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System-friendly process design: Optimizing blue hydrogen production for future energy systems

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ABSTRACT

While the effects of ongoing cost reductions in renewables, batteries, and electrolyzers on future energy systems have been extensively investigated, the effects of significant advances in CO_2 capture and storage (CCS) technologies have received much less attention. This research gap is addressed via a long-term (2050) energy system model loosely based on Germany, yielding four main findings. First, CCS-enabled pathways offer the greatest benefits in the hydrogen sector, where hydrogen prices can be reduced by two-thirds relative to a scenario without CCS. Second, advanced blue hydrogen technologies can reduce total system costs by 12% and enable negative CO_2 emissions due to higher efficiencies and CO_2 capture ratios. Third, co-gasification of coal and biomass emerged as an important enabler of these promising results, allowing efficient exploitation of limited biomass resources to achieve negative emissions and limit the dependence on imported natural gas. Finally, CCS decarbonization pathways can practically and economically incorporate substantial shares of renewable energy to reduce fossil fuel dependence. Such diversification of primary energy inputs increases system resilience to the broad range of socio-techno-economic challenges facing the energy transition. In conclusion, balanced blue-green pathways offer many benefits and deserve serious consideration in the global decarbonization effort.

1. Introduction

Momentum is gathering behind the global clean energy transition, with numerous roadmaps to net-zero emissions being published in recent years, most prominently from the IPCC [1] and IEA [2]. However, tangible policy pledges continue to fall far short of this goal [3], emphasized by short-term projections of resumed growth in fossil fuel consumption (Fig. 1). As the world recovers from the pandemic, the fossil fuel rebound continues to demonstrate the great socio-techno-economic challenges of a rapid global energy transition. Variable and non-dispatchable renewable energy (mainly wind and solar PV) are expected to drive the transition, but scaling these technologies at the required speed is proving difficult. The capital-intensive cost structure of wind and solar and the complex and similarly capital-intensive supporting infrastructure required to integrate high shares of variable sources into reliable energy systems make them ill-suited to a rapid transition.

Of particular importance is the fact that wind and solar produce electricity, which provides only 20% of final energy consumption today [7]. Thus, the bulk of the transition must happen beyond the electricity sector, requiring far-reaching changes and complex coupling to transportation, industrial, and heating sectors that previously operated independently. Aside from direct electrification in forms such as battery electric vehicles and heat pumps, hydrogen is being increasingly studied as a carbon-free energy vector to decarbonize these economic sectors [8]. It is considerably easier to store and transmit over long distances than electricity, especially when converted to forms such as ammonia, and is well suited to decarbonize sectors needing high-grade heat, a reducing agent, or sufficient energy density to enable long-distance transportation. Furthermore, the ease of storage and trade of hydrogen and its derivatives can play an important role in improving resilience in the complex and interdependent low-carbon energy system of the future.

Aside from cost and complexity, further challenges to a transition led by wind and solar arise from public acceptance [9,10] and critical material constraints [11]. Leading nations in wind and solar expansion are already experiencing considerable public acceptance challenges to wind turbines and the large transmission grid expansions they require. At the time of writing (early 2022), rising commodity prices are also elevating the cost of clean energy, potentially adding over $100 billion to the cost of clean energy up to 2024 [12] due to the high material intensity inherent in harvesting diffuse energy sources like wind and sunlight. In

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List of acronyms

ASME	American society of mechanical engineers
BEC	Bare erected cost
BECCS	Bioenergy with CO_2 capture and storage
CCS	CO_2 Capture and Storage
GAMS	Generalized algebraic modelling system
GSR	Gas switching reforming
GT	Gas turbine
H2CC	Hydrogen combined cycle
H2RC	Hydrogen recuperated cycle
HGCU	Hot gas clean-up
IEA	International Energy Agency
IEAGHG	IEA greenhouse gas R&D program
IPCC	Intergovernmental Panel on Climate Change
MAWGS	Membrane-assisted water-gas shift
MDEA	Methyl diethanolamine
MEA	Monoethanolamine
NGCC	Natural gas combined cycle
NGRC	Natural gas recuperated cycle
PSA	Pressure swing adsorption
PV	Photovoltaic
SMR	Steam methane reforming
TOC	Total overnight cost
VRE	Variable renewable energy

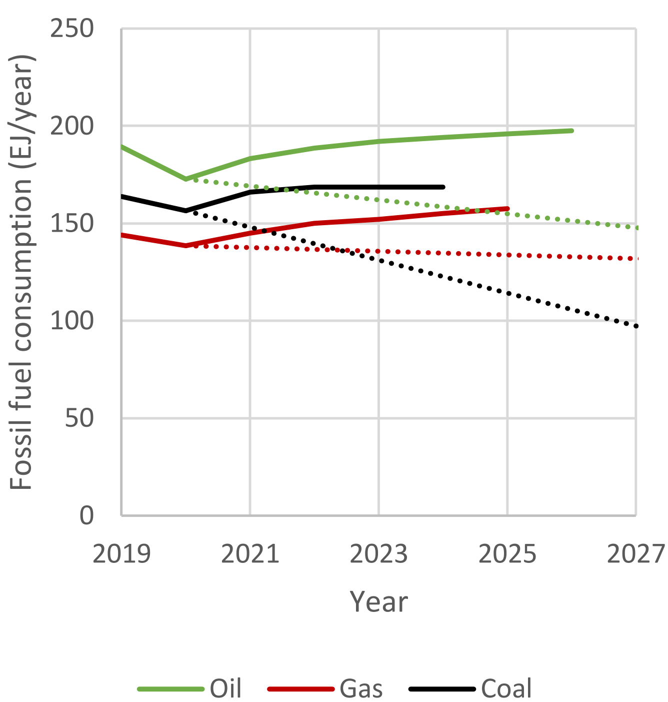

Fig. 1. The rapidly growing gap between near-term projections of fossil fuel consumption and the requirements for net-zero by 2050 [2,4–6].

the longer term, critical materials required by clean energy technologies are set to become an even more influential factor in the global energy transition. Not only is the cost of these materials expected to rise considerably as demand rapidly expands, but socio-environmental [13] and geopolitical [14] implications can also be foreseen.

For all these reasons, a balanced energy transition is advisable, including a significant role for hydrocarbon energy (fossil fuels and biomass) with CO_2 capture and storage (CCS). Hydrocarbons offer inherent energy storage and simple global trade to ensure full dispatchability and high energy security – both critical factors for energy system resilience. In addition, they offer highly concentrated energy with conversion processes largely independent of advanced materials, thus reducing public resistance and material constraints. CCS also has a critical role to play in retrofits of existing infrastructure, emissions reduction from hard-to-abate industries, and CO_2 removal from the atmosphere [15]. Furthermore, hydrocarbon energy conversion with CCS will ease socio-economic concerns related to job losses and premature asset write-downs in a rapid global decarbonization effort.

Hydrocarbons are particularly suitable to supplying hydrogen and other clean fuels to future energy systems. Their conversion to cleaner fuels is typically considerably more efficient and cheaper than conversion to electricity due to the smaller number of energy conversion steps involved. Gas, coal, and biomass are the most suitable candidates for such energy conversion to low-carbon fuels, typically identified with the prefix "blue," e.g., blue hydrogen or blue ammonia. A diverse mix of input energy to blue hydrogen processes further increases energy security, whereas the gradual introduction of biomass improves long-term sustainability and offers negative CO_2 emissions.

Blue hydrogen processes can be designed to facilitate the integration of higher shares of variable renewables. A large challenge with wind and solar integration is that it enforces low capacity utilization across the energy system [16], requiring plenty of additional capital for times with little wind and sun and other capital for times with lots of wind and sun. Low-carbon generators needed to meet residual load during longer periods of low wind and sun are an important part of this challenge. These generators (e.g., nuclear, biomass, or fossil fuels with CCS) are typically capital intensive, resulting in high levelized costs when forced to operate at low capacity factors.

The authors previously proposed flexible power and hydrogen plants to address this challenge [17,18]. Such plants can operate continuously at high capacity factors, mostly producing hydrogen but switching to electricity production when electricity prices reach high levels. This ensures high capital utilization of costly CCS components (CO_2 capture, compression, transport, and storage) while effectively balancing variations in wind and solar energy [19].

The present study builds on this philosophy by developing a methodology to allow the design of such a flexible plant to be optimized directly within energy systems modelling. Such a system-optimized plant will minimize the system costs introduced by high variable renewable shares. The natural gas-fuelled gas switching reforming (GSR) [20] and coal/biomass-fuelled membrane-assisted water-gas shift (MAWGS) [21] concepts are used as a demonstration of this methodology. Aside from system flexibility aspects, the study will also demonstrate the value of a diverse energy mix to socio-economic uncertainties related to fuel prices, commodity prices, and public resistance.

2. Methodology

In this section, an outline of the technology, economic evaluation and system scale modelling is provided according to the three stages: 1) process modelling, 2) economic assessment, and 3) system-scale modelling.

In the first stage, stationary plant models for fossil fuel H_2 and power generation plants were carried out in Unisim Design R451 using Peng-Robinson as default thermodynamic property package. ASME steam tables were used for systems containing water/steam streams. Scilab was employed to model the transient GSR reactors and 1D MAWGS reactors with an in-house thermodynamic database (Patitug) for property calculation. The results of the Scilab models were transferred to the stationary plant simulations through a CAPE-OPEN unit operation.

Second, capital and operation costs were estimated using a consistent baseline through the Standardized Economic Assessment (SEA) tool developed by the authors [22], focussing on determining comparable capital and operating costs for each technology. These metrics were then transferred to the third stage where an optimization model developed in GAMS is used to evaluate an electricity-hydrogen energy system under various scenarios defined by technology availability. Further details on each of the three modelling stages are provided in the subsections that follow.

2.1. Process modelling

A succinct outline of the plants utilizing fossil fuels and CCS is outlined below. All plants have been studied in detail in previous works and block flow diagrams with the main process units of the plants are shown in the Supplementary Material file attached to this paper.

2.1.1. H_2 plants

H_2 production plants have been assessed by the authors for natural gas, coal, and coal/biomass co-gasification. For natural gas, the conventional SMR configuration with MDEA CO_2 capture and the novel GSR H_2 plant were developed based on Arnaiz del Pozo et al. [23]. The plants were designed assuming a constant natural gas heat input of approximately 130 MW. The SMR plant was modelled with a high S/C ratio (4) to maximize methane conversion prior to pre-combustion CO_2 capture with 50%w. MDEA after a syngas shift. Relatively high H_2 efficiency compared to prior studies [24,25] was accomplished by means of optimal heat integration to provide low grade heat for solvent regeneration.

On the other hand, GSR H_2 plants [20] incorporating process improvements such as a two-phase exchanger for efficient latent heat recovery [26] were designed to operate in different modes, depending on the selected downstream integration, giving the system-scale model multiple options for deploying the GSR technology. These operating modes and designs for the GSR-H_2 plants are schematically represented in Fig. 2, with suitable stream/equipment numbering representative of each operating mode. When the plant is optimized for H_2 production (mode 1), an air recuperator maximizes heat recovery between inlet and outlet streams of the GSR oxidation step maximizing H_2 efficiency by reducing the need to combust additional fuel for heating the air stream in the GSR reactors. When the plant is coupled for power generation (mode 2), however, the hot pressurized N_2 from the oxidation step outlet is directly mixed with the H_2 from the PSA to provide a pressurized fuel with a large volumetric flow, to maximize electrical efficiency of the power unit and potentially aid in low-NOx gas turbine operation [27]. A third alternative operating mode uses excess renewable energy for additional H_2 production from the GSR reactors alongside water electrolysis (mode 3). In this mode, resistance heating [28] is applied to metal rods in the GSR reactors to satisfy the heat demand of the endothermic reforming reactions, while the PSA off-gas residual heating value is oxy-combusted with the O_2 produced from the electrolysers to produce more steam for the reformer to maximize conversion to H_2. The GSR plant operates with a certain degree of flexibility and nominal stationary values for each operating mode are subsequently assumed as system-scale model input, considering capital and operational cost assumptions of the largest corresponding units determined for each operating mode. Besides this flexible, three-mode operation GSR plant, an electrically self-sufficient configuration was also designed for standalone H_2 production (mode 4) by partially recycling the N_2 stream outlet to the compressor air intake to dilute the O_2 content of the inlet to the oxidation step and thereby increase the flow across the N_2 turbine downstream of the GSR, increasing power production to satisfy the plant internal demand at the cost of lower H_2 efficiency.

Regarding solid fuels, H_2 production plants from gasification of solid fuels were previously presented by Arnaiz del Pozo et al. [29], including a reference plant based on standard pre-combustion CO_2 capture with Selexol technology and an advanced configuration using membrane-assisted water-gas shift (MAWGS) configuration. Such plants are designed for large scale production to maximize economies of scale of gasifier technologies, with a baseline heat input of approximately 1250 MW. The reference H_2 production plant consists of a GE gasifier [30] with a radiant cooler and water quench. H_2 is produced from a pressure swing adsorption (PSA) unit after syngas shift and CO_2 removal through a dual Selexol unit [31]. This plant was considered only for

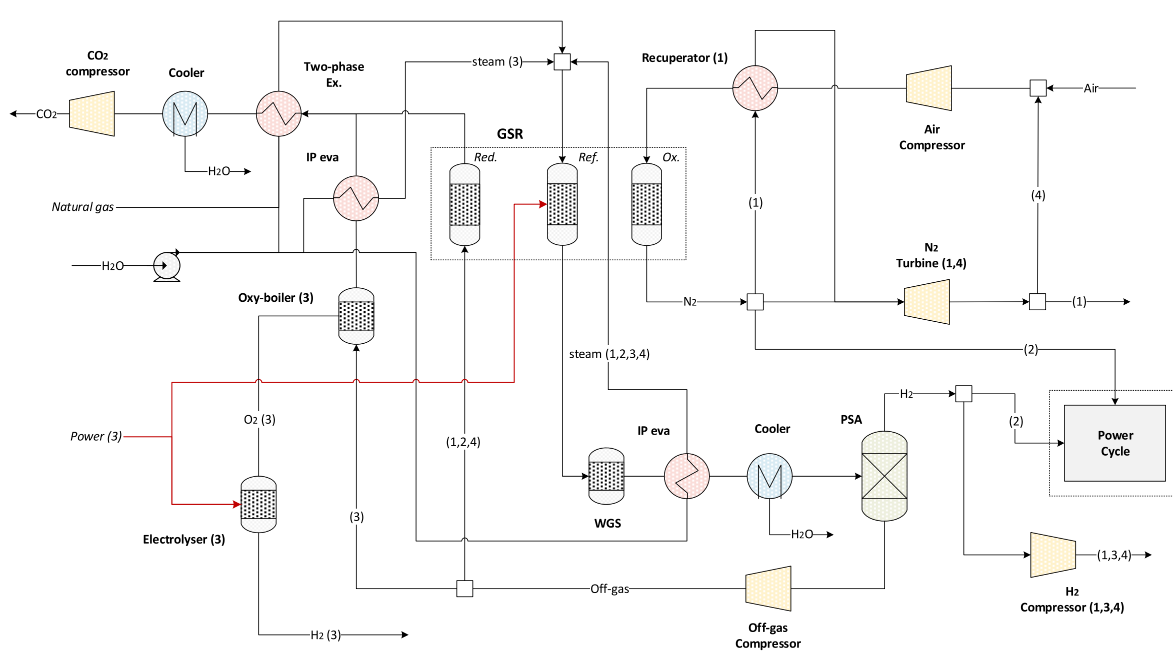

Fig. 2. GSR-H_2 plant with four possible operating modes: (1) air recuperator for maximum H_2 production, (2) integration of H_2 and N_2 with a power cycle, (3) blue-green GSR-H_2 with resistance heating, oxy-boiler and electrolyser, (4) GSR with N_2 recycle for eliminating electricity imports. GSR steps: Red. = reduction, Ref. = reforming, Ox. = oxidation.

coal/biomass co-firing using Douglas premium coal [32] with 30%w. wood chips [29], allowing negative emissions that are economically attractive under the high CO_2 taxes assumed in this study.

The advanced plants, schematically depicted in Fig. 3, employ an E-gas gasifier with slurry vaporization [33] and hot gas clean-up [34] for contaminant removal before the MAWGS reactor simultaneously shifts the syngas and extracts the H_2 product. The configuration considered in this study is designed for maximum H_2 efficiency by removing power generation units and maximizing H_2 permeation through the membrane with the aid of a larger steam sweep in the membranes (represented as mode 1). This plant is considered with feeds of pure coal and the 30%w. biomass blend from the reference plant to investigate the effect of limiting biomass availability in the system-scale model. Similarly to the GSR process, integration with power cycles for electricity generation is possible (mode 2). In this case, substantial efficiency gains are facilitated by power cycle integration due to the large amount of steam present with the hydrogen in the permeate stream. When the plant operates in H_2 mode, this steam needs to be condensed out and most of the heat is rejected, but operation in power mode effectively employs this pressurized steam for high efficiency power production by increasing the flowrate across the gas turbine expansion path.

2.1.2. Power plants

Electricity generation from either natural gas or H_2 fuels is carried out through several power cycle configurations. An H-class gas turbine [35] model is calibrated for natural gas firing reaching a turbine inlet temperature (TIT) of 1550 °C, operating with a pressure ratio of 23.6 and a net power output of 520 MW, achieving an open cycle thermal efficiency of 43%. For integration with different H_2 producing plants, it is assumed that suitable turbomachinery adjustments are attained to accommodate such fuels with varying energy density by conveniently changing the air flow intake, while preserving nominal conditions of efficiency and pressure ratio. Alongside this, advancements in combustion technology are assumed to effectively mitigate NOx emissions [36]. This assumption is aligned with original equipment manufacturers targets [37,38] and time horizon deployment of the energy systems considered in this work.

The combined cycle plant utilizes the aforementioned H-class GT and a heat recovery steam generator (HSRG) consisting of three pressure levels with intermediate reheat [39]. Alternatively, a simplified power cycle consisting of a two-stage intercooled compressor with exhaust gas heat recuperator is designed, under the assumption that lower capital investments due to bulky bottoming cycle avoidance will outweigh thermal efficiency losses in low capacity factor plants required to cover peak demands. Both configurations can utilize natural gas or H_2. Finally, a post-combustion CO_2 capture combined cycle (fuelled with natural gas only) integrating MEA absorption is designed [32,40] to represent a state-of-the-art power production plant with CCS.

2.2. Economic assessment

The capital and operational cost estimations of the H_2 and electricity power plants from fossil fuels were conducted employing the Standardized Economic Assessment tool developed by the authors [22], which utilizes cost-capacity correlations for several process units and Turton [41] correlation to estimate the bare erected cost of equipment, adjusted to the cost basis defined in Table 1. A detailed user manual is available for download [22]. The key economic assumptions for the total overnight cost estimation and operational costs of the different plants are presented in Table 2. A process contingency of 30% was taken for units presenting the largest technological uncertainty: GSR cluster, MAWGS reactor and HGCU.

Several assumptions to determine operational costs of the plants were taken and are reflected in Table 3. Fuel costs (e.g., biomass, coal, and natural gas) and CO_2 transport, storage and emissions costs are implemented in the system-scale model separately.

Further cost assumptions regarding the system-scale model and other technologies included in the assessment are presented holistically in the following section.

2.3. System-scale modelling

The energy system model employed in this work optimizes deployment and hourly dispatch of a range of electricity and hydrogen production, distribution, and storage technologies, as illustrated in Fig. 4. Wind and solar profiles and electricity demand are taken from German observations, and wind turbine performance and technology costs are adjusted to be representative of the year 2050. The model takes a long-term view, assuming all plants are greenfield investments with no constraints from legacy infrastructure.

All model assumptions as well as the model formulation are given in the Supplementary Material, but a summary of the available technologies is given below:

- **Electricity generation:** 12 different power plants, including onshore and offshore wind, utility-scale solar PV, natural gas combined cycles (NGCC) with and without CCS, H_2-fired combined cycle (H2CC), natural gas and H_2 recuperated cycles (NGRC and H2RC), and combined and recuperated cycles especially tailored for integration into the GSR and MAWGS blue hydrogen technologies.
- **Hydrogen production:** 9 different hydrogen production technologies, including low-temperature electrolyzers, conventional blue hydrogen production from steam-methane reforming (SMR) with MDEA CO_2 capture and coal/biomass co-gasification with Selexol CO_2 capture, advanced blue hydrogen production from natural gas using gas switching reforming (GSR), GSR plants designed for electricity neutrality, and GSR plants with optional resistance heating for blue-green hydrogen production, advanced gasification plants with membrane-assisted water-gas shift technology based on biomass/coal co-feeding or pure coal feed, and NH_3 cracking plants to produce hydrogen from imported ammonia.
- **Energy storage:** Electricity storage in batteries and hydrogen storage in salt caverns or tanks. Salt caverns are cheap but limited in terms of charge/discharge rate and location, requiring additional H_2 pipelines, whereas tanks are more expensive but do not require added transmission and face no charge/discharge limits.
- **Energy transport:** Electricity transmission lines associated with wind and solar power to account for the spatial mismatch between good resources and electricity demand, and pipelines for hydrogen and natural gas provision to all generators and CO_2 pipelines for CCS facilities.

As illustrated in Fig. 4, electrolysers are assumed to be co-located with wind and solar resources to displace some of the more expensive electricity transmission capacity with cheaper hydrogen pipelines. In addition, some blue hydrogen plants (GSR and MAWGS) can be integrated with a dedicated combined or recuperated power cycle to offer flexible power and hydrogen production. The model also assumes a substantial quantity of additional hydrogen and electricity demand to displace traditional fossil fuels in industrial, transportation, and heating applications.

Key model assumptions are summarized in Table 4. A complete overview of model assumptions, including cost and performance metrics for each technology, can be found in the Supplementary Material. The full model is available for download online[1] together with complete SEA tool economic assessment files for all the plant configurations described in Section 2.1. Demand data is gathered from 2019 observations in Germany [42] and several reports on longer-term electricity and hydrogen demand growth [43–45]. Natural gas, coal, wind, solar, and

[1] https://bit.ly/3rBFVDH.

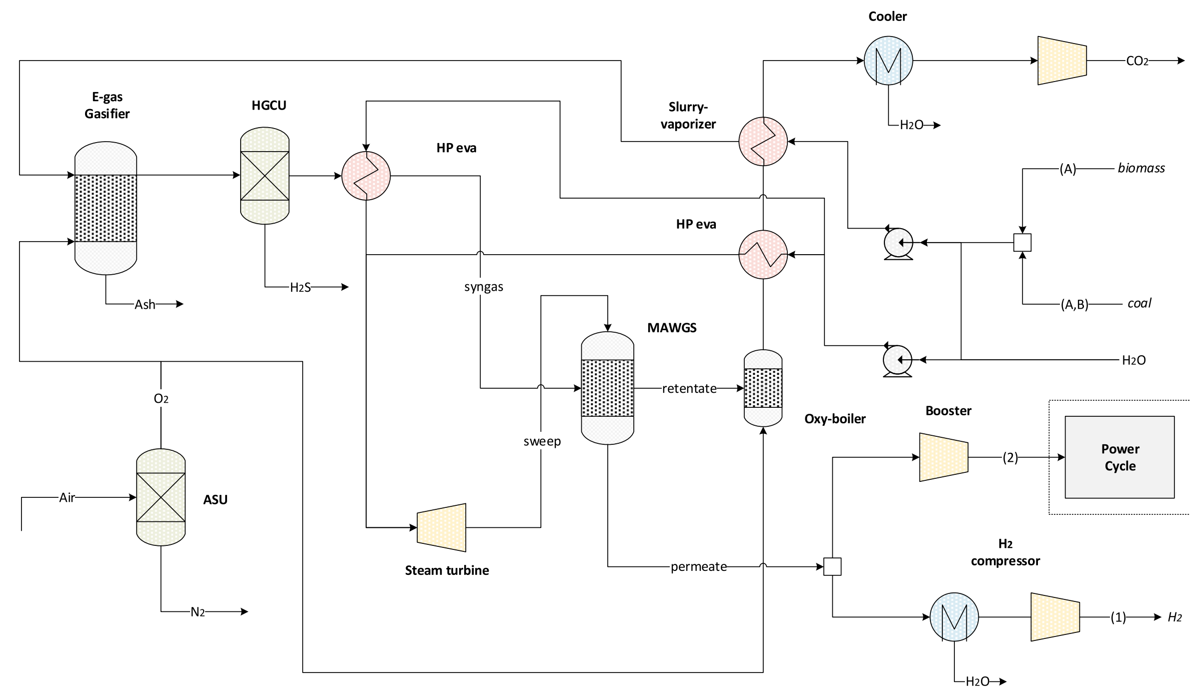

Fig. 3. MAWGS-H_2 plant with feeds of (A) coal-biomass blend and (B) coal featuring two operating modes: (1) standalone H_2 production and (2) integration of the H_2-steam permeate mixture with a power cycle.

Table 1
Target cost basis for capital cost estimation.

Location	Western Europe
Cost Year Basis	2020
Currency	€

Table 2
Methodology for estimating the total overnight cost (TOC).

Component	Definition
Bare Erected Cost (BEC)	Sum of all BEC costs of the units adjusted to the target basis in SEA tool
Engineering Procurement and Construction (EPC)	10% of BEC
Process Contingency (PC)	0–30% of BEC
Project Contingency (PT)	20% of (BEC + PC)
Total Plant Costs (TPC)	BEC + EPC + PC + PT
Owners Costs (OC)	15% of TPC
Total Overnight Costs (TOC)	TPC + OC

Table 3
Operating cost assumptions [32].

Item	Value
Cooling water make-up	0.35 €/m^3
Process water costs	6 €/m^3
Selexol make-up	5000 €/ton
WGS catalyst	16,100 $/$m^3$
Oxygen carrier	15$/$m^3$
ZnO (HGCU) cost	25,230 $/$m^3$
Ash disposal cost	9.73 €/m^3
Membrane replacement	6000 €/m^2

electrolyser costs are taken from the IEA Announced Pledges Scenario [46] for the year 2050. A high value is assumed for biomass relative to production costs of less than 3.5 €/GJ for up to 4000 TWh/year of biomass in Europe [47], assuming that all embodied emissions are included in the price. High costs are assumed for CO_2 transport, equivalent to 2000 km of onshore pipelines based on IEAGHG [48], given the resistance to CCS in Europe, while CO_2 storage costs are taken from a similar IEAGHG report [49]. The CO_2 price is also tailored according to the IEA Announced Pledges Scenario [46], and the discount rate is set to a usual value representing the weighted average cost of capital for new energy investments.

2.4. Scenario definition

Six different scenarios will be evaluated in the results and discussion section below:

- *No CCS*: All CCS technologies are disabled. Unabated natural gas and standalone hydrogen power plants are available for electricity generation during extended periods of low wind and sun. Electrolysis and NH_3 imports are the only options available for hydrogen supply.
- *Conv. CCS*: Conventional post-combustion CO_2 capture in the form of NGCC-MEA is made available for power production. For hydrogen, gasification with Selexol CO_2 capture from coal/biomass (Bio-Selexol) and SMR-MDEA from natural gas are activated.
- *Adv. Blue H_2*: The advanced blue hydrogen technologies of Bio-MAWGS from coal/biomass, Coal-MAWGS from coal (mode 1 in Fig. 3), and GSR-H_2 plants with and without electricity imports (configurations 1 and 4 in Fig. 3, respectively) from natural gas are made available.
- *Full flex*: Flexibility aspects of advanced blue hydrogen production are included in the form of integrated combined and recuperated cycles added to MAWGS and GSR blue H_2 plants (mode 2 in Figs. 2 and 3). In addition, the resistance heating option of blue-green H_2 from GSR is activated (mode 3 in Fig. 2).
- *Bio limit*: This scenario is identical to the *Full flex* scenario, except for a limit of annual biomass consumption set to 150 TWh.
- *No coal*: Relative to the *Full flex* scenario, this scenario deactivates all technologies that consume coal, i.e., Selexol and MAWGS blue H_2 plants and the optional integrated power cycles linked to MAWGS plants.

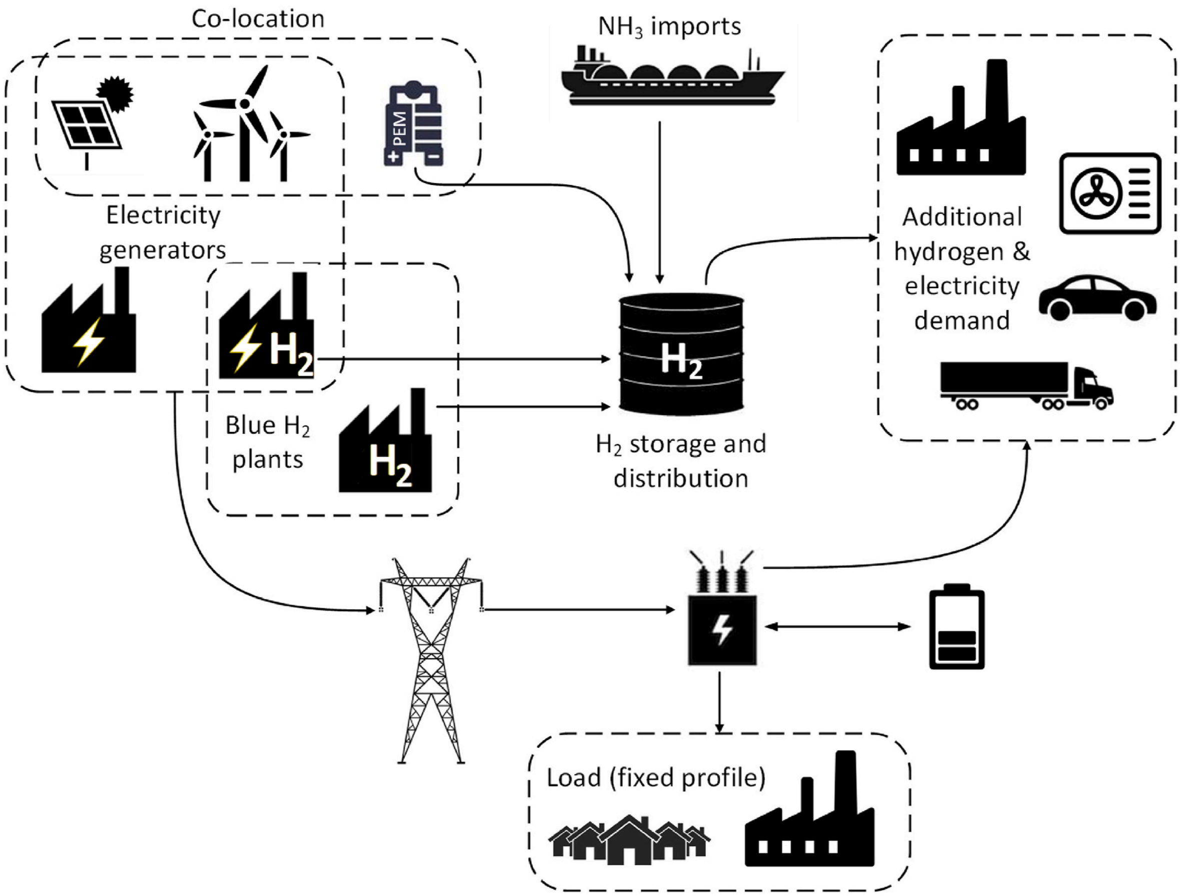

Fig. 4. Illustration of the modelled system.

Table 4
Several system-scale model assumptions. A more complete overview can be found in the Supplementary Material.

Total electricity demand	499	TWh/year
Additional H_2 and electricity demand	600	TWh/year
Natural gas import price (excluding pipeline costs)	4.1	€/GJ
Natural gas pipeline costs (at an exemplary 50% utilization rate)	1.6	€/GJ
H_2 pipeline costs (at an exemplary 50% utilization rate)	1.3	€/GJ
Coal price	1.9	€/GJ
Biomass price	7.0	€/GJ
Imported NH_3 price	35	€/GJ
Onshore wind cost	1117	€/kW
Offshore wind cost (including offshore transmission)	1783	€/kW
Solar PV cost	317	€/kW
Electrolyser cost	512	€/kW_{H2}
CO_2 pipeline cost (at an exemplary 70% utilization rate)	22.5	€/ton
CO_2 storage cost	5	€/ton
CO_2 price	150	€/ton
Battery storage cost	80	€/kWh
H_2 tank storage cost	15	€/kWh
H_2 cavern storage cost (half of which is useable)	1	€/kWh
Discount rate	7%	

3. Results and discussion

3.1. Scenario performance

The behaviour of the six scenarios investigated in this work is illustrated for a policy scenario with high CO_2 prices and VRE mandates. Two additional sub-sections are also presented where the VRE mandate is lowered and the 1:1 default ratio of electricity to hydrogen in meeting additional clean energy demand is allowed to vary.

3.1.1. Central scenario

A plausible future policy scenario with a high CO_2 price and a mandate for high shares of wind and solar is illustrated in Fig. 5. In addition, 600 TWh of extra clean energy demand (beyond the 499 TWh of basic electricity demand) is assumed, equally split between electricity and hydrogen.

Starting with the *No CCS* scenario, Fig. 5a shows that electricity is generated by wind, solar, and natural gas, with a substantial amount of consumption from electrolysis for green hydrogen production. With the high CO_2 price, the optimal share of wind and solar in gross electricity production is 77%, naturally surpassing the mandate of 70%. However, CO_2 emissions remain significant due to the 23% of unabated natural gas power production. Fig. 5c shows that the *No CCS* scenario has considerably higher costs than the scenarios that include CCS. As shown by the shadow prices of electricity and hydrogen, this premium is almost entirely attributable to hydrogen costs.

Green H_2 production can concentrate production in times of low electricity prices, but this involves trade-offs in terms of lower electrolyser utilization, more H_2 storage requirements, and, if large quantities of green H_2 are required, VRE overbuilds to create more hours of excess wind and solar power. Due to these factors, Fig. 6a shows a relatively weak correlation between electricity prices and green H_2 production. As Fig. 6b illustrates, average green H_2 prices can fall well below electricity prices when hydrogen demand is small. In such cases, H_2 production can be concentrated in times with near-zero electricity prices, and, although such a strategy requires very low electrolyser utilization (16% capacity factor in the 1% H_2 demand case) and relatively high storage volumes (equivalent to 640 h of H_2 demand), the trade-off is still worthwhile.

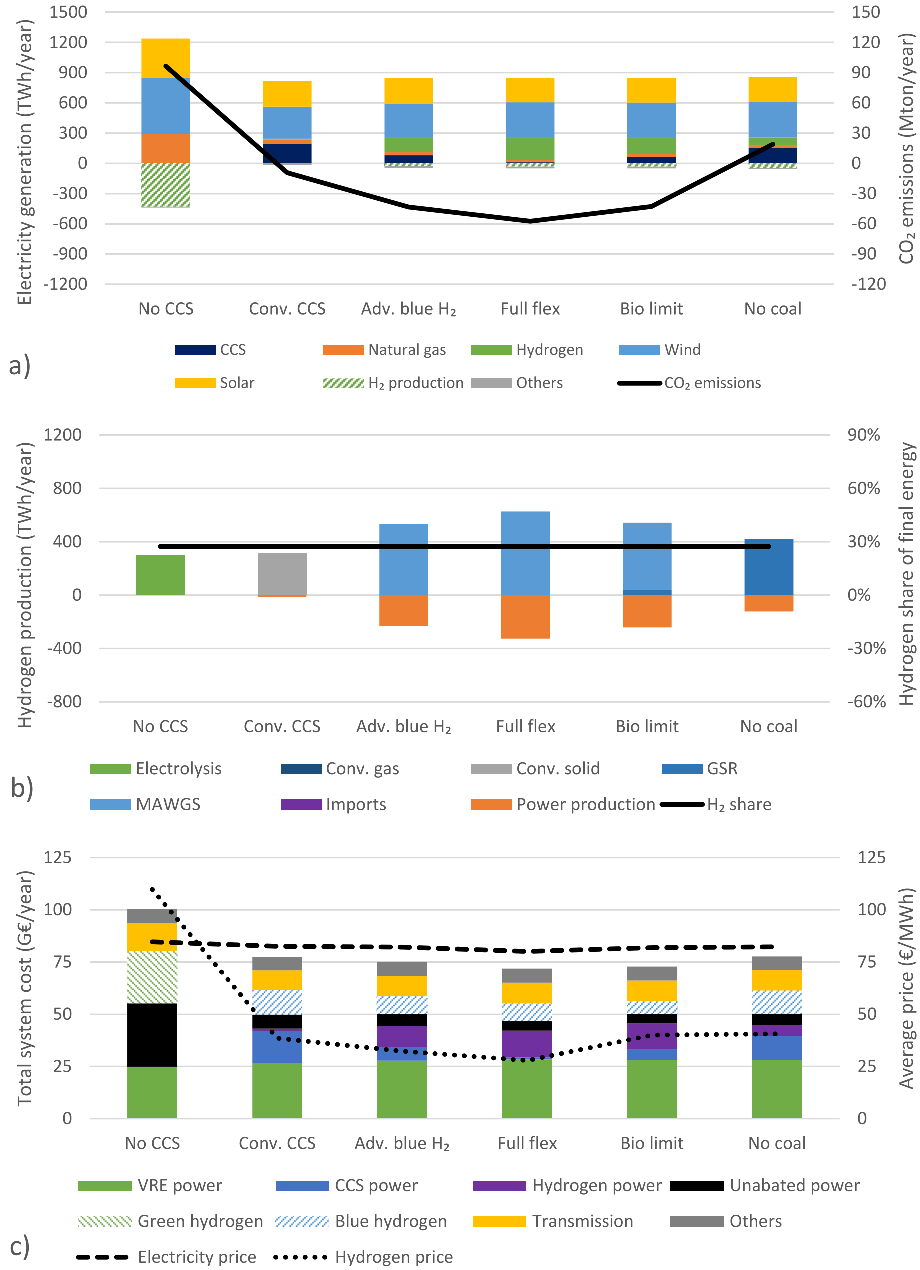

Fig. 5. Behaviour of the six scenarios with a 150 €/ton CO_2 price, a 70% VRE mandate, and equal shares of electricity and hydrogen in extra energy demand. "Others" represent power consumption by batteries and H_2 storage in panel a, and costs related to H_2 imports, energy storage, and thermal plant ramping in panel c.

However, this benefit quickly fades when hydrogen demand exceeds the availability of near-zero cost electricity.

The introduction of blue H_2 in the *Conv. CCS* scenario cuts hydrogen prices by two-thirds (Fig. 5c). Blue H_2 can be produced continuously, avoiding the costs involved in low electrolyser utilization and hydrogen storage requirements. In addition, the use of biomass in this policy scenario with high CO_2 prices brings considerable economic benefits. One GJ of biomass releases about 0.1 ton of CO_2, bringing €15 of revenue at a CO_2 price of 150 €/ton if it is captured and stored. This BECCS benefit far exceeds the assumed biomass price of 7 €/GJ, essentially resulting in negative fuel costs. Conventional NGCC-MEA power plants also displace most unabated natural gas power production in Fig. 5a, although the small electricity price reduction in Fig. 5c shows that this shift only brings marginal economic benefits at a CO_2 price of 150 €/ton. Another important observation from Fig. 5a is that CO_2 emissions become net-negative due to the biogenic CO_2 captured from the Bio-Selexol process.

The *Adv. Blue H$_2$* scenario reduces hydrogen prices by a further 16% (Fig. 5c) due to the superior efficiency and CO_2 capture ratio offered by the Bio-MAWGS technology relative to Bio-Selexol. In this scenario, Fig. 5 a & b show that hydrogen becomes cheap enough to transport it to standalone hydrogen-fired power plants and displace most of the NGCC-MEA power production in the *Conv. CCS* scenario. Still, the benefit of this shift is minor as indicated by near-identical electricity prices in the *Adv. Blue H$_2$* and *Conv. CCS* scenarios (Fig. 5c).

The *Full flex* scenario reduces total system costs by 4.4% relative to the *Adv. Blue H$_2$* scenario due to the lower capital costs and higher efficiencies of the power cycles integrated with the blue H_2 process. In the case of the Bio-MAWGS technology, the power cycle benefits from substantial additional steam injection with the H_2 fuel that is rejected when the plant is operating in H_2 mode and the avoidance of H_2 pipelines to standalone H_2-fired power plants. Fig. 5a shows that this case

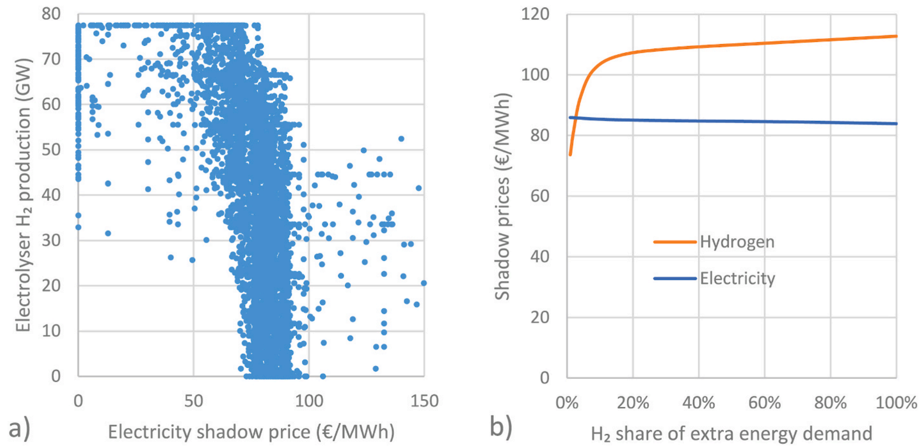

Fig. 6. Green hydrogen behaviour in the No CCS scenario: The correlation between green hydrogen production and electricity prices at 50% H_2 share of extra energy demand (a) and the evolution of hydrogen and electricity prices with the H_2 share in extra energy demand (b).

also features the largest negative emissions due to the large amount of hydrogen produced by the Bio-MAWGS technology that captures 100% of the produced CO_2.

Despite the economic benefits of storing biogenic CO_2, there are limits to the amount of biomass that can be sustainably produced. To investigate this limit, the *Bio limit* scenario curtails H_2 production by the Bio-MAWGS technology relative to the *Full flex* scenario, partially replaced by the natural gas-fuelled GSR technology (Fig. 5b). In addition, some use of H_2 for power production is displaced by natural gas-fired power plants (Fig. 5a). These modifications increased the system cost of the *Bio limit* case by only 1.3% relative to the *Full flex* case because the imposed 150 TWh biomass limit did not drastically reduce hydrogen production using Bio-MAWGS in this case.

Finally, the *No coal* scenario shows the effects of eliminating the possibility of blue H_2 production using solid fuels. In this case, natural gas is used for all hydrogen production via the GSR technology, increasing the total system cost by 8.2% relative to the *Full flex* scenario. This illustrates the benefit of the CO_2 emission credit from capturing biogenic CO_2 in scenarios with high CO_2 prices.

3.1.2. The effect of a lower VRE mandate

Next, the behaviour of the model in an alternative policy scenario with a milder VRE mandate of 40% instead of 70% is explored. As illustrated in Fig. 7, the *No CCS* scenario stays unchanged because even the 70% mandate is naturally achieved in the optimal technology mix. However, all the cases involving CCS reduce VRE deployment down to the mandated level of 40% of gross power production.

Relative to the cases with a 70% mandate (Fig. 5), system costs of the cases that allow CCS reduce by 8.4–13.3%, mainly because running CCS power plants at a higher capacity factor is cheaper than the combination of high VRE deployment and low capacity factor thermal power plant operation. In the *Conv. CCS* scenario for example, the levelized cost of natural gas-fired power plants is significantly higher than VRE technologies, but reducing the VRE mandate to 40% allows the combined capacity factor of these plants to be raised from 38% to 64%, making an increase in thermal power generation the most economical option.

Even though the integrated power cycles included in the *Full flex* scenario were originally designed for integrating higher shares of VRE, this scenario sees the largest benefit from a lower VRE mandate (13.3% reduction in total system cost). Flexible power and hydrogen production from the GSR and MAWGS technologies comes with a cost in terms of having to transport and store large intermittent fluxes of hydrogen. This drawback of high VRE operation appears to outweigh the benefit of having a low-cost integrated power cycle that limits the costs involved in low capacity factor operation.

The increase in thermal power production also strengthens the impact of a biomass consumption limit. As shown in Fig. 7b, the *Bio limit* scenario strongly reduces the amount of hydrogen used for power production, relying on NGCC-MEA power plants instead (Fig. 7a). This is even more evident in the *No coal* scenario where almost all thermal power is generated by NGCC-MEA.

From the point of view of CO_2 emissions, the lower VRE mandate increases the degree of negative emissions in the *Adv. Blue H_2* and *Full flex* scenarios due to the greater use of bio-derived H_2 in power production. If biomass supply is limited in the *Bio limit* scenario, however, these added benefits are not achieved, while emissions slightly increase in the *Conv. CCS* and *No coal* scenarios due to the displacement of some zero-emission wind and solar with NGCC-MEA that captures only 91% of CO_2.

Fig. 8 gives a broader picture of the system response to changes in the VRE mandate. The *No CCS* scenario shows no change below 77% because that is the optimal level at a CO_2 price of 150 €/ton. However, all the scenarios permitting CCS keep getting cheaper with lower VRE mandates down to 10% of gross power production. However, it is only in the *Full flex* scenario where reductions in total system costs and CO_2 emissions remain strong all the way down to a 10% VRE market share, but these gains require up to 430 TWh/year of biomass consumption (Fig. 8d), which may be unsustainable.

When biomass consumption is limited to current levels in the *Bio limit* scenario, very low VRE market shares only bring marginal system cost reductions at the cost of a large natural gas dependence (Fig. 8c). Thus, moderate VRE market shares (~50% of gross power production) can play an important role in restricting biomass consumption to sustainable levels and limiting natural gas import dependences. The low costs involved in achieving these benefits appear to be worthwhile.

3.1.3. The effect of a freely varying electricity/hydrogen ratio in extra energy demand

In the previous sections, the 600 TWh/year of additional clean energy needed to displace traditional direct uses of fossil fuels is split equally between electricity and hydrogen. However, this ratio will vary in real systems in response to electricity and hydrogen prices. If hydrogen is much cheaper than electricity, as in the scenarios that permit CCS, more of this demand will shift to hydrogen. However, for hydrogen to take over market segments more suited to electrification (e.g., urban transport using battery electric vehicles or mild space heating using heat pumps), the displacement ratio must be greater than 1:1 because electricity can be used more efficiently than hydrogen. In the opposite case, where electricity takes over shares in market segments better suited to hydrogen (e.g., long-distance freight and industrial high-grade heat and reagents), there will also be a cost premium involved. This effect was represented by specifying that a deviation from the

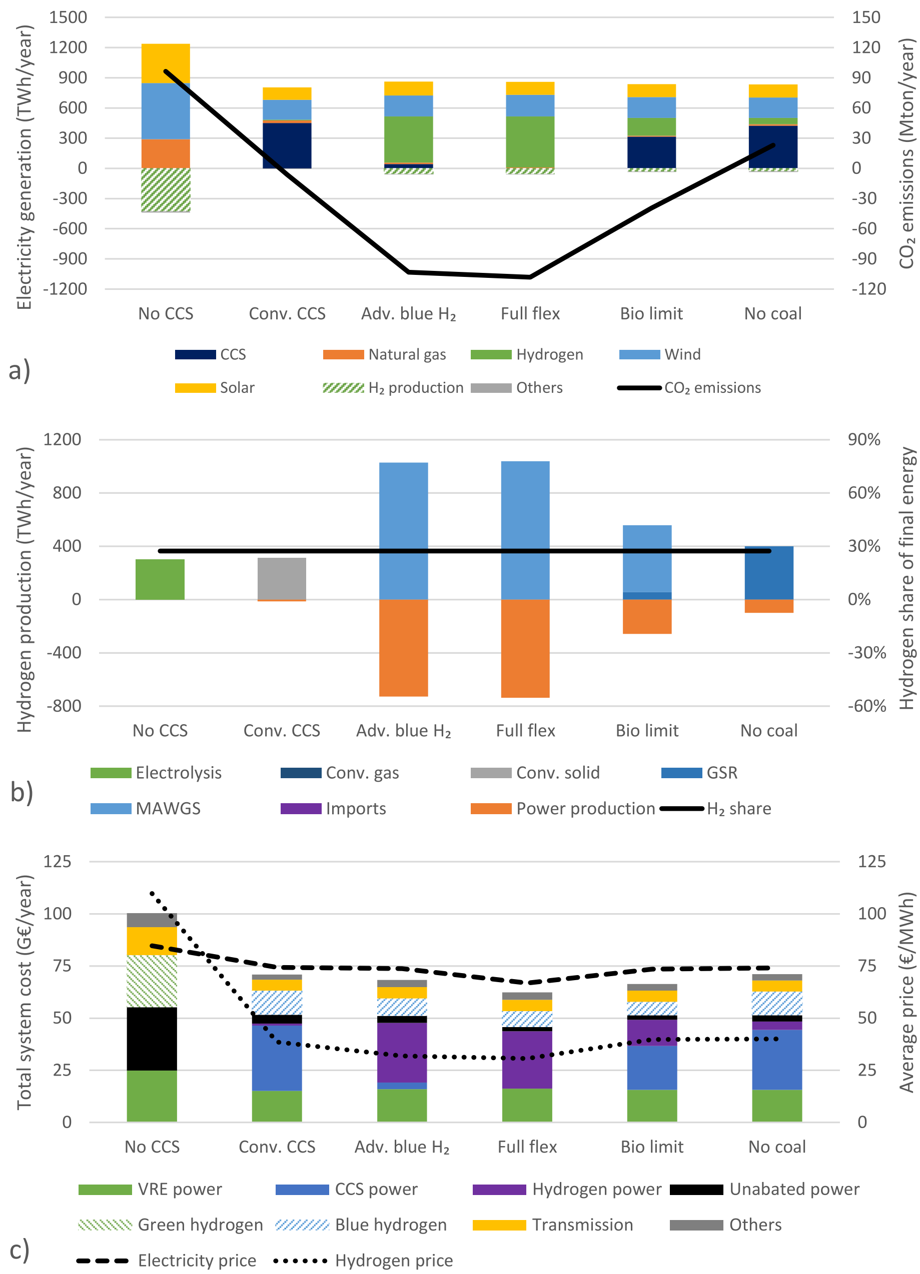

Fig. 7. Behaviour of the six scenarios with a 150 €/ton CO_2 price, a 40% VRE mandate, and equal shares of electricity and hydrogen in extra energy demand. "Others" represent power consumption by batteries and H_2 storage in panel a, and costs related to H_2 imports, energy storage, and thermal plant ramping in panel c.

default 1:1 ratio of electricity and hydrogen requires two units of the displacing energy for every unit of displaced energy. In other words, for an extreme case in which hydrogen is to take over all additional energy requirements, the system would need 900 TWh of hydrogen instead of 300 TWh each of electricity and hydrogen (as the 300 TWh of electricity is replaced by 600 TWh of hydrogen).

As illustrated in Fig. 9, the model reveals this option to be preferable in the cases permitting CCS because the price of hydrogen is less than half the price of electricity. Thus, it is economically beneficial to displace one unit of electricity with two units of hydrogen. Relative to the case with an imposed 1:1 use of electricity and hydrogen, this reduces total system costs by 0.1–6.7%. In the *Bio limit* and *No coal* scenarios, there is virtually no benefit to this switch because the hydrogen price reaches levels very close to half the electricity price.

3.2. Uncertainty quantification

Energy system modelling involves many uncertain assumptions. Hence, an uncertainty quantification study is presented where 18 model variables (Table 5) are varied according to a normal distribution where about 90% of the 500 samples fall within ±50% from the central value. Central values of all cost-related variables are set to the levels specified in Table 4 and the Supplementary Material. The central VRE mandate is set to 50%, the biomass limit to 150 TWh/year, the El/H_2 share penalty to 2, and the on/off wind ratio to 2.

The analysis is presented in two subsections: illustrative histograms of the six scenarios and regression results to illustrate the relative importance of the variables.

3.2.1. Histograms

Fig. 10 shows the histograms of all six scenarios for total system costs

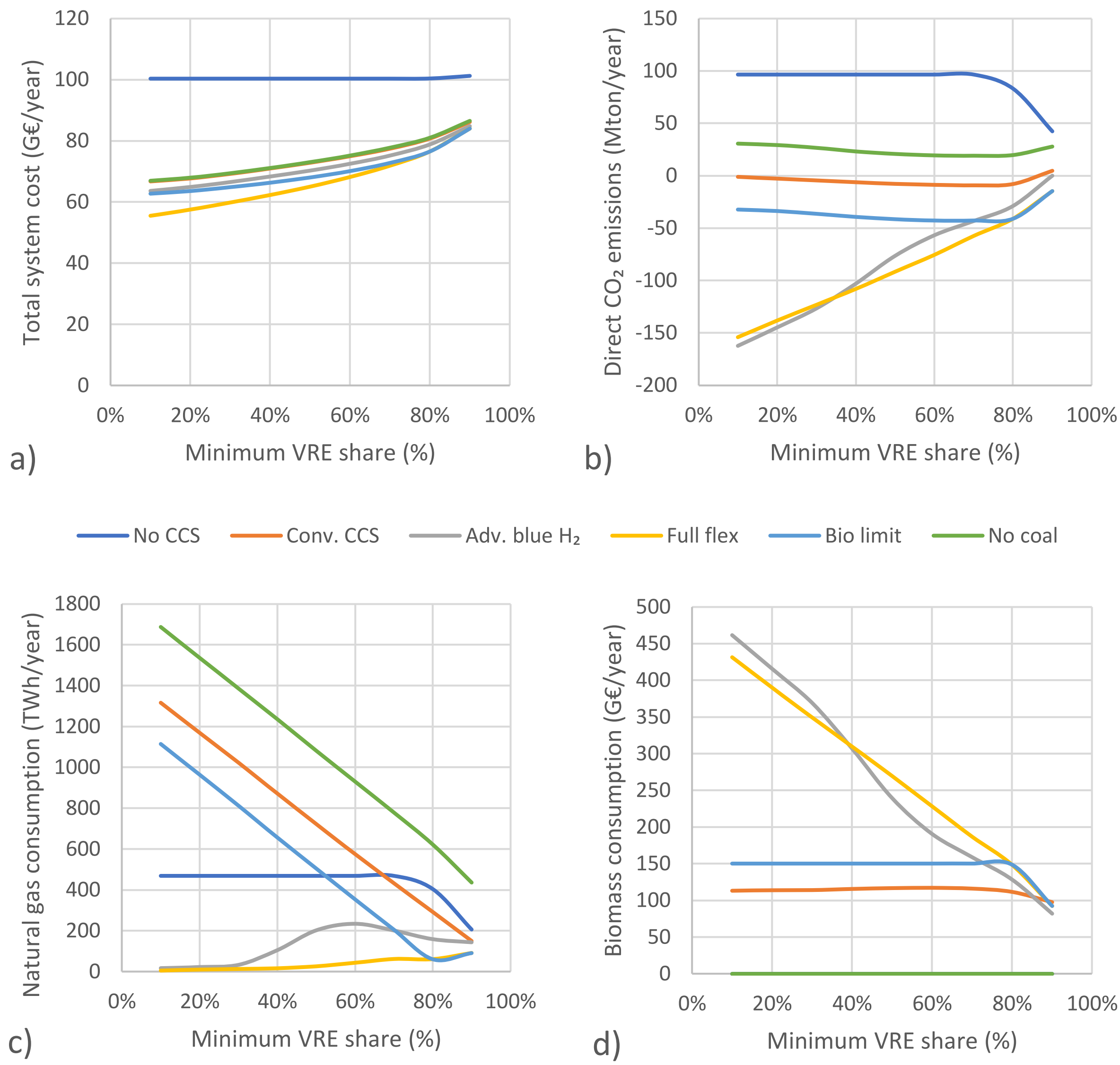

Fig. 8. The effect of the VRE mandate (fraction of gross electricity production) on key model outputs (CO_2 price = 150 €/ton).

and CO_2 emissions. The system cost histograms approach a normal distribution spanning a relatively narrow range considering the large number of variables varied over a very wide range. This indicates how the model exploits many other levers to minimize cost if one or more assumptions become unfavourable. For example, if one type of energy becomes very costly, there are several other energy vectors that can be scaled up instead, limiting the impact on total system cost.

CO_2 emissions show more complex trends, owing to the non-linear response of emissions to CO_2 taxes and other factors. CO_2 emissions tend to change rapidly within a relatively narrow band of CO_2 prices in the CCS scenarios as thresholds are crossed where the different CCS technologies become economical, creating distributions that deviate from the normal. It is also clear to see how the availability of biomass influences the ability of the model to generate negative emissions: The *Bio limit* histogram peaks at only slightly negative emissions and the *No coal* (which precludes biomass co-firing) histogram does not achieve negative emissions.

Additional descriptive statistics including means and 90% confidence intervals of total system costs, total emissions, electricity and hydrogen prices, and the share of different forms of primary energy can be viewed in the Supplementary Material.

3.2.2. *Linear regression*

An informative snapshot of the influence of all the factors listed in Table 5 can be gained from the linear regression results in Fig. 11. These results can be interpreted as the change in system cost or CO_2 emissions resulting from changing each variable from 25% below to 25% above its base value. The linear regression produced a good fit for the total system cost (R^2 = 0.917–0.973) and a reasonable fit for CO_2 emissions (R^2 = 0.467–0.800). The worse fit for CO_2 emissions stems mainly from the non-linear response of CO_2 emissions to changes in the CO_2 price described in the previous section.

The discount rate emerged as the most influential factor on the system cost. Low-carbon technologies tend to be capital intensive, and access to cheaper capital significantly reduce annualized costs. Although a low time-value of money is a powerful lever for reducing decarbonization costs, artificially low financing costs will lead to misallocation of capital considering the wide range of important infrastructure investment needs beyond the energy sector. Thus, measures such as sliding feed-in tariffs for wind and solar that socialize the revenue-risk of these variable and non-dispatchable generators must be used with care.

Costs of primary energy inputs are the next most important factor. VRE costs are by far the most important for the *No CCS* scenario, with wind costs being especially important. In a VRE-dominated future, it will be vital that technology progress can overcome cost pressures from

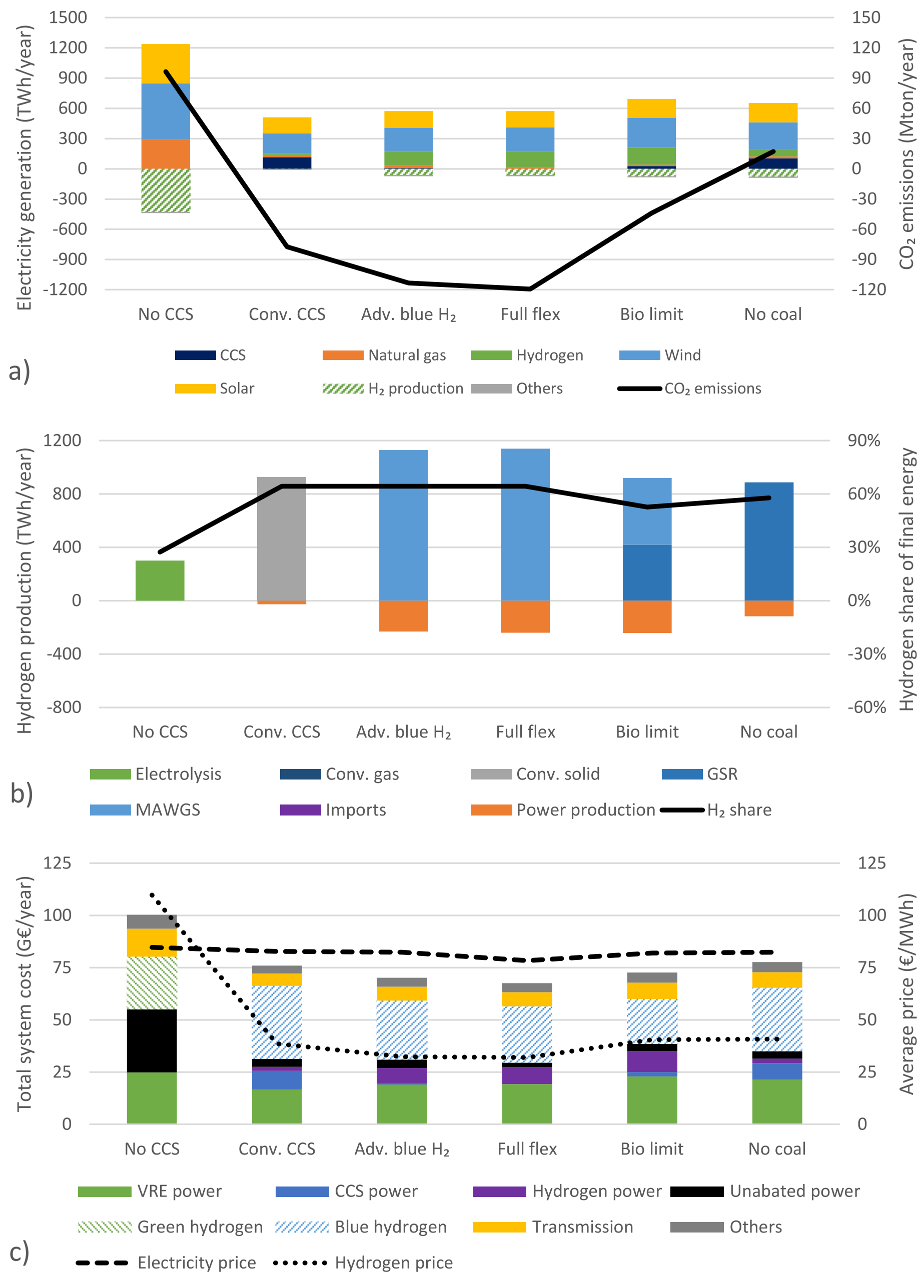

Fig. 9. Behaviour of the six scenarios with a 150 €/ton CO_2 price, a 70% VRE mandate, and the freedom for hydrogen or electricity to take over each other's share of extra energy demand at a 2:1 ratio.

factors such as public resistance, system complexity, material constraints, and end-of-life costs. Natural gas, coal, and biomass costs influence the different scenarios roughly proportionately to the mean consumptions of different fuels each scenario (data in the Supplementary Material). In general, the CCS scenarios that permit all fuels show a more even distribution of risk to changes in different primary energy costs.

In the CCS scenarios permitting capital-intensive solid fuel gasification technology, the CO_2 capture cost is the second-most influential factor after the discount rate. The real-world costs of these technologies will depend strongly on whether the policy environment is conducive to an orderly buildout of a large number of standardized plants. The CCS scenarios also show considerable cost increases with higher VRE mandates as high capacity factor operation of CCS facilities is more economical than low-cost VRE backed up by low capacity factor load-following plants. The ease with which hydrogen can displace electricity in the share of extra energy (El/H_2 share penalty) is another influential factor with a more efficient hydrogen economy lowering the cost of the CCS scenarios.

Transmission and pipeline costs are considerably more influential than electricity and hydrogen storage costs. Transmission is more important for the *No CCS* scenario where the need to transmit electricity from regions with good wind/solar resources and public acceptance to demand centres is an important factor. Pipelines are more important in the CCS scenarios, mainly due to the considerable contribution of CO_2 transport to the overall cost of CCS. Both transmission lines and pipelines face substantial risks of cost escalations from public resistance.

Higher CO_2 prices substantially increase the cost of the *No CCS* scenario but actually reduce costs of the CCS scenarios that involve biomass due to the CO_2 credit for storing biogenic CO_2. Other factors like electrolyser costs, ramping limitations, and an imposed ratio of on or offshore wind had only small effects. Thus, the cost of green H_2 is shaped

Table 5
Summary of the 18 variables considered in the uncertainty quantification.

Variable	Explanation
Wind cost	Onshore and offshore wind total overnight cost (TOC)
Solar cost	Solar PV TOC
CO_2 capture cost	NGCC-MEA and all blue H_2 technology TOC
Battery cost	Battery storage volume and charge/discharge capacity TOC
H_2 storage cost	H_2 tanks and salt cavern storage TOC
Electrolyzer cost	Electrolyzer TOC
Transmission cost	Added VRE transmission and electrolyzer avoided transmission TOC
Pipeline cost	Natural gas, hydrogen, and CO_2 pipeline TOC
Natural gas cost	Cost of natural gas excluding pipeline transport
Coal cost	Cost of coal
Biomass cost	Cost of biomass
Biomass limit	Maximum amount of biomass that can be consumed per year
CO_2 price	The price on direct CO_2 emissions
Ramping cost	The cost of ramping thermal power plants and the maximum ramp rate
VRE mandate	The minimum share of wind and solar in gross power production
Discount rate	The discount rate applied in annualizing capital costs
El/H_2 share penalty	The ratio by which electricity and H_2 can displace each other
On/off wind ratio	The maximum ratio of onshore to offshore wind

mostly by input energy costs and offshore wind could mitigate public resistance cost escalation risks faced by onshore wind.

Regarding CO_2 emissions, it is no surprise that the CO_2 price is the most influential factor. This is especially the case for the CCS scenarios relying heavily on solid fuels that produce large quantities of CO_2 and the *No CCS* case that requires high CO_2 prices to continue displacing natural gas with VRE.

Cost increases in the technologies associated with emissions reductions in the different scenarios increase system-wide CO_2 emissions. For the *No CCS* scenario, inflation of wind, solar, battery, transmission, and pipeline costs all increase CO_2 emissions. For the CCS scenarios, CO_2 capture facilities, CO_2 pipelines, and solid fuels (facilitating negative emissions) have a similar effect. Higher discount rates also lead to higher emissions by disincentivizing capital-intensive low-carbon technologies. In contrast, higher natural gas costs lead to lower emissions by reducing unabated NGCC power production and increasing the reliance on solid fuel CCS with negative emissions.

4. Discussion and conclusions

Deep decarbonization is a complex and multifaceted challenge. Many possible pathways exist, each with multiple positive and negative aspects to be considered. One way to broadly differentiate between potential pathways is to group solutions into green (predominantly wind and solar) and blue (a large role for hydrocarbon fuels with CO_2 capture). Green pathways can be inherently sustainable (although they currently rely on fossil fuels and consume large quantities of finite mineral resources), whereas blue pathways are inherently unsustainable due to their reliance on finite fossil fuels. However, the problem of fossil fuel resource depletion should not be conflated with the problem of climate change. The world has sufficient proven fossil fuel reserves [50] to consume the CO_2 budget for 2 °C of warming four times over. In addition, oil and gas reserves keep expanding despite continued record levels of production (since 2000, global oil and gas reserves have increased by 33% and 36%, respectively [50]). Hence, fossil fuels can

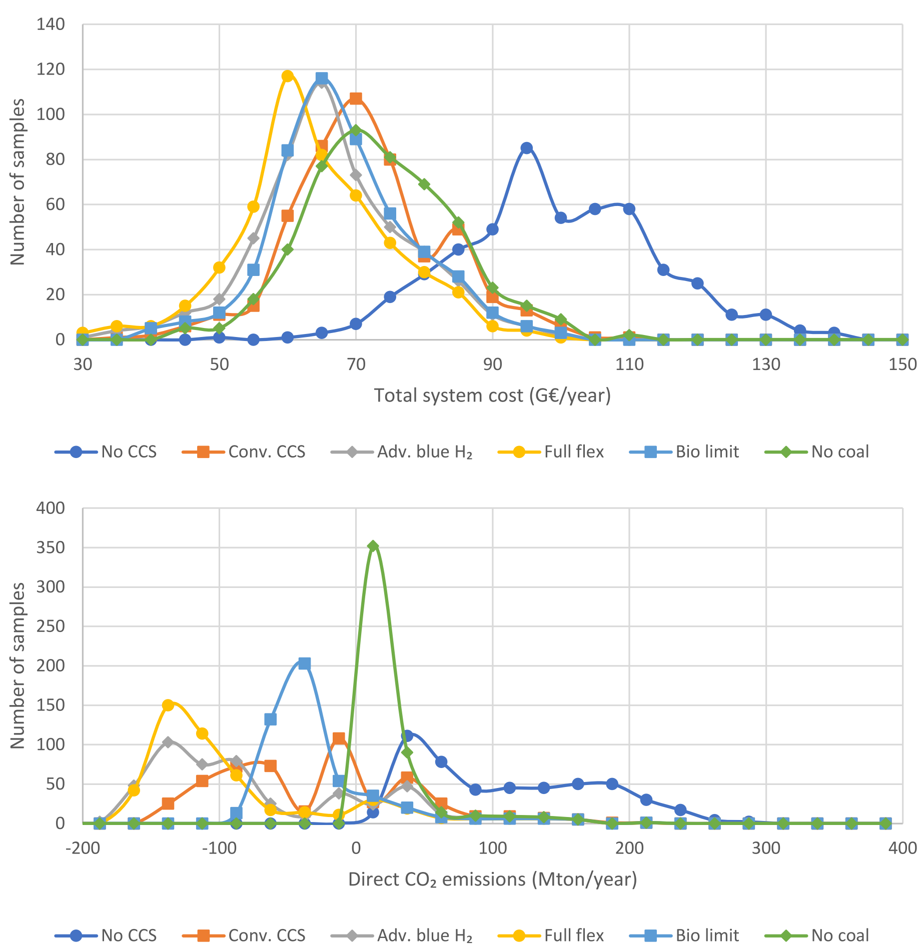

Fig. 10. Histograms of the number of the 500 runs completed for each scenario ending up in 25 equally sized bins across a range of total system costs and emissions.

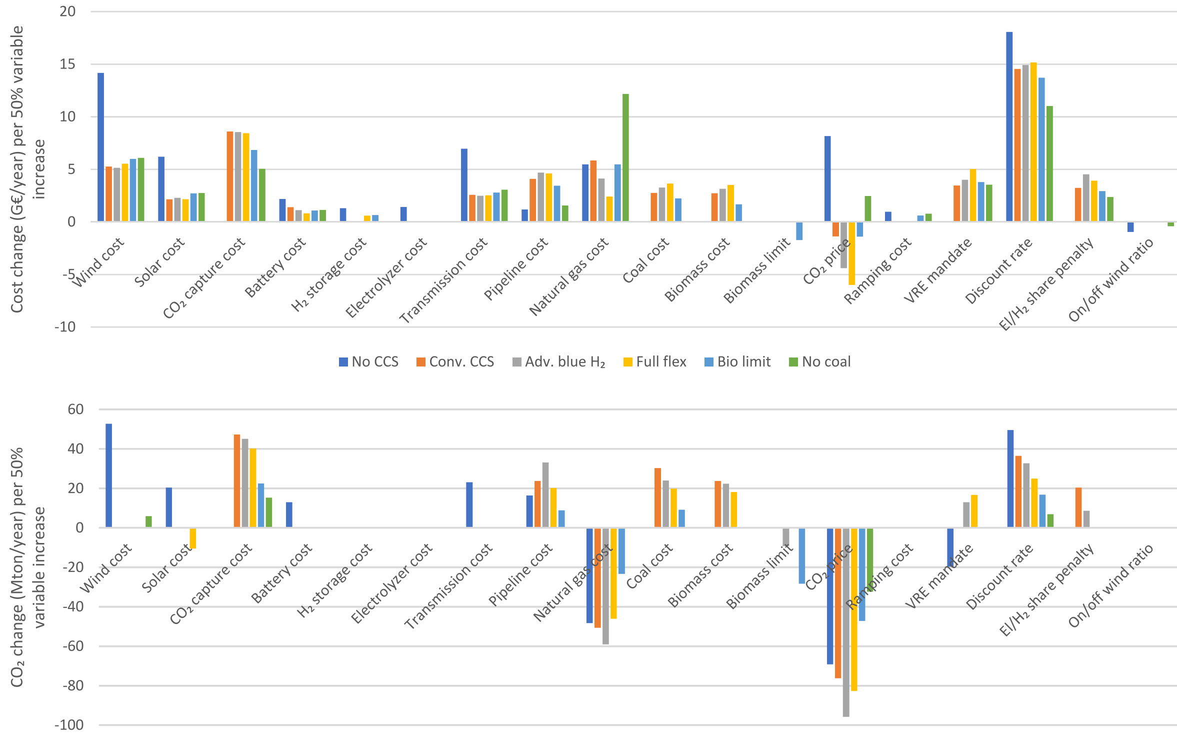

Fig. 11. Regression coefficients illustrating the relative importance of the 18 variables on the total system cost and direct CO_2 emissions. Effects with $p > 0.05$ are omitted.

continue playing a central role in global economic development if most of the produced CO_2 can be safely and economically captured and stored.

In this paper, the potential to enhance blue pathways with low-cost wind and solar power (to economically reduce fossil fuel dependence) and biomass (for achieving negative CO_2 emissions) was investigated. A Northern European perspective was presented with a modelled system loosely based on Germany. The potential of novel blue hydrogen technologies, potentially with integrated power cycles, to reduce system costs relative conventional blue technologies was also investigated in detail.

The first important conclusion from this work is that blue pathways only offer modest benefits in the power sector but large benefits in the hydrogen sector. In a future energy system where large quantities of carbon-free fuels are required for use in sectors like long-distance transport and industry, systems with CCS become considerably cheaper than those relying only on renewables. A further implication is that pathways permitting CCS will focus less on electrification and more on carbon-free fuels. The current study showed a 29% decline in system costs and a 106% decline in CO_2 emissions (due to negative emissions from biomass) when conventional CCS technologies were introduced, with hydrogen being produced at less than half the price of electricity.

Advanced blue hydrogen technologies with the potential for integrated power cycles that facilitate flexible power and hydrogen production could enable an additional 12% reduction in system costs with further negative emissions due to very high CO_2 capture ratios. These concepts were originally designed to better integrate higher shares of wind and solar, but the costs of handling the intermittent hydrogen fluxes originating from such an operational strategy proved to be considerable, making scenarios with lower VRE shares more economical.

Coal and biomass co-gasification played an important role in the attractiveness of scenarios that permit CCS. Co-gasification with coal allows biomass resources to be used more efficiently and within sustainable limits. If such co-gasification technologies are not permitted in CCS-enabled pathways, the reliance on natural gas becomes very high (with associated energy security risks) and the potential for cost-effective negative CO_2 emissions is lost. Furthermore, the inclusion of all available forms of primary energy enhances system resilience and limits the economic impact when one form of energy experiences unexpected cost escalations.

In conclusion, this study presents a strong case for a balanced blue-green decarbonization strategy that continues to utilize fossil fuels where they create most value. Such a strategy can economically integrate substantial shares of renewable energy in the form of wind and solar power and sustainably produced biomass. Even though current policy momentum is more aligned with pure green pathways, the merits of blue technologies deserve serious consideration.

Author contribution

Schalk Cloete: Conceptualization, Methodology, Formal analysis, Investigation, Writing - Original Draft. **Carlos Arnaiz del Pozo:** Methodology, Investigation, Writing - Original Draft. **Ángel Jiménez Álvaro:** 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

The system-scale model and economic assessment files are shared online as outlined in the methodology section of the paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2022.124954.

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