CO_2 emissions reduction from coal-fired power generation: a techno-economic comparison

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Abstract:

Carbon capture and storage (CCS) represents a key solution to control the global warming reducing carbon dioxide emissions from coal-fired power plants. This study reports a comparative performance assessment of different power generation technologies, including ultra-supercritical (USC) pulverized coal combustion plant with post-combustion CO_2 capture, oxy-coal combustion (OCC) unit and integrated gasification combined cycle (IGCC) with pre-combustion CO_2 capture. These technologies (with and without CCS systems) have been compared from both the technical and economic points of view, considering a reference thermal input of 1000 MW. As for CO_2 storage, the sequestration in saline aquifers has been considered.

Whereas a conventional (without CCS) coal-fired USC power plant results to be more suitable than IGCC for power generation, IGCC becomes more competitive for CO_2-free plants, being the pre-combustion CO_2 capture system less expensive (from the energetic point of view) than the post-combustion one.

In this scenario, oxy-coal combustion plant is currently not competitive with USC and IGCC, due to the low industrial experience, which means higher capital and operating costs and a lower plant operating reliability. But in a short term future, a progressive diffusion of commercial-scale OCC plants will allow a reduction of capital costs and an improvement of the technology, with higher efficiency and reliability. This mean that OCC promises to became competitive with USC and also with IGCC.

Keywords:

Carbon capture and storage; Ultra-Supercritical; IGCC; Oxy-fuel; Economic assessment.

1. Introduction

Despite environmental concerns caused by its use, coal still remains a fundamental fuel for electrical energy production. Currently most suitable technology for power generation from coal is represented by ultra supercritical (USC) pulverized coal combustion. It represents the evolution of conventional steam plants, being characterized by harder operative conditions: steam temperature up to 600-620 °C and cycle maximum pressure higher than 30 MPa. USC plants reach overall efficiencies up to 45-46% [1], sensibly higher than the typical values of conventional subcritical plants (unlikely exceeding 40%).

The combustion of coal leads to a CO_2 emission nearly double in comparison to natural gas, causing a greater contribution to anthropogenic CO_2 emission [2,3]. Coal alone accounts for about 70% of Europe's CO_2 emissions from power generation [4]. The integration between carbon capture and storage (CCS) and power generation plants could represent one of the key solutions to reducing carbon dioxide emissions [5]. The introduction of a post-combustion CCS system in a power generation plant involves a very strong reduction of plant efficiency (about 9-12 percentage points in USC plant) [6]. In this scenario, integrated gasification combined cycle (IGCC) and oxy-coal combustion (OCC) are promising alternatives to USC for CO_2-free power generation. In IGCC plants coal is converted into a fuel gas (syngas) which is fed to a combined cycle for power generation. At present, IGCC plants are more expensive and less reliable than USC plants, leading to an overall plant efficiency up to 42-45% [7]. However, the integration with CCS system may become IGCC plants more affordable, because IGCC can be integrated with the more effective CO_2 pre-combustion capture technology, with an energy penalty of about 7-10 percentage points [6]. With the aim of reducing energy penalization of CO_2 capture, USC power cycle can also be integrated with oxy-fuel combustion, which involves a flue gas mainly composed by CO_2 and steam, which can be easily separated. In this configuration, power plant performance is hampered by energy penalization related to the air separation unit, but the CO_2 capture is less energy expensive.

With the aim to comparing them, from both the technical and economic points of view, and to estimate the current potential applications of CCS technologies, this study reports a performance assessment of USC, OCC and IGCC plants. Each power generation technology has been analysed with reference to both the conventional configuration (without CCS) and the CO_2-free configuration, considering a reference thermal input of 1000 MW. In particular, the performance assessment has been carried out by using simulation models implemented through Aspen Plus 7.3 and Gate-Cycle 5.40 commercial tools. On the other hand, the economic assessment has been performed through a detailed simulation model, properly developed by Sotacarbo for feasibility studies on CCS power generation plants. The integration between technical and economic simulation models allows a detailed feasibility assessment.

2. Plant configurations

As mentioned, three different power generation technologies are compared in this study: an advanced USC plant, an OCC plant based on the same USC cycle and an IGCC plant based on a slurry-feed entrained-flow gasifier. Each technology has been analyzed in its conventional configuration without CCS system and in its CO_2-free configuration with CCS. Simplified schemes of the USC plant (that is the same for OCC one, except for the flue gas treatment process) and of the IGCC plant are reported in figures 1a and 1b, respectively.

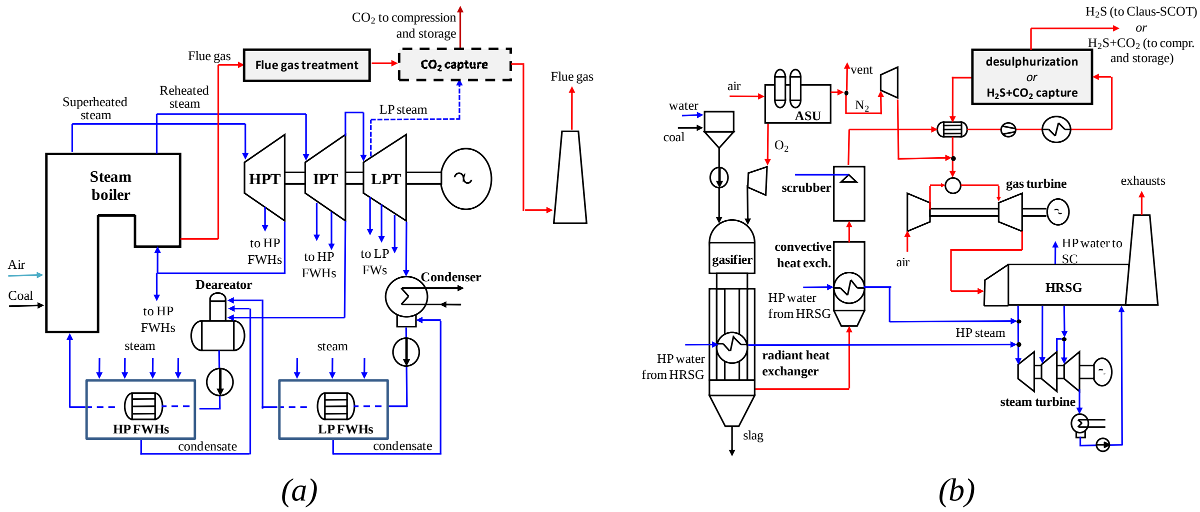


Fig. 1. Plant simplified schemes: a) USC and OCC; b) IGCC.

As mentioned, for each plant configuration, a coal chemical power input of 1000 MW has been assumed, corresponding to about 40 kg/s of a commercial South African coal, considered as reference fuel. The coal shows a lower heating value equal to 25.03 MJ/kg and is characterized by a carbon mass fraction of 65.7%, as reported in a previous paper by the authors [8].

2.1. USC plant

The USC power plant has been considered equipped with a conventional flue gas treatment and with a post-combustion CO_2 capture section, based on a chemical absorption process with an aqueous solution of monoethanolamine (MEA).

The USC plant considered in this study is based on a Rankine cycle with superheated and reheated steam (27.5 MPa/600 °C/610 °C), and with seven regenerative steam extractions. Main USC operating parameters are reported on table 1.

Table 1. Main USC operating parameters

Fuel chemical power (MW)	1000
Superheater/reheater steam temperature (°C)	600/610
Superheater/reheater steam pressure (MPa)	27.5/6.5
Cycle maximum pressure (boiler feedwater pump) (MPa)	31.5
Cycle minimum pressure (condenser) (kPa)	4.8
High/low pressure heat exchangers minimum ΔT (°C)	-1.5/1.5

USC power plant is based on a tail-end flue gas treatment configuration, which includes baghouse filters for particulate removal, a low temperature flue gas desulphurization (FGD) system and a selective catalytic reduction (SCR) denitrification system [8]. The flue gas treatment section requires an electrical power of 9.1 MW (more than 2% of the overall USC power) and a thermal power of 14.1 MW, penalizing the USC net efficiency of about 1.5 percentage points. Globally the USC plant shows a net power output of 452.1 MW and a subsequent net efficiency of 45.21%.

As mentioned, the post-combustion CO_2 capture section is based on a chemical absorption process with an aqueous solution of MEA, one of the most proven and widespread solvents [9]. Entering the CO_2 capture section, flue gas is cooled to about 30-40 °C and it rises through the absorption column, countercurrent with the solvent, leading to a substantial CO_2 removal. Purified flue gas is discharged from the top of the column and sent to the stack, while CO_2-rich solvent is withdrawn from the bottom, heated and sent to the regeneration column. A reboiler provides thermal energy to the solvent allowing the CO_2 release. Separated CO_2, together with water vapour, rises along the column; in the upper section the main fraction of steam condensates, whereas the CO_2-rich flow is sent to the compression section. The CO_2-lean solvent is extracted from the bottom, cooled and recirculated to the absorption column. A detailed scheme and description of the CO_2 removal section can be found in Tola and Pettinau, 2014 [8].

Main operating parameters of the CO_2 capture section (operating with 30% wt. MEA) are reported in Table 2. A CO_2 removal efficiency of 90% has been assumed, requiring a solvent/gas mass ratio of about 4.5 and a reboiler specific thermal energy of 3.45 GJ per ton of removed CO_2 [10].

Table 2. CO_2 capture section main operating parameters and results

MEA/solution mass fraction	0.30
CO_2 loading (lean solvent) (mol_{CO2}/mol_{MEA})	0.28
Absorber temperature (°C)	35
Carbon dioxide removal efficiency (%)	90
Solvent/gas mass ratio	4.5
Reboiler specific thermal energy (GJ/ton_{CO2})	3.45

Flue gas from decarbonized section is mainly composed by N_2 (about 78%, by volume) and water vapour (15%). Through the decarbonization section, CO_2 concentration decreases from about 14% to about 1.5%. The CO_2-rich gas is sent to the compression section. At first, the gas is compressed up to 8 MPa through three intercooled compressors in series and then, through a pump, up to the transport pressure (11 MPa). Water separation during compression allows to obtain an almost pure CO_2 flow, as required for transport and storage.

CO_2 removal notably reduces USC performance mainly due to the very-high (about 300 MW) thermal power required to separate CO_2 from the MEA solvent. Thermal power is supplied to the reboiler by a low pressure steam extraction from the turbine. The electrical power required by the CO_2 compression system (compressor and pumps) is also remarkable (about 38 MW) and notably affects USC performance. On the contrary, the power required by the flue-gas fan of the decarbonization section is relatively low (about 3 MW).

2.2. OCC plant

A steam plant based on oxy-fuel combustion has also been analyzed. The plant is still based on the same Rankine cycle of the USC plant (27.5 MPa/600 °C/610 °C). Differently from USC, the boiler is fed by an oxidant stream, composed by high purity oxygen (95% O_2, 2% N_2, 3% Ar, by volume) produced in a cryogenic air separation unit (ASU). The oxidant is mixed with recycled flue gas to control flame temperature inside the boiler and to obtain a boiler heat transfer profile similar to the air-feeding profile. In this specific case, 70% of the flue gas is recycled to the boiler [11]. The recycle of the flue gas takes place at high temperature in order to dry the coal. Main operating parameters of OCC plant are reported in table 3.

Table 3. Main OCC operating parameters

Oxydant mass flow (kg/s)	86.10
O_2/N_2/Ar molar fractions in oxydant	0.95/0.03/0.02
O_2 specific separation energy (kWh/t_{O2})	200.0
Flue gas recycle rate	0.70
Recycle gas mas flow (kg/s)	280.69
Recycle gas temperature (°C)	254.2

The OCC plant is equipped with a flue gas treatment system similar to that used in USC configuration, including filters, FGD system and SCR. The high concentration of CO_2 in flue gas influences both DeSOx and DeNOx systems, but most studies assume that they can operate with better performance than in conventional plant [11]. Clean gas from OCC plant is mainly composed by water vapour (26.4% by volume) and CO_2 (65.9%), which can be easily separated by condensation. CO_2 pressure is increased to the transport one by a compression train similar to that used in USC plant.

2.3. IGCC plant

The IGCC plant is based on a slurry-feed entrained-flow gasifier, a syngas clean-up section and a reheat combined cycle (figure 1b). The combined cycle power plant includes the gas turbine, a triple-pressure heat recovery steam generator (HRSG) and a steam power plant consisting of high-pressure, intermediate-pressure and low-pressure turbines. Integration of the IGCC plant with a CO_2 removal section based on a CO-shift conversion and a CO_2 physical absorption process has also been considered.

A coal-water slurry is fed to the gasifier, together with an oxidant stream composed by high purity oxygen (95% O_2, 2% N_2, 3% Ar, by volume) produced in a cryogenic ASU. Main operating parameters of IGCC plant are summarized in table 4.

Table 4. Main gasification section operating parameters

Gasifier pressure (MPa)	3
Gasification maximum temperature (°C)	1400
Coal mass fraction in slurry	0.65
Oxydant/coal mass ratio α	0.943
O_2/N_2/Ar molar fractions in oxidant	0.95/0.03/0.02
O_2 specific separation energy (kWh/t_{O2})	200.0
Oxydant pressure (MPa)	3.94

An oxidant/coal mass ratio of 0.943 has been calculated to obtain a gasification temperature of 1400 °C. The entrained-flow gasifier assures a cold gas efficiency of 0.722, producing a syngas almost completely free of nitrogen and mainly composed (60-65%, by volume) by CO and H_2 (H_2/CO molar ratio of 0.61) and characterized by a lower heating value (LHV) of 7.76 MJ/kg. For the oxygen purity considered in this study (95%) an oxidant separation energy consumption of 200 kWh per ton has been assumed [12], with a resulting power requirement for the cryogenic ASU, including oxidant compression, of 42.7 MW [13]. Nitrogen produced by ASU is integrated in the combined cycle as a fuel diluent for NOx reduction and power augmentation in the gas turbine.

Syngas leaving the gasifier is sent to a purification section to be treated before supplying the gas turbine. The syngas purification section includes syngas cooling, particulate removal and desulphurization processes. Syngas cooling is carried out by means of two heat exchangers in series: a high temperature radiant one and a medium-low temperature convective one [7]. Syngas cooling allows to recover a thermal power of about 160 MW, producing about 90 kg/s of high pressure (about 12 MPa) saturated steam which expands in the combined cycle steam turbine after superheating in the HRSG. Feed water for syngas cooling is extracted from the high pressure-low temperature economizer as sub-cooled liquid. Downstream of syngas coolers, after a wet scrubber, where particulate is removed, syngas enters the desulphurization section. The latter is composed of a high temperature (typically 200-300 °C) catalytic reactor for carbonyl sulphide hydrolysis and a low temperature (35 °C) hydrogen sulfide (H_2S) chemical absorption process, based on an aqueous solution of methyl-diethanolamine (MDEA) [14]. A low-pressure steam provides the required thermal power of 5 MW.

Clean syngas, which feeds the gas turbine of the combined cycle, is characterized by a mass flow of 72.00 kg/s and it is mainly composed by CO (50.6%, by volume), H_2 (31.6%) and CO_2 (15.0%), with a LHV of 9.88 MJ/kg, corresponding to a fuel chemical power of 711.4 MW. The IGCC plant is based on a hypothetical gas turbine with the same characteristics of GE PG9351(FA), but scaled down according to the actual syngas mass flow. This assumption is widely described and justified in a previous paper [8], which also reports the main operating parameters and performance of both the gas turbine and the subsequent steam cycle.

CO_2 is captured by syngas through a physical absorption process, which is the most cost-competitive CO_2 removal process for high CO_2 partial pressure gas from an entrained-flow gasifier [15]. An effective decarbonization requires a CO-shift conversion section to convert CO and H_2O into CO_2 and H_2, according to the exothermic water-gas shift (WGS) chemical reaction. The shift conversion section is composed by high and low temperature (350 and 200 °C, respectively) catalytic reactors, operating in series. A H_2O/CO molar ratio of 2 has been considered, thus assuring a CO conversion higher than 99%. The required steam (about 60 kg/s) is mainly (40%) held in the syngas entering the CO-shift section, whereas 30% is produced through the heat released by the shift conversion reaction itself and 30% is extracted at intermediate pressure from the combined cycle steam section, thus reducing steam cycle power output. Syngas leaves the CO-shift section at about 200 °C and it is cooled to nearly 0 °C to be injected into the CO_2 removal section.

Physical solvents absorb both CO_2 and H_2S. Co-capture of CO_2 and H_2S increases plant efficiency, reducing global costs, though lower capture costs are associated to specific requirements for transport and storage in comparison to pure CO_2. For these reasons, the IGCC configuration with CCS system does not include the MDEA-based H_2S removal system, but a contextual removal of H_2S and CO_2. In particular the Lurgi's Rectisol physical absorption process, based on methanol as solvent, has been considered [16]. In the Rectisol process, methanol is cooled to a very low temperature, here set at -50 °C and, in an absorption column, it captures most of CO_2 and almost all H_2S from syngas. A CO_2 overall removal efficiency of 90% has been assumed in this study. CO_2-rich solvent is regenerated through a pressure reduction. Energy consumptions of CO_2 removal and compression sections are mainly due to syngas and methanol cooling and CO_2 compression. As in the USC plant, the compression of CO_2 is carried out in multiple stages, by compressors and pumps. Inside the absorption column, CO_2 concentration decreases from about 33% to 4.7% (both by volume). Clean syngas is almost completely composed of H_2 and water vapour (63% and 30%, respectively). Small amounts of N_2, Ar and CO (around 1%, 0.8% and 0.4%, respectively) are also present. Before fuelling the gas turbine, decarbonized syngas is heated up to about 270 °C in countercurrent with CO_2-rich syngas and diluted with nitrogen separated by ASU.

The physical decarbonization process in IGCC shows lower energy penalties than the chemical removal one of the USC plant, even if CO-shift reaction reduces syngas chemical power from about 720 MW to about 650 MW.

2.4. CO_2 transport and storage

For each plant configuration, the high-purity (about 99.5% by volume) and compressed (up to 11 MPa) carbon dioxide is sent to the geological storage site through a conventional pipeline. This assessment considers that the power generation plant is located near the storage site; therefore a 25 km long pipeline has been assumed.

Considering the potential sites for carbon dioxide geological storage in Italy, the injection in saline aquifers currently represents the higher storage capacity solution [17]. Therefore, this technique has been chosen as the storage option in this study.

3. Performance comparison

Table 5 summarizes the main performance assessed through the simulation models with reference to the previously described plant configurations. It is important to underline that the OCC configuration without CCS (it means that CO_2 is not compressed, transported and stored, but just emitted) does not make sense from the commercial point of view, but it has been considered just to compare the performance with the other conventional technologies.

Table 5. Overall performance of USC, OCC and IGCC plant configurations.

	USC	USC	OCC	OCC	IGCC	IGCC
	-	CCS		CCS	-	CCS
Coal chemical power input (MW)	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Natural gas chem. power input (MW)(*)	14.5	14.5	13.7	13.7	-	-
Gross power output (MW)	452.1	385.8	461.1	461.1	513.4	459.3
- Gas turbine (MW)	-	-			*293.6*	*267.9*
- Steam cycle (MW)	*452.1*	*385.8*	*461.1*	*461.1*	*219.8*	*191.4*
Overall power absorptions (MW)	9.1	49.7	68.8	111.5	74.6	106.7
- Fans (MW)	*9.1*	*12.0*	*6.8*	*7.7*	-	-
- ASU (MW)	-	-	*62.0*	*62.0*	*42.7*	*42.7*
- N_2 compression (MW)	-	-	-		*25.3*	*25.3*
- Other auxiliaries (MW)	-	-	-		*6.6*	*6.6*
- CO_2 capture and compression (MW)	-	*37.7*	-	*41.8*	-	*32.1*
Net power output (MW)	443.0	336.1	399.1	349.6	438.8	352.6
Net efficiency (%)	43.67	33.13	39.37	34.49	43.88	35.26
Plant availability (h/year)	8000	7600	7000	7000	8000	6800
Energy production (GWh/year)	3544	2554	2794	2447	3510	2398
CO_2 emissions (Mt/year)	2.80	0.26	2.44	0.02	2.70	0.27
CO_2 specific emissions (g/kWh)	789.0	103.7	873.2	7.8	770.1	95.9

Note:
(*) In both USC and OCC configuration, the flue gas desulphurization process implies auxiliary burners fuelled with natural gas [8].

USC plant shows a net power output of 443.0 MW leading to a net efficiency of 43.67%. The integration with the CO_2 removal section causes a noteworthy power output reduction of about 107 MW, mainly due to the large steam extraction from the steam turbine and to the power requirements of the CO_2 compression section. Globally, CCS system reduces plant efficiency of about 10.5 percentage points down to 33.13%. The CO_2 specific emissions (slightly lower than 800 g/kWh without CCS) are greatly reduced by the introduction of the CO_2 removal system, decreasing to about 100 g/kWh.

OCC plant shows a gross power output slightly higher than the USC (461.1 MW vs. 452.1 MW), but the noteworthy ASU power absorption reduces the OCC performance, leading to a net power output of 399.1 MW and to a net efficiency of 39.37%. The integration with the CO_2 capture system introduces a lower penalization in comparison to USC case; absorption of CO_2 removal section accounts for just 41.8 MW due to CO_2 compression and globally net efficiency is equal to 34.49%, higher than the CO_2-free USC net efficiency.

In the IGCC plant, the combined cycle shows a gross power of 513.4 MW (293.6 MW from gas turbine and 219.8 MW from steam cycle). Due to great ASU and auxiliaries power absorptions, IGCC net power output is reduced to 438.8 MW, with a net efficiency of 43.88%. CO_2 specific emissions are 770.1 g/kWh. The introduction of the CCS system reduces IGCC performance. Overall, net power output is reduced by about 85 MW, corresponding to an efficiency reduction of 8.6 percentage points (35.26%). IGCC power output decreasing is mainly due to the power required for solvent pumping and cooling and for CO_2 compression (32.1 MW) [18]. The remaining power output reduction is due to the effects of the CO-shift process [18], which decreases syngas chemical power and requires a significant steam extraction. Overall, CO-shift leads to a power output reduction of about 54 MW (about 26 MW the gas turbine and about 28 MW the steam plant). CO_2 specific emissions are greatly reduced to 95.9 g/kWh.

Considering the conventional (without CCS) plant configurations, USC and IGCC systems show comparable net efficiencies. On the other hand, the lower energy penalties related to the introduction of a pre-combustion CCS system make CO_2-free IGCC sensibly more efficient than CO_2-free USC.

Annual availability strongly influences the economic feasibility of the project, being relevant in costs evaluation and mainly in profits assessment. A plant availability of 8000 hours per year was assumed for both USC and IGCC configurations without CCS. The introduction of post-combustion CCS system could reduce the USC availability, due to the current poor experience in industrial-scale units (a 400 hours per year reduction was assumed). The introduction of pre-combustion CCS system in the IGCC configuration leads to more technical problems, due to the high hydrogen concentration in the treated gas feeding the combined cycle. Therefore, 1200 hours per year reduction was assumed to consider the low maturity level of the technology [19]. Being OCC technology still not commercially mature, a plant availability of 7000 hours per year has been considered.

4. Costs and profits estimation

The economic and financial assessment of the overall investment was carried out for the previously described plant configurations by the evaluation, year by year, of the effective and actualized cash flow, the latter referred to the first year of the project financing phase (assumed 2016). With this aim, a detailed simulation model has been developed by Sotacarbo in order to evaluate actual costs and profits of the project, together with the profit and loss account and the balance sheet.

Table 6 reports the main financial assumptions for both USC and IGCC plant configurations.

Table 6. Main financial assumptions

		Notes
Plant construction period (years)	4	Since 2016 to 2019
Plant operating life (years)	25	Since 2020 to 2044
Annual discount rate	8%	Huang et al., 2008 [3]
Annual inflation rate	2%	
Plant value at the end of operating life (M€)	0.00	
Averaged time for payments and receipts (days)	30	

In order to allow a comparison between the different technologies (most of which are not still mature from the industrial point of view), the same operating life (25 years) has been prudently assumed for each configuration.

Moreover, the analysis assumes that 80% of the overall investment is funded by the banks through a senior debt, whereas the remaining 20% is directly provided by the owner company. This assumption significantly reduces the economic performance of the overall project, due to the financing costs (financing fees, interests and so on), but makes this study closer to the actual projects.

4.1. Capital costs

The assessment of the plant capital cost takes into account both the plant construction and the adjustment of infrastructure. Capital cost estimation is shown on table 7, on the basis of previous evaluations by the authors [8]. All the values have been adjusted considering the inflation rate.

Table 7. Capital costs (in M€).

CCS section	USC -	USC CCS	OCC -	OCC CCS	IGCC -	IGCC CCS
Basis power generation plant	598.57	598.57	1021.09	1021.09	752.42	752.42
CO_2 capture and compress. [(a)]	-	284.54	-	76.86	-	161.23
CO_2 transport via pipeline	-	26.17	-	28.35	-	22.83
CO_2 storage	-	316.44	-	342.81	-	276.05
Material handling	61.40	58.33	58.33	58.33	61.40	52.19
Total plant cost (TPC)	659.97	1284.05	1079.42	1527.44	813.82	1264.72
Other capital costs [(b)]	52.80	102.72	86.35	122.20	65.11	101.18
Contingencies [(c)]	13.20	56.69	103.28	139.66	31.32	65.65
Total overnight cost (TOC)	725.97	1443.46	1269.05	1789.30	910.25	1431.55
Financing fees and interests	133.00	264.44	203.69	327.80	166.76	262.26
Total as-spent cost (TASC)	858.97	1707.91	1501.55	2117.11	1077.01	1693.81

Notes:

[(a)] Including water gas shift process for IGCC-based configurations.

[(b)] Assumed 8% of capital investment. It includes engineering, start-up, spare parts, royalties and working capital.

[(c)] Assumed 2%, 4% or 10% of capital investment depending on the maturity of the technology [20].

Considering the conventional (without CCS) plant configurations, USC presents lower capital cost than IGCC (overall as-spent investment of about 860 M€ vs. about 1080 M€ for IGCC), whereas both the technologies present the same cost (about 1700 M€) if equipped with CCS system. This is mainly due to the lower size of the pre-combustion carbon capture system from high pressure coal syngas. Oxy-coal combustion plant presents a very high capital costs (more than 2100 M€, including CO_2 compression, transport and storage), mainly due to the lower technological maturity of the technology.

Financing fees and interests reported in table 7 are calculated assuming an annual interest rate of 6.14% for both the senior debt and the value added tax (VAT) facility. In particular, each VAT payment is refunded after two years; therefore the effective cost is only due to the interest related to the VAT facility. Finally, the interest is calculated considering that 24% of capital cost is invested during the first year of construction, whereas 39%, 32% and 5% are invested during the following three years, respectively [21]. An amortization rate of 10% has been assumed for power generation and CCS system, whereas an amortization rate of 14% is considered for the material handling system. The model also considers a yearly extra investment during the operation of the plant [21].

4.2. Overall operating costs

Overall operating cost of the power generation plant includes coal purchasing, plant operation and maintenance (O&M), together with costs for material handling and taxes.

As for primary fuel, a CIF ARA (Cost, Insurance and Freight for delivery in North-West Europe) of 77 €/t has been considered, together with an extra cost of 10 €/t to take into account the coal transport in the Mediterranean sea and an excise duty of 2.90 €/t [8]. All these costs are referred to 2010 and an annual increasing of 2% is calculated to consider the inflation.

O&M costs include all the costs for conduction and maintenance of power generation plant and, in particular, costs of labour, day-by-day maintenance, spare parts, consumables and so on. The cost for material handling also includes O&M and electrical energy consumptions of such a system. The analysis also considers all the taxes, including that related to the emission of sulphur and nitrogen oxides (106 €/t and 209 €/t, 2010 basis, respectively) [8].

A market price of 7 € per ton of emitted CO_2 (referred to year 2015) has been assumed. This cost is annually increased of 2% in order to take into account the inflation rate.

As for CO_2 compression, transport and storage, a compression cost of 0.75 c€ per kilogram of CO_2 [22] and a transport cost of 2.5 c€/(t km) for a 25 km long onshore pipeline [23,24] have been assumed. An operating cost of 0.3 €/t has also been considered for carbon sequestration in saline aquifers [22]. All these costs are referred to year 2010 and they have been increased year by year with the inflation [8].

5. Economic and financial assessment

A comparison between the different plant configurations has been carried out with reference to the typical economic indicators: cost of electricity (CoE), CO_2 capture cost and CO_2 avoidance cost.

CoE (expressed in €/MWh) is defined as the ratio between the overall plant costs (both capital and operating), evaluated during all the project life, and the total amount of electrical energy produced in the same period. Similarly, CO_2 capture cost is defined as the ratio between the overall CCS cost (capital and operating costs for CO_2 separation, compression, transport and storage), evaluated during all the project life, and the total amount of stored CO_2 in the same period. CO_2 capture cost does not consider the effects of energy penalties (due to the introduction of the CCS system). Therefore, a more detailed estimation of the effective cost for the reduction of carbon dioxide emissions is represented by the cost of avoided CO_2 (or CO_2 avoidance cost), which also includes the extra costs and failed profits related to the reduction of electrical energy production and selling. The cost of avoided CO_2 (C_a, in €/t) is defined as:

$$C_a = k \cdot \frac{CoE_{CCS} - CoE_{basis}}{e_{basis} - e_{CCS}} \qquad (1)$$

where *CoE* is the previously defined cost of electricity, *e* is the specific CO_2 emission (in g/kWh), *k* is a unit conversion coefficient (k = 1000 to convert €/kg to €/t) and the subscripts *CCS* and *basis* are referred to the plant configurations with and without CCS system, respectively. In other words, the CO_2 avoidance cost represents the minimal CO_2 tax required for a major man-made carbon dioxide emissions source to start seriously considering CCS [21,25].

The main results of the comparative economic analysis are reported in table 8. Ultra supercritical combustion is more profitable than gasification for power generation without CCS (with a CoE of 72.4 €/MWh vs. 74.5 €/MWh for IGCC); on the other hand, IGCC becomes more profitable than USC when CO_2 is captured and geologically stored (CoE is 116.5 €/MWh for USC and 110.5 €/MWh for IGCC). As a matter of facts, the economic effects of the lower energy penalties of a CO_2-free IGCC plant with respect to a corresponding USC unit (8.6 vs. 10.5 percentage points, as can be seen in table 7) exceed the effects of the higher capital cost. The main differences, from the economic point of view, between CO_2-free configurations based on combustion and gasification are due to the operating phase and, in particular, to the different plant availability. As a matter of facts,

CO_2-free IGCC plant is expected to allow a lower annual availability (assumed 6800 hours per year) than a corresponding USC configuration (7600 hours per year) but, as mentioned, also a higher overall efficiency.

Table 8. Economic assessment.

	USC -	USC CCS	OCC -	OCC CCS	IGCC -	IGCC CCS
CoE, cost of electricity (€/MWh)	72.4	116.5	89.6	119.4	74.5	110.5
Present CoE (€/MWh)	28.6	52.7	40.9	58.1	30.7	51.0
CO_2 capture cost (€/t)	n.s.	35.66	n.s.	32.20	n.s.	33.77
Present CO_2 capture cost (€/t)	n.s.	19.56	n.s.	17.02	n.s.	17.67
CO_2 avoidance cost (€/t)	n.s.	47.51	n.s.	37.51	n.s.	41.69
Present CO_2 avoidance cost (€/t)	n.s.	26.07	n.s.	19.83	n.s.	21.82

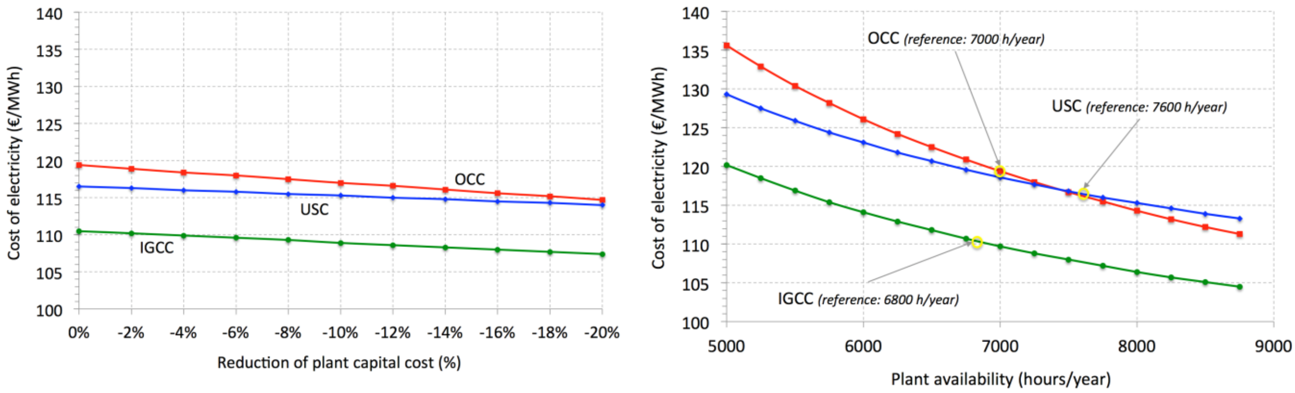
Power generation by oxy-coal combustion is currently non competitive with the other options (it presents a CoE of 119.4 €/MWh), but it is mainly due to the lower level of maturity of the technology, which involves higher capital costs (including contingencies), a relatively low efficiency and a lower plant availability.

In general CoE, for the CCS configurations, is slightly higher than that indicated in several studies [2,23,26,27], mainly due to the significantly higher cost of coal and to the assumption that 80% of the overall investment is funded by the banks through the opening of a senior debt.

6. Sensitivity analysis

The economic performance of each plant configuration depends by several parameters typically characterized by some uncertainties, due to the international markets or to technical and design assumptions. The most impacting parameters are typically represented by [8]: (i) the market prices of electrical energy, coal and CO_2, (ii) the capital and operating costs of both power generation plant and carbon dioxide capture, transport and storage systems, and (iii) the financial options (amount of the senior debt, interest rate, financing fees and so on).

Whereas USC and IGCC are mature technologies and it is relatively easy to carefully estimate capital investment, the industrial experience on OCC is very poor and there are wide margins for a technology development. Therefore, figure 2 shows, for the three CO_2-free configurations, a sensitivity analysis to assess the effects of both capital cost and plant availability on CoE.



(a) *(b)*

Fig. 2. Sensitivity analysis on CO_2-free plant configurations: a) capital cost; b) plant availability.

Figure 2a shows that a significant reduction of plant capital cost (only for the construction of the power generation plant) involves a relatively slight reduction of CoE; this reduction can be expected mainly for OCC technology (due to its lower maturity level). On the other hand, a variation of the annual availability (as a consequence of an increasing reliability or of variations of market demand) strongly impacts on CoE (figure 2b). Overall, OCC technology can be expected to become (as a consequence of an improving maturity level) competitive with USC for CO_2-free power generation whereas, in the considered conditions, IGCC is expected to remain the most profitable technology for CCS plants.

7. Conclusions

The commercial diffusion of carbon capture and storage technologies is one of the key approaches towards a sustainable energy production, but it needs a significant effort to optimize and demonstrate CCS technologies in large-scale plants. The main obstacle in the development of CCS is currently represented by the very high capital and operating costs which make investments in CCS strongly unprofitable.

In particular, the technical and economic comparison presented in this study considers three of the most promising technologies for a short-term commercial-scale CO_2-free power generation (USC, OCC and IGCC plants) and compares them with their corresponding conventional (without CCS) configurations.

For a reference size of 1000 MW_{th}, a conventional coal-fired USC power plant shows an overall efficiency (43.7%) comparable to IGCC (43.9%). IGCC is characterized by a slightly higher capital cost, but it is competitive with USC for power generation (with a CoE of 89.6 €/MWh, with respect to 72.4 €/MWh of USC plants).

An opposite trend can be obtained for CO_2-free plant configurations. As a matter of facts, being CCS energy penalties significantly higher for USC (about 10.5 percentage points vs. about 8.6 for IGCC), IGCC with CCS is more efficient (35.3%) than the corresponding CO_2-free USC (33.1%). In this scenario, oxy-coal combustion plant is currently not competitive with USC and IGCC: it presents a CoE of 119.4 €/MWh (about 8% higher than CoE by IGCC technology). This higher cost is mainly due to the low industrial experience with OCC, which means higher capital and operating costs and a lower plant operating reliability.

In a short term future, a progressive diffusion of commercial-scale OCC plants will allow a reduction of capital costs and an improvement of the technology, with higher efficiency and reliability. As shown by the sensitivity analysis, it means that OCC promises to became competitive with USC and eventually with IGCC.

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