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Flexible power and hydrogen production: Finding synergy between CCS and variable renewables

Schalk Cloete [a, *], Lion Hirth [b, c, d]

[a] SINTEF Industry, Trondheim, Norway
[b] Hertie School of Governance, Berlin, Germany
[c] Neon Neue Energieökonomik GmbH, Germany
[d] Mercator Research Institute on Global Commons and Climate Change (MCC), Germany

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A B S T R A C T

The expansion of wind and solar power is creating a growing need for power system flexibility. Dispatchable power plants with CO_2 capture and storage (CCS) offer flexibility with low CO_2 emissions, but these plants become uneconomical at the low running hours implied by renewables-based power systems. To address this challenge, the novel gas switching reforming (GSR) plant was recently proposed. GSR can alternate between electricity and hydrogen production from natural gas, offering flexibility to the power system without reducing the utilization rate of the capital stock embodied in CCS infrastructure. This study assesses the interplay between GSR and variable renewables using a power system model, which optimizes investment and hourly dispatch of 13 different technologies. Results show that GSR brings substantial benefits relative to conventional CCS. At a CO_2 price of €100/ton, inclusion of GSR increases the optimal wind and solar share by 50%, lowers total system costs by 8%, and reduces system emissions from 45 to 4 kg_{CO2}/MWh. In addition, GSR produces clean hydrogen equivalent to about 90% of total electricity demand, which can be used to decarbonize transport and industry. GSR could therefore become a key enabling technology for a decarbonization effort led by wind and solar power.

1. Introduction

Following the recent acceleration of global CO_2 emissions growth [1], the urgency of addressing climate change is greater than ever. The Intergovernmental Panel on Climate Change special report on global warming of 1.5 °C [2] illustrates the need for rapid decarbonization, with the electricity sector needing to reach net-zero or net-negative emissions by the middle of the century. It is therefore clear that urgent action is needed.

Variable renewable energy (VRE) in the form of wind and solar power appears to be the brightest prospect for achieving cost-effective decarbonization due to several decades of continuous cost reductions [3]. However, these technologies impose challenges when targeting deep decarbonization due to extended periods of limited wind and sun during which other solutions are required to meet demand. The load-following power plants fulfilling this role must operate at a low capacity factor, which increases their levelized costs. This negative effect becomes particularly severe when considering capital-intensive, low-carbon generators, such as nuclear power, biomass power plants, and coal with CO_2 capture and storage (CCS).

The tendency of VRE to reduce the capacity factor of dispatchable generators introduces a substantial cost to the overall power system [4–7]. These “system integration costs,” or more specifically, “profile costs” [8], materialize in liberalized power markets as a reduction in the economic value of wind and solar energy [9].

To limit profile costs while minimizing CO_2 emissions, a low-carbon dispatchable generator with low capital costs is needed to complement variable renewables [8]. Natural gas combined cycle (NGCC) power plants with CCS were previously found to be a competitive solution, particularly for balancing seasonal variability [10]. Such plants are technically capable of supplying the flexibility required by systems with high VRE market shares [11].

However, even though CCS is expected to play a major role in almost all deep decarbonization scenarios [12–14], it is currently far off track in terms of deployment and project pipeline [15]. One

* Corresponding author. Flow Technology Group, SINTEF Industry, S.P. Andersens vei 15B, 7031, Trondheim, Norway.
E-mail address: schalk.cloete@sintef.no (S. Cloete).

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Nomenclature

AUSC	Advanced ultra-supercritical coal power plant
CAPEX	Capital expenditure
CCS	CO_2 capture and storage
CLR	Chemical looping reforming
EBTF	European Benchmarking Task Force
GSR	Gas switching reforming power and hydrogen plant
H2CC	Hydrogen combined cycle power plant
IEA	International Energy Agency
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNG	Liquified natural gas
NGCC	Natural gas combined cycle power plant
O&M	Operating and maintenance
OCGT	Open cycle gas turbine power plant
PEM	Polymer electrolyte membrane electrolyzer
PV	Photovoltaics
tpa	Tons per annum
VRE	Variable renewable energy
α	Availability (%)
δ	Load (MW)
η	Efficiency (%)
C	Total system cost (€)
c^{cap}	Capital costs (€/kW)
c^{fix}	Fixed annual costs (€/kW/year)
c^{var}	Variable costs (€/MWh)
d	Discount rate (%)
g	Rate of electricity generation (MW)
$\hat{g}$	Installed generating capacity (MW)
l	Plant lifetime (years)
p_{H_2}	Hydrogen sales price (€/MWh)
s^i	Rate of battery charge (MW)
s^o	Rate of battery discharge (MW)
$\hat{s}$	Installed battery power (MW)
v	Current level of battery storage (MWh)
$\hat{v}$	Installed battery storage volume (MWh)
bat	Battery
i	Index for all technologies aside from GSR, PEM and batteries
GSR	GSR electric efficiency (electricity output/fuel input)
$GSRH_2$	GSR electric efficiency in hydrogen production mode
H_2GSR	GSR hydrogen production efficiency (H_2 output/fuel input)
PEM	PEM electrolysis
s	Battery power
t	Time (hours)
v	Battery storage volume

potential mechanism for accelerating CCS progress is to draw more attention to the interplay with rapidly expanding VRE. Conventional CCS can potentially aid in VRE integration by flexibility measures such as solvent storage and CO_2 venting [16], but such measures may not be profitable at the CO_2 prices required to make CCS economically viable [17]. It is also important to consider the infrastructure required to transport and store the captured CO_2. Under-utilization of this infrastructure due to low capacity factors imposed by VRE further increases levelized system costs, and intermittent CO_2 influxes pose technical challenges to CO_2 transport and storage networks [18].

If CCS is to live up to its potential as an enabler of greater VRE market shares, solutions are required to maximize the utilization of CO_2 capture, transport and storage infrastructure. Calcium looping technology has been explored as one option for addressing these challenges through storage of sorbent or cryogenic oxygen [19,20]. This is a promising pathway, but it is more suitable to shorter-term storage due to practical and economic limitations on the volume of stored sorbent or oxygen.

A CCS technology capable of supplying flexibility over longer timescales was recently proposed: the gas switching reforming (GSR) plant for flexible power and hydrogen production [21]. GSR is a natural gas reforming technology that can be deployed for efficient hydrogen production with inherent CO_2 capture. The aforementioned study [21] presented a simplistic analysis of the economic advantages of flexible power and hydrogen production with GSR. It was concluded that, although GSR plants perform similarly to conventional NGCC plants with CCS when operating under baseload conditions, they offer significant economic benefits when operated as load-following plants at a lower capacity factor. These economic benefits stem from the ability of GSR to continue producing clean hydrogen when power demand is low, thus maximizing the utilization of CO_2 capture, transport, and storage infrastructure (~90%) despite a low capacity factor of electricity generation (30–60%, depending on market conditions). Such flexible power and hydrogen production allow GSR to not only integrate larger shares of wind and solar power, but also to decarbonize sectors such as transport and industry where fewer low-carbon solutions are available.

This study provides an assessment of GSR, considering the interplay in integrated power systems with large volumes of wind and solar energy. The primary objective of the study is to quantify the system-level benefits of GSR in terms of total system costs and emissions, wind and solar power integration, and provision of clean hydrogen. To this end, a numerical electricity system model that optimizes the annualized investment and hourly dispatch of 13 different technologies is deployed.

Results show that, while conventional CCS crowds out renewables, GSR does not. This is because it remains economical at lower capacity factors (in terms of electric output) than conventional CCS. Model results also show that, due to the favorable interplay of flexible GSR with relatively cheap wind and solar energy, this technology portfolio is able to achieve deep decarbonization at moderate CO_2 prices around 60 €/ton. GSR also produces a large quantity of hydrogen, implying that large-scale GSR deployment only makes sense in a world where the vision of a hydrogen economy is successfully realized.

2. Gas switching reforming

Today, most hydrogen is produced via steam methane reforming using a fired tubular reactor [22]. Capturing CO_2 from this process is expensive, at around €100/ton [23]. GSR is a novel technology for efficient natural gas reforming with inherent CO_2 capture [24]. It is based on the principle of chemical looping reforming (CLR) [25,26] in which an oxygen carrier material (usually a metal oxide) is used to transfer oxygen from an oxidation reactor fluidized by air to a reduction reactor fluidized by fuel gases. In this way, oxygen can be supplied to combust the fuel required to drive the endothermic reforming reactions while avoiding mixing nitrogen into the produced syngas stream.

In contrast to CLR, which circulates the oxygen carrier between two interconnected reactors, GSR keeps the oxygen carrier in a single reactor and switches the inlet gases. The simple, standalone nature of a GSR reactor is expected to bring substantial simplifications with respect to scale-up and operation, particularly under the pressurized conditions required for high process efficiency. In addition, this configuration inherently separates the reduction and reforming steps (which are combined in CLR) to allow for the efficient integration of a pressure swing adsorption (PSA) unit for pure hydrogen production with integrated CO_2 capture, as illustrated in Fig. 1.

In this configuration, GSR with 97% CO_2 capture can exceed the efficiency of conventional carbon-intensive hydrogen production with steam methane reforming [27]. Fig. 1 also illustrates how GSR can be fitted into a power plant configuration where the pure hydrogen is combusted in a combined power cycle. Here, integration with the hot nitrogen steam from the GSR reactors in the oxidation step can enable high-temperature combustion with minimal NOx formation to reach very high turbine inlet temperatures for maximizing efficiency [28]. Major gas turbine manufacturers are currently investing in hydrogen turbines with near-term commercialization timelines [29], and the hot N_2 stream from GSR could help to alleviate the combustion challenge posed by the high flame speed of hydrogen. This constant and diffuse ignition source could allow for stable operation at higher flow velocities to avoid flashback issues caused by high flame speeds without encountering flame blowout.

It should be noted that, even though the GSR reactors are only part of the process configuration depicted in Fig. 1, the term “GSR” will be used to describe the entire flexible power and hydrogen plant for the remainder of this study. Under flexible power and hydrogen production, all process units in the GSR plant, aside from the combined power cycle, are used at the maximum achievable capacity factor. This alleviates the economic challenges of operating capital-intensive clean power plants at reduced capacity factors to balance wind and solar power. The heat integration is designed specifically to minimize interconnection between the reforming units and the power cycle to allow for full flexibility [28]. When operating in hydrogen mode, the hot N_2 stream is still expanded in the power cycle, but rather inefficient energy recovery is assumed due to this off-design turbine operation. As a result, the equivalent hydrogen production efficiency of the GSR plant in hydrogen mode used in the present study [21] is about 2 %-points below that of a dedicated GSR hydrogen plant [27]. It should also be mentioned that the GSR plant turns into a net electricity consumer when operating in hydrogen production mode, mainly due to the operation of compressors for air, CO_2, and hydrogen.

Pure hydrogen produced during periods of high wind and solar power output can be used to decarbonize sectors where fewer low-carbon alternatives are available, such as long-haul transport, chemicals, and iron and steel [30]. This potential for hydrogen to enable deep decarbonization of the entire energy system has led to a recent resurgence in interest, exemplified by a special report on hydrogen prepared by the IEA under the request of the Japanese government during their G20 presidency [30]. Thus, GSR has the potential to not only enable deep decarbonization of the electricity sector via wind and solar power, but also to enable deep decarbonization of the broader economy.

3. Methodology

The methodology is presented in three sections: 1) the model framework used for the system-scale assessment, 2) the technology cost assumptions, and 3) a description of the three scenarios considered.

3.1. Model framework

This study evaluates the interplay of GSR with variable renewables and the rest of the power system using a stylized long-term numerical model of a power system for one typical year, loosely

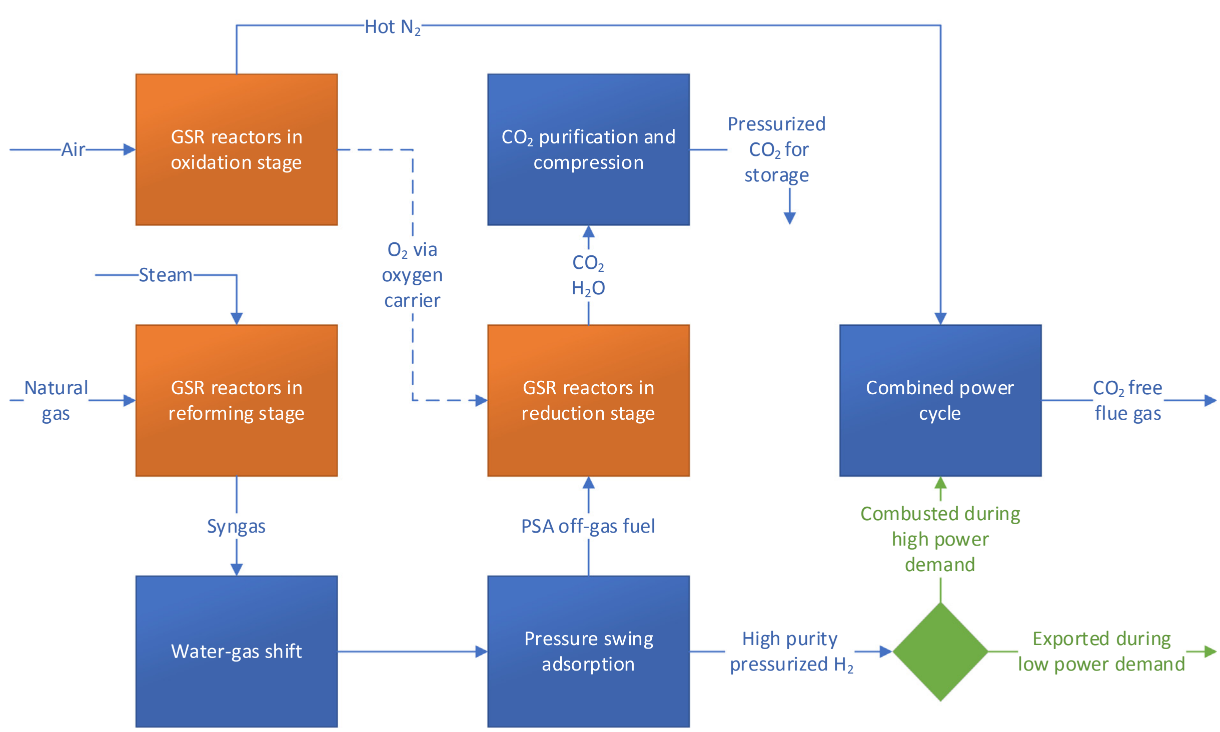

Fig. 1. Simplified flow diagram of the GSR plant for flexible power or hydrogen production. The green diamond represents the switch between power and hydrogen operating modes.

calibrated to Germany in the year 2040. The long-term nature of the model means that no investment constraints related to the existing generating fleet are imposed. Within this framework, the model optimizes both investment and hourly dispatch of 13 technologies, including onshore wind and solar PV, coal and natural-gas-fired power plants with and without CCS, hydrogen-fired power plants, polymer electrolyte membrane (PEM) electrolysis, battery storage, and GSR for flexible power and hydrogen production. Nuclear power is excluded in most cases, but is investigated in a sensitivity analysis. Electricity demand is fixed and must be served. Hydrogen is assumed to sell at a fixed price of €1.67/kg in the base case.

The objective of the model is to minimize the total system cost (Equation (1)), which is comprised of capital costs, fuel and CO_2 costs, and other fixed and variable operating and maintenance (O&M) costs summed over all hours (t) and technologies (i) for one year. Decision variables in the optimization comprise the deployed capacity $(\widehat{g})$ and hourly power production (g) of each technology.

$$C=\sum_i c_i^{\text{fix}}\widehat{g}_i+\sum_{t,i}c_i^{\text{var}}g_{t,i}+\sum_t\left(c_{\text{GSR}}^{\text{var}}\eta_{\text{GSR}}-p_{\text{H}_2}\eta_{\text{H}_2\text{GSR}}\right)\frac{g_{t,\text{GSRH}_2}}{\eta_{\text{GSRH}_2}}+c_{\text{PEM}}^{\text{fix}}\widehat{g}_{\text{PEM}}+\sum_t p_{\text{H}_2}\eta_{\text{PEM}}g_{t,\text{PEM}}+c_{\text{s}}^{\text{fix}}\widehat{s}+c_{\text{v}}^{\text{fix}}\widehat{v} \tag{1}$$

The fixed (c^{fix}) and variable (c^{var}) costs, as well as the efficiency (η) are specified exogenously for each technology. Fixed costs (€/kW/year) are composed of levelized capital costs and annual fixed O&M costs. Levelized capital costs are calculated using a specified technology capital cost, discount rate and plant lifetime according to Equation (2). Annual fixed O&M costs are taken as a percentage of capital costs. Variable costs (€/MWh) are composed of fuel costs, variable O&M costs, and the cost of CO_2 emissions. All the assumptions used to calculate these costs are detailed in the next section.

$$c_i^{\text{fix,cap}}=\frac{c_i^{\text{cap}}d(1+d)^l}{(1+d)^l-1}\rightarrow \quad \forall\ i \tag{2}$$

For the terms in Equation (1) involving hydrogen production from GSR and PEM technologies, hydrogen sales at the specified hydrogen sales price (p_{H_2}) are subtracted from the total system costs (noting that η_{GSRH_2}, g_{t,GSRH_2}, and $g_{t,\text{PEM}}$ are negative). The GSR summation (the third summation in Equation (1)) can be further explained as follows: $g_{t,\text{GSRH}_2}/\eta_{\text{GSRH}_2}$ is the ratio between power generation and power generation efficiency for GSR operating in hydrogen production mode, which represents the rate of natural gas consumption in each hour of the year. This fuel consumption can be multiplied by the hydrogen production efficiency $(\eta_{\text{H}_2\text{GSR}})$ to calculate rate of hydrogen production. Variable costs for GSR operation $(c_{\text{GSR}}^{\text{var}})$ are expressed per unit of electricity produced when GSR operates in power production mode. Thus, $c_{\text{GSR}}^{\text{var}}$ must be multiplied by the GSR power production efficiency (η_{GSR}) to calculate variable costs per MWh of natural gas input.

Minimization of the objective function must be done within several constraints. Key constraints include the overall energy balance, capacity limitations, and several stylized power system constraints, as further detailed below.

To satisfy the global energy balance, the sum of electricity generation from all available generating technologies, negative generation from GSR in hydrogen production mode (GSRH_2) and electrolysis (PEM), as well as the balance of battery discharging (s^{o}) and charging (s^{i}) must match the load (δ) for all hours in the year. The load profile was taken for Germany for the year 2012 from the Open Power System Data project [31].

$$\delta_t=\sum_i g_{t,i}+g_{t,\text{GSRH}_2}+g_{t,\text{PEM}}+\eta_{\text{bat}}s_t^{\text{o}}-s_t^{\text{i}} \quad \forall\ t \tag{3}$$

The generation of each type of technology is constrained to be smaller or equal to the available (α) capacity of that technology for every hour of the year. Wind and solar availabilities were taken from Germany for the year 2012. Given this study's focus on the year 2040, the availability of wind was specified for advanced Enercon E-115 turbines delivering an annual capacity factor of 32%, as calculated by Hirth and Müller [32] (the actual achieved German wind capacity factor was only 19% for 2012). The solar profile was taken from the Open Power System Data project [31], which returned an annual capacity factor of 11% for 2012. To match with the expected annual capacity factors for new wind and solar in Europe in 2040 of 30% and 13% respectively [33], the hourly profile of wind was adjusted by a factor of 0.946, and the solar profile was adjusted by a factor of 1.19. The availability of dispatchable generators is set to 1 (100% of rated power can be delivered when required).

$$g_{t,i}\le\alpha_{t,i}\widehat{g}_i \qquad \forall\ t,i \tag{4}$$

To account for downtime of dispatchable generators, another constraint is imposed: the full year capacity factor cannot exceed 0.9. This assumption is reasonable based on data from the National Renewable Energy Laboratory that baseload nuclear, coal and gas plants achieve capacity factors close to 90% [34].

$$\sum_t g_{t,i}\le 0.9\cdot 8760\cdot\widehat{g}_i \quad \forall\ i \tag{5}$$

For the GSR technology, a constraint is imposed that the combined power and hydrogen output must be within the limits of the plant's capacity for all hours of the year. Here η_{GSR} and η_{GSRH_2} are the electrical efficiencies of the GSR technology in power and hydrogen mode, respectively. It is noted that both η_{GSRH_2} and g_{t,GSRH_2} are negative (GSR is a net consumer of electricity in hydrogen mode).

$$g_{t,\text{GSR}}+g_{t,\text{GSRH}_2}\frac{\eta_{\text{GSR}}}{\eta_{\text{GSRH}_2}}\le\widehat{g}_{\text{GSR}} \quad \forall\ t \tag{6}$$

Next, the power consumption of PEM electrolyzers is constrained below the deployed electrolyzer capacity for all hours of the year. It is noted that $g_{t,\text{PEM}}$ is negative (PEM consumes electricity).

$$-g_{t,\text{PEM}}\le\widehat{g}_{\text{PEM}} \quad \forall\ t \tag{7}$$

Finally, several constraints are required to describe battery storage. The basic energy balance over the batteries is specified so that the balance of charge and discharge in each hour correctly changes the volume of stored energy (v). In addition, the rate of charge and discharge cannot exceed the installed battery power $(\widehat{s})$, and the level of stored energy cannot exceed the installed battery storage volume $(\widehat{v})$ in any hour of the year.

$$v_t=v_{t-1}+s_t^{\text{i}}-s_t^{\text{o}} \qquad \forall\ t \tag{8}$$

$$v_t\le\widehat{v} \quad \forall\ t \tag{9}$$

$$s_t^{\text{i}}\le\widehat{s} \quad \forall\ t \tag{10}$$

$$s_t^{\text{o}}\le\widehat{s} \quad \forall\ t \tag{11}$$

This system of equations is solved using the General Algebraic

Modelling System (GAMS) software to minimize the objective function (Equation (1)).

3.2. Technology cost assumptions

Reasonable assumptions about the different fixed and variable costs of each type of technology are critical in order to ensure a fair representation of the cost-optimized technology mix. A detailed outline of the costs in this assessment is given below. This assessment will calculate a long-term optimum energy system configuration, and will therefore use cost assumptions relevant to the year 2040.

3.2.1. Capital costs

Assumptions about the capital costs for wind, solar, coal (AUSC), and gas (NGCC) power plants are taken from the IEA World Energy Outlook 2018 [33] for Europe in the year 2040. Open cycle gas turbine (OCGT) plant costs are taken as 56% of NGCC plant costs based on capital cost estimates from the IEA Projected Costs of Generating Electricity report [35]. A sensitivity analysis is presented later, in which the influence of additional wind and solar cost reductions is quantified.

The capital costs of CO_2 capture are added onto the IEA capital costs for coal (AUSC-CCS) and gas (NGCC-CCS) power plants by taking the same relative cost increase reported in the European Benchmarking Task Force (EBTF) best practice guidelines [36]. The benchmarks in the EBTF report had similar costs to the IEA numbers, so this is a reasonable assumption. Given the low technology readiness level of GSR, the effect of potential cost escalations is included in the sensitivity analysis.

The capital costs of CO_2 transport and storage infrastructure were taken from specialized IEA greenhouse gas (IEAGHG) reports [37,38]. Specifically, the capital costs were calculated as €60/tpa for a 750-km onshore transport network in addition to €35/tpa for onshore aquifer storage. These costs are added to the capital costs of all plants that include CCS so that the plant will be able to transport and store its peak CO_2 output.

Battery storage costs were taken from the World Energy Outlook [33] projections to 2040, with an assumed 25/75 split between power and storage costs. According to the IEA, approximately half of these costs are related to the battery pack, and the other half are related to various non-battery costs.

Electrolyzer costs are taken from the center of the range of long-term future cost estimates for PEM systems provided in the IEA Future of Hydrogen report [30], which reviewed a number of appropriate studies.

All costs are summarized in Table 1. Where necessary, costs are converted using an exchange rate of 1.2 $/€.

3.2.2. Fuel costs

The base case fuel cost assumptions were also taken from the World Energy Outlook [33] for 2040, and are given in Table 2. The price hydrogen producers receive is calculated as 1.25x the natural gas price (assuming an 80% conversion efficiency) plus €5/GJ for capital and other operating costs. This is relatively low in order to obtain a conservative estimate of GSR attractiveness. A sensitivity analysis of natural gas and hydrogen prices is presented later. Costs for hydrogen consumption in backup power plants is assumed to be almost €1/kg higher than the price that is paid to hydrogen producers to account for hydrogen storage and distribution costs (these costs vary widely [30], but €1/kg is a reasonable average). It is assumed that hydrogen can be combusted in gas-fired plants with the same capital and O&M costs as NGCC and OCGT plants (referred to as H2CC and H2GT plants). Major turbine manufacturers are working on hydrogen gas turbines with near-term commercialization timelines [29], suggesting that this should be a feasible option by 2040.

CO_2 intensities are also provided for coal and gas in order to calculate the amount of CO_2 that must either be emitted (and paid for under a CO_2 tax) or captured, transported, and stored.

For thermal power plants, the energy conversion efficiency is a crucial assumption in determining the fuel costs and CO_2 generation per unit of electricity. In addition, CO_2 capture rates must be specified in order to calculate costs related to CO_2 emissions and CO_2 transport and storage. These assumptions are summarized in Table 3. Given the long-term focus of the study (around 2040), coal and gas power plant efficiencies for AUSC plants [35] and NGCC plants with advanced gas turbines [39] are assumed. CO_2 capture is assumed to impose an efficiency penalty of 9 %-points for AUSC and 7 %-points for NGCC plants. Advanced solvents could potentially reduce the energy penalty in coal plants to only 7.5 %-points [40], but a more conservative assumption is employed here. According to the EBTF report [36] and a review by Rubin, Davison [41], CO_2 capture from natural gas imposes an energy penalty approximately 20% smaller than coal, hence the 7 %-point penalty assumed for NGCC-CCS. For GSR, an energy penalty of 7 %-points is assumed when operating in power-production mode [28], whereas H_2 production efficiencies are taken from Szima, Nazir [21]. Electrolysis efficiency is taken from long-term projections of the IEA [30].

Table 1
Capital cost and lifetime assumptions for different technologies.

Technology	Capital cost	Lifetime (years)
Wind	1417 €/kW	25
Solar	633 €/kW	30
AUSC (coal)	1667 €/kW	40
NGCC (gas)	833 €/kW	40
OCGT (gas)	467 €/kW	30
AUSC-CCS	2600 €/kW	40
NGCC-CCS	1300 €/kW	40
GSR (including CO_2 capture)	1392 €/kW	40
CO_2 transport & storage	95 €/tpa	40
Battery power	45 €/kW	20
Battery storage	138 €/kWh	20
Electrolysis	458 €/kW	20

Table 2
Fuel cost and CO_2 intensity assumptions.

Fuel	€/GJ	$kgCO_2/GJ$
Coal	2.8	97
Natural gas	7.1	57
Hydrogen production	13.9	–
Hydrogen consumption	21.9	–

Table 3
Efficiency and CO_2 capture assumptions for different technologies.

Technology	Efficiency (LHV)	CO_2 capture
AUSC (coal)	50%	–
NGCC (gas)	65%	–
OCGT (gas)	45%	–
AUSC + CO_2 capture	41%	90%
NGCC + CO_2 capture	58%	90%
GSR (power mode)	58%	98%
GSR (H_2 mode)	84% (H_2) –5% (power)	98%
Batteries	90%	–
Electrolysis	70%	–

3.2.3. Operating and maintenance costs

Assumptions for fixed and variable O&M costs are largely estimated from the IEA [35] and Franco, Anantharaman [36]. Due to a lack of data, the O&M costs of batteries and electrolysis were assumed to be equal to those of solar PV. CO_2 transport and storage O&M costs were taken from the same sources as the capital costs [37,38]. Table 4 summarizes these assumptions.

3.3. Scenarios

Three main scenarios are investigated in this study, differing in the availability of technologies.

- *NoCCS*: This scenario does not allow any CO_2 capture technology to be deployed. All other technologies are available, including batteries and electrolysis. Hydrogen can be used to store energy and then be re-electrified in hydrogen-fired power plants.
- *CCS*: This scenario includes, in addition to all of the above technologies, conventional CCS from coal and natural gas that can be deployed in the optimal electricity mix.
- *AllTech*: This scenario also includes the GSR technology in addition to conventional CCS and all other technologies.

A variant of the *NoCCS* scenario, termed *NoCCS* + H_2, is also briefly investigated. This scenario produces the same amount of clean hydrogen (via electrolysis) as in the *AllTech* scenario.

All other assumptions, including the fuel costs in Table 2, a CO_2 price of €100/ton, and a discount rate of 7%, are identical across the scenarios. Nuclear power was assumed to be unavailable in all scenarios. The impact of several model assumptions is evaluated in a sensitivity study, in which the inclusion of nuclear power is briefly assessed.

4. Results and discussion

Results will be presented and discussed in three sections. First, the effect of including GSR will be assessed relative to scenarios with and without conventional CCS. Second, the marginal CO_2 avoidance cost curves for the scenarios with and without CCS and GSR will be discussed. Third, a sensitivity analysis of several important simulation parameters will be presented.

4.1. The effects of CCS and GSR on system performance

The optimal technology mixes in the three scenarios described in Section 3.3 are illustrated in Fig. 2. In the *NoCCS* scenario, half of the power generation still comes from unabated NGCC power plants, even at a CO_2 price of €100/ton. As a result, this power system has an overall CO_2 emissions intensity of 157 kg/MWh. The *NoCCS* scenario deploys the largest battery capacity among the three scenarios to balance the high share of wind and solar power, although only 1.2% of generated power is cycled through this storage medium. Due to this low utilization rate and the high charge/discharge efficiency of batteries, net electricity consumption (negative generation) from batteries is very small and hardly visible in Fig. 2. No electrolysis is deployed, suggesting that not enough zero-cost excess wind and solar power is available to justify investment in PEM capacity at the implied low running hours.

When CCS is introduced, most of the NGCC capacity is replaced with NGCC-CCS capacity. As plants with CCS included are more capital-intensive and require significant infrastructure buildouts for CO_2 transport and storage, load-following operation to balance wind and solar power becomes less attractive. The result is that the renewables share in power generation drops from 51% to 32%. This resembles previous findings that renewables and CCS are substitutes rather than complements [42]. To illustrate this effect, Fig. 2 shows that the firm capacity (thermal plants and batteries) deployed in these two scenarios is almost identical, but the power generation from dispatchable plants in the *CCS* scenario is substantially higher. Specifically, the NGCC plants in the *NoCCS* scenario operate at a capacity factor of 55%, whereas the NGCC-CCS plants in the *CCS* scenario achieve a capacity factor of 82%. Despite the lower renewables share in the *CCS* scenario, the displacement of NGCC plants with NGCC-CCS plants reduces CO_2 intensity by 71% relative to the *NoCCS* scenario.

When GSR is introduced in the *AllTech* scenario, it displaces all the NGCC, OCGT, and NGCC-CCS capacity from the *CCS* scenario, even though GSR has higher capital costs than NGCC-CCS and no higher electric conversion efficiency. As shown in Fig. 2, firm capacity in the *AllTech* scenario must remain the same as in the *CCS* scenario to satisfy load in all hours of the year, but the flexibility of GSR allows the optimal share of wind and solar power to increase back up to 47% of total generation. In addition, the inclusion of GSR reduces CO_2 emissions to negligible levels (the CO_2 emissions intensity is only 4 kg/MWh).

The flexibility of the GSR technology allows it to operate at a capacity factor of only 43% (when in power mode) to accommodate greater shares of wind and solar power. This is noteworthy, given that the GSR technology is more capital-intensive than the NGCC-CCS plant. When totaling both power and hydrogen production modes, GSR operates at the maximum achievable capacity factor of 90%, implying that it achieves a capacity factor of 47% in hydrogen mode.

GSR also produces an amount of clean hydrogen equivalent to 88% of annual electricity demand. This large hydrogen output must be utilized in other energy sectors, which is possible given that electricity is projected to account for only about a quarter of the total final energy consumption worldwide by 2040 [33]. GSR can therefore play a leading role in decarbonizing other sectors of the economy where fewer low-carbon options are available.

The high utilization rate of GSR to produce both power and hydrogen results in a large natural gas demand of 1030 TWh. For perspective, German natural gas consumption in 2018 amounted to 883 TWh [1]. Given that most of the natural gas consumption of GSR is exported as hydrogen for use in other sectors of the economy where it will displace consumption of other fuels, this high natural gas consumption is not unreasonable. The *CCS* scenario consumes 604 TWh of natural gas only in the power sector, whereas natural gas consumption in the *NoCCS* scenario is lower, at 393 TWh.

In terms of overall system costs, Fig. 3 shows that the *AllTech* scenario has both the lowest costs and emissions of the three scenarios considered. For perspective, the *NoCCS* + H_2 variant of the *NoCCS* scenario is also shown, returning an electricity cost that is 79% higher than the *AllTech* scenario. This illustrates that flexible GSR plants can supply the economy with clean hydrogen at a

Table 4
Operating and maintenance cost assumptions for different technologies.

Technology	Fixed (% of CAPEX per year)	Variable (€/MWh)
Wind	2.3	–
Solar	2.2	–
AUSC (coal)	2	3
NGCC (gas)	2.5	2
OCGT (gas)	2.5	2
AUSC + CO_2 capture	2	5
NGCC + CO_2 capture	2.5	4
GSR	2.5	4
CO_2 transport and storage	–	2 €/ton
Batteries	2.2	–
Electrolysis	2.2	–

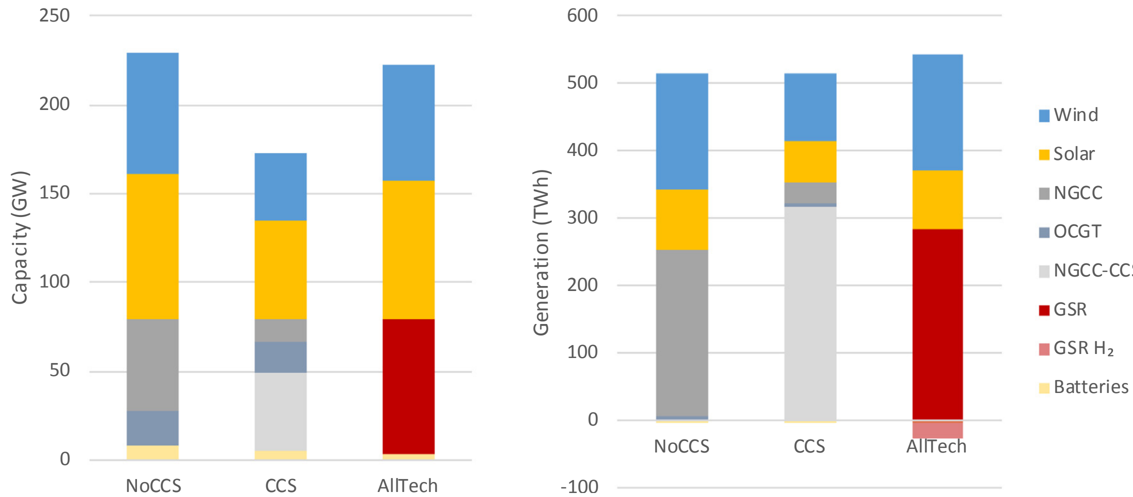

Fig. 2. Capacity and annual generation for the optimal technology mix in the three scenarios.

substantially lower cost than electrolysis. In fact, electrolysis is not deployed in the optimal technology mix unless the model is forced to produce hydrogen without GSR deployment (e.g., the *NoCCS* + H_2 scenario). For this reason, Fig. 3 shows no hydrogen production in the *NoCCS* and *CCS* scenarios. CO_2 emissions in the *NoCCS* + H_2 scenario are much lower than in the *NoCCS* scenario because electrolysis now plays an important integration role for wind and solar power, thus requiring less unabated NGCC capacity.

These results suggest that GSR is a good candidate for reducing the overall system costs and emissions in deep decarbonization strategies that rely heavily on wind and solar power. Not only can GSR provide economical and clean balancing power, but it can also affordably produce large quantities of clean hydrogen to decarbonize other parts of the economy.

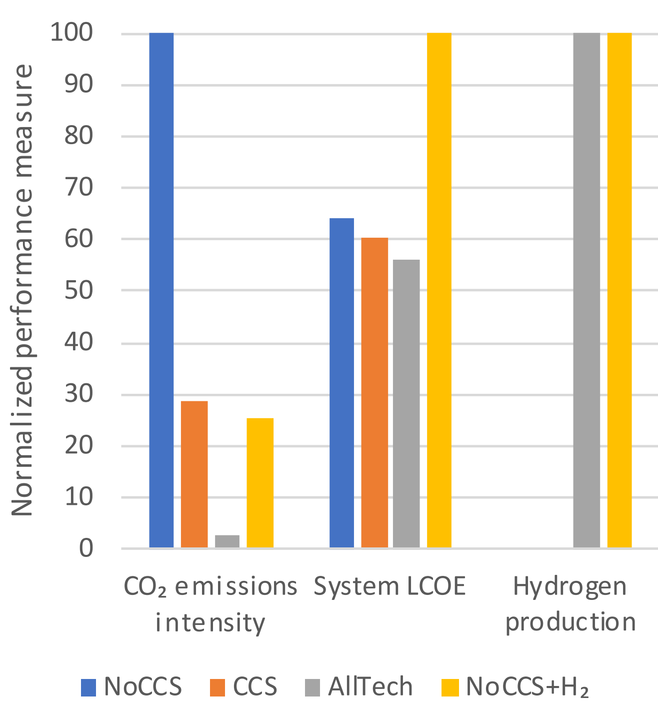

Fig. 3. Normalized comparison of the four scenarios in terms of three key performance metrics. Here, a value of 100 represents a CO_2 emissions intensity of 157 kg/MWh, a system levelized cost of electricity (LCOE) of 121 €/MWh, and hydrogen production of 453 TWh/year. System LCOE is quantified as the total system cost (Equation (1)) divided by the total annual electricity demand.

4.2. Deep decarbonization costs

The marginal CO_2 avoidance costs (CO_2 price) for achieving ever-decreasing CO_2 emissions intensities in the three scenarios are shown in Fig. 4. At low CO_2 prices, the three scenarios behave similarly. Indeed, a large reduction in CO_2 intensity can be achieved by replacing the coal plants that are responsible for almost all generation in the optimal energy mix below a CO_2 price of €20/ton with natural gas and some wind and solar power. At the time of writing, coal-to-gas switching is being incentivized in Europe by a CO_2 emissions allowance price nearing €30/ton, illustrating this effect.

Beyond €40/ton of CO_2 avoidance costs, significant differences between the different scenarios become visible. The *NoCCS* scenario requires a large increase in CO_2 price from €50/ton to €250/ton to reduce the system-scale emissions intensity from 200 to 100 kg/MWh. At a CO_2 price of €260/ton, it becomes economically feasible to displace natural gas-fired power plants with hydrogen-fired power plants, bringing the total system emissions to zero (provided that all of the consumed hydrogen is produced from zero-carbon sources).

Interestingly, the *NoCCS* scenario has lower emissions than the other two scenarios at CO_2 prices of €260/ton and above, implying that it has lower marginal CO_2 abatement costs for reaching zero emissions. This happens because the hydrogen-fired power plants required to reach zero emissions can displace unabated natural gas plants in the *NoCCS* scenario at a lower CO_2 price than they can replace NGCC-CCS and GSR plants in the other two scenarios. As will be discussed below around Fig. 5, however, the total abatement costs of the *NoCCS* scenario remain higher than the other two scenarios (as expected when fewer technological options are included in the optimization).

The *CCS* scenario can already achieve overall system-scale emissions intensities below 50 kg/MWh at a CO_2 price of €100/ton. As discussed in the previous section, this is achieved by displacing most of the unabated NGCC plants used as load-following plants in the *NoCCS* scenario with NGCC-CCS plants (at the cost of lower wind and solar power shares).

When GSR is included in the mix in the *AllTech* scenario, significant reductions relative to the other scenarios are already

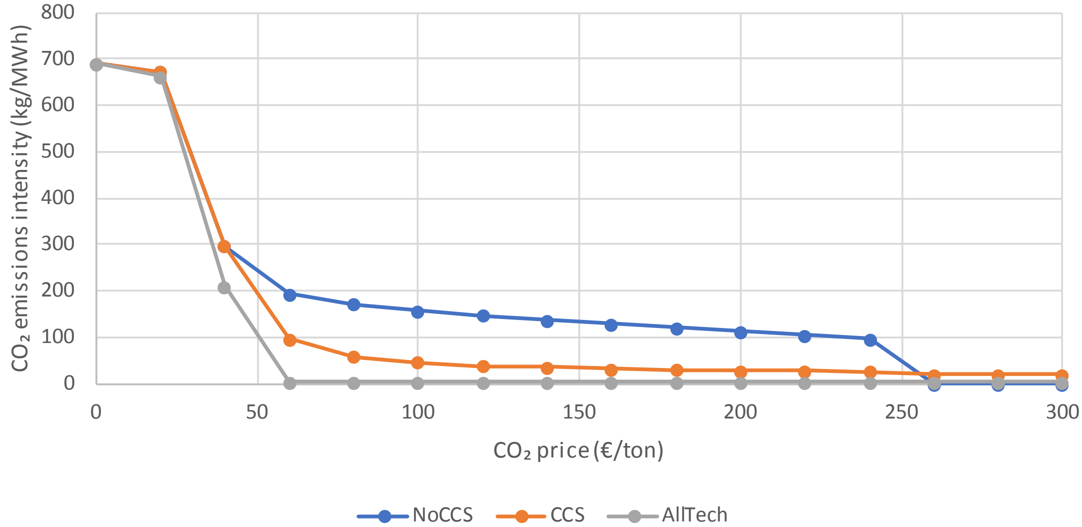

Fig. 4. Marginal CO_2 abatement cost curves for the three scenarios.

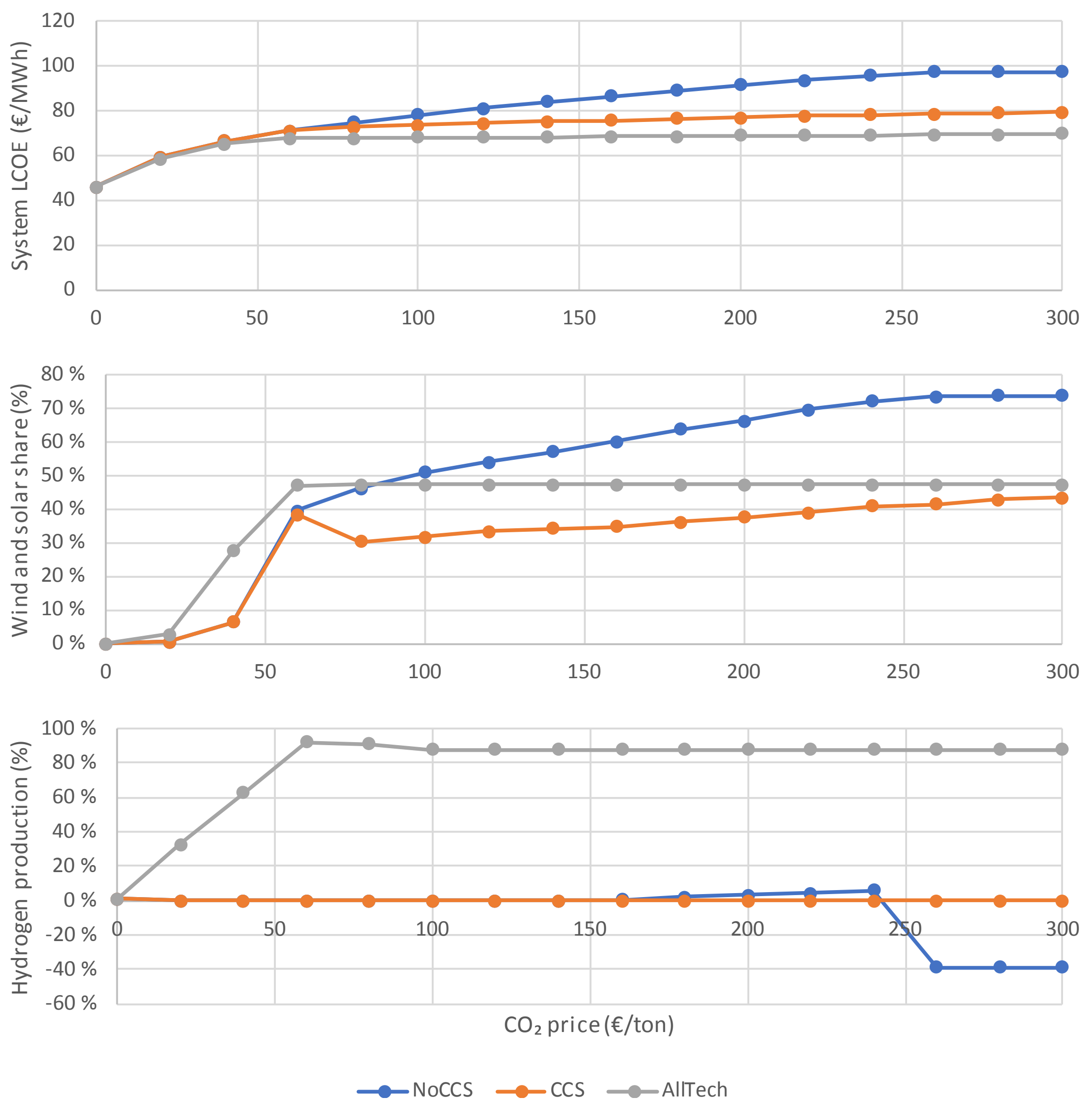

Fig. 5. More details of scenario performance across different CO_2 prices. Hydrogen production is expressed as a fraction of total annual electricity demand.

achieved at a CO_2 price of €40/ton, and the goal of near-zero emissions is achieved at €60/ton.

More details from these different scenarios are provided in Fig. 5. The relatively high cost of achieving deep decarbonization without CCS is clearly shown by the continued rise in system LCOE in the *NoCCS* scenario with increasing CO_2 prices. After the coal-to-gas switch is completed, this scenario must rely on ever-increasing shares of wind and solar power in which excess generation is balanced using battery storage and electrolysis for continued decarbonization. At €300/ton CO_2 prices, the *NoCCS* scenario is 23% more costly than the *CCS* scenario and 40% more costly than the *AllTech* scenario.

In the *NoCCS* scenario, electrolysis starts generating some clean hydrogen from excess wind and solar power beyond a CO_2 price of €150/ton. However, when hydrogen-fired power plants are introduced to achieve complete decarbonization beyond €250/ton, large net imports of clean hydrogen are required (Fig. 5, bottom). For perspective, when a limit is imposed that all hydrogen consumed by these hydrogen power plants must be produced using electrolysis within the system, total electricity costs increase by only 4% to €101/MWh. However, if the net hydrogen production within the system must be the same as in the *AllTech* scenario (i.e., the *NoCCS* + H_2 scenario at a CO_2 price of €300/ton), costs increase to €131/MWh (89% higher than in the *AllTech* scenario).

As Fig. 4 showed, the scenario with conventional CCS can already achieve quite deep decarbonization at CO_2 prices around €100/ton. However, a significant amount of unabated NGCC power generation is still present in this case (Fig. 2). Further increases in CO_2 price gradually displace this NGCC capacity with more wind and solar power, forcing the more capital-intensive NGCC-CCS plants to lower capacity factors. Hence, a gradual increase in system LCOE and wind and solar share in the *CCS* scenario with increasing CO_2 price can be observed in Fig. 5.

When GSR is included, the system already reaches near-zero emissions at a CO_2 price of €60/ton. Increasing the CO_2 price from €60/ton to €100/ton displaces a small amount of H_2 production with battery storage, beyond which no change in the optimal power mix is observed. The large amount of clean hydrogen production from GSR relative to the other two scenarios is also clearly observed in Fig. 5 (bottom).

Some GSR capacity is already deployed at a CO_2 price of €20/ton and plateaus out at €60/ton. In this range, the *AllTech* scenario achieves substantially higher wind and solar power market shares than the other two scenarios. This is because GSR must operate at reduced capacity factors (in power mode) to capitalize on its ability to produce power when electricity prices are high and hydrogen (with some power consumption) when electricity prices are low. GSR therefore benefits from more wind and solar power, which causes greater electricity price volatility and forces dispatchable plants to lower capacity factors.

4.3. Sensitivity study

The sensitivity of the *AllTech* scenario to changes in six important parameters will be investigated in this section: 1) natural gas price, 2) hydrogen price, 3) GSR capital cost increases, 4) wind/solar power cost reductions, 5) nuclear share, and 6) discount rate. It should also be pointed out that, in the cases with varying natural gas prices, it is assumed that each €1/GJ increase in natural gas price will result in a €1.25/GJ increase in hydrogen price under the assumption of an 80% conversion efficiency of natural gas to hydrogen using steam methane reforming.

The first four cases in Fig. 6 show that the natural gas price has a large impact on the attractiveness of GSR. When a natural gas price of €4/GJ (representative of large natural gas exporters) is assumed, the optimal mix consists of GSR only. However, when natural gas prices increase to €10/GJ (importers relying mostly on LNG), most GSR generation is displaced by coal with CCS. As these AUSC-CCS plants are capital-intensive and operate best as baseload generators, the optimal share of wind and solar power also reduces.

Higher hydrogen prices naturally incentivize GSR plants to operate more as hydrogen producers than electricity producers. In the case with a hydrogen price of €1.2/kg, it becomes unprofitable for GSR to export any hydrogen, forcing the plant to operate as a power plant only, thus losing the large benefits brought by flexible power and hydrogen production. Fig. 6 shows that this case still deploys a large amount of GSR, but it is noted that all GSR generation would be displaced with NGCC-CCS if GSR capital costs were to increase by only 8%. GSR has the same efficiency as NGCC-CCS and has slightly higher capital costs. It is preferred in this scenario only because of its high CO_2 capture rate, minimizing CO_2 costs at €100/ton.

When GSR cannot operate flexibly (H_2 price = €1.2/kg), significant unabated NGCC generation is retained to balance the system. In fact, some unabated generation remains in the optimal generation mix all the way up to a CO_2 price of €260/ton. Conversely, when GSR can operate flexibly, all unabated generation is already pushed out of the optimal mix at €60/ton (Fig. 4).

When hydrogen prices increase, GSR can start capitalizing on its ability to provide flexible power and hydrogen. The power plant capacity factor of GSR declines from 88% at €1.2/kg to 39% at €1.8/kg, allowing for the cost-effective integration of significantly larger shares of variable renewables. This increase in the wind and solar power market share inherently *reduces* electricity generation from GSR, but GSR capacity increases with the H_2 price to enable greater hydrogen sales. Specifically, GSR generation reduces from 354 to 276 TWh when varying the H_2 price from 1.2 to 1.8 €/kg, while hydrogen production increases from 0 to 515 TWh. It is noted that even a hydrogen price of €1.8/kg is relatively low at natural gas prices of €7.1/GJ. For example, a benchmark steam methane reforming plant was calculated to produce hydrogen at €2.6/kg at a natural gas price of €9.15/GJ [23]. Using an 80% conversion efficiency, this amount reduces to €2.3/kg at a natural gas price of €7.1/GJ. Thus, if the hydrogen economy can be established, GSR will be one of the lowest-cost suppliers of clean hydrogen.

Increases in GSR capital costs cause GSR to be gradually displaced by NGCC-CCS. However, GSR remains an important part of the generation mix even at a capital cost increase of 30%. It can also be pointed out that GSR is only driven completely out of the generation mix at a capital cost increase of 56%. As noted earlier, when GSR can only operate as a power plant because no hydrogen market exists, a mere 8% capital cost increase is enough to displace all GSR capacity with NGCC-CCS. This is a direct quantification of the benefits of flexible power and hydrogen production.

Another interesting observation is that, due to its ability to flexibly produce power and hydrogen, GSR retains the role of a load-following plant even as its capital costs increase. Specifically, GSR capacity factors in power mode decline from 43% to 33% over the range of 0–30% cost increase. The NGCC-CCS plants displacing GSR operate as baseload generators close to the maximum allowable 90% capacity factor. This introduction of more baseload capacity also reduces the optimal share of wind and solar power.

Cheaper wind and solar power gradually displace power generation from GSR. Over the range of a 0–30% wind and solar power cost reduction, the optimal wind and solar power share increases from 47% to 62% of total generation. Hydrogen production from GSR stays essentially constant with VRE cost reductions, implying gradually lower power production capacity factors. In the 30% cost reduction case, some electrolysis is deployed as periods of excess electricity from wind and solar generators become sufficiently

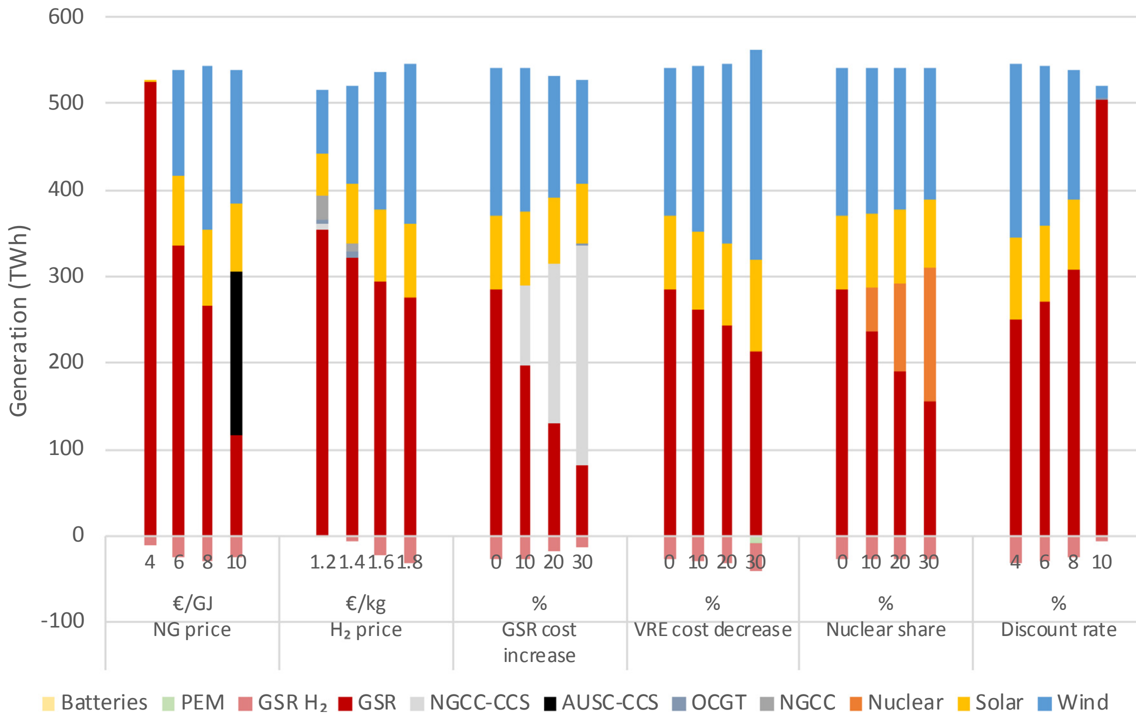

Fig. 6. Sensitivity of the *AllTech* scenario to changes in six important model parameters.

frequent to justify investment in PEM capacity. Battery storage capacity is relatively low (<12 GWh) in all cases because of the cost-effective flexibility offered by GSR.

Including nuclear power in the generation mix largely displaces GSR power production, but it also displaces a portion of wind and solar generation. Again, GSR hydrogen generation stays relatively constant, signaling that GSR predominantly becomes a hydrogen generator when more nuclear power is introduced into the system. The capital-intensive nature of nuclear power implies that it serves best as a baseload generator, forcing GSR to lower capacity factors. Specifically, the GSR power production capacity factor decreases from 43% to 30% as nuclear power increases from 0 to 30% of electricity demand, whereas overall GSR capacity factors remain close to 90% in all cases.

The final four cases in Fig. 6 show the discount rate effect. Clearly, GSR performs best at high discount rates. This is because of its high capital utilization rate enabled by flexible power and hydrogen production. Lower discount rates bring more wind and solar power into the system as the capital-intensive nature of these technologies becomes of lesser significance. GSR will therefore be more attractive in developing economies where the weighted average cost of capital is generally higher than in developed countries [43].

5. Summary and conclusions

This study investigated the system-level benefits of gas switching reforming (GSR) in a future decarbonized energy system with high shares of wind and solar power. The primary advantage of GSR is its ability to flexibly produce either electricity or clean hydrogen, which offers flexibility to the power system without reducing the utilization rate of the capital stock embodied in CO_2 capture, transport, and storage infrastructure. In addition, the clean hydrogen produced by GSR can facilitate decarbonization of other sectors of the economy where fewer clean energy options are available.

The value of this flexibility and efficient capital utilization was assessed in simulations, which suggest that an optimized system including GSR will phase out all unabated generators to achieve near-zero emissions (4 kg/MWh) at a CO_2 price as low as €60/ton. If GSR is disabled, system-level emissions increase to 97 kg/MWh and the optimal wind and solar share falls by 20% because conventional CCS plants are best operated as baseload generators with flexibility provided by unabated natural gas plants. In this case, complete phase-out of all unabated generators is only achieved at a very high CO_2 price of €260/ton.

As a technology that converts natural gas to hydrogen, GSR deployment is sensitive to the prices of both these fuels. With higher prices of natural gas, GSR is gradually substituted by renewables and, eventually, by coal with CCS. Higher hydrogen prices lead to the deployment of more GSR capacity to enable greater hydrogen sales, while electricity generation declines to accommodate more wind and solar power. This product flexibility may be beneficial for risk mitigation, a potential topic for future research.

In conclusion, this analysis showed that GSR is a promising enabling technology for achieving cost-effective deep decarbonization with wind and solar power, provided that a large hydrogen market is established. Simulations also showed that GSR performs even better in scenarios with a high discount rate, which is representative of the developing world, where the majority of future energy infrastructure will be built. GSR can therefore play an important role in the global energy transition.

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