Will hydrogen and synthetic fuels energize our future? Their role in Europe's climate-neutral energy system and power system dynamics

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Will hydrogen and synthetic fuels energize our future? Their role in Europe's climate-neutral energy system and power system dynamics

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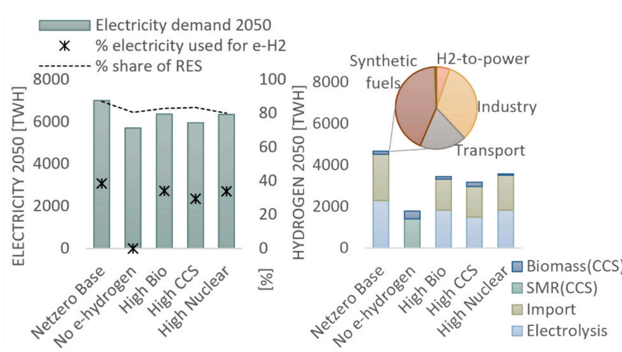
HIGHLIGHTS

- We analyse the EU's direct and indirect electrification requirements and impact.
- We apply a novel soft-linking approach of JRC-EU-TIMES and PLEXOS.
- Net-neutrality in EU requires 2- to 3-fold increase in electricity demand by 2050.
- Increased CCS, biomass, or nuclear largely reduces reliance on electrolytic hydrogen.
- Indirect electrification improves power system adequacy through flexibility.

GRAPHICAL ABSTRACT



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ABSTRACT

This study evaluates the technoeconomic impacts of direct and indirect electrification on the EU's net-zero emissions target by 2050. By linking the JRC-EU-TIMES long-term energy system model with PLEXOS hourly resolution power system model, this research offers a detailed analysis of the interactions between electricity, hydrogen and synthetic fuel demand, production technologies, and their effects on the power sector. It highlights the importance of high temporal resolution power system analysis to capture the synergistic effects of these components, often overlooked in isolated studies. Results indicate that direct electrification increases significantly and unimpacted by biomass, CCS, and nuclear energy assumptions. However indirect electrification in the form of hydrogen varies significantly, between 1400 and 2200 TWh_{H2} by 2050. Synthetic fuels are essential for sector coupling, making up 6–12% of total energy consumption by 2050, with the power sector supplying most hydrogen and CO_2 for their production. Varying levels of indirect electrification impact electrolysers, renewable energy, and firm capacities. Higher indirect electrification increases electrolyser capacity factors by 8%, leading to more renewable energy curtailment but improves system reliability by reducing 11 TWh unserved energy and increasing flexibility options. These insights inform EU energy policies, stressing the need for a balanced approach to electrification, biomass use, and CCS to achieve a sustainable and reliable net-zero energy system by 2050. We also explore limitations and sensitivities.

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Nomenclature

ACER	Agency for the Cooperation of Energy Regulators
BECCS	Bioenergy with carbon capture
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCGT+CCS	Combined Cycle Gas Turbine with Carbon Capture and Storage
CCS	Carbon Capture and Storage
CF	Capacity Factor
CHP	Combined Heat and Power
CO2	Carbon Dioxide
CSP	Concentrated Solar Power
DAC	Direct Air Capture
ENSPRESO	Energy System Potential Renewable Energy Simulation Output
ENSTOe	European Network of Transmission System Operators for Electricity
ERA5	ECMWF Reanalysis 5th Generation
EU	European Union
FF55	Fit for 55 (EU's plan to reduce greenhouse gas emissions by 55% by 2030)
FF55-proxy	Proxy for Fit for 55 measures
FO&M	Fixed Operation and Maintenance
FOM	Fixed Operating and Maintenance costs
GDP	Gross Domestic Product
GHG	Greenhouse Gas
H2	Hydrogen
IDEES	Integrated Database of the European Energy System
IIASA	International Institute for Applied Systems Analysis
JRC	Joint Research Centre
JRC-EU-TIMES	Joint Research Centre - European Union - The Integrated MARKAL-EFOM System
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
LP	Linear Programming
LT	Long Term
MIDDEN	Manufacturing Industry Decarbonisation Data Exchange Network
MILP	Mixed-Integer Linear Programming
NUC	Nuclear
OCGT	Open Cycle Gas Turbine
PEM	Proton Exchange Membrane
PRIMES	Price-Induced Market Equilibrium System
PtG	Power-to-Gas
PV	Photovoltaic
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SMR-CCS	Steam Methane Reforming with Carbon Capture and Storage
ST	Short Term
TIMES	The Integrated MARKAL-EFOM System
TYNDP	Ten-Year Network Development Plan
UCED	Unit Commitment and Economic Dispatch
UK	United Kingdom
VO&M	Variable Operation and Maintenance
VOM	Variable Operating and Maintenance costs
vRES	Variable Renewable Energy Sources

1. Introduction

The transition to a climate-neutral energy system is a pivotal objective of the European Union (EU) under its Green Deal and Fit for 55 package. To limit global warming to 1.5 °C, renewable energy technologies that do not emit direct greenhouse gases (GHG), are crucial [1]. Renewable energy generation has tripled from 1990 to 2020, accounting for 12.5% of the global primary energy supply [2]. These technologies are primarily available in the power sector, making efficient electricity-based end-use technologies central to make direct electrification a key strategy. Direct electrification is challenging in "harder-to-abate" sectors due to high capital costs or the need for specific molecules like hydrogen. These sectors include aviation, shipping, heavy-duty road transport and certain industrial processes such as ammonia production and reduction of iron ore. [3]. Sector coupling could enable these sectors to switch to highly renewable electricity through direct and indirect electrification routes [4]. Additionally, supply-demand imbalances in green electricity could make long term storage, such as producing electrolytic hydrogen, more attractive.

These mechanisms are crucial drivers for the role and market size of indirect electrification. [3,4] Indirect electrification predominantly relies on electrolytic hydrogen as an energy carrier, or power to gas (PtG). Hydrogen can then be used as an energy carrier, industrial feedstock or converted to synthetic fuels [4]. To meet the EU's 2050 net-zero target, the European Green Deal [5] and RePower EU [6] scenarios project a threefold increase in electricity demand (3700–4500 TWh) and a substantial rise in electrolytic hydrogen production from 0.5 TWh in 2022 [7] to 800–3300 TWh[1] by 2050, along with comparable outcomes in other long-term strategies [8–11].

Despite the EU's ambitious goals, there remains a significant gap in the literature regarding the comprehensive analysis of interconnected elements in a net-zero energy system, particularly involving hydrogen and synthetic fuels [9,12,13]. Understanding the combined interactions between hydrogen and synthetic fuel demand, the selection of production technologies (e.g., electrolysis, steam methane reforming, biomass, imports), and their impacts on the power sector (power-to-X and X-to-power) is crucial [11]. These aspects are often studied in isolation [12]. Most existing research addresses only one or two aspects at a time, overlooking the synergistic effects that a linked approach could reveal [12,13]. As shown in Table 1, relevant studies cover various components such as overall net-zero energy systems, cost optimization, comprehensive sector coupling representation and modelling, high temporal resolution analysis of power system and hydrogen interactions. However, current literature lacks in modelling the combined interactions of all these aspects, despite its importance for understanding these interactions in systems with highly variable renewable energy sources [14] [12]. This research addresses this gap by analysing electricity and hydrogen interactions at an hourly resolution, optimising electricity and hydrogen demands across the entire net-zero energy system.

This study aims to contribute to existing knowledge by comprehensively addressing all aspects outlined in Table 1 across four critical dimensions, each essential for examining the significant impacts of hydrogen, synthetic fuels and electrification in the EU:

1. Modelling **cost-minimised net-zero EU27 energy system** from a technoeconomic perspective. Previous studies [4,9,10,14–18] have investigated the role of green hydrogen in dynamic long-term decarbonisation scenarios, typically targeting 80% or 95%

[1] All conversions in this study takes place with LHV

Table 1
Summary of existing literature on the important aspects regarding the knowledge gaps.

		Europe	Net-zero ambition	Cost optimisation	Sector coupling	Power system analysis [a]	Hourly resolution	H2 flexibility
Knowledge gap[b]:		Overarching all 1–4.			2.	3.	3. & 4.	3.
Blanco et.	[4,15]	✓	×	✓	✓	×	×	×
Evangelopoulou et.	[14]	✓	×	✓	✓	✓	×	×
Staffell et.	[28]	×	×	×	×	✓	✓	✓
Rabiee et.	[24]	×	×	×	×	✓	✓	✓
Wang et.	[26]	×	×	×	✓	✓	✓	✓
S. Diéguez et.	[17]	×	×	✓	✓	✓	✓	×
Sgobbi et.	[18]	✓	×	✓	✓	×	×	✓
Korberg et.	[29]	✓	✓	×	✓	×	✓	✓
Sorknæs et.	[30]	×	✓	×	✓	✓	✓	✓
Pickering et.	[10]	✓	✓	✓	✓*	✓	×	×*
Neumann et al.	[9]	✓	✓	✓	✓	✓	×	×
Wolf et al..	[32]	✓	✓	×	×	×	✓	×
Öberg et al.	[33]	✓	✓	✓	×	×	✓	✓
Weiss et al.	[34]	×	×	✓	×	×	✓	✓
Egerer et al.	[35]	×	✓	✓	×	×	✓	✓
Boldrini et al.	[36]	✓	×	✓	×	×	✓	✓
Rogeau et al.	[37]	✓	✓	×	×	×	×	✓
Durakovic et al.	[38]	✓	×	✓	✓	✓	✓	×
Hanto et al.	[39]	✓	✓	✓	✓	✓	×	×
Li et al.	[40]	✓	×	×	✓	×	×	×
This study		✓	✓	✓	✓	✓	✓	✓

[a] Power system analysis is included in some studies, only with a limited set of technologies (e.g. wind and solar).
[b] Which of the 4 main knowledge gaps are relevant to the important category groups.
[*] To some degree it is included, not extensive.

reduction[2] and not 100%. Changing the emission reduction constraint from 95% to 100% can significantly change the final direct and indirect electricity demand [15]. Some studies considered net-zero target [13,14,20,21], however these exclude green hydrogen imports [22] or only consider a greenfield approach for 2050, neglecting the transition period [13,20].

2. Addressing increased power demand through **sector coupling** via introducing the resulting green hydrogen production. Several studies have investigated the impact of potential future increase in power demand by sector coupling in the EU, assuming 5000–6000 TWh/year$_{2050}$ electricity demand [16,19,20]. However, these analyses do not distinguish between direct and indirect electrification and are often determined exogenously. Nuemann et al. (2023) analysed the impact of direct and indirect electrification, their focus was primarily on hydrogen and the electricity network rather than generation. Moreover, the study has only 3 hourly temporal resolution and imports to the EU are disregarded [9].
3. Covering the **entire EU power system**, the role of hydrogen as fuel for power generation, and the interplay with other generation options (competing technologies, complementary etc). Existing literature [20–24] has explored green hydrogen for storage (P2G and back G2P); however, the main focus is coupling with wind and/or solar for standalone systems or decentralised micro systems, rather than the entire power system of the EU.
4. Analysing the **flexibility impacts of hydrogen** demand on the overall power system and H_2 storage requirements. Studies [24,26] investigated the flexibility benefits of electrolytic hydrogen production in significant peak shaving and ramp mitigation, identifying a positive relationship between H2 storage size and flexibility. However, the studies only include fuel cell electric vehicle demand, and the scope is not the EU. Frischmuth and Härtel [27] examined demand flexibility for the EU, in a net-zero setting; however, electrolyser flexibility and storage scaling are outside the scope, and many important power related technologies, like biomass or CCS, are excluded. Pickering et al., 2022 [10] investigated flexibility in the power sector, with a focus on spatial distribution and a 2-hourly temporal resolution.

To address these knowledge gaps, we model the overall EU energy transition up to 2050 with net-zero ambition. We evaluate various electrification and hydrogen technologies to identify optimal sector coupling pathways and the total end use energy mix, focusing on electricity, electrolytic hydrogen and synthetic fuels demand from a technoeconomic perspective. This includes limited hydrogen imports, considering various import prices and transport methods, such as shipping ammonia and dehydrogenation. We assume no imports of synthetic fuels containing renewable carbon from outside the EU and restrict extensive use of biomass and CO_2 storage, emphasizing alternative renewable carbon sources like direct air capture within the EU. The study involves a detailed analysis of direct and indirect electrification and resource use in the EU energy system, employing high temporal resolution power system analysis, explore generation portfolios, costs, reliability, flexibility and the role of green hydrogen across these characteristics. Furthermore, the overall energy transition analysis and the detailed power system analysis are coupled through a novel coupling approach, with technology- and region-specific hourly curves assigned to all demand technologies.

In addition to the cost-optimised power system capacity and demand portfolios, a more policy-driven portfolio is also analysed based on the Fit fot 55 package by the European Commission 2022.[3] This framework allows us to assess the impact of the significant 6600 TWh electricity demand [6].

2. Methodology

For this study, the long-term energy model JRC-EU-TIMES (Joint Research Centre EU: The Integrated MARKAL-EFOM System, also referred to as 'TIMES' hereafter) [4] is soft-linked with the power system model PLEXOS [31]. JRC-EU-TIMES addresses knowledge gaps 1–2 by focusing on both direct and indirect electrification requirements for decarbonizing

[2] compared to 1990, based on the emission reduction target prior to European Green Deal of 2019

[3] reconstruction of projections from the Fit for 55/EU Commission scenario based on private communications and https://visitors-centre.jrc.ec.europa.eu/tools/energy_scenarios/

the EU by 2050. It offers robust capabilities for optimising a technology-rich, long-term, dynamic energy system, with detailed representation of member states, encompassing vintage capacity, resource availability, and trade dynamics [4]. This model is particularly suited for assessing sector coupling during the transition, given its detailed representation of hydrogen and electricity production/demand technologies, as well as CO_2 capture utilization and storage pathways, including synthetic fuel production. PLEXOS tackles knowledge gaps 3–4 by examining the impact on the power system. With its high temporal resolution and advanced representation of power plants, including planned outages, min/max downtime, and heat rate curves through mixed-integer linear and quadratic programming optimization capabilities, PLEXOS is well suited for analysing the role of hydrogen within the broader European power system context [31]. Technoeconomic input data for both models are harmonised, as well as geographical scope, including copper plate countries of EU-27, with cross-border transmission capabilities by ENSTO-E TYNDP [32]. The surrounding areas, including Switzerland, Norway, the UK, and the Balkans, are also modeled, but their results are not reported, since the study focuses on the EU. The model linking approach ensures power system analysis with dynamically changing endogenous electrification demands. It optimizes generation, based on detailed hourly demand technology representation in each scenario.

Long-term dynamic energy system runs from 2020 to 2050, with 5-year steps, while the power system model focuses on the 2050 target year in an hourly temporal resolution, with a greenfield approach. An overview of the methodology is presented in Fig. 1.

The following sections detail three modelling blocks: the long-term energy model, soft-linking, and power system model. This is followed by the presentation of harmonised input data and the introduction of various modelling scenarios.

2.1. Long-term dynamic model

The JRC-EU-TIMES (The Integrated MARKAL-EFOM System) is a bottom-up cost minimisation model that offers multi-period flexibility cost-minimization with welfare maximization through price elasticities. The optimization includes the entire energy system, optimising the net present value of system costs consisting of investment, fixed, annual, decommissioning, operational costs, taxes, subsidies, and salvage value within the objective function [4]. This model is discussed in the IPCC AR6 report [33], as the previous version has contributed to AR6 Scenarios Database by IIASA [34].

Macroeconomic assumptions driving demand are based on GDP and population data summarised in Table 2, with additional key macroeconomic demand drivers listed in Appendix A. A general real discount rate of 8% is applied to future costs, varying between 7% and 18% for specific sectors and technologies. Sectoral demand drivers and elasticities are derived from GEM-E3, as provided in Appendix A, including demand assumptions for 2020 in PJ and breakdown of demand processes of selected demand sectors [35].

The model operates with 5-year timesteps starting from 2020, dividing each milestone year into 12 time slices, representing typical day, night, and peak demand patterns across the four seasons [35]. Detailed information on supply and demand technologies can be found in references [4,18,35].

Technology representation enables the optimization of sector-coupling through direct and indirect electrification. The demand side for electricity covers electrification in light, medium, and heavy-duty transport, space and water heating, and heating and machine drive in industry. Hydrogen demand includes applications in industry, light, medium, and heavy-duty transport (including aviation and maritime bunkers), and the production of synthetic fuels, such as synthetic diesel, jet fuel, and through methanation of captured CO_2 and hydrogen. Synthetic fuels are defined as liquid hydrocarbons derived from non-crude oil sources. Synthetic fuels include renewable fuels from non-biological origin (RFNBO) and those partially derived from blue hydrogen. For hydrogen production, options include proton-exchange membrane (PEM) or alkaline electrolysis, biomass gasification with or without CCS, steam methane reforming, with or without CCS, and can be enhanced using concentrated solar heat. The technology representation extends to various CCS technologies, including carbon removal options like direct air capture (DAC) or biomass with CCS for power, heat, or hydrogen generation. Hydrogen storage and delivery options include underground and tank storage, along with compression and various delivery routes such as hydrogen pipelines, or liquification for ship or road transport, with associated costs and losses accounted for. More detailed discussion on hydrogen, biomass and CO_2 related processes and flows is provided in Blanco et al. [4].

2.1.1. Model updates

Compared to the JRC-EU-TIMES version last updated by Blanco et al. [4], several modifications have been made to address electricity and hydrogen supply and demand. Firstly, the electrification of heavy-duty transport has been implemented, with battery electric trucks operational from 2025. Since hydrogen fuel cell trucks are available in the model, the direct electrification option is crucial for fair comparison with technoeconomic data from PRIMES [36] (Table 3). Similarly, more diversified hydrogen options have been added in industry, including hydrogen boilers, combined heat and power (CHP) for low, medium and high-pressure steam, and hydrogen furnaces. Data are taken from MIDDEN [37] assuming that Dutch technoeconomic specifications of industrial processes are applicable for the EU. Additionally, ammonia production with Haber-Bosch NH_3 synthesis is implemented, requiring 21.4 TJ of hydrogen per kiloton of ammonia and 6.2 TJ of electricity input. The investment costs are set at 27,100 $EUR_{2019}/kt_{ammonia}$/year, with fixed operation costs assumed to be 2% of investment costs.

Based on the European hydrogen strategy of importing equal amounts of green hydrogen to the EU as produced domestically from 2030 onwards, a constraint has been constructed in the model that 50% of hydrogen demand must be met by imported hydrogen [38]. The cost of imported green hydrogen is considered to be on average 4.5 EUR_{2019}/kg_{H2}, based on the IEA H2 report 2022 [39].

Technoeconomic data and scenario settings regarding the power sector and some sector coupling options have also been updated (see Input data section).

2.2. Hourly resolution power system model

A model for analysing the EU-27 2050 power system has been constructed in PLEXOS,[4] a mixed-integer linear programming (MILP) model, well regarded for power system cost optimisation and system adequacy studies [40]. Optimisation is driven by demand and cost, with hourly demand profiles. The process involves long-term (LT) planning to create the least-cost capacity expansion configurations, minimizing the total net present value (NPV) of build costs, fixed operation and maintenance (FOM) costs, and variable operating and maintenance (VOM) costs. Subsequently, the resulting capacity portfolios undergo further analysis using short-term (ST) schedule cost-optimal unit commitment and economic dispatch (UCED) calculations, along with power system adequacy, flexibility, and limitations assessments [41].

2.3. Model linking approach

To soft-link the two models, results from the JRC-EU-TIMES model are used as input to PLEXOS. Only power system-related results are further analysed, including final electricity by demand technology type, and green hydrogen or indirect electricity demand (including all synthetic fuels).

[4] More information about the PLEXOS modelling tool: https://www.energyexemplar.com/PLEXOS

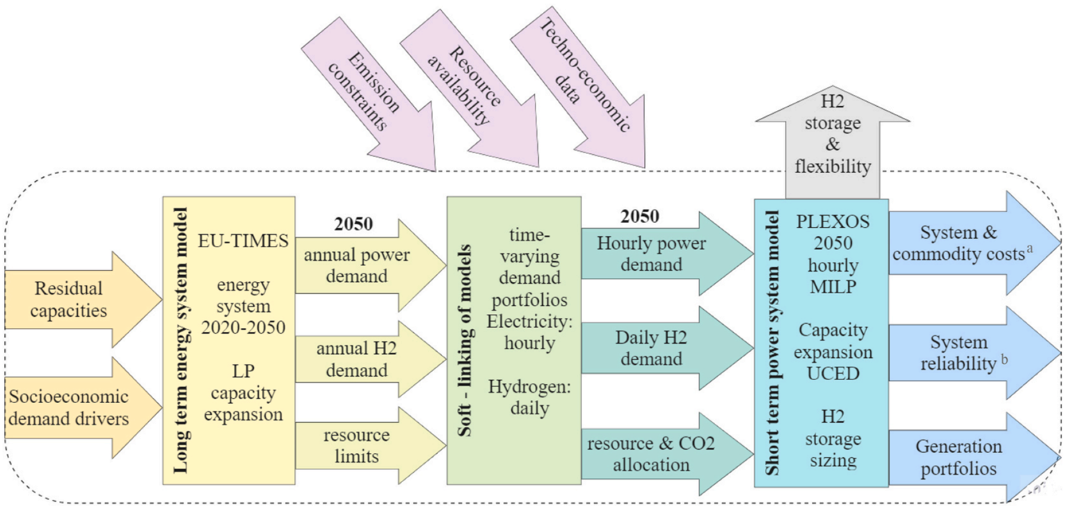

Fig. 1. Overview of the study methodology (arrows represent input/output blocks represent modelling steps). LP: linear programming, MILP: mixed integer linear programming, UCED: unit commitment and economic dispatch. [a] overall system costs include annualised investment costs and all fixed and operational costs, commodity costs include cost of electricity, hydrogen and CO_2. [b] system reliability measures include unserved energy, loss of load, curtailed energy and transmission congestion.

Table 2
Demand driver macro-economic assumptions in EU-27.

Period	GDP annual growth rate	GDP (billion EUR_{2019})	Population million inhabitants
2020	–	13,200	448
2030	1.7%	14,800	449
2040	1.5%	16,900	449
2050	1.5%	19,500	447

Table 3
Added electric heavy duty transport technologies.

	Capital cost EUR_{2019}/vehicle				Average consumption kWh/km
	2020	2030	2040	2050	
16–32 t truck	265,400	182,400	152,500	144,600	1.30
> 32 t truck	338,400	241,900	206,300	196,500	1.65
Bus	434,800	317,800	297,600	289,000	1.15

Hydrogen fuel cell equivalent of these are already in TIMES values based on PRIMES input data for EU reference scenario [36].

Hourly consumption patterns are generated based on sector-specific demand and profiles, detailed in Appendix C. The 2050 annual demand for each sector and technology is distributed across technology-specific, and sometimes country-specific, normalized curves, as outlined in Table 4. These curves are then aggregated to total country level hourly direct electricity demand curves. Indirect electricity demand involves aggregating daily country-level hydrogen patterns, with the requirement that daily hydrogen demand must be met by the end of each day, allowing a certain amount of flexibility.

Some electrolytic hydrogen is used for power generation, creating a closed loop (power to hydrogen and then hydrogen to power). Although this hydrogen is modeled in TIMES, this study models this intricate dynamic in the hourly resolution PLEXOS, optimising power system-related hydrogen demand (hydrogen to power, via utility scale fuel cell for power generation) endogenously. Thus, hydrogen to power optimisation by TIMES must be removed from electrolytic hydrogen and synthetic fuels demand upon soft linking with PLEXOS. To isolate non-power electrolytic hydrogen demand as exogenous in PLEXOS, we exclude power system-related hydrogen demand from TIMES results. Assuming a uniform distribution of the hydrogen mix across sectors, we apply the share of domestic electrolytic hydrogen in total consumption to fuel cell demand, removing that portion from electrolytic hydrogen and synthetic fuels demand in PLEXOS.

Additional endogenously produced results from the JRC-EU-TIMES model are implemented in PLEXOS as constraints are maximum CO_2 capture utilization and storage allowed by the power system and maximum biomass available by the power system.

2.4. Input data

The input data are harmonised between models, unless specified otherwise. Regarding the TIMES model, only data relating explicitly to the power system and sector coupling are presented. For additional data, e.g., other energy sectors, refer to [4]. Some hourly input data only concern the PLEXOS model, such as the hourly capacity factor of solar and wind, and the flexibility of generation and storage technologies. In the following sections, technoeconomic data regarding the power system, resource availability assumptions of solar, wind, biomass, and hydro, and residual capacities inherited by future power systems are summarised.

2.4.1. Technoeconomic assumptions

Technoeconomic assumptions for the entire energy system in JRC-EU-TIMES are described in Blanco et al. 2018 [4]. Power and hydrogen related system technologies are summarised in Table 5, with costs expressed in Euro 2019 (€$_{2019}$). Built costs include interest during construction of 8%. All thermal processes are displayed at lower heating value (LHV).

Furthermore, technoeconomic specifications and limitations included in PLEXOS for accurate hourly unit commitment optimisation, such as run up/down, mean time to repair, minimum stable level, run up rate and start costs are based on Zappa et al. [19] and presented in detail in Appendix C1.

Exogenous fuel costs are displayed in Table 6. Domestic hydrogen and electricity prices are endogenously determined/optimised. Fuel prices, particularly natural gas are further analysed with extensive sensitivity analysis, where prices are increased by 50%.

For hydrogen storage, the power system has two options in the PLEXOS model: salt cavern or pressurised tank storage. The investment costs are 1 and 1.2 million €/TJ storage capacity and with 10% and 13%

Table 4
The method how electricity demand for specific purposes is converted from annual output of TIMES to input of PLEXOS with respect to country specificity ('no' = same profile for all EU countries), temporal resolution, and source of normalized curves.

		Temporal resolution of demand curve	Country specific demand curve	Source of demand curve
Non-residential	Appliances	Hourly	No	[42]
	Cooling air-conditioning	Hourly	No	[42]
	Cooling heat pump water	Hourly	No	[42]
	Lighting	Hourly	No	[42]
	Space heating	Hourly	Yes	[43]
	Water heater	Hourly	Yes	[44]
Residential	Space heating (detached)	Hourly	Yes	[43]
	Space heating (Flat/semi-detached)	Hourly	Yes	[43]
	Water heater (Detached home)	Hourly	No	[42]
	Water heater (Flat/semi-detached home)	Hourly	No	[42]
	Cooling air-conditioning	Hourly	No	[31]
	Cooling heat pump ground water	Hourly	No	[43]
	Appliances	Hourly	No	[42]
	Lighting	Hourly	No	[42]
Industry	Chemical	Hourly	Yes	[45]
	Steel & iron	Hourly	Yes	[45]
	Paper & pulp	Hourly	Yes	[45]
	Food	Hourly	Yes	[45]
	Other	Hourly	Yes	[45]
	Hydrogen (electrolytic)	Daily	No	[46,47]
Transport	Electric car	Hourly	Yes	[48]
	Electric motorcycle	Hourly	Yes	[48]
	Electric train freight	Hourly	No	[49]
	Electric train passenger	Hourly	No	[49]
	Electric truck	Hourly	No	[49]
	Electric van	Hourly	No	[49]

Table 5
Techno-economic specifications of considered power generation technologies and costs for 2050.

Technology		Build costs (€$_{2019}$/kW)	FOM[b] (€$_{2019}$/kW/year)	VOM[b] (€/MWh)	Efficiency[c] (–)	Lifetime (year)	Build time (year)
Firm low carbon thermal	OCGT	700	17	12	44%	30	1
	CCGT	1120	22	2	62%	30	3
	CCGT-CCS	2100	30	4	55%	30	4
	PCSC	2600	39	3	48%	35	4
	PCSC-CCS	4400	69	7	38%	40	5
	Coal IGCC	4410	30	1	47%	35	5
	Coal IGCC-CCS	5237	85	6	41%	35	5
	Nuclear power plant	6190	50	3	38%	50	6
	Fuel cell	377	15	3	65%	15	1
	Biogas-OCGT	700	17	11	44%	30	1
Renewable technologies	Onshore Wind	1020	23	0	–	25	1
	Offshore Wind	1400	35	0	–	25	1
	Utility PV	320	6	0	–	25	1
	Roof PV	400	7	0	–	25	1
	CSP	2800	35	8		30	1
	Bioenergy[e]	3650	58	6	38%	38	3
	BECCS	4900	86	8	30%	25	4
	Geothermal	4690	26	0	–	26	3
	Hydropower (PHS)	3680	20	0	–	60	3
	Hydropower (STO)	3680	20	2	–	75	3
	Hydropower (ROR)	3200	15	5	–	30	3
	Tidal	2037	36	14	–	30	1
Storage	Electrolyser (PEM)[i]	360	6	8	70%	10	1
	Battery[h,i]	700	20	2	85%	10	1
	CAES[i]	720	35	2	65%	45	1

Cost related figures are in €2019, converted with EU-27 domestic industrial producer prices [50].
Abbreviations: OCNGT: open cycle natural gas turbine, OCBGT: open cycle biogas turbine, CCGT: Combined cycle gas turbine, PCSC: Pulverised coal super critical, IGCC: Integrated gasification combined cycle, PV: Photovoltaics, PHS: Pumped hydro storage, STO: dam storage, ROR: Run-of-river, CCS: Carbon capture and storage; DAC: Direct air capture of CO2; BE: bioenergy, BECCS: Bioenergy with carbon capture and storage.
Build costs, FOM (fixed operational costs), VOM (variable operational costs) and lifetime are from JRC European Commission technoeconomic assumptions [51], construction times are based on [20]
a Build costs include 8% interest during construction, assuming costs are evenly distributed during construction time.
c Efficiencies defined at low heating value (LHV).
d For all carbon capture technologies, 90% capture rate is assumed. Also, costs for CO2 transport and storage are assumed to be 13.5 €/tCO2.
e Fluidised bed boiler power generation is assumed for Bioenergy (BE) and BECCS.
h For batteries, 12 h storage capacity is assumed for daily balancing
i kW based on output.

Table 6
Fuel cost and emission assumptions.

	Price (€/GJ)[a]	Emission factors[c] ($kgCO_2$/GJ)
Natural Gas	7.5	56
Coal	2.1	101
Biomass	7.1	0[d]
Uranium	0.54	0
Biogas	17.9[b]	0

[a] Fuel prices are from IEA World Energy Outlook predicted for 2050 [52] unless stated otherwise.
[b] Biogas substrates are assumed to cost 6.4 €/GJ. Additionally, the production of biogas from these substrates through a digester costs 10.4 €/ GJ.
[c] Emission factors are taken from [53].
[d] The study considers biomass as zero-emission, excluding indirect or upstream emissions from the biomass supply chain. We only allow limited, highly sustainable biomass use, assuming that this limited biomass has minimal upstream emissions.

overall compression, diffusion and leakage losses, respectively. VOM costs including compression, short-distance transport, and maintenance are 0.2 €/GJ injected. [54]

In addition to electrolytic hydrogen production using alkaline or PEM electrolysis, hydrogen can be generated through coal gasification (with or without CCS), biomass gasification (with or without CCS), the natural gas Kvaerner process, steam methane reforming (with or without CCS), and CSP-enhanced steam methane reforming (see technoeconomic specifications in Appendix C2). Additionally, captured CO_2, can be utilised with hydrogen to synthesize fuels such as synthetic diesel, synthetic jet fuel, synthetic gas, and synthetic methanol (technoeconomic data in Appendix C1).

2.4.2. *Resource availability*

Wind, solar, and biomass necessitate distinct spatial and geophysical conditions compared to conventional firm technologies due to their location sensitivity and larger spatial footprint [55]. In this study solar and wind energy potential per region is based on the EU JRC-ENSPRESO database, using the 170 W/m^2 average irradiation and 3% of the available non-artificial areas scenario for solar photovoltaics, and the medium average capacity factor scenario for onshore and offshore wind, resulting in total of 4240 GW solar, 2000 GW onshore wind and, 400 GW offshore wind potential in the EU [55].

Hourly solar photovoltaic capacity factor (CF), onshore and offshore wind CF at 100 m height are derived from the European Reanalysis, ERA5 database [56]. The 30 km spatial grid resolution of the database has been aggregated for EU countries by weighted mean, based on solar/ wind potentials of grid cells and countries described in JRC-ENSPRESO [55].

From the ERA5 weather data, advantageous 'good', average and disadvantageous 'bad' weather years are classified to test adequacy. Hourly data spanning 1979–2020 yields 41 weather years, from which capacity factors for photovoltaic solar, onshore wind, and offshore wind (see Fig. 2). Weather year 2014 is employed in long-term (LT) capacity expansion runs, whereas short-term (ST) runs utilize data from 2014, 2010, and 2018.[5] To further improve resilience under different weather years a reserve capacity constraint with minimum 8% reserve margin[6] is also enforced.

Fig. 3 displays the maximum biomass available for utilization in the EU energy and power system. The potential is determined by EU-JRC-ENSPRESO medium availability, incorporating restricted forestry, ensuring a conservative estimate for biomass availability in the energy sectors. These potentials serve as inputs for the JRC-EU-TIMES model. In the PLEXOS power system model, the biomass potentials allocated to the power system are derived from the results of the TIMES model.

[5] The years were chosen based on the most average representative 'bad' (2010), 'average' (2014) and 'good' (2018) also avoiding the selection of leap years

[6] Capacity reserve margin is the total firm capacity minus peak demand, divided by peak demand

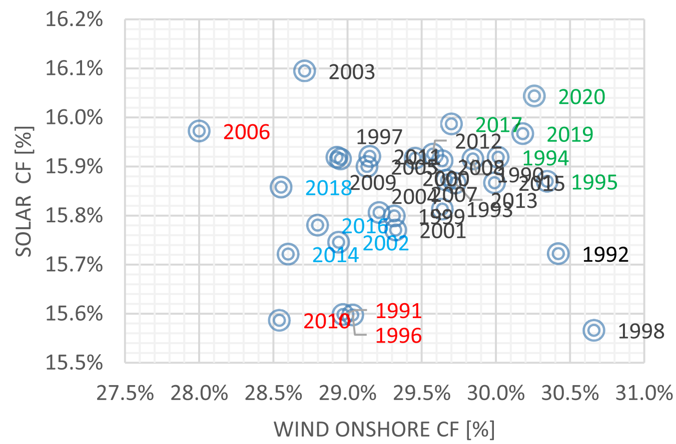

Fig. 2. Weather year selection process, aggregated EU+ annual weighed average solar and wind capacity factors 1979–2020 from ERA5. Countries are weighed based on specific resource potential. Average years are depicted in blue, bad weather years in red, and good weather year in green., For the base scenarios 2014, for sensitivity 2010 and 2018 have been chosen. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

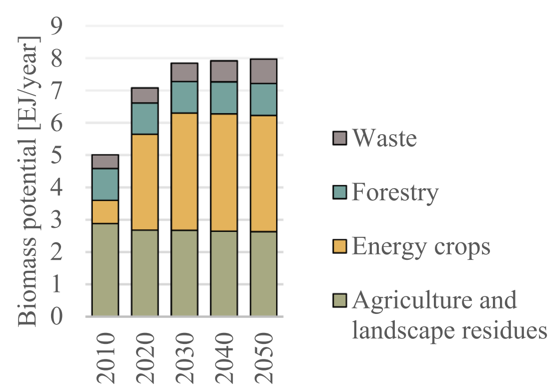

Fig. 3. Biomass potential for the whole energy sector at base availability with business-as-usual forest management [55].

2.4.3. *Residual capacities*

Existing power generation technologies serve as a starting point for capacity expansion in the JRC-EU-TIMES starting from 2020. Residual capacity data are taken from the JRC "Integrated Database of the European Energy System" (JRC-IDEES) [57]. Option for lifetime extension of residual capacities is included for some technologies, including nuclear. The assumed power system-related residual capacities are displayed in Appendix E.

2.5. *Scenarios and sensitivities*

Blanco et al. [4] show that hydrogen demand in Europe is influenced most by CO_2 storage and biomass availability, particularly under constrained conditions. To fully analyse the impact of hydrogen, our base scenario is designed with conservative estimates for biomass availability and CO_2 storage potential in the European energy system. Additionally, we explore scenarios with higher availability of these resources to understand their influence on the energy system. Given the emphasis on electrolytic hydrogen and its influence on the power sector, it is vital to

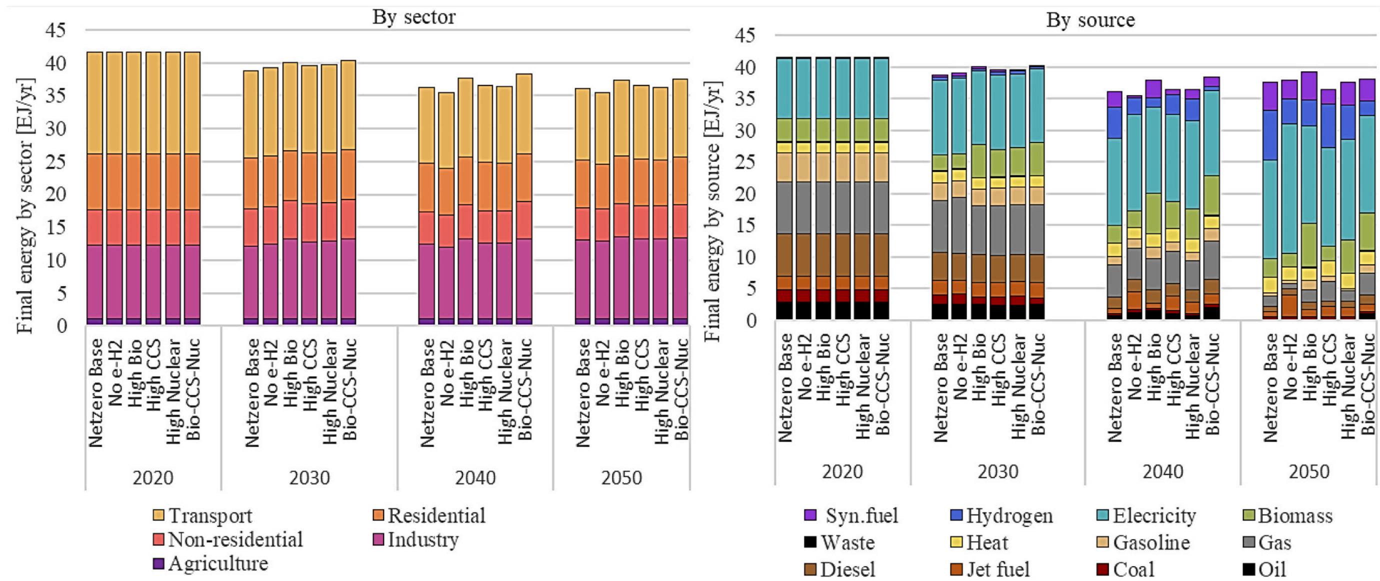

Fig. 4. Total end use energy demand in the EU by demand sector on the left and by supply source on the right Jet-fuel, dieasel and gasoline exclude synthetic equivalents, hydrogen only include final pure hydrogen demand. Synthetic fuels include 1.7 EJ of non-energy feedstock. Non-residential includes all non-residential building and infratstructure lighting, heating and appliances 'No electro-H2' is modeled with high CCS availability due to infeasibility of runs without it Jet fuel is mainly kerosine blended with increasing amount of biodiesel from 0% to 7% 2020–2050.

assess the implications of its absence. Thus, this study includes a scenario without electrolytic hydrogen to compare how the energy and power systems would function. Although, the study maintains a purely technoeconomic focus, acknowledging the politicization of nuclear power is crucial to maintain applicable results in the base scenario (see Appendix F for nuclear capacity restrictions). Additionally, an unconstrained nuclear scenario is included, allowing for purely technoeconomic standpoint.

Therefore, six core scenarios are designed:

1. ***Netzero Base***: Achieves net-zero CO_2 emissions by 2050 with 55% reduction by 2030 compared to 1990. Biomass potential is 8 EJ/year in 2050 [58]. Underground CO_2 storage is capped at 300 Mt./year, based on [59] low estimates, whereas CO_2 capture is unrestricted provided it is stored or utilised. Nuclear energy is restricted in certain countries, based on member state policy (see Appendix F). The scenario is based on the European Commission 2050 long-term strategy 1.5TECH[7] [60]
2. ***No e-H2***: '*Netzero base*' without hydrogen production via electrolysis (hence also excludes imported electrolytic hydrogen). Other hydrogen production methods are included.
3. ***High Bio***: '*Netzero base*' with increased biomass availability to 20 EJ/year.
4. ***High CCS***: '*Netzero base*' with increased CO_2 storage potential of 1000 Mt./year [58].
5. ***High Nuclear***: '*Netzero base*' without nuclear constraints.
6. ***High Bio-CCS-Nuc***: Combines scenarios 3–5, creating a less restricted scenario, utilised exclusively in JRC-EU-TIMES for overall energy system analysis, and is excluded from PLEXOS.

Additionally, there is the FF55-proxy scenario for 2050 to provide comparison, based on the European Commission Fit for 55 analyses from 2022, emphasizing deep decarbonization aligned with the European Green Deal [6]. This scenario focuses on the PLEXOS power system model, excluding the JRC-EU-TIMES energy system model.

The sensitivity analysis explores the impact of alternative assumptions[8], throughout the entire modelling framework, including:

- Electrolyser built costs: Low (250 €$_{2019}$/kW) and high (650 €$_{2019}$/kW) compared to the base case assumption of 360 €$_{2019}$/kW, covering a wide range of cost projections [4,39,61] for 2050.
- High natural gas price scenario: 50% increase to 11 €$_{2019}$/GJ in 2050.
- Low nuclear capital expenditure (CAPEX): 4500 €$_{2019}$/kW (the assumed overnight cost of nuclear plants in this study) in 2050.
- Fuel cell CAPEX variations: Low (250 €$_{2019}$/kW) and high (650 €$_{2019}$/kW) values tested against the base cost of 495 €$_{2019}$/kW in 2050.
- Hydrogen storage CAPEX sensitivity analysis: $\pm$50% range.
- Import hydrogen price: base 4.5 €$_{2019}$/kg, with a $\pm$ 50% change.

These sensitivity analyses provide a robust framework to assess the resilience and adaptability of the modeled scenarios under varying economic, technological, and resource conditions.

3. Results

This section presents the results of a systematic analysis on the impact of direct and indirect electrification in the EU, addressing four key knowledge gaps. Section 3.1 presents cost-optimised direct and indirect electrification of the entire energy system. Section 3.2 explore sector coupling and its influence on power demand. Section 3.3 evaluates the impact of electrification levels and the role of hydrogen within the power sector. Lastly, Section 3.4 examines the system adequacy and flexibility impact of direct and indirect electrification.

[7] The European Commission 2050 LTS 1.5TECH scenario specifically focuses on achieving carbon neutrality by 2050 through sustainable technologies, emphasizing innovation and technological advancements, with efficiency and cost improvements on renewables, CCS and hydrogen technologies.

[8] These assumptions are selected following a thorough analysis of the results and key conclusions, aiming to address bottleneck technologies and assumptions. Various pre-sensitivity model runs involving hydrogen, nuclear, CCS and power system costs, efficiencies or lifetimes were conducted but are not included in this article to maintain conciseness.

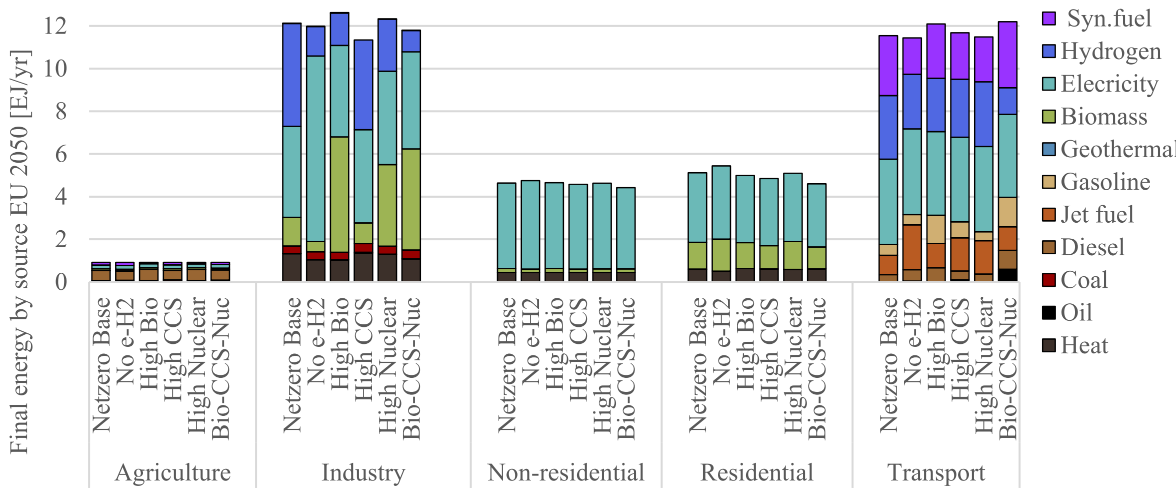

Fig. 5. Total end use energy demand by sector in EU 2050, expressed in EJ/yr
Jet fuel is mainly kerosine blended with increasing amount of biodiesel from 0% to 7% 2020–2050. Kerosine, gas and diesel emissions are compensated via carbon removal (biodiesel production with CCS, DAC and BECCS in the power sector). Synthetic fuels include 1.7 EJ of non-energy feedstock.

3.1. Role of electrification in total end use energy demand

From 2020 to 2050, electricity and hydrogen (including synthetic fuels) final consumption increases from 9.5 to 17 EJ/year (2700 to 4700 TWh/year) and from near zero to 12 EJ/year (3300 TWh/year), respectively. Simultaneously, total end use energy demand decreases by 8% to 14% across all scenarios, primarily due to declining population increase, heightened electrification, and improved energy efficiency in future technologies. Fig. 4 provides a breakdown of total end use energy demand by sector in the EU from 2020 to 2050.

In 2050, the share of electricity and hydrogen in total end use energy varies significantly, ranging from 42% to 60% and 10% to 32%, respectively, depending on biomass potential, carbon capture and storage (CCS), nuclear availability, and the option for electrolytic hydrogen (eH2 + synthetic fuels). The lowest direct electrification occurs in the *High Bio* scenario and the highest in the *No e-H2* scenario. Hydrogen and synthetic fuels have the lowest levels on the *No e-H2* and the *Netzero Base* has the highest. *High CCS* accounts for a 9% share of gas in the total end use energy demand in 2050, double that of the *Netzero Base* case. This can be attributed to increased CO_2 storage availability and the combination of additional natural gas with CCS in most instances. Carbon removal through BECCS and DAC experiences a modest 15% increase in this scenario.

Conversely, the *No e-H2* scenario leads to a 50% reduction in final natural gas demand, accompanied by a 20% increase in carbon removal. Despite this reduction, natural gas with CCS remains significant in secondary energy processes, mainly for electricity or hydrogen production.

Biomass in total end use energy ranges from 6% to 18%, with the *High Bio* scenario having the highest share and decreasing to 8% in *High CCS* due to biomass preference as secondary energy combined with CCS. Country-level shares of total end use energy are shown in Appendix G.

An important finding is that the *No* eH_2 scenario - without electrolytic hydrogen - only shows feasibility if combined with the *High CCS* scenario.[9] Excluding electrolytic hydrogen requires extensive CCS deployment, while CO_2 utilization options for synthetic fuel production is limited. Consequently, an additional 270 $MtCO_2/year_{2050}$ demand for carbon removal technologies also necessitates increased CO_2 storage.

Across scenarios, total system costs for the EU energy system from 2020 to 2050 show minimal deviation, with a maximum reduction of 2.9% observed in scenarios like *High Bio*, *High CCS,* and *High Nuc*, compared to the *Netzero Base* case. Deviation of annual system costs peaks in 2050, with maximum reduction of 5%. Despite minor deviations in cost, the composition and costs within the power sector and the proportions of direct and indirect electrification exhibit significant variations in the system design.

Sectoral shift in total end use energy consumption between 2020 and 2050 show modest change. Transport total end use energy demand increases by 21% and residential use decreases by 15% due to an increase in efficiency and slight population decrease. Significant shifts in transport and industry from 2020 to 2050 are attributed to sector coupling.

3.2. Sector coupling

3.2.1. Sectoral electrification

In a climate-neutral EU by 2050, significant variations in electricity, hydrogen, or synthetic fuel demand are observed across industry and transport sectors, contingent upon biomass availability, CO_2 storage, e-hydrogen, and nuclear availability. Fig. 5 shows energy sources by sector in 2050. Within industry, electricity demand doubles when electrolytic hydrogen is unavailable, while the use of hydrogen decreases by 70%. The *High Bio* scenario sees a 75%–80% reduction in hydrogen use, replaced by a threefold increase in biomass. Synthetic fuels are less favoured in industry, with hydrogen being directly used for high-temperature heat processes and machine drive.

In the transport sector, synthetic fuels account for 15%–25% of the total transport demand, while direct hydrogen use ranges from 10%–26% of total transport demand (mostly bunkers). Synthetic fuel is mainly used in aviation, coastal and inland navigation, and certain heavy-duty road transport applications through methanation. Additionally, 1.7 EJ of syntetic fuel is used for non-energy feedstock. Liquid hydrogen is preferred for bunkers and minor contribution to heavy-duty road transport (particularly trucks). In the *No e-H2*, *High Bio*, and *High CCS* scenarios, synthetic fuel use decreases by 10%–40%, increasing fossil fuel use. This shift is attributed to the absence of electrolytic hydrogen in the *No e-H2* scenario, high biomass availability offsetting emissions in the *High Bio* scenario, and increased CO_2 storage enabling more direct storage in *High CCS*. The combination of high biomass CCS and nuclear availability restores synthetic fuel use to the same level as in the *Netzero Base* scenario.

[9] From here on No e-H2 scenario refers to No e-H2 + High CCS (1000 Mt_{CO2}/yr)

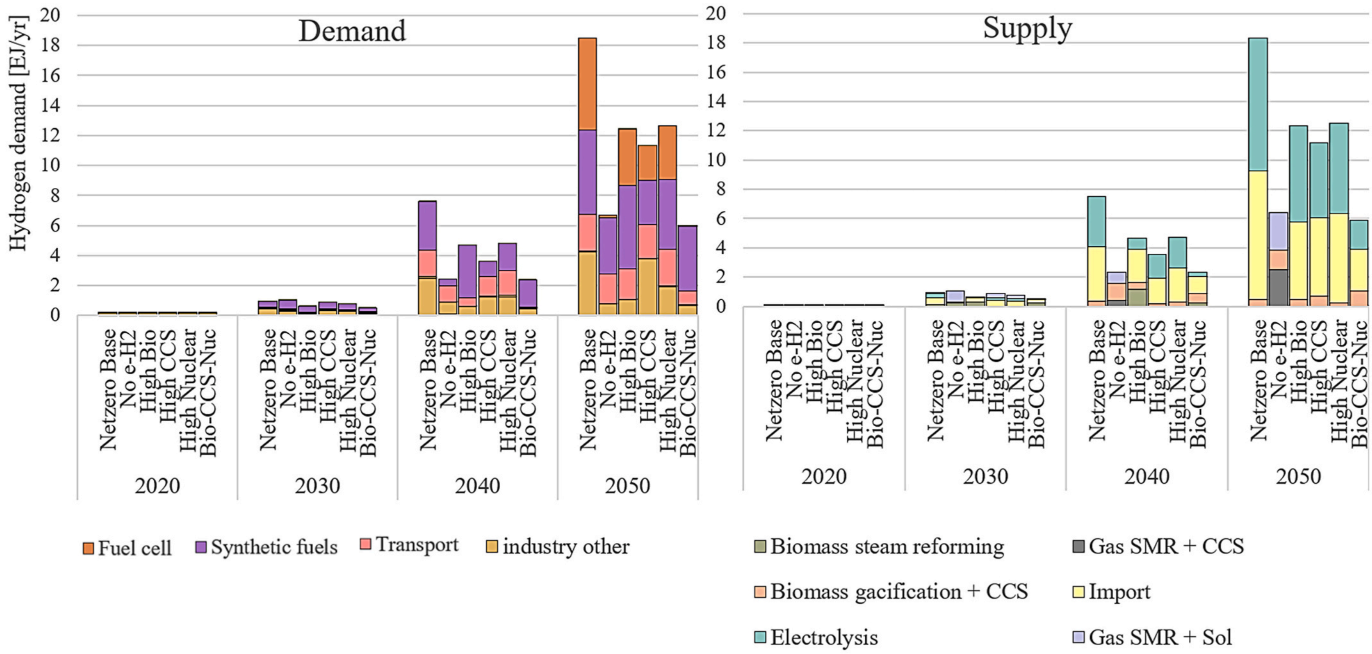

Fig. 6. Hydrogen demand (left) and supply (right) including secondary energy transformed before total end use energy consumption 'No electro-H2' is modeled with high CCS availability due to infeasibility of runs without it 'Fuel cell' refers to utility scale fuel cell for power generation, representing all hydrogen to power. Synthetic fuels include 1.7 EJ of non-energy feedstock, Fuel cell or H2-to-power will be reoptimised in PLEXOS, this is not the final result.

3.2.2. Role of hydrogen

In the *Netzero Base* case hydrogen consumption peaks at 18 EJ (5000 TWh), predominantly used for industry, synthetic fuel production, and power generation in 2050. High biomass availability, CCS, or nuclear options reduce hydrogen utilization by 32% to 39%. When high biomass, CCS, and nuclear are combined, hydrogen use, drops significantly to about 6 EJ, similar to the *No e-H2* scenario with 6.5 EJ (1800 TWh) (see Fig. 6).

Electrolysis emerges as the preferred method for hydrogen production in all scenarios except *No e-H2*. Domestic-EU electrolysis production ranges from 2 to 9 EJ (550 to 2500 TWh), with the *Netzero Base* case having the highest value in 2050. Another favoured route is biomass with CCS, ranging from 0.2 to 1.2 EJ, with the *High Nuclear* scenario having the lowest and the *High Biomass* and *No e-H2* having the highest values. 50% of total hydrogen is imported, driven by the policy constraints outlined in Section 2.1.1. In scenarios without electrolytic hydrogen, steam methane reforming (SMR) is the preferred route, particularly when coupled with concentrated solar as a heat source, alongside SMR with CCS and biomass gasification with CCS to produce synthetic fuel for aviation. The net-zero constraint and unavailability of electrolytic hydrogen force optimization on this route due to slightly lower costs and ~25% lower carbon content of synthetic kerosene compared to crude oil kerosene. However, the viability of this result requires further investigation.

Excluding electrolytic hydrogen significantly reduces industry's hydrogen demand by 78% compared to *Netzero Base* in 2050. This reduction replaces 3.3 EJ of hydrogen demand mostly by direct electrification (2.5 EJ or 700 TWh) and some biomass (0.5 EJ or 140 TWh). Additionally, 1 EJ/year (28 TWh) of hydrogen used in direct iron reduction is replaced by electric arc furnaces. Despite similar overall hydrogen demand in *High Bio*, *High CCS*, and *High Nuc*, the share of demand sectors in high CCS differs, with about 50% less hydrogen used for synthetic fuels and twice as much directly in industry. This shift is primarily due to the role of synthetic fuel production in CO_2 recycling, which is advantageous when CO_2 storage is limited in net-zero scenarios. With increased CO_2 storage capacity, synthetic fuel production decreases, thereby enhancing direct hydrogen utilization.

3.2.3. Electricity demand

Direct electricity demand remains consistent at approximately 4300–4400 TWh/year$_{2050}$ (15–16 EJ//year$_{2050}$) in most scenarios, with a notable exception in the *No electro-H2* scenario, where it rises to 5700 TWh/year$_{2050}$ (20 EJ/year$_{2050}$). In this scenario, industrial electricity demand more than doubles, constituting about 42% of the total electricity demand (see Fig. 7). In the *Netzero Base* scenario, 41% of the total electricity demand is attributed to indirect electricity demand, which reduces to 28% - 33% in the *High Biomass*, *High CCS*, and *High Nuclear* scenarios. In the compounded *High Bio-CCS-Nuc* scenario, the share of indirect electrification decreases to 13%.

The total projected electricity demand is expected to surge to 5000–7500 TWh by 2050, marking a two- to threefold rise compared to 2020 levels. These varying levels significantly influence power system dynamics. In the subsequent chapter, we will analyse the impact of differing levels of direct and indirect electrification resulting from heightened sector coupling in 2050.

3.3. Impact on power generation

Power system portfolios were optimised using PLEXOS with electricity demand, electrolytic hydrogen and synthetic fuels demand, CO_2 capture[10] and biomass[11] utilization constraints derived from JRC-EU-TIMES modelling results. This section presents the hourly capacity

[10] For 2050, CO_2 capture allowance of the power sector (that is captured from the power sector in TIMES to be stored or utilised in other processes): Netzero Base: 270 $MtCO_2/year_{2050}$, No e-H2: 260 $MtCO_2/year_{2050}$, High Bio: 570 $MtCO_2/year_{2050}$, High CCS 450 $MtCO_2/year_{2050}$, High Nuc: 88 $MtCO_2/year_{2050}$

[11] For 2050, Netzero Base and High Bio biomass allocation of 6 EJ/year$_{2050}$, other three scenarios: 1–3 EJ/year$_{2050}$. In Netzero Base scenario, 73% of biomass is allocated to the power sector, due to widespread hydrogen use in other sectors. High Nuc scenario allocates the lowest at 13%, driven by reduced hydrogen demand and high nuclear availability for the power system, resulting in diverse green molecule requirements elsewhere. The remaining three scenarios allocate approximately 30% of the total biomass potential to the power sector.

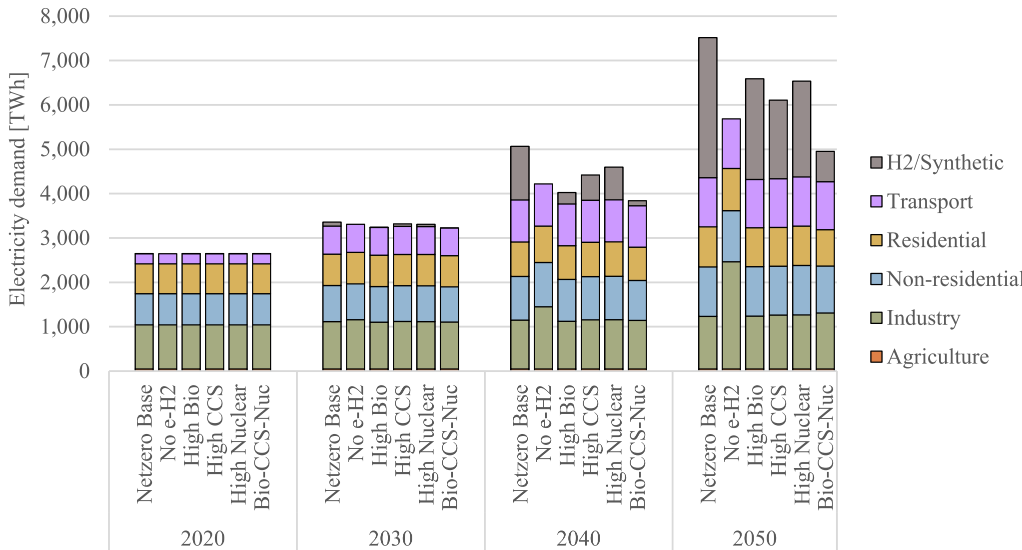

Fig. 7. Electricity demand by demand sectors, including secondary energy demand before final energy consumption H2/Synthetic fuel include hydrogen to power demand resulted from JRC-EU-TIMES, while excluded from PLEXOS since hydrogen to power us engogenously modeled in both models 'No electro-H2' is modeled with high CCS availability due to infeasibility of runs without it.

expansion and generation portfolios optimised by PLEXOS, and the flexibility and adequacy impacts of direct and indirect electrification in the five core scenarios[12]: *Netzero Base*, *No e-H2*, *High Bio*, *High CCS*, *High NUC*, and an additional *FF55-proxy* policy scenario by the European Commission for comparison.

3.3.1. *Electricity supply*

Fig. 8 illustrates the significant range of total power system capacities from 3000 GW to 5500 GW, depending on the levels of direct and indirect electrification. In the *Netzero Base* scenario, power capacity increases almost sixfold from 1000 GW in 2020, exceeding the *FF55-proxy* policy scenario by 32% for the EU in 2050 (see Fig. 8). Solar PV experiences the most substantial capacity increase, driven by heightened demand for hydrogen and direct electricity. For flexibility options, the *Netzero Base* favours hydrogen fuel cells and open cycle gas turbines (OCGT) due to a firm capacity constraint on reserves. Notably, 220 GW of fuel cell capacity is integrated but not considered in firm capacity, favouring OCGT. The maximum load reaches only one-third of the total installed capacity and two-thirds of solar capacity, reflecting cost-effective solar PV installation, which incentivizes oversizing despite potential curtailment. The power system includes 550 GW of electrolyser capacity and 150 GW of fuel cells, making up 9% and 2.5% of the total installed capacity, respectively. Bioenergy is paired solely with CCS, resulting in 18 GW capacity. Country-specific power system results are shown in Appendix G.

In contrast, the *No e-H2* scenario optimizes total capacity below 3000 GW in PLEXOS, falling below 50% of the *Netzero Base* case. Variable renewable energy sources (vRES) dominate, claiming 88% share, with CSP more preferred due to decreased flexibility from hydrogen demand. The share of offshore wind in the total capacity increases by 50%, while the share of solar decreases by 10% due to reduced flexibility.

In the *High Bio, CCS*, and *Nuclear* scenarios, solar, wind, and electrolyser capacities decrease due to reduced electrification compared to Netzero Base. *High Bio* and *CCS* scenarios see a 10% increase in BECCS capacity, while the *High Nuc* scenario fulfils most firm capacity

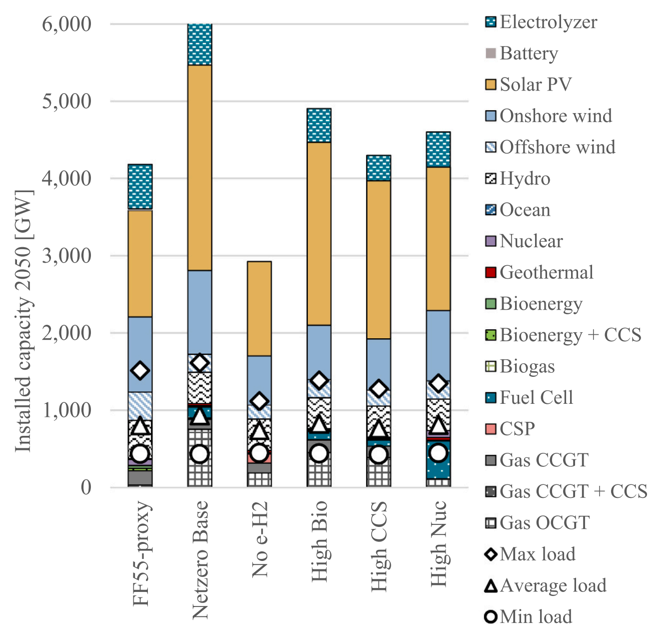

Fig. 8. Power system related capacities installed in the EU, 2050 in the 5 core scenarios as an output of PLEXOS and an additional policy scenario based on European Commission strategy [62,63]minimum, maximum and average load is also displayed.

requirement with 93 GW of nuclear power; thus, firm capacity BECCS is reduced and OCGT is replaced with 490 GW of fuel cell capacity.

In PLEXOS, the optimisation of hourly unit commitment and economic dispatch optimization (UCED) results in varying shares of wind and solar energy in total power generation, ranging from 36% to 50% for wind (offshore and onshore) and 26% to 41% for solar (see Fig. 9). The lowest shares of both solar and wind can be observed in the *No-eH2* scenario, while the highest combined share is at *Netzero Base* with 33% and 45% of wind. The High Nuclear scenario has the highest share of wind energy, with 50% and highest generation from offshore wind

[12] High Bio-CCS-Nuc together is not analysed further

compared to other scenarios (except *FF55-proxy* policy), while the lowest share of solar energy is only 26%. This is most likely due to higher baseload by nuclear, which reduces flexibility to deal with highly variable solar.

Adherence to the net-zero emission constraint is achieved by high-capacity-factor BECCS generation, enabling some utilization of natural gas for system flexibility without CCS on the gas turbines. 1 MWh of BECCS enables approximately 4.2 MWh of combined cycle gas turbine, still resulting in net-zero. In the High Nuclear scenario, natural gas demand reduces by 62% in the power sector as well as BECCS by 50%, since BECCS is used as base load and negative emissions offset natural gas, neither of these are required when nuclear is used.

Solar and wind curtailment ranges between 12% and 19% across scenarios, with *No e-H2* being the lowest- and *High Nuc* the highest, due to inflexibility in the system with high nuclear presence (see Fig. 9). Although electrolysers operating at full capacity to utilize maximum curtailment in curtailment hours, *Netzero Base* scenario still has 35% higher curtailment than *No-eH$_2$*. This is due to the investment decision to oversize solar and onshore wind for the additional indirect electrification demand of 3100 TWh rather than oversizing electrolysers. Consequently, with increased hydrogen demand, curtailment is also increasing due to additional solar installations to meet that demand.

3.3.2. Electrolytic hydrogen production

Table 7 shows that electrolysers have similar capacity factors across scenarios varying between 42% - 50%. The hydrogen storage capacity endogenously optimised in PLEXOS is small, only about 0.5% of the annual hydrogen demand, holding about 1.5 days' worth of demand. Regarding electrolytic hydrogen and synthetic fuels demand (non-power and power generation related), hydrogen storage does not function as seasonal storage. Focusing solely on power generation related hydrogen demand relative to storage size, the ratio is more comparable to seasonal storage.

3.3.3. Electricity and hydrogen specific system costs

PLEXOS optimisation revealed that despite a large variation of 20%–30% difference in power system and electrolytic hydrogen related annualised system costs, neither levelized cost of electricity (LCOE) nor levelized cost of hydrogen (LCOH) show significant variation across

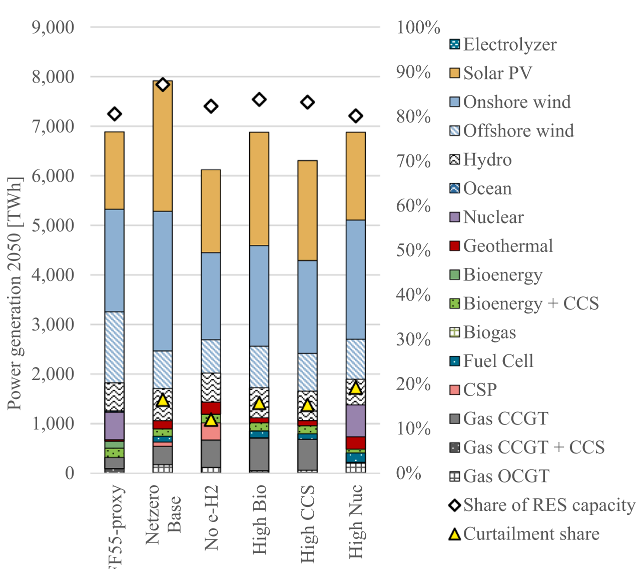

Fig. 9. Generation portfolios from UCED optimisation in hourly resolution PLEXOS with share of vRES and vRES curtailment in percentage on the secondary axis for the EU 2050.

scenarios with 56–62 €$_{2019}$/MWh and 2.8 €$_{2019}$/kg respectively (see Fig. 10). Total discounted and annualised system costs of the power system range from 330 to 445 billion €$_{2019}$, excluding an additional, about 60 billion euros$_{2019}$ transmission fixed costs across all scenarios. In terms of electrolytic hydrogen system costs, the largest contributor is the 'fuel cost' or the LCOE of input electricity, with 65% - 80% share. Therefore, the scenarios with large LCOE also have the largest LCOH.

3.3.4. System adequacy and flexibility

Despite the consistent LCOE and LCOH, results revealed certain benefits of large-scale indirect electrification with regard to flexibility. Fig. 11 shows the correlation between the degree of power system flexibility[13] and electrolysers capacity factor, fuel cells, solar and wind curtailment, and net-electricity import rate across scenarios. The analysis reveals strong correlation between the degree of available flexibility, providing resilience and system adequacy and the level of solar and wind curtailment.[14] It is also visible that curtailment increases with the level of e-H2 demand in the system and the share of fuel cell capacity in the system also corresponds to increasing flexibility.

Although unserved energy does not exhibit a linear correlation with flexibility, 'Ne-electro-H$_2$' with no electrolyser or fuel cell, and 'High-CCS' with the lowest installed electrolyser and fuel cell experience some unserved energy, with 0.0016% - 0.0041% average unserved energy factor (based on load) over 3 different weather years[15] (see Table 8), while the EU tolerance in 2021 in 0.003% according to ACER [64] .

Cross-border net-electricity import ranges between 2.2% - 3.7%, the highest being the *No eH$_2$* and *High Nuc* scenarios, with the highest unserved energy and in case of *No eH$_2$, also* lowest flexibility.

The *High Nuc* scenario exhibits the lowest annual average capacity factor for electrolysers, indicating an oversized electrolyser system, while vRES curtailment remains high. In contrast, other scenarios with lower average electrolyser capacity factor experience reduced vRES curtailment. This difference is likely due to the inflexibility of nuclear power, with the economic disadvantage of frequent shutdowns and restarting. As a result, nuclear power operates at an average capacity factor of 87%, and it is only shut down 32–57 times annually, depending on the country.

Altough hydrogen production rates remain relatively stable at the EU level, countries with substantial solar share may experience highly variable hydrogen production patterns, resulting in lower capacity factors of 25%–35% (see Fig. 12). For instance, Spain, with about 80% of its annual electricity production from solar, exhibits a strong correlation between electrolyser load and solar generation (see Fig. 13), leading to lower average capacity factors for electrolysers compared with other countries. This phenomenon is not observed in countries with high wind penetration. This variability highlights the critical role of cross-border transmission networks, with net-exporter countries transmitting up to 209 TWh annually to net importer countries in 2050 in the *Netzero Base* scenario.

3.4. Sensitivity analysis

The sensitivity analysis was conducted in two stages: first, in JRC-EU-TIMES, examining direct and indirect electrification within the broader energy system context; and second, in PLEXOS, focusing specifically on power system-related sensitivities.

[13] Power system flexibility is the hourly capacity to increase generation, measured in additional megawatt-hours (MWh) the system can ramp up if needed. Degree of flexibility is expressed as the percentage of the total annual flexibility relative to the total load.

[14] Undispatchable solar PV, onshore- and offshore wind curtailed

[15] System adequacy has been tested with weather years 2014, 2010, 2019

Table 7
Electrolytic hydrogen production for direct hydrogen and synthetics indicators for the EU 2050.

	H2 demand (non-power)	H2 demand (to power)	Electrolyser capacity	Capacity Factor	H2 storage capacity	Injection	Withdrawal
	TWh/year	TWh/year	GW	%	TWh	TWh/year	TWh/year
FF55-proxy	1911	0	594	45%	8	123	778
Netzero Base	2013	193	574	50%	10	825	808
High Bio	1502	237	467	46%	7	1055	1023
High CCS	1224	191	358	50%	7	890	849
High Nuc	1426	320	484	42%	8	1245	1220

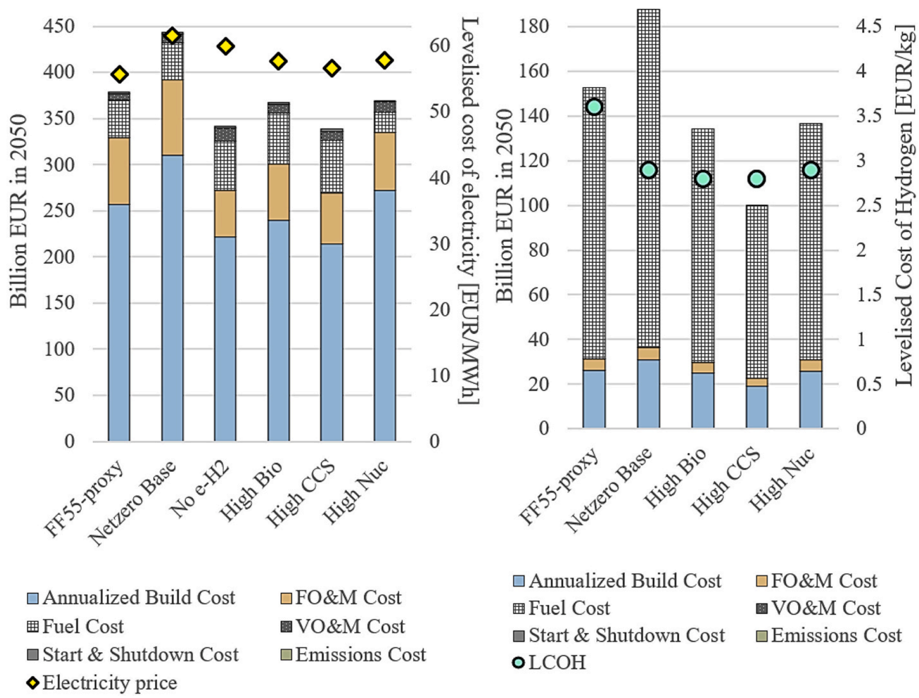

Fig. 10. Power system related costs for the EU power system in 2050 with annualised total system costs on the main axis and levelized cost of electricity (LCOE) on the secondary on the left, and total annualised electrolytic hydrogen related system annualised system costs with levelized cost of hydrogen on the right. Costs are annualised with 8% discount rate. Fixed operation and maintenance cost (FO&M), variable operation and maintenance costs (VO&M). Fuel costs Start and shut down costs (also includes ramping costs) and emission costs, power system transmission costs are excluded, electrolytic hydrogen related costs include electrolyser and storage CAPEX, FO&M, compression water consumption and distribution. Input fuel cost for electrolyser based on LCOE.

3.4.1. *JRC-EU-TIMES sensitivity*

Lowering imported hydrogen prices by 50% shows high sensitivity in hydrogen demand, resulting in a 17% increase in overall hydrogen demand and a 6% rise in total electrolytic hydrogen and synthetic fuels demand within the EU energy system by 2050. Conversely, a 50% increase in hydrogen prices reveals lower sensitivity, leading to a 9% decline in total hydrogen demand. Fig. 14 shows electricity and hydrogen demand sensitivity in JRC-EU-TIMES.

Changing the electrolyser CAPEX demonstrated low sensitivity to hydrogen demands, affirming model robustness in this aspect. Although a high electrolyser CAPEX resulted in a substantial 22% decrease in installed electrolyser capacity, the impact on electrolytic hydrogen demand was moderate, with only a 5% reduction. Notably, despite the elevated electrolyser CAPEX, all other sensitivity runs increased electrolyser capacity (see Fig. 14).

3.4.2. *PLEXOS sensitivity*

The sensitivity analysis includes variations: ± 200 $€_{2019}$/kW for electrolyser construction costs, a 50% increase in gas prices, overnight nuclear build costs, and a weather year with 5% - 8% lower capacity factors than the base year. Lower hydrogen storage CAPEX primarily impacted hydrogen storage capacity, increasing it by 52%. Raising electrolyser CAPEX by 62% only marginally reduced capacity by 10%, whereas an equal price decrease have increased capacity by 7%. Furthermore, reduced fuel cell prices amplified electrolyser capacity by 14%. The shares of renewables and total power system costs remained stable across sensitivity runs, with the most substantial effect on total power system costs being a 3% reduction due to decreased nuclear CAPEX (See Fig. 15).

Fig. 16 show that, 50% higher gas prices have a significant impact on power system configuration with 105 GW combined cycle gas turbine, and over 150 GW solar PV is replaced by mainly wind capacity and CSP. Power system capacity mix is highly robust against hydrogen storage CAPEX changes. Lowering nuclear CAPEX results in additional 43 GW nuclear replacing solar PV and CSP. Lower fuel cell CAPEX results in higher total capacities, installing more solar PV, wind, electrolyser and fuel cell, without significant capacity reduction elsewhere, while higher fuel cell CAPEX results in additional solar PV, but lowering of fuel cell and hydrogen.

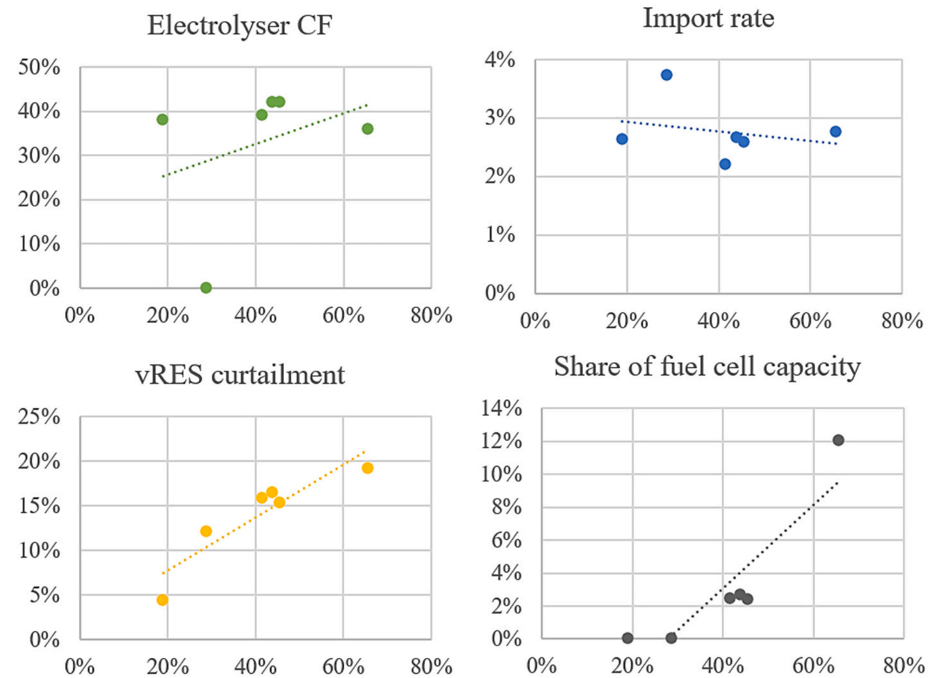

Fig. 11. Percentage of average flexibility up available from each time slice (compared to load) on the x-axis. On the y-axis: annual average electrolyser capacity factor, intra-EU cross boarder net-import rate (share of total import in load), solar & wind curtailment (percentage of solar and wind generation thrown away/curtailed) and share of fuel cell out of total capacity on the y-axis.

Table 8
Power system adequacy specific indicators.

	Flexibility up Specific	Net-import	Unserved energy	H2 production	Fuel cell capacity	vRES curtailment	Electrolyser CF [%]
Netzero Base	43.8%	2.7%	0.0000%	37.1%	2.7%	16.5%	50%
No e-H_2	28.7%	3.7%	0.0016%	0.0%	0.0%	12.0%	0%
High Bio	41.5%	2.2%	0.0000%	32.6%	2.4%	15.8%	46%
High CCS	45.5%	2.6%	0.0000%	26.7%	2.4%	15.4%	50%
High Nuc	65.7%	2.8%	0.0041%	32.1%	12.0%	19.2%	42%

Total load includes direct and indirect electrification load.

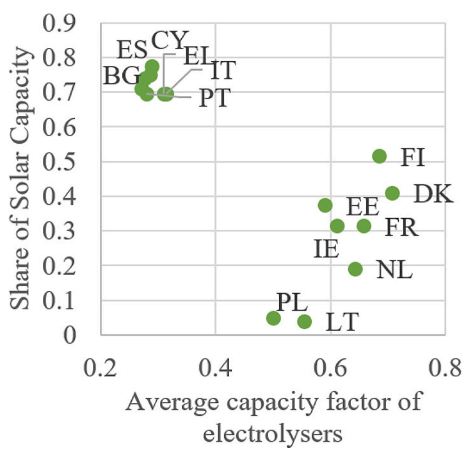

Fig. 12. Share of solar capacity out of total installed capacity vs average electrolyser capacity factors.

4. Discussion

4.1. Limitations

This study should be interpreted with the following limitations and uncertainties in mind.

Due to computational intensity and large data, only limited aspects of the two models have been linked. Soft-linking models may not fully capture feedback loops and complex interdependencies between different components of the system. Within the scope, only aspects closely related to the power system were considered. Hard linkage between the models, with PLEXOS incorporating long-term expansion from 2020 could result in different power system portfolios. The greenfield approach in PLEXOS provided high flexibility in power system design to show the optimum portfolios in 2050 to fulfil the electricity and electrolytic hydrogen and synthetic fuels demand in the energy system. This valuable contribution would have been lost with strongly connected hard linkage [65].

Due to computational limitations, countries are single-node, in a country-level copperplate approach. Capturing countries high detail internal transmission and distribution systems could have resulted in different power system portfolios. However, in the TIMES energy model, higher spatial resolution for all energy and material flows would be highly complex that most currently available solvers could not solve in the given timeframe. Changing the spatial scope only in PLEXOS would have triggered inconsistencies.

Although intra-EU cross-border transport for hydrogen, biomass, and CO_2 were modeled in TIMES, these aspects were excluded from the PLEXOS model. However, transport costs were integrated into the variable costs of technologies associated with these sources. Assuming highly interconnected EU-27 in terms of transport infrastructure by

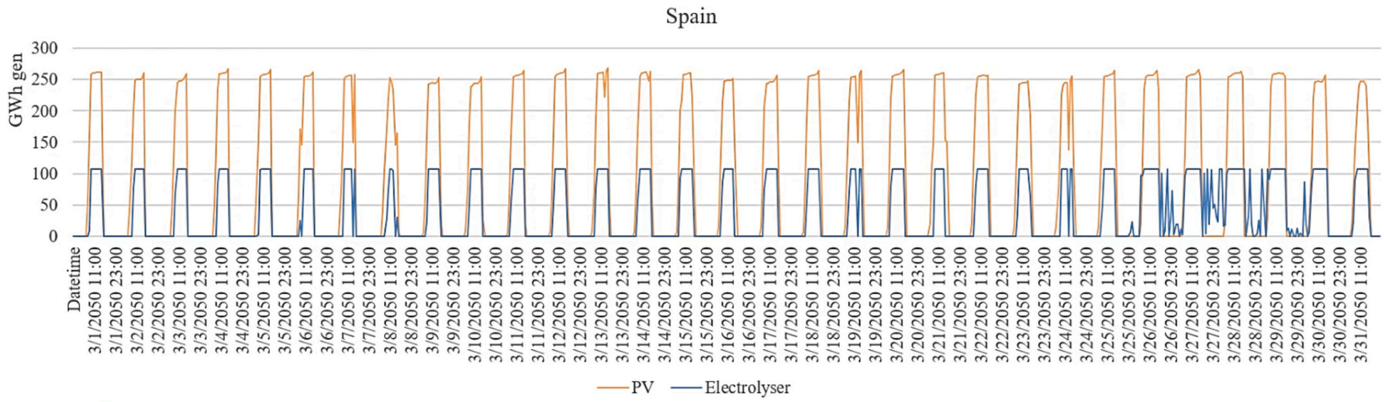

Fig. 13. Solar PV generation and electrolyser load in Spain March 2050 under Netzero Base assumptions.

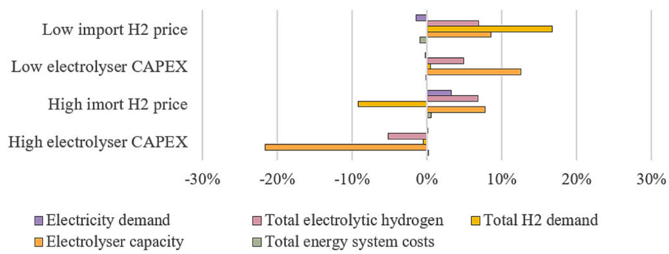

Fig. 14. TIMES energy system model sensitivity. Low electrolyser CAPEX: 250 €$_{2019}$/kW and high 650 €$_{2019}$/kW, Low fuel cell CAPEX: 250 €$_{2019}$/kW and high 650 €$_{2019}$/kW, low nuclear: 4500 €$_{2019}$/kW, high gas price: 11 €$_{2019}$/GJ.

2050, this modelling choice would not significantly affect main conclusions.

Resource availability for the EU-27, including solar irradiation, wind speeds, hydro flows, and biomass is based on historical data and some policy related projections for the future. The effect of climate change on these aspects has not been considered, although it could be significant [66]. There is significant uncertainty regarding how weather patterns will change by 2050, particularly at a country-specific hourly resolution, where data availability is not guaranteed. Although the weather sensitivity analysis and rigorous reserve margin constraints partly account for these impacts on the power system, further research is recommended in this area.

Uncertainties in future costs, technology availability, and efficiency improvements can significantly influence power system design. Although some of these uncertainties are explored in sensitivity analyses, demonstrating robustness against a wide range of electrolyser CAPEX projections for 2050 in the literature [4,39,61], highly uncertain technoeconomic assumptions can still affect future power system portfolios, regarding CCS, or other hydrogen related costs.

4.2. Comparison to existing literature

The results for primary and total end use energy from TIMES align closely with findings by Seck et al., [13] using long-term energy system modelling for Europe. However, the power system capacities are different, with 20% lower installed solar and over 50% more onshore wind. This can be the result of higher solar PV build costs of about 610 EUR/kW, which in this study are only 320–400 EUR/kW, while wind CAPEX is similar across both studies. Installed capacities of solar PV, wind, and electrolysers are comparable to those in the European net-

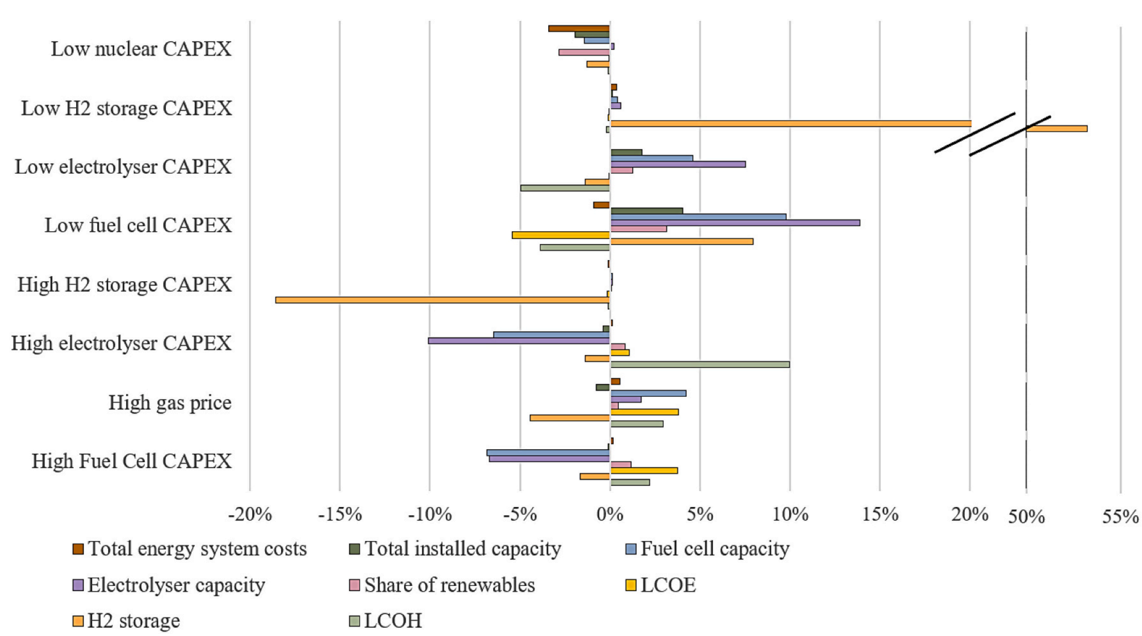

Fig. 15. Sensitivity analysis on PLEXOS model. Low electrolyser CAPEX: 250 €$_{2019}$/kW and high 650 €$_{2019}$/kW, Low fuel cell CAPEX: 250 €$_{2019}$/kW and high 650 €$_{2019}$/kW, low nuclear: 4500 €$_{2019}$/kW, high gas price: 11 €$_{2019}$/GJ.

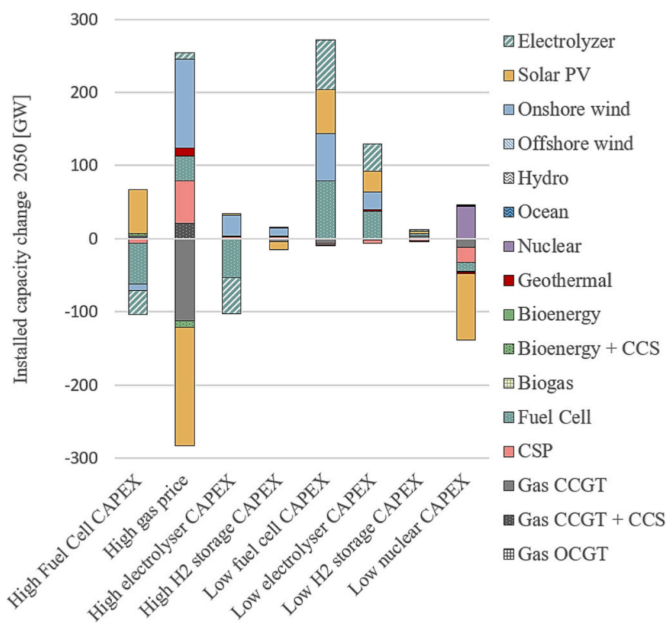

Fig. 16. Change in installed capacities, compared to the Netzero Base scenario in 2050 in the EU Low electrolyser CAPEX: 250 $€_{2019}$/kW and high 650 $€_{2019}$/kW, Low fuel cell CAPEX: 250 $€_{2019}$/kW and high 650 $€_{2019}$/kW, low nuclear: 4500 $€_{2019}$/kW, high gas price: 11 $€_{2019}$/GJ.

zero expansion study by Neumann et al. [9]. Neumann's study suggests capacities of 200–250 GW for offshore wind, 1700–1800 GW for onshore wind, 2670–3600 GW for solar PV, and 937–1250 GW for electrolysers. In our *Netzero Base* scenario, the installed capacities are 200 GW, 1800 GW, 2600 GW, and 550 GW for these respective technologies, aligning with the lower end of Neumann's ranges. This is most likely due to their higher spatial resolution and lower temporal resolution. The lower, 3-hourly temporal resolution in Neumann's study may also result in lower curtailment levels.

Regarding hydrogen costs, 2.8 EUR/kg for 2050 is relatively higher, compared to other literature estimates of 1.5–2.5 EUR/kg in 2050 [38,39,61,67]. Ueckerdt et al., 2021 [67] concluded about 30 EUR/MWh (or about 1 EUR/kg) for hydrogen production in Europe, 2050, assuming 30 ± 10 EUR/MWh for electricity and 334 ± 189 EUR/kW for electrolyser. Electricity costs are almost double in this study, and the assumed electrolyser CAPEX is almost 20% higher, resulting in higher hydrogen costs. Additionally, our study includes higher hydrogen transportation costs to compensate for the lack of hydrogen transport infrastructure representation in the PLEXOS model. Hydrogen costs become more comparable if transport costs are removed, as most studies do not consider transportation for the base hydrogen price. For the *Netzero Base* scenario, this would result in 1.9 EUR/$kg_{H2.}$ Additionally, most studies assume higher rates of capacity factor for the electrolyser. Increasing the capacity factor to 95% would further decrease costs to 1.2 EUR/$kg_{H2.}$

Regarding power system flexibility, results show that natural gas is preferred over battery or hydrogen for flexibility; whereas, Maeder et al. [68] concludes battery and hydrogen are more preferred in 2050, Central Europe. The different conclusions can be a result of 50% higher natural gas prices in the referred study, and the exclusion of CCS technologies.

4.3. Implications of results

The role of direct electrification increases significantly towards 2050 across scenarios, surpassing previous estimations by approximately 10% to 25% compared to reports like ENTSOe-TYNDP [7] or Fit-for-55 [59] by approximately 10%–25%, which under conditions excluding electrolytic hydrogen increases to 60%. Levels of direct electrification remain consistent despite varying biomass, CCS, or nuclear assumptions. In contrast, indirect electrification is heavily impacted by these assumptions. For the broader EU context, this interplay between biomass, CCS, nuclear, and the need for electrolytic hydrogen is crucial. In case of high availability of these three, the need for EU produced electrolytic hydrogen decreases by 80% to 550 TWh. Separately, they decrease electrolytic hydrogen by 30%–45%, with high CCS resulting in the most reduction. Policy decisions on the extent of nuclear, CCS and biomass use will greatly affect the development of electrolytic hydrogen and sector coupling. Extensive use of these technologies could diminish the role of indirect electrification.

Electrolysis is the preferred hydrogen production method, with natural gas steam methane reforming + CCS used only when electrolytic hydrogen is unavailable. This preference arises from two primary factors: the anticipated substantial reduction in electrolyser investment costs from 1500 €2019/kW_{out} in 2020 to 360 €2019/kW_{out} in 2050, and the net-zero emissions constraint, which poses significant challenges in managing CO2 emissions, even with 90% capture rate. Furthermore, if captured CO_2 is utilised for synthetic fuels and subsequently emitted, only negative emission technologies such as BECCS and DAC are considered truly zero-emission options. Hence, mostly negative emission technologies are the preferred route for carbon capture. This conclusion remains consistent across all milestone years spanning from 2020 to 2050 within this modelling framework, thereby making a substantial contribution to the debate regarding the role of blue hydrogen in 2050 or the transitional period leading up to it [4,11].

As emission targets decrease linearly from 2020 to 2050, demand for direct electrification also increases linearly. However, demand for indirect electrification shows an exponential increase, shooting up significantly only in the latter milestone years (2035–2050). Despite indirect electrification only increasing steadily by 10%–15% from 2040 to 2050, demand for direct electrification increases 2.6-fold in the same period. This finding is crucial, as previous studies often focused on the 80% or 95% emission reduction target when analysing the role of hydrogen in the EU energy system [4,11,13,16]. While findings on direct electrification could potentially be extrapolated linearly to a 100% emission reduction target, closing this gap for indirect electrification from 85% to 100% reduction is significantly more impactful with exponential increase in demand. These conclusions are expected to hold if future EU emission targets for 2050 shift towards net-negative, given hydrogen's pivotal role in CO_2 utilization. Policymakers should focus on hydrogen as a CO_2 utilization tool, emphasizing synthetic fuel research and development, and establishing a comprehensive framework for CO_2 accounting and utilization monitoring. This ensures fossil-based CO_2 does not escape into the atmosphere, jeopardizing net-zero targets.

Another form of sector coupling emerges where the power sector supplying hydrogen and CO2 for production of synthetic fuels. The transport sector, especially aviation and navigation, emerges as the largest consumer, with over 90% consumed there. CO2 (CCS) is sourced from various channels, including natural gas, bioenergy, industrial processes with CCS, and direct air capture, highlighting the strong coupling between transport and the power sector. This coupling extends beyond direct electrification via electric vehicles to include indirect electrification through electrolytic hydrogen and synthetic fuels.

Power system-related results reveal that the level of direct and indirect electrification significantly influences the power system capacity mix, particularly impacting highly variable sources such as solar PV and onshore wind. Contrary to previous expectations [23,25,27], higher levels of indirect electrification lead to a slight increase in curtailments of solar and wind rather than a decrease. Although hydrogen production predominantly takes place when curtailable wind and solar are available, oversizing electrolysers to consume all curtailment was not cost-effective, as solar and wind capacities were oversized due to lower investment costs. Despite these unexpected curtailment results, high levels of indirect electrification enhance power system adequacy by minimizing unserved energy and offering greater flexibility options. Policymakers should incentivize hydrogen and synthetic fuel technologies for their flexibility and robustness in the power sector, which decrease unserved energy. However, electrolysers must be oversized due to their 42–50% capacity factor. Policies should focus on cost reduction, upscaling, and the role of imported hydrogen.

5. Conclusion

EU strategies to achieve a 55% reduction by 2030 and net-zero by 2050 involve sector coupling and extensive electrification, including hydrogen and synthetic fuels. Our study offers a comprehensive analysis of these interconnected elements within a net-zero energy system. By integrating a long-term energy system model (JRC-EU-TIMES) with an hourly resolution power system model (PLEXOS), we simultaneously model the interactions between hydrogen and synthetic fuel demand, production technologies, and their impacts on the power sector. Our integrated approach reveals that electricity demand is estimated to rise to 5000 TWh–7500 TWh by 2050, a 2–3 fold increase compared to 2020 levels. Direct electrification levels in 2050 remain stable despite changes in biomass, CCS, or nuclear assumptions. However, indirect electrification is significantly influenced by these factors. The interplay among biomass, CCS, nuclear, and the demand for electrolytic hydrogen is crucial for the broader EU context. Policy decisions regarding nuclear and biomass use will strongly impact the development of electrolytic hydrogen and sector coupling. Widespread adoption of bioenergy or nuclear may reduce reliance on indirect electrification significantly. Despite variations in scales and shares of direct versus indirect electrification, total discounted energy system costs show a maximum variation of 2.8% across scenarios.

Sector coupling, primarily facilitated through hydrogen along with CO_2 capture and utilization for synthetic fuels, plays a pivotal role. Approximately 3–5 EJ/year of hydrogen is used for synthetic fuel production, whereas 3–13 EJ/year of hydrogen is directly consumed, primarily by industry and transport sectors. Synthetic fuel is mainly used in the transport sector, whereas pure hydrogen both industry and transport. Industry demand and sector coupling are highly sensitive to the availability of biomass, CCS, nuclear, and electrolytic hydrogen. The power sector provides most of the hydrogen and a significant portion of CO_2 for synthetic fuel production in the transport sector. This underscores the strong connection between transport and the power sector, achieved not only through direct electrification with electric vehicles but also through indirect electrification for synthetic fuels.

Soft-linking a long-term dynamic energy system model (JRC-EU-TIMES) and an hourly resolution power system model (PLEXOS) also revealed some specific power system-related implications of this significant electrification in the EU towards 2050 through hourly capacity expansion and unit commitment, and economic dispatch optimisation. In terms of power system related costs, levelized cost of electricity (LCOE) and levelized cost of hydrogen (LCOH) are relatively stable with low variation across scenarios of 56–62 $€_{2019}$/MWh and 2.8–2.9 $€_{2019}$/kg, respectively, despite the large differences in the magnitude and share of direct and indirect electrification. However, total discounted and annualised system costs of the power system are showing a high variety from 330 to 445 billion $euros_{2019}$ in the EU, 2050, with the highest being the *Netzero Base* scenario with the highest level of indirect electrification. The *Netzero Base* scenario presents an 87% share of variable renewable energy (vRES) in the EU 2050 generation, 7.5% higher than the *No electrolytic hydrogen* highlighting how electrolytic hydrogen and synthetic fuels facilitate increased vRES generation. As such, the *No electrolytic hydrogen* scenario sees the lowest vRES curtailment, around 20–25% lower than that in scenarios involving electrolytic hydrogen. This can be attributed to slightly oversizing solar PV and wind power capacities when electrolysers are installed as cost-optimal solution. Assessing power system operational flexibility, increasing fuel cell availability, and vRES curtailment show high correlation with increasing system flexibility. Even during unfavourable weather years, the *Netzero Base* scenario avoids unserved energy, whereas the *No electrolytic hydrogen* scenario experiences 0.0015% unserved energy factor. In solar-rich countries, low electrolyser capacity factors suggest oversizing to match solar variability, unlike low-solar countries with 75%–80% average annual electrolyser capacity factors.

Sensitivity analysis revealed that the price of imported hydrogen significantly impacts hydrogen demand, with about ±15% change with ±50% change in price, while ±50% change in the cost of electrolysers do not impact total hydrogen demand, only electrolytic hydrogen and synthetic fuels demand by ±5%. The model is also highly sensitive to H_2 storage costs; however, this did not change final conclusions, regarding power generation mix or system costs.

CRediT authorship contribution statement

Rebeka Béres: Conceptualization, Investigation, Methodology, Validation, Visualization, Writing – original draft. **Wouter Nijs:** Investigation, Methodology, Resources, Validation, Writing – review & editing. **Annika Boldrini:** Methodology, Resources, Writing – review & editing. **Machteld van den Broek:** Conceptualization, Resources, Supervision, Validation, Writing – review & editing.

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.

Data availability

Data will be made available on request.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2024.124053.

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