short
SUP supply
TIMES The integrated MARKAL-EFOM system
tkm tonnes per kilometre
TR transmission pipeline
TRA transport
USTOR underground storage

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