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Comparative analysis of energy storage options in connection with coal fired Integrated Gasification Combined Cycles for an optimised part load operation

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ABSTRACT

A large number of research undertakings and system modelling works study different coal fired Integrated Gasification Combined Cycle (IGCC) configurations, mostly with the conflicting purposes and aims, to increase system efficiencies, to reduce costs and to diminish environmental impacts. The increased penetration levels of intermittent renewable energy systems experienced in many parts of the world, however, makes the establishment of flexible power generation systems to be a more challenging task. The integration of a diurnal syngas storage system as a means to increase system flexibility is investigated in this work with reference to different syngas qualities. All the systems are based on a reference coal-fired IGCC power plant. The system modification is limited to the gas processing units including a CO_2 removal option allowing for different syngas compositions. Apart from the reference syngas, four further options are proposed here: hydrogen rich syngas with and without a carbon capture, a scenario with a partial carbon capture and finally a Synthetic Natural Gas (SNG) production case. The techno-economic analysis is implemented in connection with a short-term geological syngas/hydrogen rich gas storage reservoir. The results show that a hydrogen rich gas generation without a carbon capture will be techno-economically less attractive and requires a relatively large reservoir volume. A methanation process towards a SNG production adds significantly to the overall cost and reduces the cold gas efficiency. The storage volume requirement is however considerably reduced. Finally, a short comparison will be drawn to a potential case configuration with a compressed air energy storage system.

1. Introduction

The increasing penetration levels of renewable resources for electricity generation will have an adverse effect on the operation of conventional base load plants in particular on coal-fired systems. More frequent power plant cycling duties result in a considerable drop of efficiency, higher specific emissions, and increased fuel consumptions. In addition, more forced outage incidents, higher maintenance intervals and reliability penalties are to be envisaged during the plant life. As a result, higher maintenance and operating costs will occur, affecting the economic viability of the power plants. To enable the coal power plants to elevate part load operations during low demand periods and to be able to dispatch during peak intervals, the integration of a number of selected energy storage mechanisms are examined in this work.

The chemical process plant simulation package ECLIPSE is used to study five different scenarios. All the proposed cases are derived from an Integrated Gasification Combined Cycle (IGCC) with a nominal power output of 500 MW, which serves as the reference plant. The system integration includes a gasification system, which is universally employed for all scenarios as well as a gas cleaning and conditioning division followed by a geological syngas/hydrogen-rich gas storage extension. This type of storage systems has been suggested in several research works preferably for short-term storage option [1] and is commercially practised in sites such as Teeside (England) and a site operated by Gas de France [2,3]. The cycle utilises a Shell gasifier operated at a pressure of 42 bar. The techno-economic analysis of the gas production unit is implemented in isolation of the electrical power plant. In this way, a better understanding and appreciation of gas production and power generation processes can be gained. The assessment of fuel storage is implemented to smooth out variable ramping rates. In connection with the gas production unit, the following scenarios are simulated: (1) reference case, (2) hydrogen rich gas, (3) system with 95% and (4) 65% carbon captures and storage (CCS) as well as (5) Synthetic Natural Gas (SNG) production using a catalytic methanation process with 65% CCS. A similar CO_2 emission level to natural gas fired systems can be obtained using the two latter options.

Among the suggested systems, a hybrid configuration of Combined Cycle (CCGT) and Open Cycle Gas Turbine (OCGT) has been selected to enter the techno-economic assessment. The proposed system utilises the produced gas either directly in CCGT for a base load process or combined with OCGT run on the stored gas for a

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load following operation. During low demand times, the system continues producing syngas, hydrogen rich gas, or SNG for geological storage. Due to large reservoir requirements and energy intensity of highly compressed gas products, a diurnal storage provision is selected for the suggested case scenarios, which is considered to be techno-economically a more promising option. The storage possibilities are highly dependent on the characteristics of geological formations and on the gas compositions. In general, the energy density of fuel affects the techno-economic viability of any storage systems. A geological storage is considerably less costly than aboveground options. The specific cost of aboveground storage for hydrogen given in the literature can be as high as €16,000/GJ [4]. Typical figures are around €9000/GJ corresponding to €1080/kg if adjusted to 2008 figures [5–7]. The potential areas for geological storage are salt cavern, sandstone and abandoned mines as well as porous rock formations. The specific cost of geological cavern development corresponding to an excavation and storage space creation in impervious rocks can be as high as €500/GJ. This option is significantly more expensive than the other geological storage alternatives listed above – for example, the cost for solution mined salt caverns are many times lower than the cavern development in impervious rocks. The assumed value in this paper corresponds to a higher spectrum given in the literature [8,9]. In comparison to compressed air storage system requirements with an energy density of around 2.4 kW h/m^3, the simulated scenarios show energy densities between 65 kW h/m^3 for hydrogen rich gas and 240 kW h/m^3 for SNG at 40 bar pressure. The energy density can significantly be improved if the pressure is increased. Energy densities up to 250–465 kW h/m^3 is reported in the literature for hydrogen storage in underground caves if operating pressures are varied between 80 and 160 bar [10].

The hydrogen loss is reckoned to be negligible in connection with diurnal gas storage; literature suggests 1–3% total volume loss of hydrogen per year from caves. Further issues such as gas contamination, degradation and biological or mineralogical interactions are not considered in this study but worth to be addressed in further investigations. Crotogino et al. mention the possibility of hydrogen reactions with micro-organisms and minerals in depleted fields and aquifers [11]. It is assumed that the selected short-time storage will not adversely affect the gas quality. However, the permanent presence of a cushion gas in the storage caverns may influence the storage quality.

Finally, an additional scenario is presented using a multi-shaft gas turbine configuration with an integrated compressed air energy storage system. A single shaft arrangement can be established as a retrofit with additional renewable energy integration schemes. This variation however, requires component redundancies, which adds to the overall cost of the plant and suffers higher efficiency losses. A multistage turbine compressor configuration is devised to improve the performance attributes. The system flexibility, however, suffers under this arrangement increasing the ramping rates on the ground of limited syngas flow splits between the power island and air compressor stages compared to the previous option. Furthermore, the system commercialisation seems to lend itself more towards industrial scale applications.

2. Methodology

For a more dynamic operation of IGCC, five gas production scenarios are analysed in this work followed by geological storage. The mass and energy balance of the selected systems were modelled using the ECLIPSE chemical process simulation package. This software has been used in connection with many International and European projects and is validated against other models as well as demonstration plants and real case studies [12,13]. The selected system has a nominal power output of 500 MW. The reference plant utilises a Shell gasifier with basic gas cleaning facilities and acid gas removal stages. Based on the core plant, different modifications have been implemented to improve the quality of gas. The power islands and the gas production units are studied in isolation from each other. The flexibility of the system depends on the autonomous operation of both plants. With regard to the economics, the capital costs of all the basic equipment types are estimated according to the step count exponential costing method using the dominant process variable or a combination of variables. Following the plant cost estimation, the Breakeven Electricity Selling Price (BESP) is determined based on the net present value (NPV). To cover uncertainties, a number of sensitivity analyses were carried out in connection with factors such as discounted cash flow, fuel prices, and capital investments.

3. Reference case

The Reference IGCC consist of five main units: the cryogenic air separation unit (ASU), fuel processing, Shell gasifier, heat recovery and gas cleaning as well as acid gas removal units. The system operates on 151 tonnes per hour (tph) bituminous coal with a calorific value of 25.17 MJ/kg AR (As Received). The ASU provides more than

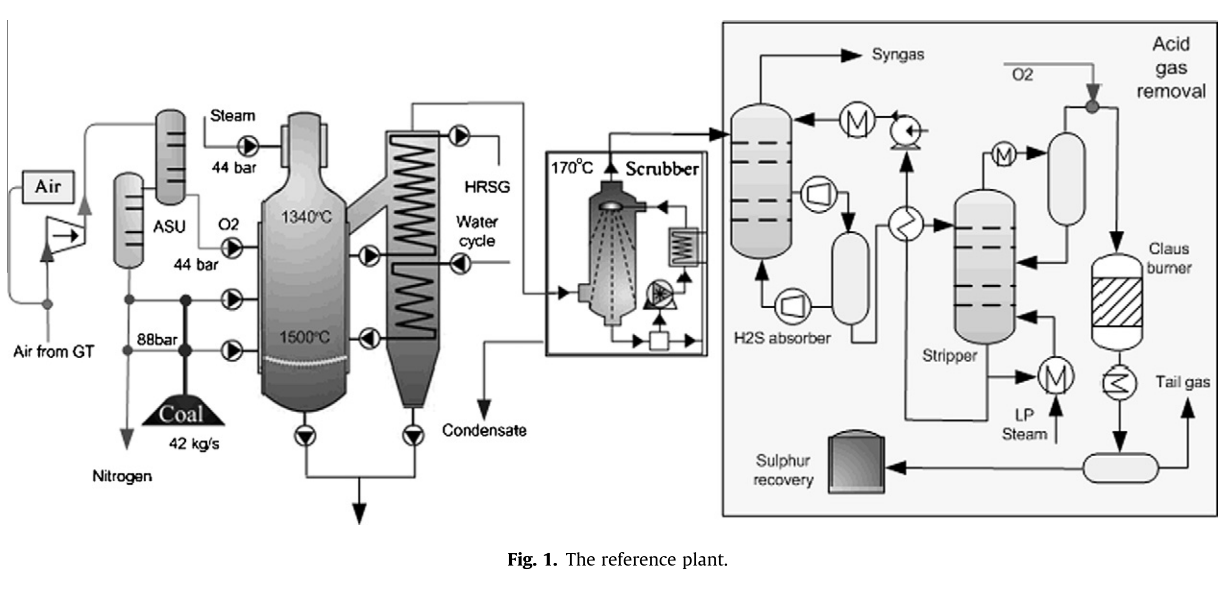


Fig. 1. The reference plant.

140 tph oxygen to the gasifier. A fraction of generated nitrogen (23 tph) is used at high pressure for the coal supply. The remaining part is used in the gas turbine in order to maintain adequate flow rates and for cooling with the rest vented to the atmosphere. The gasifier develops a temperature of around 1500 °C. A steam injection of around 47 tph moderates the temperature and contributes to the shift reaction. This approach also reduces the requirement for a steam injection in the water gas shift reactor. The gas is gradually cooled in the heat recovery system and sent to a scrubber. The reference case can deliver up to 214 MWth high to medium grade thermal energy (from 1340 °C down to 140 °C) and 45 MWth low-grade energy (below 140 °C). The remaining cycle simulations show a considerable elevation in high to medium grade heat but require additional low-grade heat input into the system. The overall thermal load of all the gas generation cycles, however, remains comparable apart from SNG production, which generate more thermal energy due to the exothermic methanation process. The elimination of sulphur compounds takes place in the acid gas removal unit. Following the Carbonyl Sulphide (COS) hydrolysis to H_2S, the H_2S compounds are removed in an absorber using Selexol solvents. Solvent recovery and H_2S release occurs in the stripper part. The resulting gas is sent to a Claus burner, where it reacts with oxygen and sulphur dioxide to supply Sulphur and tail-gas. The composition of the latter strongly depends on the amount of oxygen supplied. At high H_2S/O_2 ratios the tail gas will be mainly water and hydrogen. A simplified flow diagram of the systems is given in Fig. 1.

4. Case studies

All the scenarios studied in this work consist of the following units: (a) gas production, (b) diurnal storage and (c) power island. The case studies examined in this work are as follows: (case 1) basic syngas production corresponding to the reference case, (case 2) hydrogen rich gas generation, (case 3) hydrogen rich gas production with 95% carbon capture and storage (CCS) (case 4) hydrogen rich gas production with 65% CCS and finally (case 5) synthetic natural gas generation with 65% CCS. Apart from the reference case, all the plants are also equipped with a water gas shift reaction unit in a sour shift configuration. The CO_2 capture is achieved using a Selexol unit followed by a gas saturation stage and a CO_2 compression train. Similar to acid gas removal, Selexol cycles through an absorber and a stripper. A fraction of the syngas is bypassed around the water gas shift reactor in the case of a partial CO_2 capture requiring smaller unit integrations. This design is less costly than a 95% CSS option. In connection with 65% CO_2 capture, the CO_2 emission is comparable to that of a natural gas fired system. Higher energy densities can be achieved through a methanation process. This method is used for the synthetic natural gas (SNG) production. In this work, the plant is designed with a 65% CCS. The considerably higher energy density of SNG is moderated by noticeably lower cold gas efficiencies.

Fig. 2 shows the integration of a combined cycle gas turbine for base load operation and an open cycle gas turbine for load following management. The daily plant operation consists of eight hours of gas generation, 8 h base load and eight hours load following process. The CCGT system operates for around 16 h and has a power output of up to 491 MW. The OCGT part is designed to operate on the stored gas for up to eight hours a day with a maximum power output of up to 350 MW. The available heat from IGCC can be utilised to run the steam turbine between 38% and 59% of the maximum continuous rating. In this way, a parallel start-up of the gas turbine and the steam turbine can be achieved (hot-start on the fly). In addition, it is also possible to use the available energy from the steam turbine to generate compressed air during the low demand. A compression power saving of up to 200 MW could be achieved through this option during peak demand.

4.1. Gas production: Main technical results

Table 1 shows the main gas compositions and the gas production features of the studied cases. Although the last case gives the highest gas heating value, the cold gas efficiency is considerably lower than that of other cases. This is due to a high heat generation during the methanation process. A heat transfer of over 44 MW including a steam injection of around five MW is required for the methanation plant. This is further sustained by a stream recirculation rate of above 97 MW. The exothermic nature of this process transfers part of the energy available in the gas to the steam cycle. This results in a lower overall cold gas efficiency.

The thermal loads of the main components are given in Table 2. Extra heat can be recovered from air and CO_2 compression units. A higher heat transfer capacity is available through the exothermic methanation process. The overall heat transfer capacity is divided in low (<130 °C), medium and high-grade heat.

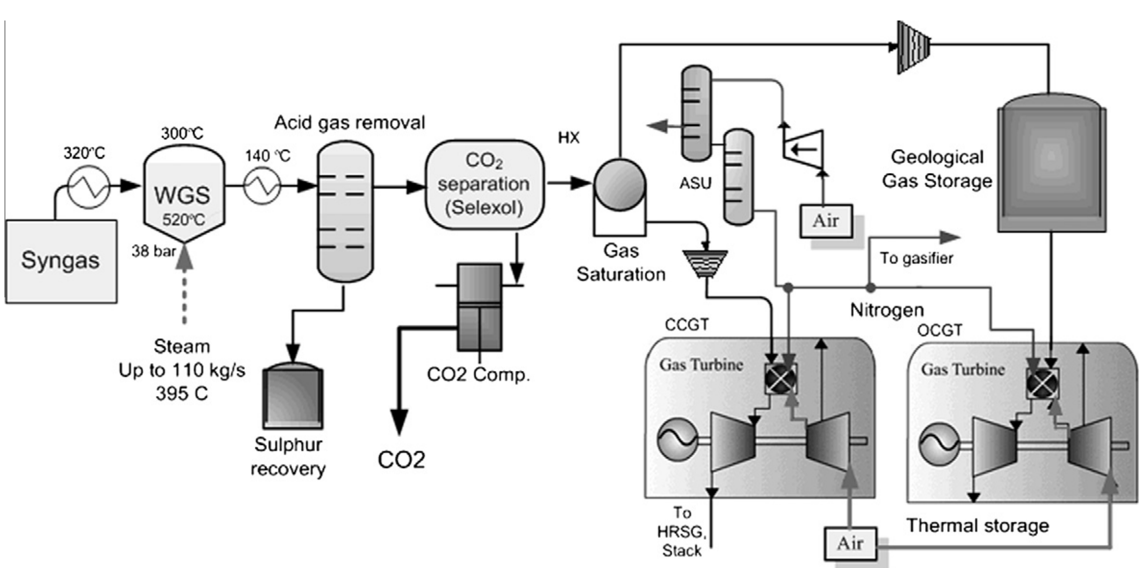


Fig. 2. IGCC plant with CCS and gas storage (*thermal storage not considered but it could be an option*).

Table 1
Gas production.

		Case 1 Reference	Case 2 H_2-rich	Case 3 95% CCS	Case 4 65% CCS	Case 5 SNG
Flow rate	kg/s	79.2	**115.8**	24.5	43.8	**26.4**
Flow rate	kmol/s	3.8	5.7	3.6	3.5	1.3
CO_2	mol%	4.19	38.56	3.04	1.94	5.86
N_2	mol%	7.43	5.42	8.55	8.67	21.26
Argon	mol%	1.17	0.74	1.17	1.18	3.2
H_2S	mol%	0.002	0.001	0.002	0.002	0.005
CH_4	mol%	0.022	0.014	0.023	0.023	56.0
H_2	mol%	25.89	53.41	84.29	62.33	11.76
CO	mol%	57.72	1.79	2.82	25.75	1.35
Water	mol%	3.55	0.05	0.08	0.09	0.50
NH_3	mol%	0.025	0.014	0.021	0.022	0.058
LHV	MJ/kg	10.4	6.5	31.3	18.2	24.6
LHV	MJ/Nm^3	10.2	5.7	9.7	10.0	21.7
ED @ 40 bar	kW h/m^3	106.7	64.6	99.2	104.5	237.7
ED @ 100 bar	kW h/m^3	266.0	199.8	242.5	257.7	652.7
CGE	%	0.78	0.72	0.73	0.76	0.62
CO_2 emission	kg/s	102.0	102.0	9.3	40.1	36.2
SCE	kg/MW h	830.8	963.9	90.8	362.7	391.1

ED: energy density, CGE: cold gas efficiency, SCE: specific CO_2 emission.

Table 2
Thermal loads.

		Case 1	Case 2	Case 3	Case 4	Case 5
HTC (med.–high)	MWth	214.5	383.2	407.2	334.8	487.5
HTC (low)	MWth	45.4	−137.2	−142.5	−57.6	−43.2
Total HTC	MWth	259.9	246.0	264.7	277.2	444.4
TO from ASU/N2	MWth	50.6	50.6	50.6	50.6	50.6
TO from CO_2 comp.	MWth	0.0	0.0	75.7	56.3	41.1
TO from gas refining	MWth	0.0	0.0	0.0	0.0	213.6
WGS SR	MWth	0.0	356.4	356.4	198.8	239.5
Gasifier SI	MWth	40.2	40.2	40.2	40.2	40.2
GT HRSG	MWth	418.3	367.3	361.2	380.5	312.6

HTC: heat transfer capacity, TO: thermal output, SR: steam requirement, SI: steam injection, GT: gas turbine.

Table 3
Power balance and efficiency figures.

		Case 1	Case 2	Case 3	Case 4	Case 5
ASU	MW	33.40	33.40	33.40	33.40	33.40
O_2 Compression	MW	15.05	15.05	15.05	15.05	15.05
N_2 to gasifier	MW	4.34	4.34	4.34	4.34	4.34
N_2 to GT	MW	31.90	0.00	24.65	31.90	0.00
CO_2 capture	MW	0.00	0.00	18.13	12.38	12.38
CO_2 Compression	MW	0.00	0.00	24.83	16.90	16.90
Auxiliaries	MW	23.99	22.06	20.89	22.11	20.57
Energy consumption	MW	108.68	60.79	128.40	121.97	90.07
Compressor work	MW	226.66	193.08	209.87	210.29	215.33
GT output	MW	354.11	286.46	314.44	334.39	231.46
Steam turbine output	MW	245.31	220.71	223.89	235.36	258.34
Base load PO	MW	490.73	432.32	397.03	433.68	387.16
Base load efficiency	%	46.42	40.90	37.56	41.02	36.62
Load following output	MW	844.84	718.78	711.47	768.07	618.62

ASU: air separation unit without GT integration, GT: gas turbine, gas turbine inlet temperature: 1300 °C, PO: power output.

The overall power generation output is illustrated in Table 3. It shows the main power consumption, power generation components, and the overall IGCC plant efficiency. The resulting GTCC and OCGT efficiency is between 48% and 54%. It is the highest for the first case and the lowest for case (3).

4.2. Economic assessment

The economic assessment consists of a bottom up cost estimation, economic assessment and sensitivity analysis. The total plant cost includes the gas generation plant, the power island and the syngas/hydrogen rich gas storage. The capital investment for the CO_2 transportation and storage is not included in this study since these costs will strongly vary from case to case. The cost estimation for the gas generation part has been implemented using a bottom-up approach. Apart from the air separation unit and the gasifier (Shell) as the main building blocks, coal and ash-handling units, heat exchangers, and cooling utilities as well as gas-processing and water-treatment system are considered as further key components. The economics of the gas-processing unit depends on the system configuration and is the main source of cost deviations. The individual costs were estimated according to vendor quotes or, where directly calculated, according to the step count exponential costing method integrated in ECLIPSE using a dominant process variable or a combination of variables. As part of the direct engineering costs, the individual component expenditures are further inflated allowing for corresponding outlays such as instrumentation, piping and civil works as well as electrical installations, insulation, paintings etc. In addition, an indirect cost of 14% is considered in this work. The cost estimation for the combined cycle and the storage is done using a top-down approach [14,15].

In connection with the gas storage, geological option is often considered as economically more viable option for a short-term gas supply [16]. The economics of storage given in the literature is rather variable showing a wide range of values. Aboveground storage options will add significantly to the gas cost. The specific costs for already available underground or geological storage alternatives are between €1.5/GJ and €5/GJ [17,18]. The cost spectrum given by Crotogino is categorised according to the geological formation [19]. The specific cost given however refers to the geological storage cavern development cost indicating expenditures in proportion to the GJ of gas storage capacity. The most lucrative option is given in connection with naturally occurring porous rock formation at a specific capital cost of around €1 per GJ of gas storage capacity. At the other end of the spectrum lies the impervious rock formation at a significantly higher specific cost, which is up to €500 per GJ of gas storage capacity. In this work, we use a total specific investment of €444/GJ (€1.6/kW h), which contains all the construction and installation expenses including indirect, civil and structural costs as well as piping, instrumentation, safety, etc. Further parameters, which are already added, are 14% indirect costs and 15% contingencies including the owner's costs. In comparison to the economics of syngas/hydrogen rich gas storage studied in this work, the specific cost of salt dome storage of natural gas is given at €60/GJ for a real case in Denmark [20,21].

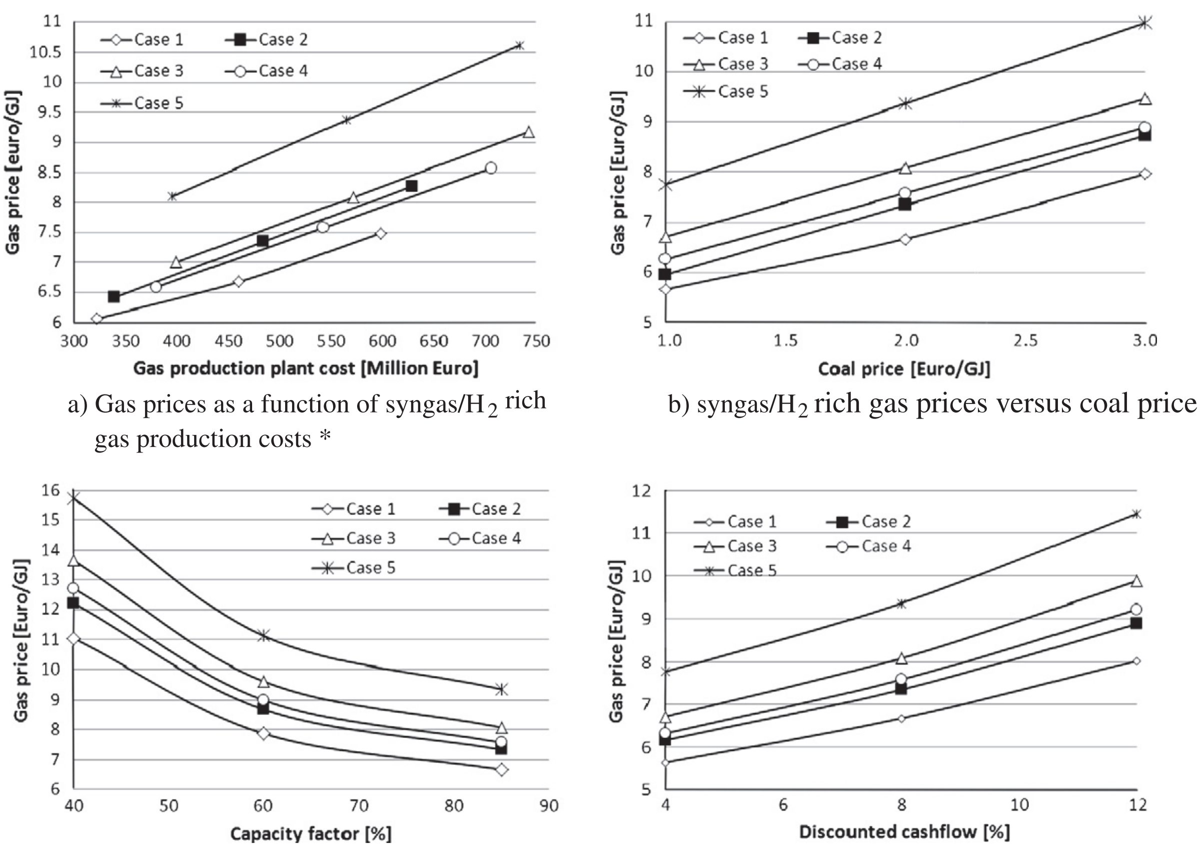
The gas and the electricity costs are calculated in the second stage. The economics is summarised in Table 4. The main assumptions are as follows: (1) plant lifetime: 25 years, (2) discounted cash flow (DCF): 8%, (3) construction time: 3 years, (4) contingency and owners cost 15% (not included in the table). The table shows the main capital expenditures for the gas production unit and the gas turbine combined cycle. The costs are based on the listed gas turbine fabrications. The specific cost of the gas is slightly higher for case one and two compared to natural gas. The specific cost of the gas (€/GJ) increases significantly in connection with SNG due to a higher capital investment and lower gas efficiencies. The additional cost of the methanation plant is reflected in the capital investment. The overall costs are however slightly moderated because of the use of a smaller water gas shift reactor compared to the plant with 95% CCS.

The net plant output corresponds to a cycling schedule, which is characterised by 8 h base load and 8 h peak load operations per day.

Table 4
Gas production and electricity cost.

		Case 1	Case 2	Case 3	Case 4	Case 5
GT for main plant		4 X V84.3A	4 X V94.2	4 X V84.3A	4 X V84.3	2 X PG9331FA
Total GT Cost	M€	194.96	180.35	180.35	180.35	114.31
CCGT Cost	M€	373.44	351.08	336.59	343.23	273.86
IGCC-GP	M€	460.55	484.43	571.33	543.24	564.62
Syngas cost	€/GJ	6.67	7.34	8.09	7.58	9.36
Net PO	GW h/a	3314.91	2857.05	2751.31	2982.74	2496.35
OGC	GW h/a	7400.84	6296.54	6232.50	6728.29	5419.12
Resulting CF	h/a	3923.69	3974.84	3867.06	3883.43	4035.35
BESP	€/MW h	66.17	74.64	82.34	76.36	86.90

M€: million €, CCGT Cost: total cost of gas turbine combined cycle, IGCC-GP: cost of IGCC plant without CCGT (cost of the gas generation plant) PO: plant output, OGC: overall generation capacity, CF: capacity factor, BESP: Breakeven Electricity Selling Price at a discounted cash flow of 8%.



a) Gas prices as a function of syngas/H_2 rich gas production costs *

b) syngas/H_2 rich gas prices versus coal price

c) syngas/H_2 rich gas prices in connection with the capacity factor of gas production plant

d) Gas price variations depending on DCF

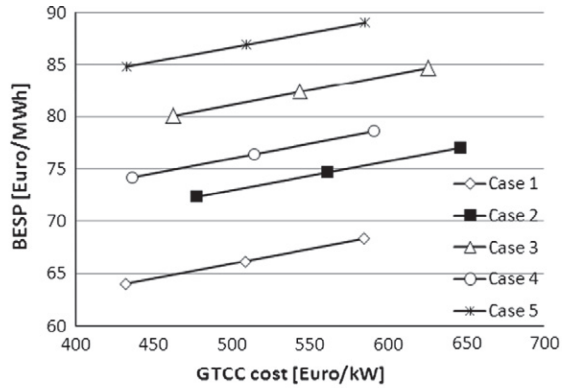
Fig. 3. Economic sensitivity assessment of the gas production unit (gasification, gas processing and storage) for case 1–5. *∗X-axis excludes contingencies and owner's costs. This, however, is included in the calculation of the gas price using an overall value 15%.*

The rest of the day is used for gas production and storage. The overall generation capacity reflects to a theoretical full load peak operation. The resulting capacity factor of around 45% is the ratio between the overall generation capacity and the net plant output. The equivalent cost of electricity is calculated using a net present value model.

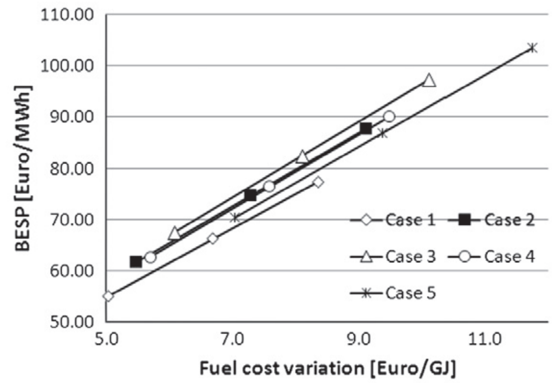
4.3. Sensitivity assessment

The economic sensitivity assessment of the plant is implemented in two levels: (a) gas production plant and (b) power generation unit. In connection with the former section, it is necessary to achieve a high capacity factor in order to minimise the produced gas cost (see Fig. 3c). With regard to the power generation unit, however, higher annual operating hours are only achievable through additional fuel utilisation or longer gas storage intervals (see Fig. 4c). A larger gas production plant integration as a further option would not make techno-economically much sense as the system is not designed for a base load operation. The typical capacity factor for this type of power plant configuration is estimated at around 45%.

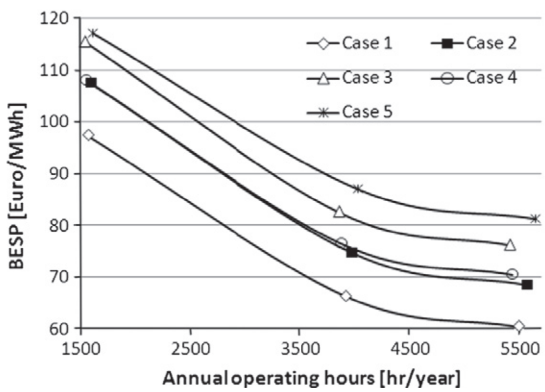
The sensitivity assessment covers the impacts of a wide range of uncertainties on the techno-economic viability of the project during the plant lifecycle. In this study, the focus is given to five parameters namely (a) plant capital investment, (b) fuel prices, (c) capacity factors, (d) discounted cash flow (DCF) and finally (e) the operating and maintenance (O&M) costs. The impact of the latter parameter on the cost of the produced gas is relatively linear and steady resulting in gas (syngas/hydrogen rich gas) price variations of around 10% in connection with an operating and maintenance



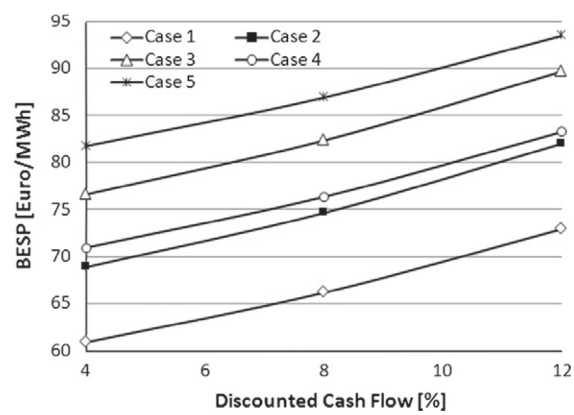
a) BESP according to the specific investment of the power plants *(CCGT + OCGT)* *



b) BESP versus syngas/H_2 rich gas prices



c) BESP variations in connection with the power plant capacity factor



d) BESP as a function of DCF

Fig. 4. Economic sensitivity assessment of the power production unit (*CCGT* + *OCGT*) for case 1–5 ∗*X-axis excludes contingencies and owner's costs. This, however, is included in the calculation of the Breakeven Electricity Selling Price (BESP) using an overall value 15%.*

cost spectrum of up to ±50%. With regard to the power generation sector, the same O&M cost range reflects up to 5% change in Breakeven Electricity Selling Price (BESP).

Fig. 3 shows the impact of further parameters on the produced gas prices. The impact of the plant cost in million € is given in Fig. 3a. Apart from the fixed capital investment, the BESP estimation also includes all the other fixed and variable expenses such as contingencies, owner's costs, construction fees and fuel costs as well as operating and maintenance costs. The synthetic natural gas (SNG) case with 65% carbon capture does not seem to be economically viable mainly due to the lower cold gas efficiency rates and is unlikely to attract stakeholders without any government supported DCF rates (see Fig. 3d) or lower coal prices (see Fig. 3b).

Fig. 4 illustrates the economic sensitivity assessment of the power generation sectors. In comparison with case 4 with 65% carbon capture operated as mid-merit plant, a natural gas fired combined cycle system in base load operation will give an economic advantage of around €22/MW h at a natural gas price of €6.5/GJ [22]. This economic benefit, however, diminishes as the capacity factor of the natural gas fired cycle is reduced to the same level of case 4 resulting in a price difference of around €10/MW h [22]. This system configuration has the potential to become more attractive if the gas production costs could be reduced from its current level and/or if the gap between natural gas and coal prices widens. In comparison to the natural gas fired system with 95% capture rate using amine system, case 3 shows a slight reduction in BESP if both plants are operated in mid-merit modes [22].

The sensitivity analysis shown in graph 3 and 4 corresponds to a univariate assessment. The economic viability of the project can significantly change beyond the limits shown in these graphs if a multivariate assessment is used implying multiple parameter changes. An effective decision making process will strongly depend on multivariate economic models describing adverse or favourable scenarios for the integration of potential plants.

4.4. System comparison with CAES

An integration of compressed air energy system (CAES) is also considered here. This can be achieved on a single or multi-shaft gas turbine. The latter is a more flexible option. Fig. 5 shows the example of a CAES-integration with IGCC. The configuration allows the generation of compressed air during low demand. For peak following operations, the stored energy is utilised in the gas turbine instead of employing the energy intensive compressor. In this way, a maximum power output of 720 MW can be established using the first case.

The energy density of CAES is considerably lower than the syngas storage requiring a much larger storage reservoir (2–3 kW h/m^3) [19]. A comparable hydrogen reservoir provides a specific energy density of up to 170 kW h/m^3 if operated at comparable pressures [8]. This depends strongly on the pressure level of the gas. At around 40 bar, the energy density of the hydrogen and syngas scenarios studied here are around 100 kW h/m^3 (see Table 2). The capital investment for compressed air storage given in the literature is

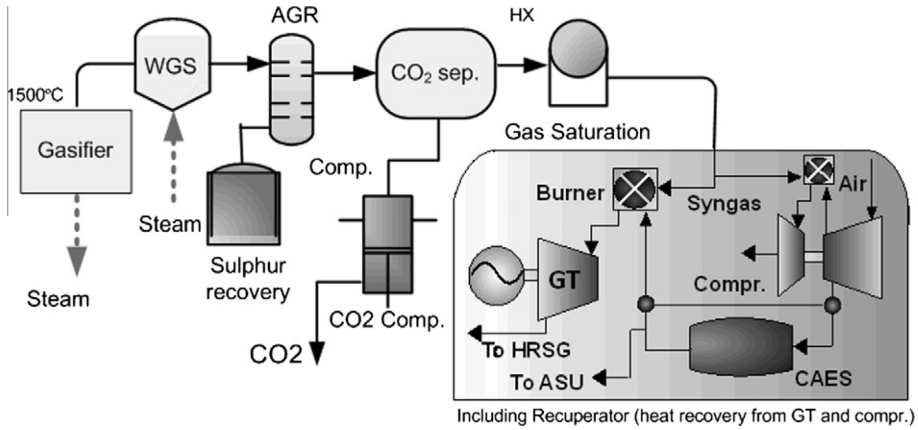


Fig. 5. An example of CAES integration with IGCC.

significantly higher than the one for syngas [23]. A reservoir volume of almost 1.3 million m^3 for an 8-h operation (0.16 million m^3/h) is required for this plant size if the pressure in the reservoir is designed to slide from 66 bar to 46 bar, which is in accordance with the operation of Huntorf CAES plant in Germany [24]. On the other hand, the specific volume requirements for the reservoir is below 30,000 m^3 in relation to the syngas production from the reference plant (case 1), hydrogen-rich gas process with CO_2 capture (case 3) and the modified version using a partial CO_2 capture (case 4) if operated at a pressure range sliding from 40 bar to 20 bar. As a variation to these values, the SNG scenario (case 5) requires a considerably lower reservoir volume below 10,000 m^3, at the other end of the scale, the hydrogen-rich syngas scenario without CCS (case 2) necessitates a volume at around 40,000 m^3.

5. Conclusion

A comparison made between different syngas compositions in this work shows the techno-economic variation of syngas processing options with short-term geological storage. The reference case provides the best economics. The removal of CO_2 from the gas does not seem to reduce the required storage volume considerably. A zero-emission option, however, can be realised at an additional fuel cost of around €1.42/GJ (CO_2 transportation and storage not included). The economic can be improved slightly by using a partial CO_2 capture to a level equivalent to the emissions from natural gas fired combined cycles. A production of hydrogen rich gas without a CO_2 capture is not techno-economically attractive. This option also requires a larger storage volume. The SNG production adds considerably to the cost and reduces the cold gas efficiency. On the other hand, the gas quality is improved considerably requiring smaller storage volumes. Finally, a preliminary comparison was made between the studied syngas storage options and potential compressed air energy storage system integrations within IGCC. The latter option requires a storage volume, which is up to 70 times larger than the one estimated for the syngas storage. The techno economic comparison was limited to the storage requirements. A more detailed comparison is left to future studies. Furthermore, issues such the techno-economic implications of excess hydrogen production, gas contaminations and geological permeation characteristics as well as efficiency losses as a function of parameters such as cushion gas provision, gas deterioration and hydrogen purity requirements need to be investigated.

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