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Finding synergy between renewables and coal: Flexible power and hydrogen production from advanced IGCC plants with integrated CO_2 capture

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ABSTRACT

Variable renewable energy (VRE) has seen rapid growth in recent years. However, VRE deployment requires a fleet of dispatchable power plants to supply electricity during periods with limited wind and sunlight. These plants will operate at reduced utilization rates that pose serious economic challenges. To address this challenge, this paper presents the techno-economic assessment of flexible power and hydrogen production from integrated gasification combined cycles (IGCC) employing the gas switching combustion (GSC) technology for CO_2 capture and membrane assisted water gas shift (MAWGS) reactors for hydrogen production. Three GSC-MAWGS-IGCC plants are evaluated based on different gasification technologies: Shell, High Temperature Winkler, and GE. These advanced plants are compared to two benchmark IGCC plants, one without and one with CO_2 capture. All plants utilize state-of-the-art H-class gas turbines and hot gas clean-up for maximum efficiency. Under baseload operation, the GSC plants returned CO_2 avoidance costs in the range of 24.9–36.9 €/ton compared to 44.3 €/ton for the benchmark. However, the major advantage of these plants is evident in the more realistic mid-load scenario. Due to the ability to keep operating and sell hydrogen to the market during times of abundant wind and sun, the best GSC plants offer a 6–11%-point higher annual rate of return than the benchmark plant with CO_2 capture. This large economic advantage shows that the flexible GSC plants are a promising option for balancing VRE, provided a market for the generated clean hydrogen exists.

1. Introduction

Climate change from anthropogenic greenhouse gas (GHG) emissions is one of the major global challenges of the 21st century. The Intergovernmental Panel on Climate Change presented a wide range of options for rapid GHG emissions reduction [1]. CO_2 emission account for almost 75% of anthropogenic GHG emissions [2], so reducing these emissions can have the greatest effect on limiting global warming. The IEAGHG report [3] presents the fields where action is needed to limit global CO_2 emissions. Some of these recommendations are on track to limit the global temperature increase to 2 °C [4], like the deployment of variable renewable energy (VRE). Other options, like CO_2 capture and storage (CCS) are off track. However, CCS is critical to reduce industrial emissions, retrofit existing infrastructure, balance VRE, and achieve negative emissions. Cost remains a significant barrier to the deployment of CCS [3,5] and further cost reductions are critical.

Liquid-gas absorption is the most mature CO_2 capture technology at this moment, but these technologies impose a large energy penalty [6]. More advanced solvents can improve the economic attractiveness of these systems, but the energy penalty remains substantial [7]. An emerging alternative is chemical looping combustion (CLC) [8,9] that offers a promising path for CO_2 capture in power plants at a lower energy penalty thus making the process more cost effective [10]. However, with the rapid growth of VRE, low energy penalty and cost are no longer the only criteria for competitive CCS in the power sector.

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Nomenclature

ACF	Annual cash flow
ASU	Air separation unit
CCS	CO_2 capture and storage
CEPCI	Chemical engineering plant cost index
CLC	Chemical looping combustion
COCA	Cost of CO_2 avoidance
EPCC	Engineering, procurement and construction cost
GE	General electric
GHG	Greenhouse gas
GSC	Gas switching combustion
GT	Gas turbine
HGCU	Hot gas clean-up
HP	High pressure
HRSG	Heat recovery steam generator
HTW	High temperature Winkler
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
LCOE	Levelized cost of electricity
LP	Low pressure
MAWGS	Membrane assisted water–gas shift
NPV	Net present value
O&M	Operating and maintenance
OC	Oxygen carrier
PA	Paris agreement
PSC	Process contingency
PTC	Project contingency
ST	Steam turbine
TIC	Total install cost
TOC	Total overnight cost
TPC	Total plant cost
T&S	Transport and storage
VRE	Variable renewable energy
WGS	Water-gas shift

1.1. The need for flexible power plants

The variable and non-dispatchable nature of VRE impose several costs on the power system. Hirth et al. [11] identified three such costs. The largest of these is the profile cost, related to the temporal variability of wind and solar power. This is the cost of maintaining a large fleet of underutilized dispatchable power plants for generating electricity during times of low wind and sunlight. Such underutilization strongly reduces returns on the capital invested in these plants. This also leads to a difference in power cost per source. For example, the cost of energy produced by a coal or a gas power plants in Germany can worth 50% more than the average unit of energy from wind and solar [12].

The second cost is grid related costs. Wind and solar energy sources are usually concentrated in windy and sunny regions that requires an extended grid to be able to deliver the power from the point of generation to its destination. This cost can amount to € 9.9/MWh [13]. The third VRE integration cost is the balancing cost that arise from the uncertainty in predicting wind and solar output, requiring dispatchable power plants on stand-by. This cost is lower, spanning from € 2–4/MW h at a 40% VRE market share [14].

It can be safely assumed that even though the VRE share will increase in the future, dispatchable thermal power plants will still be required to be kept as a back-up. However, plants with higher capital costs impose higher profile costs on the system when their utilization rate is reduced by the need to balance VRE. CCS involves substantial additional capital to capture, compress, transport, and store CO_2, making them less economically feasible for balancing VRE. Hence, CCS and VRE are often seen as competitors instead of complements [15].

This challenge can be alleviated by designing the plant to produce flexible power and hydrogen, depending on demand. During low VRE output, the power plant can produce electricity, switching to hydrogen production during high VRE output when electricity prices are also low. This shift can keep the utilization level of the power plant high to avoid large profile costs.

Such a plant has previously been proposed for natural gas [16] and shown to significantly reduce the costs and emissions of a low-carbon electricity system [17]. The present study looks to apply the same principle to coal-fired integrated gasification combined cycle (IGCC) plants. Due to the high capital costs of IGCC plants, the need for the high capital utilization in VRE-rich energy systems becomes even greater. Hence, the strategy of flexible power and hydrogen production can be expected to be of great value in natural gas-poor world regions with plans for large expansions of VRE.

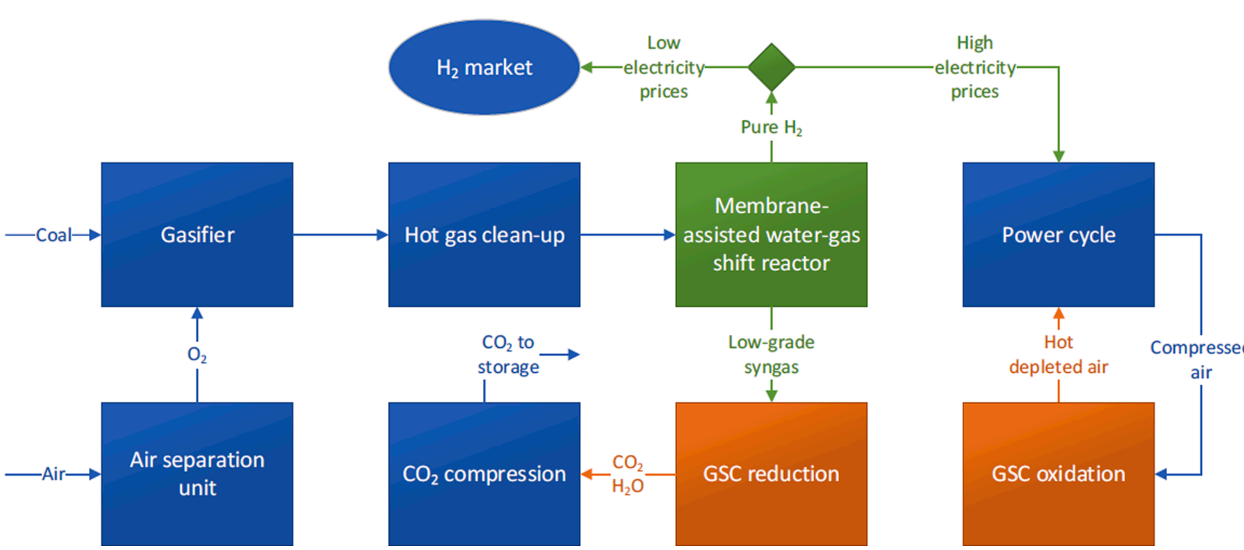

Fig. 1. Simplified schematic of the proposed flexible IGCC power plant layout [21].

Table 1
Plant performance summary.

Plant	Benchmarks		Flexible GSC plants							
	IGCC	IGCC-PCC	GSC-Shell			GSC-HTW		GSC-GE		
Item			Power	H_2 small GT	H_2 10% GT	Power	H_2 small GT	Power	H_2 small GT	H_2 IP sweep
				Power Breakdown						
Heat Input (MW)	1534,1	1794,9	1487,0	1487,0	1487,0	1224,0	1224,0	1569,3	1569,3	1569,3
Net GT (MW)	561,0	585,3	475,5	55,4	29,1	466,0	92,9	525,2	25,8	40,2
Net ST (MW)	333,1	347,3	328,3	40,4	150,9	205,0	0,0	311,7	23,6	22,4
Air/Syngas Expander (MW)	15,5	18,1	17,8	21,5	63,1	12,5	14,1	41,5	37,3	31,4
ASU (MW)	47,4	55,5	58,6	58,6	58,6	20,3	24,0	69,6	69,6	69,6
N_2 compression (MW)	52,0	61,1	0,0	0,0	0,0	0,0	0,0	34,3	0,0	0,0
H_2 compression (MW)	0,0	0,0	19,2	62,1	43,8	19,6	53,8	0,0	73,2	18,4
CO_2 compression (MW)	0,0	40,7	18,7	19,2	35,6	11,6	11,9	15,2	14,9	14,8
Other Auxiliaries (MW)	22,1	46,4	23,0	15,2	19,8	16,2	8,7	21,2	13,0	13,8
*Gross Power (MW)	913,6	955,5	821,6	117,3	243,0	683,5	105,8	879,2	87,5	94,5
Net Power (MW)	792,1	751,8	702,1	−37,8	85,2	615,9	7,4	738,9	−83,2	−22,0
H_2 LHV (MW)	0,0	0,0	0,0	902,7	754,0	0,0	810,8	0,0	1051,3	996,9
				CO_2 Emissions Performance						
**Specific Emissions (kg/MW h)	670,9	70,6	38,3	29,5	30,2	13,2	7,6	11,6	4,0	4,9
CO_2 Capture (%)	0,0	91,5	94,8	94,8	95,6	98,1	98,5	98,4	99,2	99,1
CO_2 Avoidance (%)	–	89,5	94,3	–	–	98,0	–	98,3	–	–
SPECCA (MJ/kg)	–	2,70	1,03	–	–	0,28	–	1,02	–	–
				Plant Efficiencies						
Gross Electrical Efficiency (%)	59,6	53,2	55,3	7,9	16,4	55,8	8,7	56,0	5,1	6,0
Net Electrical Efficiency (%)	51,6	41,9	47,2	−2,5	5,7	50,3	0,6	47,1	−5,8	−1,4
Hydrogen Efficiency (%)	–	–	–	60,7	50,7	–	66,2	–	67,0	63,5
Equivalent Efficiency (%)	–	–	–	57,9	57,0	–	67,0	–	60,3	61,8

*Extra power may be obtained from HGCU.
**Expressed per MWh of electricity or H_2 LHV.

1.2. Gas switching combustion (GSC)

Gas switching combustion (GSC) technology is a promising variant of CLC that eliminates one of the main issues of the chemical looping system: the circulation of solid material from one unit to another under high pressure. In GSC, several reactors are filled with the OC and are used in batch to achieve the same result as in the case of chemical looping. Each reactor is alternately exposed to a fuel stream that reduces the OC to produce an outlet gas of CO_2 and H_2O for inherent CO_2 capture, and an air stream that oxidizes the OC, producing a large CO_2-free stream of hot depleted air for driving a power cycle. Continuous operation requires a coordinated cluster of such reactors, each with a valve system to switch between reduction and oxidation.

Integration of GSC into integrated gasification combined cycle (IGCC) system results a highly efficient energy conversion process. Cloete et al. [18] performed an initial economic analysis of the GSC process in an IGCC system, Arnaiz del Pozo et al. [19] showed that this process can achieve near zero energy penalty with the inclusion of CO_2 capture. High GSC operating temperatures are important for maximizing the process efficiency, which is why a Ni-based OC that is capable of operating at 1200 °C [20] is selected for this work.

The present study proposes GSC-IGCC concepts that consume solid fuel (coal in this case) to produce syngas that can either be combusted to produce power or transformed into hydrogen depending on the demand. Aside from the GSC reactors, the key component securing the flexibility is a membrane-assisted water–gas shift (MAWGS) reactor that extracts hydrogen from the syngas stream. As illustrated in Fig. 1, this hydrogen can either be combusted with the hot depleted air from the GSC oxidation step to fire a highly efficient H-class gas turbine or it can be directly sold to the market. This allows the expensive gasification train and downstream CO_2 handling infrastructure to be used at full capacity, even though the plant is delivering variable electricity output to balance VRE.

Our previous study presented detailed reactor and process simulations of this flexible power plant configuration, illustrating that electric efficiencies exceeding 50% are achievable with almost complete CO_2 capture [21]. The present study adds another configuration using a GE gasifier to the previous assessed configurations using Shell and High Temperature Winkler (HTW) gasifiers and presents a comparative economic assessment of all three cases. in addition, the proposed plants are benchmarked against two reference IGCC plants, one without CO_2 capture and a second using liquid–gas CO_2 absorption for pre-combustion CO_2 capture. In addition to a standard baseload levelized cost of electricity assessment, this study also quantifies the economic benefit of flexible power and hydrogen production in a scenario where these plants are forced into a mid-load role to balance VRE.

2. Methodology

2.1. Power plant simulation

The main process units of the power plants were represented in Unisim Design R451 using the Peng-Robinson thermodynamic model (gasification, syngas treating, etc.) and ASME steam tables (for the bottoming cycle). The dynamic GSC cluster and the membrane reactor (MAWGS) models were developed in Scilab, using an inhouse thermodynamic database for property calculation (Patitug). The models were coupled to the stationary flowsheet via a CAPE-OPEN unit operation. The fuel composition and properties obtained from the integrated GSC-MAWGS power plant model were introduced in the GS code from Politecnica di Milano to determine the gas turbine (GT) performance. The predicted flow rates of air (to the GSC and combustion chamber of the GT, depending on the case) were converged by tuning the fuel input to the stationary model. An iterative procedure was carried out until convergence was reached when both software tools predicted the same air flow.

The present work constitutes an economic assessment of a series of IGCC power plants employing advanced H-class gas turbines for the topping cycle as a baseline in combination with hot gas clean-up for syngas treatment, thus maximizing efficiency. The five cases are defined as follows:

- Case 1: IGCC benchmark power plant without CO_2 capture (IGCC)
- Case 2: IGCC benchmark power plant with pre-combustion CO_2 capture using Selexol^{TM} liquid–gas absorption (IGCC-PCC)
- Case 3: GSC-MAWGS flexible power and hydrogen plant using a Shell gasifier (GSC-Shell)
- Case 4: GSC-MAWGS flexible power and hydrogen plant using a High Temperature Winkler gasifier (GSC-HTW)
- Case 5: GSC-MAWGS flexible power and hydrogen plant using a GE gasifier (GSC-GE)

Block flow diagrams with the main process units for the Benchmark and the GSC-MAWGS power plants are provided in Figs. 7 and 8 in the Appendix, respectively. Detailed process flow diagrams and stream data for all five plants are provided in the Supplementary Information file included in this submission. The plant performance from an energy and CO_2 emissions perspective of Cases 1–4 is presented and discussed in detail in our previous study [21]. The power plant results of all the cases considered in this work are summarized in Table 1, considering both electricity and hydrogen operating modes. The performance parameter definitions are provided in Table 13 in the Appendix.

The Unabated IGCC power plant employs a Shell gasifier for syngas generation [22,23], using an oxidant stream provided by a high pressure ASU which is partially integrated with the GT compressor, to compensate for the negative effect in the compressor performance that a higher volumetric fuel intake presents. The syngas desulphurization takes place at elevated temperature [24], and the product syngas is diluted with compressed N_2 from the ASU (originally available at around 2.6 bar) and IP steam to reduce NOx emissions upon combustion in the GT. Additional electricity is produced from the GT exhaust remnant heat in a three pressure level with reheat HRSG.

On the other hand, in the IGCC-PCC power plant, which has a similar gasification island, the syngas after high temperature clean-up is shifted to H_2 in two adiabatic reactors with intercooling [22,23], while CO_2 is removed with a Selexol unit and finally compressed to delivery pressure after dehydration. All available N_2 from the ASU is mixed with the H_2 rich fuel and, after water saturation and heating, it is combusted in the GT. The steam cycle produces electricity from the exhaust gases, the hot syngas from the gasifier gaseous quench outlet, and the heat released in the WGS reaction.

Regarding the plants with GSC technology, a brief description of their operation in power generation mode is given in the following lines. The GSC-Shell plant uses a low pressure ASU with no GT integration to generate the oxidant stream, to allow the plant to operate flexibly. The syngas after hot gas clean-up (HGCU) is partially bypassed to the GSC reactors and partially shifted in the MAWGS after steam addition from the HP stage steam turbine outlet at around 40 bar. The retentate and bypassed syngas are expanded in the syngas turbine and preheated in a recuperator prior to combustion in the GSC, delivering a pressurized reduction CO_2 stream which, after heat recovery and water knock out, is compressed to 150 bar. The permeate stream, consisting of pure H_2, is compressed to 35 bar and then combusted with the hot depleted air from the GSC oxidation step, to reach operating temperatures of the H-class GT. Extra electricity is produced in a similar way to the benchmark plants in a bottoming steam cycle.

The GSC-HTW plant [25] makes use of the GSC reduction outlet to preheat a coal-water slurry feed. Gasification occurs in the preheating unit to a certain degree which, together with the low HTW operating temperature, reduces the O_2 demand from the ASU considerably. The syngas is cooled down in a recuperator and in a small exchanger which generates some HP steam prior to HGCU. A similar bypass configuration to the previous plant is adopted, but in this case the expanded syngas from the turbine is preheated with the gasification outlet.

Finally, in the GSC-GE plant, a slurry feed is gasified at 80 bar and cooled to around 800 °C in a partial water quench. After slag removal the syngas is further cooled generating HP steam, with a configuration similar to Uebel et al. [26]. The steam to CO ratio in the syngas required for the shift conversion is controlled through the partial quench, so there is no need for steam extraction from the bottoming cycle. The MAWGS-GSC-Recuperator setup is identical to the Shell case. However, due to the high pressure of the syngas, permeation of H_2 is enhanced in the MAWGS. This allows using a compressed N_2 stream from the ASU as sweep gas inside the membranes, in order to deliver a pressurized H_2-rich fuel to the firing chamber (avoiding the need for H_2 cooling and compression from a low permeate pressure). This N_2 sweep increases the volumetric flow rate of fuel to the GT, relative to the previous GSC configurations, bringing the GT operating point close to the nominal natural gas fired efficiency values. The bottoming cycle follows similar assumptions as before, although a fraction of the heat contained in the reduction gases after the recuperator is used to preheat the coal-water slurry feed to 250 °C [27].

Finally, regarding the GSC plant operation in H_2 mode presented in this work, the H-class GT is shut down for all configurations (cases *H_2 small GT* in Table 1), and most of the heating value is retrieved as pure H_2 in the MAWGS permeate at low pressure (imposed to maximize H_2 permeation), which is cooled and compressed to 150 bar. The remaining low-grade syngas is sent to the GSC which is integrated with a small, *ad hoc* GT to deliver and expand a small oxidation step flow to and from the cluster to deliver the oxygen needed to combust the syngas with integrated CO_2 capture. The exhaust heat after expansion in the small GT is used primarily for water economization to satisfy the demand of the syngas coolers in the plants with Shell and GE gasifiers: only the HP stage turbine is operative at part load to expand the HP steam generated in these units. Depending on each case, the remaining low temperature heat is retrieved as IP or LP steam product which is exported outside the plant battery limits.

For comparison, two alternative H_2 modes were also considered: one for the GSC-Shell plant consisting of ramping down the H-class GT to 10% of its nominal power output (case *H_2 10% GT* in Table 1), thus avoiding the small GT and associated costs, and another for the GSC-GE plant in which, because of the high syngas pressure from the GE gasifier, the membrane reactor is operated with IP steam sweep to produce the H_2 product at a much higher pressure, thereby minimizing the H_2 compression cost (case *H_2 IP sweep* in Table 1). The GSC-Shell case with the 10% GT operation was investigated in detail in our prior study [21], but Table 1 shows that it performs considerably worse than the case with the small GT due to the poor power cycle efficiency under such a low load. In addition, the capital cost savings this case achieved by avoiding the additional small GT are cancelled out by the need to oversize the syngas expander and CO_2 compressors due to the reduction in GT pressure ratio under part-load operation. Hence, this case was discarded for further investigation in the present study. However, the GSC-GE case with IP steam sweep brought significant H_2 equivalent efficiency gains and capital cost reductions by avoiding most of the hydrogen compression requirements, and therefore this case was selected for further investigation. In summary, all three GSC cases analysed in the remainder of this study use the small GT in H_2-production mode, with the GSC-GE case also employing the IP steam sweep in the MAWGS to minimize H_2 compression costs.

2.2. Economic assessment

The economic assessment methodology applied in the evaluation of the plants comprises three major components: capital cost estimation, fixed and variable operating cost estimation, and a discounted cash flow analysis for quantifying the levelized cost of electricity and the CO_2 avoidance cost. For evaluating the value of flexible power and hydrogen production, the cash flow analysis is used to calculate the expected investment returns under given assumptions of electricity and hydrogen prices.

2.2.1. Capital cost estimation

The capital cost estimation methodology for the GSC reactor follows

Table 2
Scaling parameters, reference costs, capacities and scaling exponents for the case without CO_2 capture applied in Eq. (1).

Equipment	Scaling parameter	Reference cost (M€)	Reference capacity	Scaling exponent	Year	Refs.
ASU	Oxygen produced [kg/s]	64.48	26.54	1	2011	[22]
Coal handling	Coal input [kg/s]	49.50	32.90	1	2011	[22]
Ash handling	Ash flowrate [kg/s]	16.00	4.65	1	2011	[22]
HRSG	ST gross power [MW]	35.46	182.36	1	2011	[22]
Gas turbine	GT gross power output [MW]	109.20	520.00	1	2020	[29]
Steam turbine	ST gross power [MW]	55.00	182.36	1	2011	[22]
Condenser	ST gross power [MW]	40.56	182.36	1	2011	[22]
Gasifier	Thermal input [MW]	162.00	828.02	1	2011	[22]
Hot gas clean-up	Syngas flowrate [kg/s]	43.52	75.26	1	2011	[22]

Table 3
Reference costs, capacities and scaling exponents for the cases with CO_2 capture applied in Eq. (1).

Equipment	Scaling parameter	Reference cost (M€)	Reference capacity	Scaling exponent	Year	Refs.
Air separation unit	Oxygen produced [kg/s]	72.80	31.45	1	2011	[22]
Coal handling	Coal input [kg/s]	53.89	38.72	1	2011	[22]
Ash handling	Ash flowrate [kg/s]	17.42	5.48	1	2011	[22]
HRSG	ST gross power [MW]	34.10	168.46	1	2011	[22]
Gas turbine	GT gross power output [MW]	109.20	520.00	1	2020	[29]
Steam turbine	ST gross power [MW]	52.00	168.46	1	2011	[22]
Condenser	ST gross power [MW]	39.00	168.46	1	2011	[22]
Shell gasifier	Thermal input [MW]	180.00	954.08	1	2011	[22]
HTW gasifier and pre-gasifier	Thermal input [MW]	180.00	954.08	1	2011	[22]
GE gasifier	Thermal input [MW]	96.48	954.08	1	2011	[22,27]
Hot gas clean-up	Syngas flowrate [kg/s]	46.12	89.21	1	2011	[22]
Selexol™ CO_2 capture unit	Captured CO_2 [kg/s]	45.00	83.47	1	2011	[22]
WGS unit	Syngas flowrate [kg/s]	21.12	89.21	1	2011	[31]
CO_2 compression and condenser	Compressor power [MW]	30.00	20.69	1	2011	[22]
Membranes	Surface area [m^2]	0.006	1.00	1	2017	[32]

a similar approach as in the previous study regarding gas switching reforming [16]. The reactor wall is divided into three major parts, from inside to outside the first layer is to withstand the corrosion and abrasion load of the fluidization environment. This is assumed to be a 0.005 m thick Ni-alloy layer. The second layer is the 0.54 m thick heat insulating layer. The thickness is calculated using the heat balance assuming 1200 °C inner temperature and 80 °C outer wall temperature. The temperature of the external environment is assumed to be 25 °C. The outermost layer of the reactor is a carbon steel shell responsible for carrying the pressure load of 23.3 bar. The initial load of OC and the valves [28] are also added to the installed cost of the GSC reactors.

Major units are grouped and their capital cost is estimated based on a chosen scaling parameter according to the results of Franco et al. [22]. The capital cost of the gas turbine is obtained according to the Gas Turbine Handbook [29]. In this study, the same GT machine is used in all the plants. Hence, its cost is identical in all cases, even though the net power output varies due to changes in the mass flow rate of fuel added to the combustor. The general equation used for the calculation is presented in (Eq. (1)). C_0 and Q_0 are the reference cost and capacity of the evaluated unit, and M is an exponent that depends on the equipment type. Because of significant technological differences, separate parameters are used in the cases with and without CO_2 capture. Tables 2 and 3 presents the parameters used for the estimation of the capital cost for the cases without and with CO_2 capture, respectively. The results obtained are updated for 2018 using Chemical Engineering Plant Cost Index (CEPCI) [30].

$$C = C_0 * \left(\frac{Q}{Q_0}\right)^M \quad (1)$$

The capital cost estimation parameters presented in Table 2 were applied for the estimation of the capital cost of the IGCC reference case, according to Eq. (1).

A scaling exponent of 1 is selected because the plants are designed according to the air throughput to the H-class GT that had to be simulated using an in-house code calibrated to a specific machine. In the detailed design of such a plant, the gasification train, being the most expensive section of the plant, would be sized for optimum economies of scale and an appropriately sized gas turbine would be selected as a secondary consideration. For example, the IGCC-PCC plant in Table 1 has a 47% larger gasification train than the GSC-HTW case, and, since the gasification train is around 5x more expensive than the gas turbine, the use of conventional scaling exponents (~0.67) would bias the results towards the less efficient IGCC-PCC plant. In addition, the plants in this study are about twice the size of the plants for which the reference costs were derived [22] and may require parallel gasification trains. In this case, the use of typical scaling factors will produce overly optimistic results.

The parameters employed for estimating the costs of the plants with CO_2 capture are presented in Table 3. Most of the parameters are obtained from the results of Franco et al. [22]. The reference cost and reference size parameters for the WGS unit are obtained from the results of Spallina et al. [31]. As for the unabated plant, the parameters for the gas turbine cost estimation is obtained from Gas Turbine Handbook. The parameters for the cost estimation of the membrane are obtained from the work of Plazaola et al. [32]. The capital cost estimation described by Turton et al. [33] is used in the estimation for the N_2 compression, intercoolers, and other heat exchangers. Hydrogen compressors are assumed to have the same capital costs as CO_2 compressors.

Table 4
Estimation methodology for the TOC of the plant.

Component	Definition
Total install cost (TIC)	Sum of all install costs
Process contingency (PSC)	10–30% of TIC
Engineering procurement and construction costs (EPCC)	14% of (TIC + PSC)
Project contingency (PTC)	12% of (TIC + PSC + EPCC)
Total plant costs (TPC)	TIC + PS + EPCC + PTC
Owners cost	18% of TPC
Total overnight costs (TOC)	TPC + Owners costs

Table 5
Fixed and variable operating & maintenance cost assumptions.

Fixed O&M costs		
Maintenance and labour for the case without CO_2 capture	50	€/kW/year
Maintenance and labour for the cases with CO_2 capture	56	€/kW/year
Variable O&M costs		
Cost of coal	2.5	€/GJ LHV
Cost of ash disposal	9.73 [35]	€/t
Process water costs	6	€/t
Cooling water make up costs	0.325	€/t
Oxygen carrier replacement	12,500 [16]	€/t
Selexol™ replacement	5000 [22]	€/t
WGS catalyst replacement	12,978 [36]	€/m^3
Membrane replacement	6000 [32]	€/m^2
CO_2 transport and storage	10	€/t

Table 6
Cash flow analysis assumptions.

Economic lifetime	25 years
Discount rate	8%
Construction period	4 years
Capacity factor	85%
First year capacity factor	65%

Table 7
Installed costs for the five cases.

Unit	IGCC	IGCC-PCC	GSC-Shell	GSC-HTW	GSC-GE
Heat exchangers		39.81	32.32	14.68	33.05
Gas Switching Island			99.39	99.39	99.39
ASU	129.26	144.09	119.37	41.31	130.64
Coal handling	94.43	102.20	84.67	69.69	89.36
Ash handling	30.52	33.03	27.37	22.53	28.88
Membrane assisted WGS			84.70	76.54	105.03
Gas Turbine	109.20	109.20	109.20	109.20	109.20
Steam Turbine	108.48	112.30	106.15	66.29	100.79
HRSG	67.78	73.64	69.61	43.47	66.09
Condenser	77.52	84.23	79.61	49.72	75.59
Gasifier	309.06	348.68	288.88	238.95	163.41
Hot gas clean up	73.55	76.82	69.62	49.46	119.92
WGS		31.98			
CO_2 compression		57.80	34.86	23.03	33.80
Selexol™ plant		87.81			
Hydrogen compression			28.09	28.59	
N_2 compressor	32.54	35.03			18.00
Total Install cost (M€)	1032.34	1336.64	1233.82	932.84	1173.16
Total overnight cost (M€)	1555.33	2013.78	1858.88	1405.42	1767.48
Net power output (MWe)	792.11	751.85	702.13	615.95	738.92
Specific investment cost (€/kWe)	1963.52	2678.44	2647.48	2281.72	2391.99

Costs of the Shell gasifier are given in Franco et al. [22], but not for HTW and GE gasifiers. The GE gasifier will be considerably cheaper, given its use of a simple slurry feed system instead of dry lock hoppers and replacement of the syngas effluent cooler with a simple water quench. This gasifier was taken to be 53.6% of the cost of the Shell gasifier based on a comparative assessment by [27]. The HTW gasifier and pre-gasifier are assumed to cost the same as the Shell gasifier. This assumes that the HTW fluidized bed gasifier is roughly the same cost as the Shell gasifier and syngas effluent cooler, while the pre-gasifier and slurry pumps have similar costs to the lock-hoppers with CO_2 feed system.

Table 4 presents the methodology applied for the calculation of the total investment cost for each plant. The process contingency (PSC) is applied in the case of proposed new technologies. This is applied for the GSC reactors (a PSC of 30%) and the hot gas clean-up unit (a PSC of 10%). Project contingency (PTC) and Owners cost are estimated at 12% and 18%, respectively in line with the recommendations of Rubin et al. [34]. This sums to 30%, which is double the project contingency recommended in Franco et al. [22] to account for the uncertainty related to the construction of IGCC power plants.

2.2.2. Operating and maintenance cost

The assumptions for the fixed and variable operating and maintenance (O&M) costs are presented in Table 5. The operating labour cost is included in the maintenance cost and is scaled according to the gross power output of the plant according to Franco et al. [22] for both without and with CO_2 capture cases. References are provided in the table for the costs applied.

The oxygen carrier selected for the process is a NiO based material, to maintain continuity with our previous works [16]. OC lifetime can have a significant effect on the economic indicators of the plant, in the present work this is assumed to be two years. Similarly, a catalyst lifetime of 2 years is assumed for the WGS catalyst. The membrane lifetime is assumed to be higher, 5 years [32]. The assumed Selexol™ loss is 58 g/MWh gross [22] in Case 2.

2.2.3. Cash flow analysis

The key assumptions of the discounted cash flow analysis are listed in Table 6. The parameters are selected in order to maintain continuity with our previous works on flexible power and hydrogen production from natural gas [16]. The levelized cost of electricity (LCOE) is calculated using the cash flow analysis. All costs and additional revenue are considered and the LCOE is calculated for a net present value (NPV) of zero at the end of the economic lifetime, given a specified discount rate. The NPV is calculated using Eq. (2). Here, i is the discount rate and ACF is the annual cash flow in every year over a 4-year construction and 25-year operating period.

In the cases evaluating the value of flexible power and hydrogen production, the electricity and hydrogen prices are fixed, and the discount rate is calculated to result in a NPV of zero at the end of the plant lifetime. This discount rate is an indication of the expected return on investment that can be expected from constructing and operating the different plants.

$$NPV = \sum_{t=0}^{n} \frac{ACF_t}{(1+i)^t} \tag{2}$$

$$COCA\left(\frac{€}{tCO_2}\right) = \frac{LCOE_{cc} - LCOE_{ref}}{E_{ref} - E_{cc}} \tag{3}$$

Eq. (3) presents the equation used for the calculation of the cost of CO_2 avoidance (COCA). In the equation, $LCOE$ represents the levelized cost of electricity and E the specific CO_2 emissions of the plant, respectively. Subscript CC denotes the plant with CO_2 capture and ref the reference plant without CO_2 capture (Case 1), respectively.

3. Results and discussion

3.1. Baseload power production

Table 4 shows the capital cost breakdown of all five plants according to the methodology outlined in Section 2.2.1. As described earlier, all plants use the same air flow rate fed to the same gas turbine. Hence, the gas turbine costs are identical for all plants. A few other key features of the different plants can also be highlighted here. As indicated in Table 1,

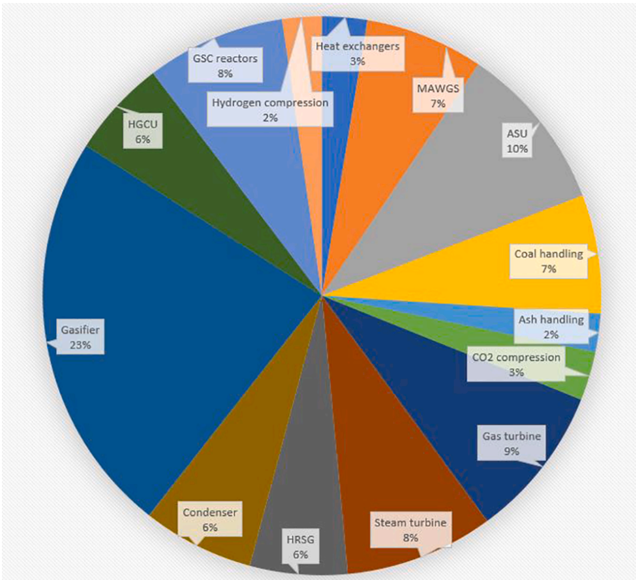

Fig. 2. Share of the units install cost in the TIC of the GSC-Shell case.

Table 8
O&M costs for the different cases.

Fixed O&M costs (M€/year)	IGCC	IGCC-PCC	GSC-Shell	GSC-HTW	GSC-GE
Maintenance incl. labour	45.68	53.51	46.01	38.28	49.24
Variable O&M costs (M€/year)					
Cost of coal	102.88	120.36	99.72	82.08	105.24
Cost of ash disposal	2.25	2.63	2.18	1.80	2.30
Process water	5.45	11.18	2.89	2.63	2.83
Cooling water consumption	2.16	2.05	1.91	1.68	2.01
Oxygen carrier replacement			4.05	4.05	4.05
WGS catalyst replacement		0.88	0.76	0.63	0.81
Membrane replacement			9.61	9.61	9.61
Selexol™ make up		2.08			
CO_2 transport and storage		42.43	37.77	31.44	41.23
Total cost (M€/year)	**158.39**	**235.10**	**204.90**	**172.19**	**217.32**
Specific operating cost (€/MW h)	**26.84**	**41.97**	**39.17**	**37.52**	**39.47**

the IGCC, IGCC-PCC, and GSC-GE plants get considerably more power out of the same gas turbine than the GSC-Shell and GSC-HTW plants due to the added feed of N_2 to the combustor. However, the added N_2 feed contributes significant additional costs and power consumption for N_2 compressors. The GSC-HTW plant has particularly low bottoming cycle costs (steam turbine, HRSG, condenser) due to the very high cold gas efficiency of the gasifier and pre-gasifier arrangement. Hence, almost all the energy contained in the fuel can be fed through the topping cycle, avoiding a large amount of steam generation for the bottoming cycle to recover heat from the gasifier in the other plants. The pre-gasifier also strongly reduces the oxygen demand, causing much lower ASU costs. The GSC-GE plant achieves large savings via the cheaper gasifier, although some of this benefit is lost by having a much more expensive HGCU unit to treat the syngas diluted with a large amount of steam from the quench. In addition, the N_2 sweep through the membranes in this case avoids the added cost of hydrogen compressors.

When considering the specific investment costs, the addition of conventional pre-combustion CO_2 capture adds 36.5% to the cost of the conventional IGCC plant. About half of this cost increase arises from the added process units required for CO_2 capture, with the other half coming from the large efficiency penalty (Table 1) that reduces the power output from the invested capital by almost 19%. The GSC-Shell case shows almost the same costs as the IGCC-PCC benchmark, indicating that the savings related to higher plant efficiency and avoidance of the WGS and Selexol units are cancelled out by the addition of the GSC and MAWGS reactors. The other two GSC plants show considerably lower specific investment costs. As outlined earlier, this is mainly due to the lower ASU and power cycle costs for the GSC-HTW case and the lower gasifier cost for the GSC-GE case. The high efficiency of the GSC-HTW case also reduces the specific capital cost of the gasification train by getting more power out a given fuel input.

Table 9
LCOE and COCA indicators for the evaluated cases.

	IGCC	IGCC-PCC	GSC-Shell	GSC-HTW	GSC-GE
LCOE [€/MW h]	54.28	80.89	77.63	70.68	76.24
COCA [€/ton]		44.29	36.87	24.90	30.25

The innovative technologies in the proposed configurations are the Gas Switching Island, the Membrane assisted WGS reactors and the Hot gas clean up unit. The share of these new technologies in the TIC of the GSC-Shell case is about 20%, as represented in Fig. 2. These are the units with the highest cost uncertainty, implying that the cost of the entire plant will not be overly sensitive to significant changes in the cost estimates of these novel units.

The fixed and variable operations and maintenance costs are presented in Table 8 together with the specific operational cost. Fuel costs represent the largest cost share, followed by fixed O&M and CO_2 transport and storage. Among the minor cost components, the GSC-MAWGS plants save considerable process water costs by recovering a large quantity of water from the GSC reduction outlet gases, but this saving is cancelled out by significant oxygen carrier and membrane replacement costs. Ultimately, the main differentiator in the specific operating cost of the plants with CO_2 capture is the plant efficiency that is inversely proportional to fuel and CO_2 transport and storage costs. The IGCC benchmark plant has substantially lower specific operating costs due to the avoidance of CO_2 transport and storage costs.

The key performance indicators of the plants, LCOE and COCA are presented in Table 9. The LCOE obtained for the two reference cases show the benefits offered by the advanced gas turbine and HGCU technology. In a previous study [18], using a similar methodology, the IGCC benchmarks with a less advanced F-class turbine and conventional cold gas clean-up returned LCOE values of 63.4 and 95.3 €/MWh for the cases without and with CO_2 capture, respectively. The aforementioned study also contained a supercritical pulverized coal benchmark plant that returned a LCOE of 55.7 €/MWh, indicating that these advanced components make IGCC technology competitive with conventional Rankine cycle coal plants.

Table 9 also shows that the GSC-MAWGS plants outperform the IGCC-PCC benchmark. For the GSC-Shell case, capital costs are similar, so the primary benefit is the reduction fuel and CO_2 T&S costs (Fig. 3). However, the other two novel plants also offer significant capital cost reduction (Table 7), further increasing the economic benefit. Thanks to having the lowest capital costs and the highest efficiency, the GSC-HTW configuration reduces LCOE by more than 10 €/MWh relative to the IGCC-PCC benchmark.

Szima et al. [37] presents a detailed sensitivity analysis of the GSC-IGCC process, the highest effect being observed in the case of the coal price and the capacity factor of the plant. OC lifetime and reactor design assumptions have a smaller contribution to the LCOE. Similar conclusions will hold for the present study. An important novelty in the plants evaluated in this work is the MAWGS reactor. With this in mind, the variation of the LCOE is evaluated considering a wide range of the membrane cost. The calculation is performed in the GSC-Shell case. As shown in Table 10 a six-fold drop in the membrane cost equals a LCOE

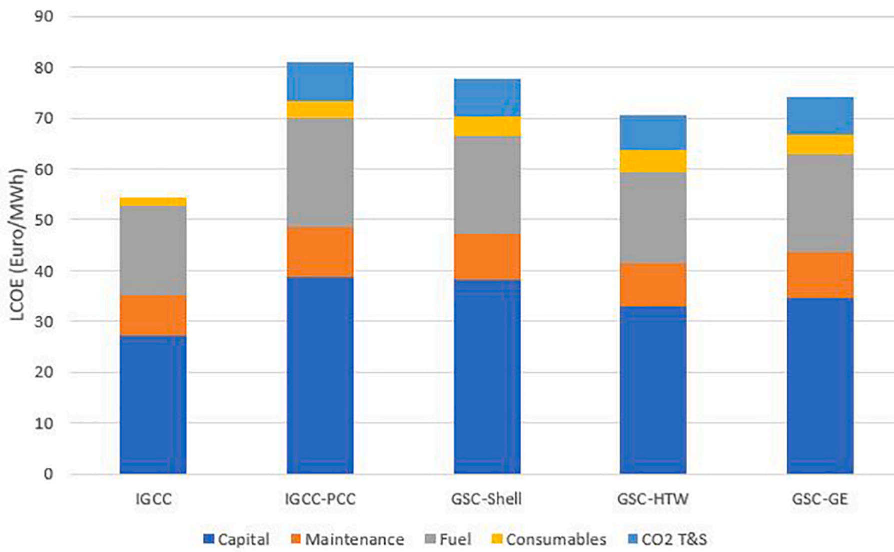

Fig. 3. LCOE breakdown for the evaluated cases.

Table 10
LCOE variations with membrane cost.

Membrane cost (€/m^2)	LCOE	Variation
1000	74.63	−3.86%
6000	77.63	
12,000	81.22	+4.63%

Table 11
Assumption for the economic assessment of mid-load plants.

Grid average electricity price	60 €/MW h
Mid-load price premium	10–40 €/MW h
Hydrogen sales price	€1.35/kg
Capacity factor	45%
H_2 capacity factor	45%
First year capacity factor	30%
CO_2 price	30–100 €/ton
CO_2 T&S cost for IGCC & GSC	15 & 10 €/ton

drop of around 4% whereas doubling the cost leads to an increase of around 4.6%.

This section presented the results of the common practise baseload economic analysis when assessing new technologies and comparing to available options. However, considering the increasing share of VRE and CO_2 taxes, one can expect for these plants to operate below baseload conditions (capacity factor significantly lower than 85%). Therefore, the plants discussed in this section are also evaluated under mid-load conditions in the next section.

3.2. Flexible power and hydrogen production

Similar to our previous study on flexible power and hydrogen production from natural gas [16], the present work will evaluate the value of flexibility by comparing mid-load power plants responsible for balancing variable renewables at a capacity factor of 45%. Given that the electricity sales price will be considerably higher during times of low wind and sun when such mid-load plants are producing power, an electricity sales price premium of 10–40 €/MWh over the average grid electricity price of 60 €/MWh is explored. In addition to this higher sales price, the GSC-MAWGS plants also sell hydrogen to the market at a conservatively low price of €1.35/kg relative to alternatives [38] to maximize the utilization of plant capital. This flexibility also maximizes the utilization of downstream CO_2 T&S infrastructure, reducing the cost of storing CO_2 relative to the benchmark cases where this infrastructure is only utilized half the time. The main assumptions for the calculation are summarized in Table 11.

Table 12
Capital cost increase to ensure flexible operation.

Plant configuration	Baseload capital cost (€/kW)	Flexible capital cost (€/kW)
GSC-Shell	2647.48	2792.11
GSC-HTW	2281.72	2485.83
GSC-GE	2391.99	2463.92

In this analysis, the total capital cost of the GSC-MAWGS plants increase relative to the numbers shown in Table 7, mainly due to the addition of the small GT for operation during H_2 production mode and the larger H_2 compression train needed to export a large amount of hydrogen at 150 bar. As shown in Table 12, the GSC-GE plant is the least expensive in flexible mode, mainly due to the large saving in hydrogen compressor costs achieved by sweeping the membranes with IP steam at 40 bar. The GSC-HTW plant sees the largest cost increase due to high hydrogen compression costs and the need to install the largest additional gas turbine of the three plants.

The cash flow analysis is completed using the fixed hydrogen price and range of electricity prices listed in Table 11 to calculate the discount rate that results a net present value of zero at the end of the economic lifetime of each plant. The discount rate is an indicator of the attractiveness of the investment. The higher the value, the higher the return on the investment.

Assuming a CO_2 tax of zero, Fig. 4 presents the effect of the electricity price premium variation on the evaluated power plants. The value of flexible power and hydrogen production is clearly illustrated by the good performance of the GSC-MAWGS plants, particularly the GSC-HTW

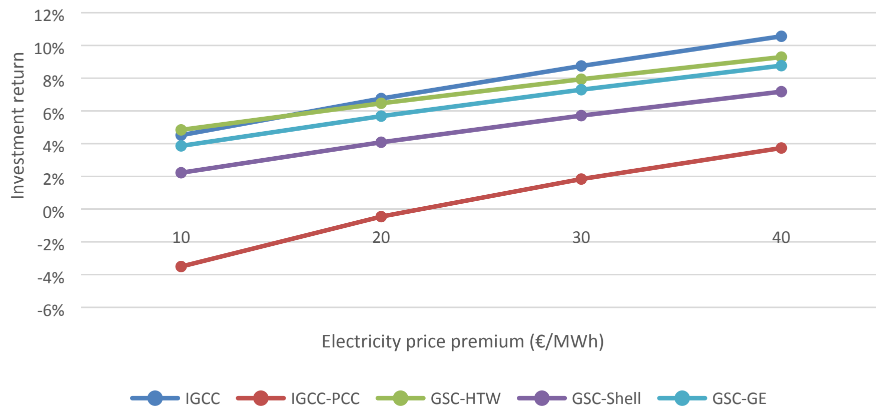

Fig. 4. Investment return as a function of the electricity price premium assuming a CO_2 tax of €0/ton.

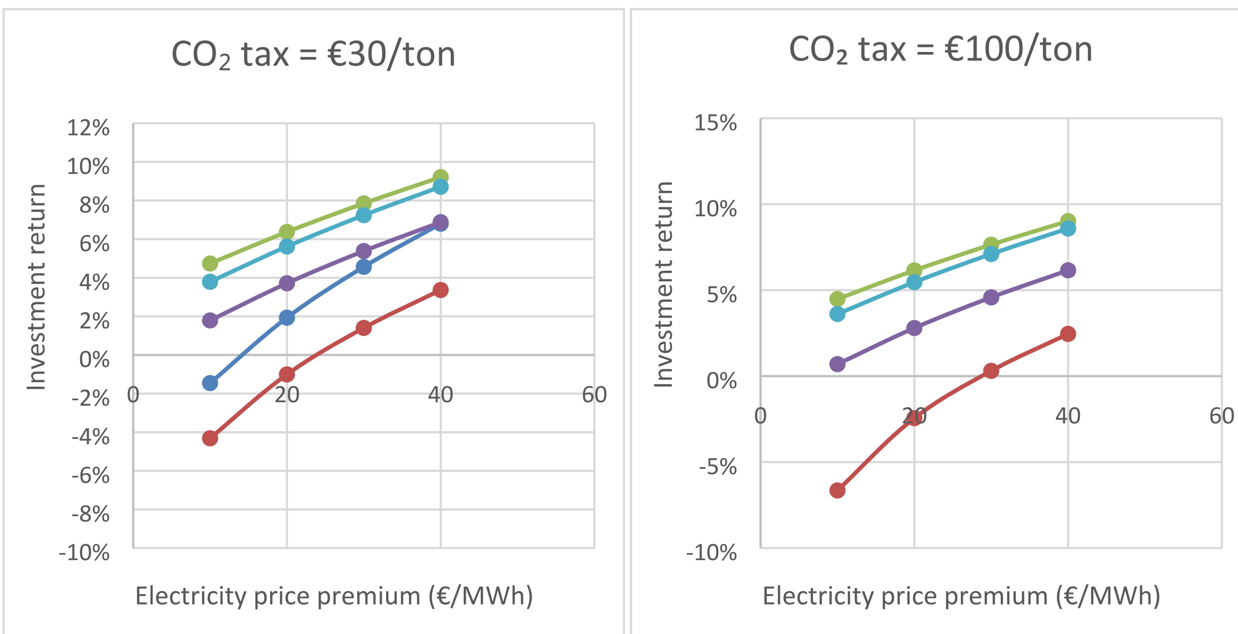

Fig. 5. Investment return as a function of the price premium.

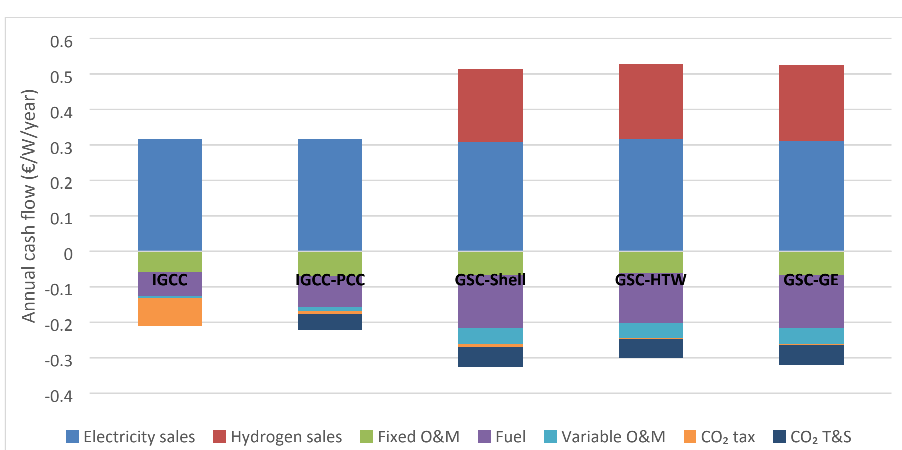

Fig. 6. Breakdown of annual operating cash flow at a CO_2 tax of €30/ton and a price premium of €20/MWh.

and GSC-GE cases. These plants show competitive performance with the unabated IGCC benchmark, even without any CO_2 pricing. At a moderate electricity price premium of 20 €/MWh, these plants offer a reasonable return of around 6%, whereas the IGCC-PCC benchmark results in a small loss. In terms of investment returns, the 6%-point premium offered by the best GSC-MAWGS configurations over the IGCC-PCC benchmark is very attractive.

Fig. 5 presents the results of the discounted cash flow analysis for the evaluated cases when a CO_2 tax higher than zero is considered. Given the very high CO_2 avoidance of the GSC-HTW and GSC-GE plants (Table 1), the investment returns from these plants are almost unaffected by the CO_2 tax. A mild effect can be seen for the GSC-Shell and ICGG-PCC cases, which emit 3-5x more CO_2. The unabated IGCC plant becomes less attractive than all the GSC-MAWGS plants at a 30 €/ton CO_2 tax and yields negative returns at all electricity price premiums when the tax exceeds 50 €/ton. The IGCC case was omitted from the graph with the CO_2 tax of € 100/ton because this gave values for the investment return below −10% or did not give any result because the high costs associated with the CO_2 tax resulted in negative free cash flow.

Due to the minor increase in capital costs to achieve flexibility shown in Table 12, the GSC-GE case shows almost similar returns to the GSC-HTW case. This is notable, given that the GE gasifier is substantially simpler and lower risk than the HTW gasifier with pre-gasification system. This case also automatically dilutes the H_2 fuel with N_2 to ensure low-NOx combustion of the fuel. A risk-reward analysis may therefore favour the GSC-GE case, even though it shows slightly lower returns in this assessment. The GSC-Shell case appears to be clearly inferior to the GSC-GE case, returning about 2%-points per year less on the invested capital.

Fig. 6 presents a breakdown of the operating income and expenses of the plants for one year assuming a CO_2 tax of 30 €/ton and a price premium of 20 €/MWh. The high CO_2 emissions of the IGCC case substantially increases the expenses, resulting a similar net income as in the IGCC-PCC case. The substantial additional revenue from hydrogen sales is evident for all GSC cases. Although the expenses are also higher mainly because of the increased fuel and CO_2 T&S costs, the result is a substantial increase in net-income relative to the reference cases. Fig. 6 reemphasizes the advantage of the GSC-HTW case, the same income can be expected as in the case of the GSC-GE case however at a smaller expense.

4. Summary and conclusions

This paper evaluates a novel integration of gas switching combustion (GSC) and membrane-assisted water gas shift reactors into an integrated gasification combined cycle (IGCC) power plant. The evaluated plants can flexibly produce electricity or hydrogen with integrated CO_2 capture depending on electricity demand. This flexibility ensures high capital utilization in power systems with high shares of VRE where baseload power plants become uneconomical.

Three GSC options are evaluated based on three different gasification systems: Shell, High Temperature Winkler (HTW), and GE, both under baseload and flexible operation. Benchmark plants used for the comparison are an unabated IGCC system and an IGCC system with conventional pre-combustion CO_2 capture (PCC). All plants make use of an advanced H-class gas turbine and hot gas clean-up to ensure maximum efficiency, which makes IGCC technology competitive with conventional supercritical pulverized coal plants. In the baseload assessments, the GSC plants achieve a cost of CO_2 avoidance in the range of 24.9 and 36.9 €/ton, lower than for the IGCC-PCC benchmark (44.3 €/ton). The GSC-HTW configuration achieved the lowest cost, although it faces significant technological uncertainty from the pre-gasification heat exchanger employed to maximize cold gas efficiency. These calculations assumed a capacity factor of 85%, which is not realistic given the rise of variable renewable energy.

A more realistic mid-load comparison is also performed that represents the flexible operation of the GSC plants. This calculation assumed a capacity factor of 45% for power generation and 45% for hydrogen production with an average electricity price of 60 €/MWh and hydrogen price of 1.35 €/kg. Due to the ability to sell hydrogen during times of low electricity prices, the flexible GSC plants give similar returns to the IGCC case, even when there is no CO_2 price. This shows the value of maximizing the utilization of the expensive gasification train by continuing to produce hydrogen when electricity demand is met by renewables. The added CO_2 tax makes the GSC plants a significantly more attractive investment option presenting about 6%-points better investment returns than the IGCC-PCC benchmark. In flexible operation, the GSC-GE case achieves only marginally lower returns than the GSC-HTW case, but it promises a significant reduction in plant complexity and technical risk. Thus, the efficient, flexible, and cost-effective GSC power and hydrogen plants with HTW or GE gasifiers present attractive value propositions to regions with limited natural gas resources and large wind and solar expansion plans, provided the successful establishment of the hydrogen economy.

CRediT authorship contribution statement

Szabolcs Szima: Methodology, Formal analysis, Investigation, Writing - original draft. **Carlos Arnaiz del Pozo:** Methodology, Formal analysis, Investigation, Writing - original draft. **Schalk Cloete:** Conceptualization, Methodology, Formal analysis, Writing - original draft, Supervision, Funding acquisition. **Paolo Chiesa:** Formal analysis, Writing - review & editing. **Ángel Jiménez Alvaro:** Writing - review & editing, Supervision, Funding acquisition. **Ana-Maria Cormos:** Writing - review & editing, Supervision, Funding acquisition. **Shahriar Amini:** Writing - review & editing, Project administration, Funding acquisition.

Declaration of Competing Interest

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

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Appendix

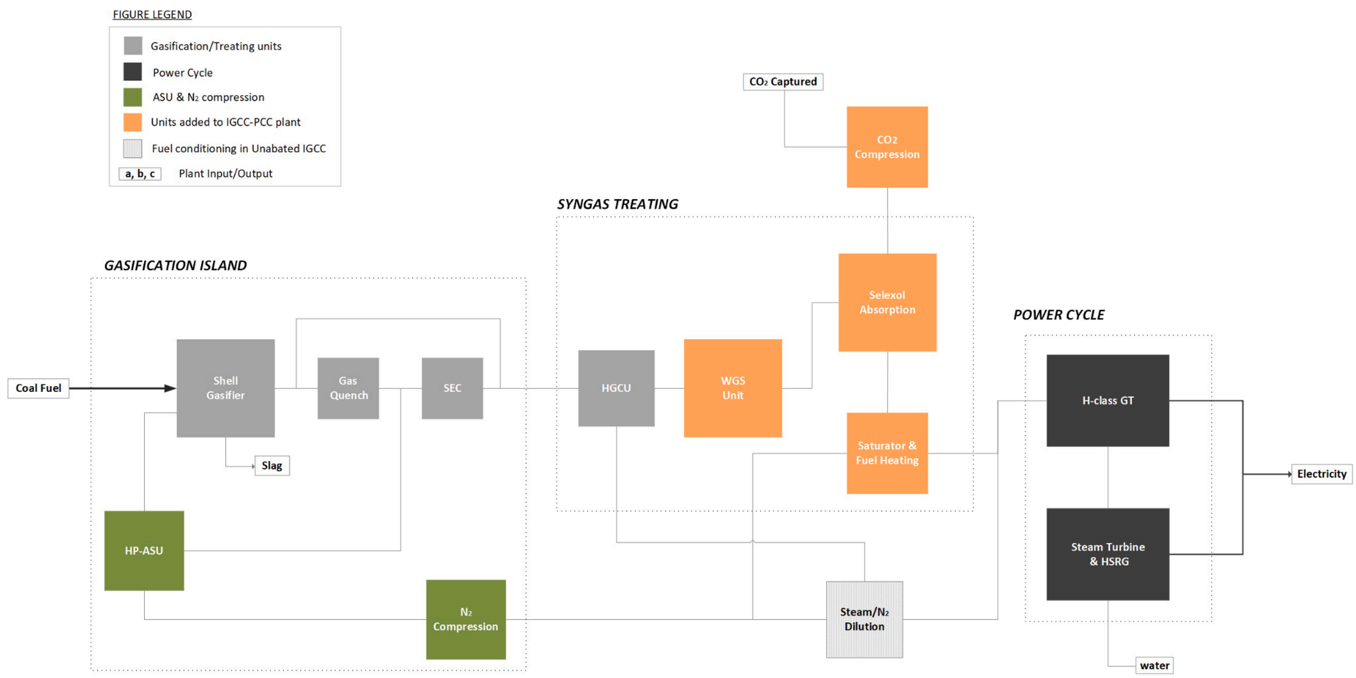

Fig. 7. Block flow diagram of IGCC benchmark plants.

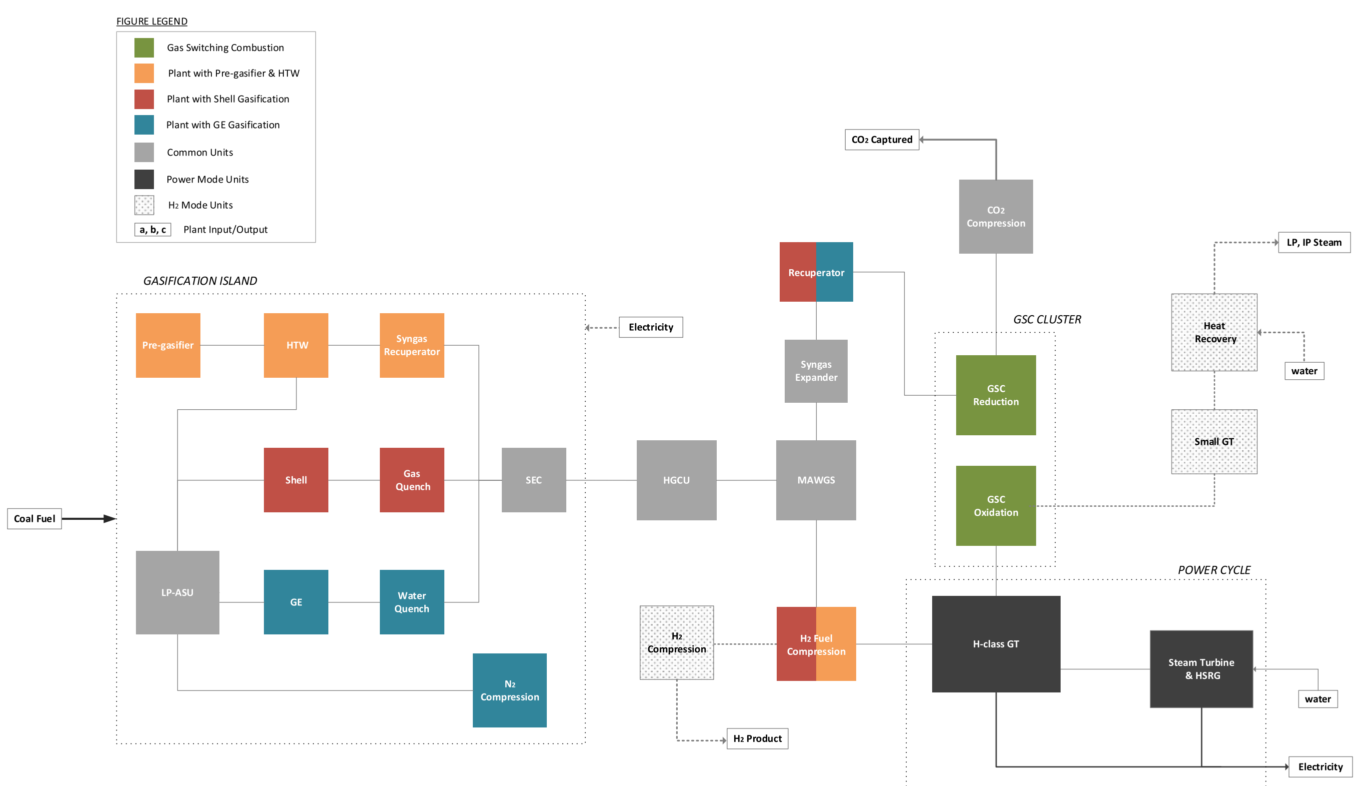

Fig. 8. Block flow diagram of the flexible GSC-MAWGS IGCC power plants.

Table 13
Plant performance parameter definition.

Net electrical Efficiency	$\eta_t^w = \frac{\dot{W}_{net}}{\dot{m}_{coal} LHV_{coal}}$
H_2 Efficiency	$\eta_t^{H_2} = \frac{\dot{m}_{H_2} LHV_{H_2}}{\dot{m}_{coal} LHV_{coal}}$
H_2 Equivalent Efficiency	$\eta_{t,eq}^{H_2} = \frac{\dot{m}_{H_2} LHV_{H_2}}{\dot{m}_{coal} LHV_{coal} - \frac{\dot{W}_{net}}{\eta_{ref}}}$
CO_2 Avoidance	$A_{co_2} = \frac{E_{CO_2,Ref} - E_{CO_2,CCS}}{E_{CO_2 Ref}}$
Specific Primary Energy Consumption of CO_2 Avoided	$SPECCA = 3600 \frac{\frac{1}{\eta_{t,CCS}} - \frac{1}{\eta_{t,Ref}}}{E_{CO_2,Ref} - E_{CO_2,CCS}}$

Where η_t stands for efficiency, $\dot{m}$ is the flow rate, *LHV* corresponds to the lower heating value, $\dot{W}_{net}$ is the net electricity production, A_{co_2} represents the CO_2 avoidance, while E_{CO_2} corresponds to the CO_2 specific emissions. The subscripts *Ref* and *CCS* refer to plants without and with CO_2 abatement respectively.

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