



Techno-economic assessment of blast furnace gas pre-combustion decarbonisation integrated with the power generation

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ABSTRACT

Aiming at the iron and steel industry decarbonisation with blast furnace gas (BFG) utilisation, a techno-economic feasibility of the pre-combustion carbon capture with methyl diethanolamine (MDEA) is evaluated herein. The effectiveness of water gas shift (WGS) implementation on the capture performance is also investigated. The integration of a power plant with decarbonised fuel from the capture unit is taken into account from both technical and economic perspectives. Aspen Plus® is used to develop the process. The results obtained from the techno-economic analysis showed that the WGS implementation increases the capture efficiency from 46.5% to 83.8%, with increased CO₂ capture cost from € 39.8/t_{CO2} to €44.3/t_{CO2}. The sensitivity analysis on the effect of 1) different BFG composition and 2) different carbon capture rate (CCR) on the capture unit integrated with WGS performance is performed. The obtained results revealed that BFG with a lower calorific value is less practical from a techno-economic point of view as it increases the specific primary energy consumption for CO₂ capture avoidance (SPECCA) from 3.3MJ_{LHV}/kg_{CO2} to 3.8MJ_{LHV}/kg_{CO2}. Moreover, the lower CCR increases the thermal energy of the H₂-rich gas from the capture unit from 266.8 MW to 269.6 MW. The techno-economic advantages of the based case do not result beneficial for an environment point of view since at lower CCR the specific CO₂ emissions increase from 51 kg_{CO2}/GJ_{LHV} to 70 kg_{CO2}/GJ_{LHV}. The fully integrated power plant to the capture unit reveals that the 37.52% (without WGS) and 24.27% (with WGS) efficiencies are achievable through the combined cycle integration. For the combined cycle, the integration of WGS reactor will reduce the CO₂ specific emission to 675.1 kg_{CO2}/MWh in comparison to 1391.5 kg_{CO2}/MWh for the case with no WGS.

1. Introduction

Energy-intensive industries have to implement innovative low carbon initiatives to reduce greenhouse gas emissions. Among industries, the iron and steel (I&S) sector is the second-largest CO₂ emitter contributing to 7% of the global direct CO₂ emissions [1]. The two dominant steel production methods are the integrated steel mill or blast furnace-basic oxygen furnace (BF-BOF) and the electric arc furnace (EAF) processes. Around 70% of the worldwide steel production is from the integrated steel mill [2], with the reported CO₂ emission ranging between 1.6 and 2.2 t_{CO2}/t_{steel} [3]. This is the steel production method with a higher significant emission rate compared to 0.4 to 1.2 t_{CO2}/t_{steel} associated with EAF [3]. Improving energy saving in the I&S industry plays a significant role in reducing fossil fuel consumption as a primary

energy, and consequently, CO₂ emissions. The recovery of secondary energy in the I&S industry- steel mill by-products such as blast furnace gas (BFG), coke oven gas (COG), and basic oxygen furnace (BOFG)- is also known as a promising option for energy-saving [4]. Power plant integration to the steel mill has been extensively endorsed recently. It has been shown that with a BFG-fired combined cycle, a thermal efficiency of 45% can be achieved [5]. Among the integrated steel mill off-gases, BFG has a higher CO and CO₂ content; therefore, although the power plant integration is essential to energy saving, the steel mill off-gases decarbonisation is still necessary to reach the carbon neutrality goal.

Recently, there has been growing attention on BFG decarbonisation. However, pre-combustion decarbonisation via amine is yet to be considered. Hence, this research aims to present the feasibility of BFG pre-combustion decarbonisation. Methyl diethanolamine (MDEA) is

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Nomenclature			
ACCR	Annualised Capital Charge Ratio (-)	n	Time (years)
CCC	Cost of CO ₂ capture (€/t _{CO2})	TAC	Total Annualised Cost (M€/y)
C _{CO}	Contingencies cost (M€)	TDPC	Total Direct Plant Cost (M€)
C _{EPC}	Engineering, procurement and construction cost (M€)	TEC	Total Equipment Cost (M€)
CCR	Carbon capture rate (%)	TIC	Total Installation Cost (M€)
C _{OC}	Owner Cost (M€)	TPC	Total Plant Cost (M€)
CF	Capacity factor (%)	V _{O&M}	Variable operating cost (€/MWh)
C _{fuel}	Fuel cost (M€/y)	W _{net}	Net power output (MW)
CGE	Cold Gas Efficiency (%)	<i>Abbreviations and definitions</i>	
ΔC _{HRC}	Incremental cost for HRC (€/t _{HRC})	BFG	Blast Furnace Gas
ΔCO ₂	Incremental CO ₂ emission HRC (kg _{CO2} /t _{HRC})	CC	Combined Cycle
ΔT	Temperature difference (°C)	CCUS	Carbon Capture Utilisation and Storage
f	Scaling factor	COG	Coke Oven Gas
FCF	Fixed charge factor (-)	DCF	Decarbonised Fuel
F _{O&M}	Fixed operating cost (€/MWh)	EAF	Electric Arc Furnace
LCOE	Levelised cost of electricity (€/MWh)	HP/IP/LP	High-Pressure, Intermediate-Pressure, Low-Pressure
LCODF	Levelised cost of decarbonised fuel (€/t)	HRSG	Heat Recovery Steam Generator
LHV _i	Lower heating value (MJ/kg)	HRC	Hot Rolled Coil
\dot{m}_i	Mass flow rate, (kg/s)	IPT	Intermediate-pressure Turbine
OEE	Overall energy efficiency (%)	LHV	Lower Heating Value
\dot{Q}_i	Heat rate, (MW)	LPT	Low-pressure Turbine
r	Interest rate (%)	MDEA	Methyl diethanolamine
SPECCA	Specific primary energy consumption for CO ₂ capture avoidance (MJ/kg _{CO2})	SC	Steam Cycle
		TGRBF	Top Gas Recycling Blast Furnace
		WGS	Water Gas Shift

considered as a solvent due to its remarkably more stability and lower regeneration energy requirement than other amines [6]. The novelty of this study relies on: i) the comparison of two thermodynamic cycle, a subcritical steam cycle and a combined cycle simulated using state of the art operating conditions fully integrated with a pre-combustion CO₂ capture, including also the case with WGS for further conversion of CO into H₂ and CO₂; ii) the presentation of a comprehensive methodology validated with industrial partner and selected as benchmark for the comparison with novel processes as currently under development in the EU H2020 C4U project; iii) the use of real BFG compositions that are generated in an industrial blast furnace operated with different fuel co-feeding including natural gas; iv) the sensitivity analysis on the possibility to use BFG for other chemical processes by manipulating the final H₂/CO ratio. A single-stage water gas shift (WGS) reactor is later implemented to convert CO content in the BFG to CO₂ and H₂, thus enhancing the carbon capture efficiency. Aspen Plus® is used to develop the process simulations. The results obtained from the thermodynamic performance are used for economic feasibility evaluation. A detailed comparison is implemented between the reference case (no capture), the base case (capture unit only) and the enhanced case (capture unit and WGS). A sensitivity analysis is carried out regarding the effect of different BFG compositions and carbon capture rates (CCR) on enhanced case performance. Finally, a detailed evaluation of fully integrated decarbonised BFG with power units (subcritical steam and combined cycles) is also performed and summarised from technical and economic perspectives.

1.1. Literature review on acid gas removal from BFG

Various processes have been proposed to decarbonise the I&S industry, which are currently either at the pre-demonstration or demonstration stage. The exhaust gas from the hot stove and power plant are the two primary CO₂ sources at an integrated steel mill. Therefore, cost-effective decarbonising of these primary sources is compulsory.

One of the novel technologies is a top gas recycling blast furnace (TGR-OBF) developed in the European Ultra-Low CO₂ Steelmaking

(ULCOS) project [7]. It comprises injecting pure O₂ or O₂ enriched-air instead of air into the furnace, thereby eliminating (or significantly reducing) the presence of N₂ in the BFG, increasing the CO₂ concentration in the BFG and therefore reducing the cost of downstream absorption-based CO₂ separation at the expense of the cost of oxygen production. After CO₂ separation, the reducing gases (mainly CO and H₂) are partly recirculated back to the BF and partially used in the steel mill's power plant. Jin et al. [8] investigated the TGR-OBF regarding its energy consumption and CO₂ emission. They showed that an energy reduction of 29.7% is achievable for TGR-BOF together with a net CO₂ reduction of 33.5% compared to conventional BF. CO conversion into H₂ and CO₂ with a water gas shift (WGS) reactor is another technology with a significant impact on decarbonisation. In this case, deeper decarbonisation is achieved compared to the case without WGS, and an H₂-rich stream is available for different applications. The sorption-enhanced water gas shift (SEWGS) technology that combines WGS with CO₂ adsorption shows the potential of removing over 80% CO₂ from BFG [9]. Scaling up the SEWGS to the commercialise level is the main objective of the H2020 STEPWISE EU project [10], where the main challenge is finding an efficient and cost-effective method for sorbent regeneration. A packed-bed Ca-Cu looping process to supply the regeneration heat from the reduction of CuO is proposed in [11] and validated experimentally in the ASCENT project [12] and recently proposed for steel mill [13,14]. BFG is converted into an H₂/N₂ rich stream, and concentrated streams of CO₂ are produced during regeneration of CaCO₃ by burning a fuel gas using the CuO/Cu materials as these are the only oxygen carriers with high enough exothermic reduction enthalpy [12,14,15]. COURSE50 project [13] worked on the steel mill CO₂ emission reduction of 30% by replacing coke with hydrogen, natural gas and biomass (10%) and chemical/physical absorption implementation (20%) [16]. The COREX process [17] consists of two zones, where lump ore/pellets are first reduced in a reduction zone using gas with a high calorific value. Then, in a second zone called a melter-gasifier, non-coking coal and the reduced metal are in contact with pure oxygen to generate the hot metal slag. The gas generated in the melter-gasifier (mainly CO and H₂) is used in the reduction zone. After that, it can be separated into a CO₂ capture

unit (30–40% carbon capture rate) or a WGS + CO₂ capture unit (high CO₂ capture, >90%). The Hisarna process [18] is a smelting technology in which ore is fed at the top of the smelter and reacts with coal and oxygen to produce slag and hot metal collected at the bottom. The produced gas is a concentrated CO₂ stream, which can be further processed. Both coal and biomass can be used, reducing the specific CO₂ emissions of the system by up to 50% (without an additional CO₂ capture system). A summary of the status of these technologies is reported in Table 1.

The sulphur in BFG is mainly inorganic, H₂S, or organic sulphur like COS and CS₂ [20]. Since inorganic sulphur removal is more accessible, the main goal of organic sulphur removal methods such as i) Catalytic hydrolysis [21] and ii) hydrogenation hydrolysis is to convert other types of sulphur to H₂S [22] and remove the H₂S by adsorption, absorption and membrane. However, to the best of our knowledge, there is a lack of literature on BFG desulphurisation. Hence, the leading H₂S removal technologies (absorption and adsorption [23]) are summarised in Table 2 with their merits and disadvantages. The sulphur concentration is closely related to the sulphur content of coke, and about 90% of it is already removed inside the blast furnace [24]. It is worth mentioning that the H₂S removal is not considered in this study since we have only considered high-temperature WGS, which is sulphur tolerant process and can tolerate small quantities of sulphur-based compounds without de-activating the Fe-based catalyst. Instead, in the presence of a low-temperature WGS reactor using a Cu-based catalyst, sulphur removal is required. Furthermore, any trace of H₂S will be separated along with CO₂ since the reaction rates of H₂S with MDEA are effectively instantaneous with respect to the mass transfer rates and enormously higher than the reaction rates of CO₂ with MDEA [25–27].

2. Process description and model development

2.1. BFG decarbonisation

Fig. 1 is a schematic of the base case decarbonisation scenario. BFG enters the bottom of the absorber column at 3 bar and 35 °C while being contacted counter-current with the lean solvent (MDEA). These assumptions are consistent with the H2020 3D EU project, where a new DMX absorption process is used to decarbonise BFG [19]. Decarbonised clean fuel (DCF) and CO₂-rich solvent exit from the absorber from the top and bottom of the column, respectively. The CO₂-rich solvent is pumped before entering the regenerative heat exchanger and the

stripper. The high-purity CO₂ stream leaves the stripper columns after the evaporated water is removed in a condenser while the lean solvent from the bottom of the stripper column is sent back to the absorber column after being cooled down. The high purity CO₂ is sent to the CO₂ compression and conditioning units before being transported. The dense phase is regarded as the most energy-efficient condition due to its high density and low viscosity. Consequently, the current operating practice for CO₂ pipelines is to maintain the pressure well above the critical pressure. Considering the pressure drop along the length of the pipeline and the impact of the elevation change and impurities, the entry pressure of the CO₂ pipeline network is as high as 110 bar. Thus, a compression train is required to pressurise the CO₂ stream from the captured plant to reach a high entry pressure. The CO₂ compression unit includes a multistage compressor to increase the pressure up to 78 bar and cool down the stream to 25 °C to liquefy the CO₂-rich stream and pump it to the final delivery pressure [35].

In the enhanced decarbonisation case, the BFG is first converted into H₂/CO₂-rich gas in a single-stage water gas shift (WGS) by reacting with steam (H₂O to CO ratio equals 1.5 [9]). H₂O is available at 3 bar and 145 °C, heated up to 330 °C before entering the WGS reactor (operating at ~ 3 bar). The shifted gas is cooled down by recovering high-temperature heat from WGS, and then it is used to pre-heat the feed mixture. Further cooling process and condensation are necessary before entering the absorber column, as shown in Fig. 2.

The shifted syngas is then sent to an MDEA process designed according to the same operating conditions of the Base Case. The BFG composition and the assumptions for the capture unit modelling are summarised in Table 3 and Table 4. A detailed mass balance for the capture unit is provided in the supplementary material along with the Aspen File used for the simulation. The primary assumptions for the chemical absorption and power generation simulation have been taken from existing literature [10,36]. The operating conditions have been selected according to the benchmark assumptions proposed in the H2020 3D EU project [34] and supported by the industrial partner within the H2020 C4U EU project which is currently demonstrating the use of an advanced solvent to decarbonise steel mill (up to 1 MtCO₂/year) by 2025.

2.2. Power plant integration

In integrated steelworks, the BFG is burned to produce electricity in a conventional subcritical steam cycle power plant. In this study, we have

Table 1
Blast Furnace Gas CO₂ capture technologies.

CO ₂ capture technology	Advantages	Disadvantages	CO ₂ emissions (t _{CO2} /t _{steel})	CO ₂ capture/avoidance cost, €/t _{CO2}	TRL	Ref.
BF + separation (amine, Selexol)	<ol style="list-style-type: none"> 1. Retrofittable 2. Low impact on the interlinked energy system in the steel mill 	<ol style="list-style-type: none"> 1. High energy consumption 2. Limited CO₂ separation 	≈1.4 (15–20%)	40–70	8–9	[19]
TGRBF integrated with a CO ₂ separation technology	<ol style="list-style-type: none"> 1. Retrofittable 2. 25% less carbon usage 3. 60% CO₂ reduction with CO₂ storage application 	<ol style="list-style-type: none"> 1. The increased electric power demand for CO₂ separation 	0.8–1 (40–55%)	30–50	7	[7]
COREX + separation (amine, Selexol)	<ol style="list-style-type: none"> 1. It does not require sinter and coking plants 2. Non-coking coal can be used 3. N₂-free high-quality gas production 	<ol style="list-style-type: none"> 1. Non-retrofitable 2. Large oxygen consumption 	0.3–1.6 (30–90%)	9–30	7–8	[17]
Hisarna technology (smelter technology)	<ol style="list-style-type: none"> 1. 20% CO₂ reduction per t_{steel} 2. 80% CO₂ reduction with CCS 	<ol style="list-style-type: none"> 1. Non-retrofitable 2. Large oxygen consumption 	0.8–1.4 (20–55%)	10–20	7	[18]
BF + SEWGS	<ol style="list-style-type: none"> 1. High hydrogen and CO₂ recovery 2. WGS combined with CO₂ capture leads to better heat integration 	<ol style="list-style-type: none"> 1. Lack of pilot-scale testing 2. Large reactor volume 3. High steam consumptions 	0.1–0.3 (>90%)	30–40	6	[9]
Ca-Cu based	<ol style="list-style-type: none"> 1. High hydrogen and CO₂ recovery 2. WGS combined with CO₂ capture leads to better heat integration 	<ol style="list-style-type: none"> 1. Lack of pilot-scale testing 2. Large reactor volume 3. High fuel demand for CaCO₃ regeneration 	0.1–0.3 (>90%)	30–40	4–5	[14]

Table 2
H₂S removal technologies used in oil & gas, chemical and energy industries.

			Advantages	Disadvantages	Ref.
Absorption	Chemical	Water scrubbing	The low energy requirement of 0.3–0.9 kWh/Nm ³ clean biogas	1. High pressure and low-temperature operation condition	[28]
		Amine	High efficiency	1. High Capex and OPEX	[29]
	Physical	Methanol	The high sulphur absorption rate	1. High CAPEX and OPEX	[30]
		DEPG*	1. High H ₂ S selectivity compared to CO ₂ 2. Lower vapour pressure 3. Lower heat duty for regeneration than chemical solvent	2. high-temperature requirement for regeneration 1. Better performance at an extremely low temperature	[23,31]
Adsorption	Activated carbon	Metal oxide	High purification rate	Low stability	[32]
			1. medium to high-temperature operation range	1. prior water removal is necessary to avoid absorbent accumulation	[33]
	PSA		2. high removal efficiency Low energy requirement	1. High CAPEX and OPEX	[34]

*Dimethyl ether of polyethylene glycol.

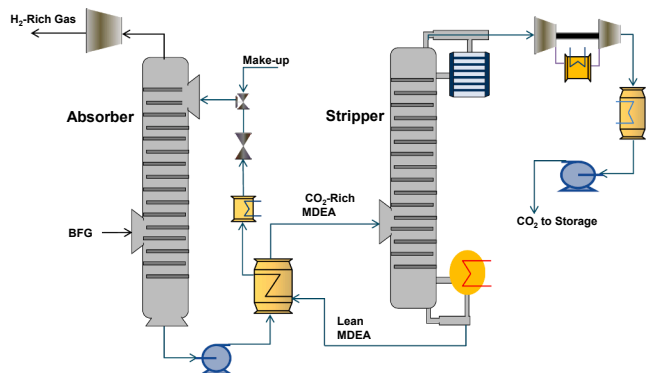


Fig. 1. BFG decarbonisation with MDEA (Base Case).

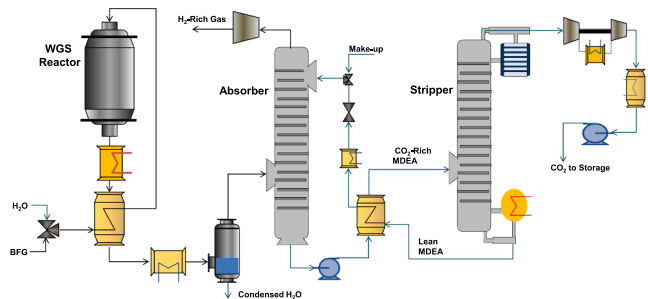


Fig. 2. BFG enhanced decarbonisation (Enhanced case).

Table 3
Specifications of BFG 1 implemented in the simulation.

Parameter	Value
Temperature (°C)	35
Pressure (bara)	3
Composition (%mol)	
CO ₂	22.2
CO	22.7
C ₂ H ₄	0.2
H ₂	2.4
N ₂	53.5
S compounds	Not considered
Lower heating value (MJ/kg) ^a	2.35

Table 4
Assumptions and initial inputs to simulate the capture plant configurations.

Parameter	Value	Ref.
MDEA CO₂ absorption process		
MDEA/water content in the lean solvent (%wt)	25/72	[2]
Absorber stage number	20	
Solvent/CO ₂ ratio, (%wt basis)	3/25	
Stripper stage number	20	
Steam condition at the reboiler (bar)	6.0	
Pinch point ΔT in the regenerative heat exchanger (°C)	10.0	
Pump hydraulic/mech efficiency (%)	75/95	
Heat Exchangers		
Minimum ΔT gas–gas heat exchanger (°C)	25	[37]
Minimum ΔT gas–liquid heat exchanger (°C)	10	
Minimum ΔT liquid–liquid heat exchanger (°C)	10	
Turbomachines		
Expander isentropic efficiency (%)	93	
Expander delivery pressure, (bar)	1.015	
CO₂ compression train		
Number of stages	2	[37]
Intercoolers temperature (°C)	40	
Intercoolers pressure drops (% of p _{inlet})	5	
Isentropic efficiency, (%)	80	
Mechanical efficiency (%)	95	
CO ₂ delivery pressure (bar)	110	
CO ₂ delivery temperature (°C)	25	

compared the more conventional steam cycle with a more efficient combined cycle. The assumptions for the power plant modelling are summarised in Table 5 and taken from existing literature [2,37].

In the steam cycle, air and fuel (BFG, or DCF) combust in a boiler to produce steam. Air is pre-heated before entering the boiler by cooling the exhaust gas from the combustion chamber. High/intermediate-pressure steam is generated and sent to the high-pressure turbine (HPT) and intermediate-pressure turbine (IPT), respectively. The steam required for the stripper reboiler and WGS is taken from the steam cycle before entering the low-pressure turbine (LPT), see Fig. 3. In the enhanced decarbonisation, the heat recovered after the WGS is used to produce high-pressure steam added to the overall system. The plant is fully integrated, as represented in Fig. 3.

The combined cycle gas turbine (CCGT) comprises a combination of the Brayton cycle (gas turbine) and Rankine cycle (steam turbine) for electricity/heat generation, as presented in Fig. 4. The fuel is compressed to the injecting condition in the combustor in a multistage inter-cooled compressor. After the expansion in the gas turbine, the exhaust gas enters the heat recovery steam generator (HRSG), by which the

Table 5
Turbomachinery assumption for Power plant simulation [2,37].

Parameter	Value
Subcritical Steam Cycle	
Maximum steam temperature (°C)	500
Maximum steam pressure, (bar)	160
Re-heater temperature (°C)	500
Re-heating pressure (bar)	28
Pump efficiency (HP, MP) (%)	83, 75
Condensing pressure (bar)	0.048
Turbine isentropic efficiencies (HP, IP, LP) (%)	92,94,88
Combined Cycle	
BFG compressor	
Isentropic efficiency (%)	80
Mechanical efficiency (%)	95
delivery pressure, (bar)	28
Number of stages	3
Gas turbine	
Pressure ratio	17
Turbine inlet temperature (°C)	1180
Generator efficiency (%)	98.5
Mechanical efficiency (%)	99.6
Isentropic/polytropic efficiency compressor (%)	88
Isentropic/polytropic efficiency expander (%)	99.6
Heat Recovery Steam Generator [9]	
Pressure levels (bar)	130, 28, 4
Maximum temperature (°C)	540
Condensing pressure (bar)	0.048
Turbine isentropic efficiencies (HP, IP, LP) (%)	92,94,88
Pump efficiency (HP, MP) (%)	83, 75
HRSG pressure losses (kPa)	3.0
ΔT pinch point (°C)	10
ΔT approach point (°C)	25
Heat Exchangers	
Minimum ΔT gas–gas heat exchanger (°C)	25
Minimum ΔT gas–liquid heat exchanger (°C)	10
Minimum ΔT liquid–liquid heat exchanger (°C)	10

sensible heat of the exhaust gas is recovered producing steam at different pressure levels (2 or 3 in this study). A detailed mass balance for the capture unit integrated with the power plant unit is also provided in the supplementary report.

2.3. Model development

The process models were developed in Aspen Plus®, V8.8. The equations of state used for thermodynamic property estimation were the *ELECNRTL* and *Peng-Robinson* for the CO₂ capture unit and power plant, respectively. The equilibrium calculation type is considered to simulate the absorber and stripper columns. Other parameters used in the simulation are summarised in Table 6.

2.4. Model validation

The MDEA capture plant and combined cycle are validated with results presented by Romano et al. [38] and the National Energy Technology Laboratory (NETL) [39], respectively. It can be seen in Table 7 and Table 8 that there is a good agreement between the model prediction and the literature. Although the rate-based simulation provides results with greater accuracy than the equilibrium model, the MDEA validation results revealed that the employment of the equilibrium model is unbiased.

2.5. Techno-economic assessment indicators

To evaluate the thermodynamic performance, the analysis is distinguished between the simulation of the CO₂ capture plant and the analysis in case the CO₂ capture plant is integrated with the power generation [9]. In the case of the CO₂ capture unit, the performance assessment is based on:

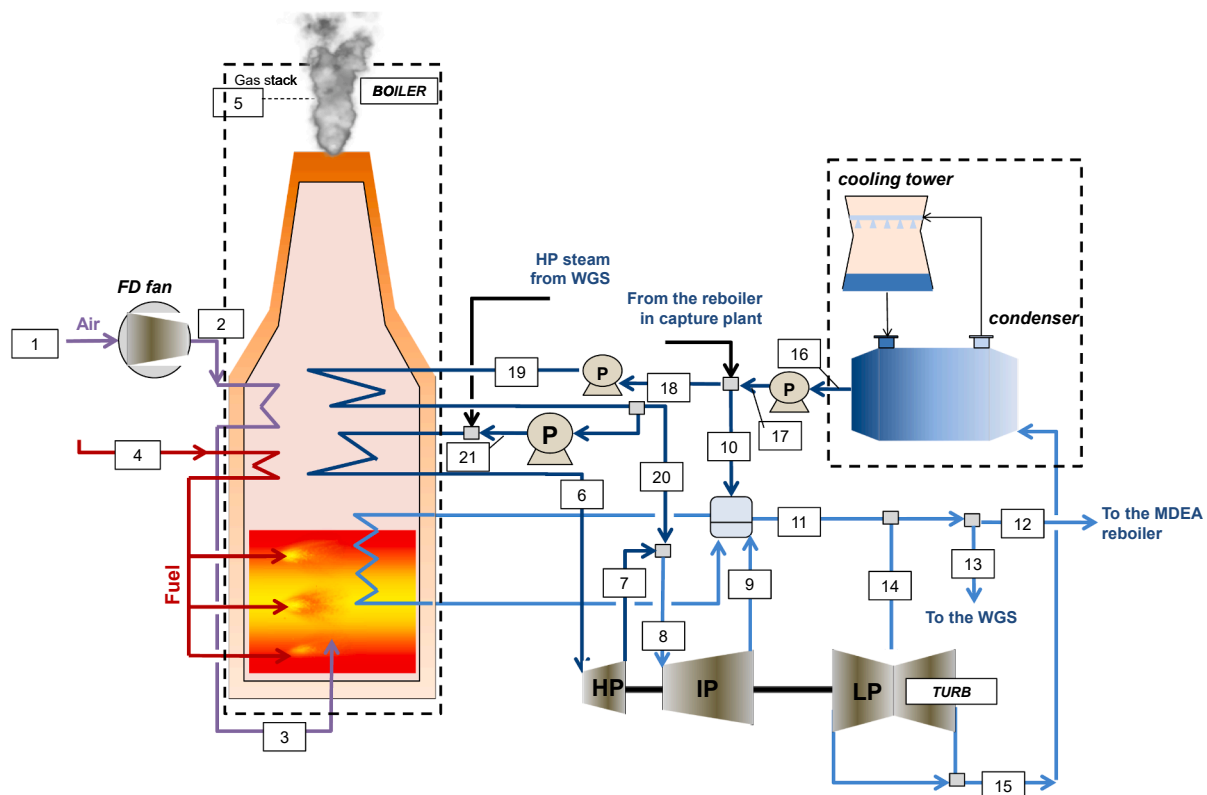


Fig. 3. Steam cycle integration with CCS unit.

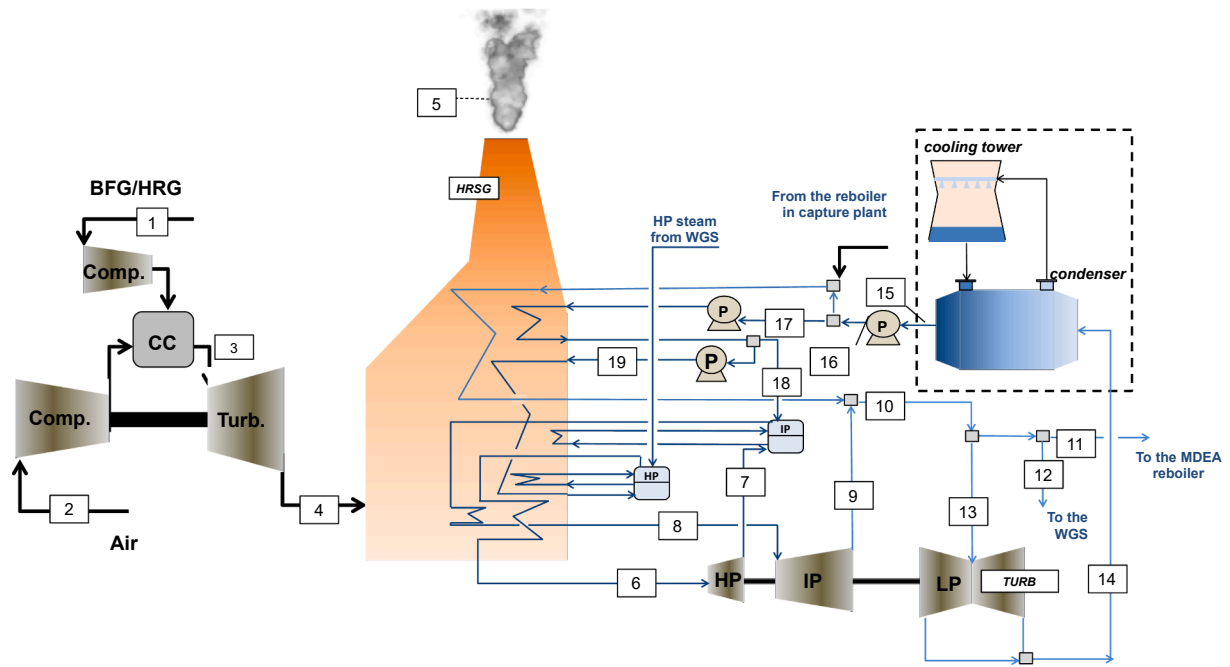


Fig. 4. Combined cycle integration with CCS unit.

Table 6
Aspen plus components used in the process modelling.

Unit	Aspen Plus ID	Description
Condenser	Flash2	Pressure change = 0, Duty = 0
Cooler	Heater	
Heat exchanger (s)	HeatX, MHeatX	
Combustor	RGibbs	
Turbine, Compressor	Compr, MCompr	
Expander	Compr	
Absorber	RadFrac	15 stages, standard convergence
Regenerator	RadFrac	20 stages, partial vapour condenser, Standard convergence, Reflux ratio = 0.6 mol, Boil up ratio = 0.1 mol
WGS	RGibbs	
Pump	Pump	
Valve	Valve2	

Table 7
Validation of the MDEA plant.

	Feed (mole %)	Clean gas		CO ₂ for storage	
		This study (mole %)	Ref. [38] (mole %)	This study (mole %)	Ref. [38] (mole %)
Ar	0.35	0.44	0.46	-	-
CH ₄	0.06	0.07	0.08	-	-
CO	0.53	0.67	0.70	-	-
CO ₂	15.3	0.1	1.00	98.2	96.02
H ₂	44.29	56.53	57.88	0.07	0.04
H ₂ O	9.22	3.5	0.34	1.7	3.92
N ₂	30.23	38.55	39.52	0.03	0.02
He	0.02	0.02	0.03	-	-

$$CGE = \frac{\dot{m}_{DCF} \times LHV_{DCF}}{\dot{m}_{BFG} \times LHV_{BFG}} \quad (1)$$

In which the CGE is the cold gas efficiency, and it considers the amount of chemical energy left in the decarbonised fuel (DCF) to the BFG at the inlet of the process. The overall energy efficiency (OEE) reflects other

Table 8
Validation of the combined cycle.

Parameter	Ref. [39]	Simulation	Relative error (%)
LHV thermal input (MW)	1222.9	1222.9	0
Gas turbine gross power (MW)	477	468	1.8
Steam turbine gross power (MW)	263	258.3	1.7
Net power (MW)	727	712.3	2
LHV Net plant efficiency (%)	59.4	58.2	2

energy consumptions (electricity and heat) associated with operating the unit.

$$OEE = \frac{\dot{m}_{DCF} \times LHV_{DCF}}{\dot{m}_{BFG} \times LHV_{BFG} + \dot{Q}_{req} + W_{req}} \quad (2)$$

The CO₂ specific emissions (E_{CO_2}), CO₂ capture rate (CCR) and the specific primary energy consumption for CO₂ avoided (SPECCA) are calculated as below;

$$E_{CO_2} \left[\frac{kg_{CO_2}}{GJ_{LHV}} \right] = \frac{\dot{m}_{CO_2}}{\dot{m}_{DCF} \times LHV_{DCF}} \times 10^3 \quad (3)$$

$$CCR[\%] = \frac{E_{CO_2, nocapt} - E_{CO_2, capt}}{E_{CO_2, nocapt}} \quad (4)$$

$$SPECCA \left[\frac{MJ_{LHV}}{kg_{CO_2}} \right] = \frac{\left(\frac{1}{OEE_{capture}} - \frac{1}{OEE_{no.capt}} \right)}{E_{CO_2, nocapt} - E_{CO_2, capture}} \quad (5)$$

The SPECCA is defined as the additional primary energy required (in MJ_{LHV}) to avoid the emission of 1 kg of CO₂ producing the same amount of product (partly or enhanced decarbonised fuel or electricity) [40]. This parameter is related only to the capture plant and not the integrated steelmaking plant. In a fully integrated power plant, the OEE is replaced with net electric efficiency, Equation (6), and the CO₂ specific emissions are expressed in (kg_{CO2}/MWh).

$$\eta_{net} = \frac{W_{net}}{\dot{m}_{BFG} \times LHV_{BFG}} \quad (6)$$

The economic performance is assessed in terms of levelised cost of

products - levelised cost of decarbonised fuel gas production (**LCODF**, €/GJ) or levelised cost of electricity (**LCOE**, €/MWh), Eqs. (7) and (8). Another economic performance indicator is the cost of CO₂ capture (**CCC**, €/t_{CO2}), Equation (9). It compares a plant with CCS to a reference plant without CCS and quantifies the average cost of capturing CO₂ per unit of generated electricity. In a fully integrated steel mill with power generation, the **LCOE** is used instead of **ODF**. This index should not be confused with the CO₂ avoidance cost where also the cost for transportation, deep conditioning and storage is included and it will be developed in a more detailed study during the H2020 C4U EU project.

$$LCODF \left[\frac{\text{€}}{\text{GJ}} \right] = \frac{TAC \left[\frac{\text{M€}}{\text{y}} \right]}{\dot{m}_{DCF} \left[\frac{\text{kg}}{\text{s}} \right] \times LHV_{DCF} \times 3600 \times 7884 \left[\frac{\text{h}}{\text{y}} \right]} \quad (7)$$

$$LCOE \left[\frac{\text{€}}{\text{MWh}} \right] = \frac{TAC \left[\frac{\text{M€}}{\text{y}} \right]}{W_{el} [\text{MW}] \times 3600 \times 7884 \left[\frac{\text{h}}{\text{y}} \right]} \times 1 \cdot 10^6 \quad (8)$$

$$CCC = \frac{LCODF_{\text{capture}} \left[\frac{\text{€}}{\text{X}} \right] - LCODF_{\text{ref}} \left[\frac{\text{€}}{\text{X}} \right]}{E_{CO_2, \text{ref}} \left[\frac{\text{t}_{CO_2}}{\text{X}} \right] - E_{CO_2, \text{capture}} \left[\frac{\text{t}_{CO_2}}{\text{X}} \right]} \quad (9)$$

To calculate the **LCOE** or **LCODF**, the total annualised cost (**TAC**) has to be calculated by considering the total plant cost (**TPC**), the fuel cost (**C_{fuel}**), variable (**V_{O&M}**) and fixed (**F_{O&M}**) operating and maintenance costs.

$$TAC \left[\frac{\text{M€}}{\text{y}} \right] = TPC \times ACCR + C_{\text{fuel}} + V_{O\&M} + F_{O\&M} \quad (10)$$

TPC is calculated according to the methodology proposed in Manzolini et al. [9]. The equipment purchase costs (**C_B**) were calculated based on reference cost data from the literature (Table 8) using Equation (11) where **C_A** is the cost of the reference component with the capacity of **Q_A** and **f** is the scaling factor.

$$C_B = n \times C_A \left(\frac{Q_B}{n \times Q_A} \right)^f \quad (11)$$

The total equipment cost (**TEC**) is calculated as in Equation (12). The main economic assumptions used for component purchase cost calculation are presented in Table 9.

$$TEC = \sum_i^n C_{B,i} \quad (12)$$

Table 9
Scaling parameters for the component purchase cost.

Component	Scaling factor	C _A (M€)	Q _A	f	Ref.
CO ₂ capture unit (MDEA)	CO ₂ mass flow rate (t/h)	8.8	12.4	0.6	[41]
CO ₂ compressor and condenser	Power (MW)	44	50.5	0.67	[9]
Boiler	Heat duty (MW)	0.25	1	0.67	[42]
Compressor	Power (kW)	0.44	413	0.68	[41]
Pump	Volumetric flow m ³ /h	0.017	250	0.14	[43]
WGS	H ₂ and CO flow rate (kmol/s)	18.34	2.45	0.65	[44]
Fuel Compressor	Power (MW)	8.1	15.3	0.67	[9]
Expander	Power (MW)	33.7	200	0.67	[9]
Steam turbine	Power (MW)	33	200	0.67	[9]
Gas turbine	Power (MW)	49.4	272.1	0.67	[9]
HRSG	U·S (MW/K)	32.6	12.9	0.67	[9]
Cooling tower, BOP	Heat rejected (MW)	49.6	470	0.67	[9]
Heat exchanger	Heat transfer (MW)	6.1	828	0.67	[9]

The total direct purchase cost (**TDPC**) equals the sum of **TEC** and total indirect cost (**TIC**), Equation (13), which is assumed to be 66% of **TEC** in the case of power generation units and 104% in case of CO₂ capture section [9].

$$TDPC = TEC + TIC \quad (13)$$

TPC is calculated as in Equation (14), which correlates **TPC** to the **TDPC**, the engineering procurement and construction cost (**C_{EPC}**), the contingencies cost (**C_{CO}**) and the owner's cost (**C_{OC}**). In which the **C_{EPC}** is 15% of the **PC**. While the **C_{CO}** and the **C_{OC}** are respectively 10% and 5% of the sum of **TDPC** and **C_{EPC}**.

$$PC = TDPC + C_{EPC} + C_{CO} + C_{OC} \quad (14)$$

The annualised capital charge ratio (**ACCR**) is defined using Equation (15), considering the project interest rate (**r**) and project lifetime (**n**).

$$ACCR = \frac{r(1+r)^n}{(1+r)^n - 1} \quad (15)$$

Another index considered in this study is the incremental cost per ton of Hot Rolled Coils if the BFG is integrated with CO₂ capture. For the case with electricity generation, the total annualised cost (with capture technologies) also considers the purchase cost of electricity required to compensate for the lower power produced compared to the no capture case (Equation (16)). It is worth mentioning that the BFG purchase price is assumed to be 5.2 €/GJ [45].

$$\Delta C_{HRC} \left[\frac{\text{€}}{\text{t}_{HRC}} \right] = \frac{TAC_{\text{capture}} + \Delta C_{el, \text{capture}} - TAC_{\text{no capt}} \left[\frac{\text{M€}}{\text{y}} \right]}{\dot{m}_{HRC} \left[\frac{\text{M}_{HRC}}{\text{y}} \right]} \quad (16)$$

3. Results and discussion

The thermodynamic performance of the base case and the enhanced case are presented in Table 10. It reveals that the energy consumption for the enhanced case is 1.8 times higher than the base case, mostly related to the CO₂ compression stage, which is due to the higher CO₂ mass flow rate sent to storage in the enhanced case (65.8 kg/s and 36.5 kg/s, respectively). This higher CO₂ mass flow rate results from WGS implementation leads to higher reboiler heat duty in the stripper. The total heat requirement for the base case and the enhanced case are 50.62 MW and 142.4 MW, respectively, of which 66.5 MW of the heat consumption for the latter case is associated with the steam generation for the WGS process. Assuming that all the required energy (electricity and heat) for the capture plant will be purchased from external sources, the economic evaluation for both cases are presented in Table 11. The CGE in the base case is also 100% as in no capture case since the decarbonised gas results from an inert gas separation (CO₂) without modifying the lower heating value of the stream. In comparison, the cold gas efficiency drops to 90.5% in the enhanced case due to the exothermic WGS reaction that partially degrades the energy content of

Table 10
Thermodynamic performance comparison of the capture plant.

	Base case	Enhanced
Total Fuel Input (MW)	294.67	294.67
Net power consumption (MW)	14.9	33.7
CO ₂ flow rate for storage (kg/s)	36.5	65.8
Specific electricity demand (kWh/kg _{CO2})	0.113	0.142
Reboiler heat duty (MW)	50.1	91.4
Reboiler heat duty/CO ₂ flow rate for storage (MJ/kg _{CO2})	1.3	1.3
Required heat for WGS (MW)	-	66.5
CO ₂ capture efficiency (%)	46.5	83.80
CO ₂ purity for storage (%)	98.2	98.1
Thermal energy output (DCF)(MW)	294.61	266.80

Table 11
Techno-economic performance comparison.

	Unit	no capture	Base case	Enhanced
Steelmill size	$M_{t_{HRC}}/y$	3.16	3.16	3.16
Thermal input (BFG LHV)	[MW]	294.67	294.67	294.67
Thermal output (decarbonised fuel LHV)	[MW]	294.67	294.61	266.80
Heat requirements	[MW]	–	50.62	142.47
Electricity requirements	[MW]	–	14.90	33.62
Cold gas efficiency	[%]	100.0%	≈100.0%	90.5%
Overall energy efficiency	[%]	100.0%	81.8%	56.7%
CO ₂ specific emissions	[kg _{CO2} /GJ _{LHV}]	267.1	153.38	51.19
CO ₂ capture avoidance	[%]	–	42.6%	80.8%
CO ₂ specific emissions ^{a)}	[kg _{CO2} /t _{HRC}]	1737.9	1409.6	1146.3
SPECCA	[MJ _{LHV} /kg _{CO2}]	–	1.96	3.54
MDEA unit	[M€]	–	37.10	56.65
WGS reactors + Heat exchangers	[M€]	–	0	12.36
Gas expander	[M€]	–	3.73	2.80
CO ₂ compressor units	[M€]	–	16.66	19.98
Pumps	[M€]	–	0.02	0.02
Total Equipment Cost	[M€]	–	57.50	91.81
Total Direct Plant Cost	[M€]	–	117.31	187.29
Total Plant Cost	[M€]	–	155.14	247.69
Annualised Plant Cost	[M€/y]	–	17.69	28.24
Fuel Cost	[M€/y]	43.49	43.49	43.49
variable, heat and electricity	[M€/y]	–	12.44	27.78
fixed O&M	[M€/y]	–	7.76	12.38
Total Annualised cost	[M€/y]	43.49	81.37	111.9
LCODF	[€/GJ]	5.20	9.73	14.78
Δcost of HRC	[€/t _{HRC}]	–	11.99	21.65
CO ₂ capture cost	[€/t _{CO2}]	–	39.84	44.35

a) Assuming the CO₂ emissions from other steel mill sources equal to 1026 kg_{CO2}/t_{HRC}.

BFG into heat. The specific CO₂ emission of the enhanced case is significantly lower than the base case (51.19 kg_{CO2}/GJ_{LHV,DCF} and 151.3 kg_{CO2}/GJ_{LHV}, respectively); however, the lower overall efficiency of the enhanced case brings forth the higher SPECCA for about 1.6 MJ_{LHV}/kg_{CO2}.

The higher TEC for the enhanced case (9.18 M€ in opposition to 57.5 M€) is mainly related to the WGS reactor and more costly capture unit and CO₂ compression stage due to the higher CO₂ separated in the enhanced case compared to the base case. Although the cost of CO₂ capture for the enhanced case is higher than the base case by about € 4.5/t_{CO2} (€ 44.3/t_{CO2} and € 39.8/t_{CO2}, respectively), the higher CO₂ removal potential associated with the enhanced case make this technology more environmentally advantageous.

A sensitivity analysis was performed on the enhanced case performance with different BFG compositions, as reported in Table 12 (resulting from different integrated steel mill sources and natural gas co-feeding and provided by the industrial partner of the H2020 C4U EU project). Another sensitivity analysis is related to the BFG sent to the capture plant featuring the case where partial CO₂ capture is

Table 12
BFG compositions considered for the sensitivity analysis.

Composition (%mol)	BFG 2	BFG 3
CO	24.1	25.7
CO ₂	24.75	25.6
H ₂	3.09	5.7
O ₂	1.2	–
N ₂	46.84	42.5
CH ₄	0.02	–
Ar	–	0.5
LHV (MJ/kg)	2.43	2.82

implemented or in the case where the composition of BFG is manipulated by changing the H₂/CO ratio for further fuel synthesis as in the case of methanol synthesis [46–48] which are currently considered for CCU. To achieve different R, the BFG is partially separated before entering the WGS reactor using a splitter and mixed with the H₂-rich gas from the absorber. The split fractions (SF) considered for the sensitivity analysis are 5%, 10%, and a split fraction of 2.6% to achieve the M factor equals 2, Equation (17), as the optimal syngas composition for methanol production.

$$M = \frac{H_2 - CO_2}{CO + CO_2} = 2 \tag{17}$$

Table 13 and Fig. 5 reveal that the energy requirement and LCODF are inversely proportional to the SF. This is because SF increase leads to a lower volume flow rate entering the capture unit; consequently, less volume flow rate enters the CO₂ compression stage. This results in lower energy requirements (thus higher overall energy efficiency), lower fixed and variable plant costs, and lower LCODF.

The techno-economic performance of the enhanced case capture unit under different BFG compositions is illustrated in Table 14 and Fig. 6. Although BFG 2 has lower carbon content than BFG 3 (Table 12), it has the highest CO₂ specific emission; since the decarbonised fuel from BFG 2 has a lower LHV due to its higher O₂ and N₂ content compared to other BFG compositions. This low LHV, therefore, affects the overall energy efficiency and results in higher SPECCA among other BFG composition.

The overall energy balance and the techno-economic comparison for the power plant integrated cases are reported in Table 15 and Table 16. With an efficiency of 2.5%, integration of the steam cycle with the enhanced case is the lowest. This extremely low efficiency, as mentioned before, is a result of supplying heat for the MDEA and WGS units. It is worth noting that, among the base case and enhanced case power integration options, extra heat must be provided from external sources only for enhanced case integrated with combined cycles (65.4 MW). As part of the generated heat from the power plant is used for steam production for the WGS process. For other cases, the power plant integration is capable of generating all the required heat needed in the process. The lower power output from the gas turbine for the enhanced case integration with the combined cycle compared to the based case integration (128.7 MW and 135.9 MW, respectively) is a result of the lower mass flow rate of the decarbonised fuel of the enhanced case (75.8 kg/s) than the based case (90.8 kg/s). Despite the lower CGE, the overall power generation from steam cycle is higher in the enhanced case. This is because of the additional steam provided from the WGS heat recovery, as presented in Fig. 4. The difference between the capture plant power consumption in Table 15 and Table 11 results from expander implementation in the capture unit without power integration to partially compensate for the power consumption.

Table 13
The technical performance of enhanced case based on different CCR.

	Unit	SF = 0	M = 2	SF = 5%	SF = 10%
Thermal input (BFG LHV)	[MW]	294.67	294.67	294.67	294.67
Thermal output (decarbonised fuel LHV)	[MW]	266.80	267.58	268.23	269.61
Heat requirements	[MW]	142.47	138.65	135.40	129.62
Electricity requirements	[MW]	33.62	32.61	31.97	30.88
Cold gas efficiency	[%]	90.5	90.8	91.0	91.5
Overall energy efficiency	[%]	56.7	57.4	58.1	59.2
CO ₂ specific emissions	[kg _{CO2} /GJ _{LHV}]	51.19	58.15	61.6	70.2
CO ₂ capture avoidance	[%]	80.8	78.2	76.9	73.7
SPECCA	[MJ _{LHV} /kg _{CO2}]	3.54	3.56	3.53	3.51

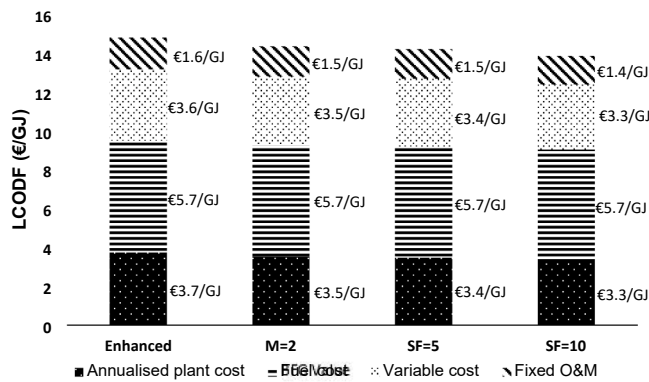


Fig. 5. Distribution LCODF production for the enhanced case at different CCR.

Table 14
The effect of different BFG compositions on the technical performance of enhanced case.

	Unit	BFG 1	BFG 2	BFG 3
Thermal input (BFG LHV)	[MW]	294.67	294.67	294.67
Thermal output (decarbonised fuel LHV)	[MW]	266.80	245.22	267.94
Heat requirements	[MW]	142.47	129.74	134.78
Electricity requirements	[MW]	33.62	35.97	33.69
Cold gas efficiency	[%]	90.5	83.2	90.9
Overall energy efficiency	[%]	56.7	53.3	57.9
CO ₂ specific emissions	[kg _{CO2} /GJ _{LHV}]	51.19	57.9	43.72
CO ₂ capture rate	[%]	80.8	79.6	83.2
SPECCA	[MJ _{LHV} /kg _{CO2}]	3.54	3.89	3.36

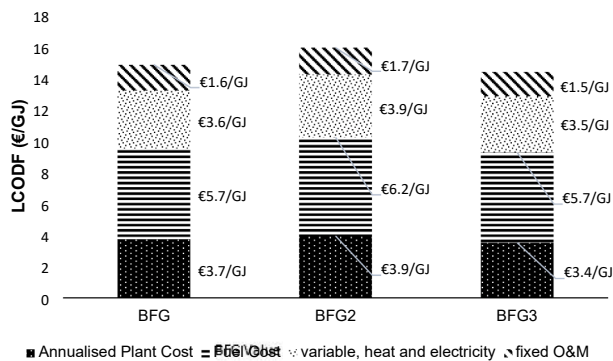


Fig. 6. Distribution LCODF production for the enhanced case with different BFG composition.

The enhanced case integrated with the steam cycle has the highest CO₂ specific emission (6293.89 kg_{CO2}/MWh) due to its very low efficiency (2.6%). Moreover, this low energy efficiency results in negative SPECCA (−40.5 MJ_{LHV}/kg_{CO2}) and consequently the negative cost of CO₂ capture (−411.5 €/t_{CO2}) however, the latter results are due to the combination of two negative effects (higher specific emission and higher costs) and thus not meaningful. In other words, this case results in an increase of CO₂ specific emissions despite the attempt of capturing CO₂. The CO₂ capture purchase cost difference between the enhanced case integration with the combined cycle and the steam (€ 89M and € 91.8M, respectively) is related to the DCF expander, which is not used in the combined cycle. The higher LCOE of the combined cycle integrated with the enhanced case compared to the base case (€224.2/MWh and €121.8/MWh, respectively) is mainly due to the difference in annualised

Table 15
Thermodynamic performance of the integrated plant.

Steam Cycle	no capture	MDEA	WGS + MDEA
Thermal Energy input (BFG) (MW)	294.67	294.67	294.67
Gas turbine power output (MW)	–	–	–
Air blower (MW)	0.97	0.89	0.02
BFG/DCF compressor (MW)	–	–	–
HPT power output (MW)	13.87	11.04	14.93
IPT power output (MW)	27.04	21.51	17.04
LPT power output (MW)	51.25	40.96	10.35
HP-Pump power consumption (MW)	0.77	0.62	0.77
IP-Pump power consumption (MW)	0.25	0.20	0.14
LP-Pump power consumption (MW)	0.05	0.04	0.01
Capture plant power consumption (MW)	–	14.89	33.69
Excess heat to purchase for reboiler (MW)	–	0.00	0.00
Net power output (MW)	90.11	56.85	7.66
Efficiency (%)	30.58	19.30	2.59
Combined cycle			
Thermal Energy input (BFG) (MW)	294.67	294.67	294.67
Gas turbine power output (MW)	139.05	135.91	128.75
Air blower (MW)	–	–	–
BFG/DCF compressor (MW)	40.39	30.48	37.35
HPT power output (MW)	12.12	5.52	8.85
IPT power output (MW)	14.98	7.81	10.38
LPT power output (MW)	21.82	13.56	–
HP-Pump power consumption (MW)	0.48	0.23	0.38
IP-Pump power consumption (MW)	0.13	0.07	0.10
LP-Pump power consumption (MW)	0.02	0.01	–
Capture plant power consumption (MW)	–	21.42	38.59
Excess heat to purchase for reboiler (MW)	–	0.00	65.48
Net power output (MW)	146.96	110.58	71.54
Efficiency (%)	50.00	37.52	24.27
Total CO ₂ emission (kg/s) a	78.52	41.99	17.33

^a It is assumed that the CO₂ emission from heat generation is 220 g/kWh [49].

plant cost, coming from the higher CO₂ capture plant purchase cost in the enhanced case integration.

The integration of the WGS + MDEA (Enhanced case) with respect to the case with only MDEA results in a reduction of the technical performance (the efficiency drops from 37.5% to 24.3%), an improvement of the environmental performance as the CO₂ capture avoidance increases from 28.3% to 65.2% and overall an additional economic penalisation since the cost for CO₂ capture increases from 93.57 €/t_{CO2} to 121.55 €/t_{CO2}. In a different scenario where the carbon tax could increase the cost of the processes with low CO₂ capture rate (as the case with only MDEA in this study), the economics of the Enhanced case could result more favourable however this is not the case with current conditions. It is worth mentioning that the higher annualised cost for combined cycle integration with the enhanced case compared to the base case (126.48 M€/year and 106.18 M€/year, respectively) results in a reasonable difference in the Δcost of HRC, 23.65 €/t_{HRC} and 12.35 €/t_{HRC}, respectively. This is competitive to the integrated steel-mill post-combustion decarbonisation (Δcost of HRC = 14 €/t_{HRC}) or SEWGS technology (Δcost of HRC = 27 €/t_{HRC}) [9].

Despite conventional integrated steelmills are using subcritical steam cycle, this study has demonstrated that the integration of a more efficient combined cycle for power generation would be able to generate enough electricity for the integrated steelmill and cover the energy cost for CO₂ capture. In presence of a more efficient cycle, there will be no need for electricity import as all the existing electricity requirement would be provided using BFG.

4. Conclusion

The iron and steel industry is amongst the main contributors to anthropogenic CO₂ emissions. This research investigates the techno-economic performance of two different MDEA scrubbing BFG decarbonisation processes (with and without WGS). It is later followed by a detailed investigation of integrating two power generation units (steam cycle and combined cycle). In CO₂ capture processes, CO₂ avoidance is

Table 16
Techno-Economic performance of the considered plants.

		Steam cycle			Combined cycle		
		no capture	MDEA	WGS + MDEA	no capture	MDEA	WGS + MDEA
Steel mill size	Mt _{HRC} /y	3.16	3.16	3.16	3.16	3.16	3.16
Thermal input	[MW]	294.70	294.70	294.70	294.70	294.70	294.70
Net electric output	[MW]	90.11	56.85	7.66	146.96	110.58	71.54
Net electric efficiency	[%]	30.6%	19.3%	2.6%	49.9%	37.5%	24.3%
CO ₂ specific emissions	[kg _{CO2} /MWh]	3166.6	2704.21	6293.89	1941.60	1391.49	675.11
CO ₂ capture avoidance	[%]		14.6%	-98.8%		28.3%	65.2%
SPECCA	[MJ _{LHV} /kg _{CO2}]		14.90	-40.52 ^{c)}		4.32	6.01
CO ₂ Capture Unit ^{a)}	[M€]		57.50	91.80		53.77	89.00
fuel compressor	[M€]				19.45	15.99	18.40
Gas turbine	[M€]				36.52	53.46	52.23
Heat Recovery Steam Cycle	[M€]	34.00	30.09	21.45	25.97	19.61	17.55
Heat exchangers	[M€]	0.72	0.68	0.70			
Cooling system	[M€]	24.89	26.36	20.31	17.51	12.93	11.14
Total Equipment Cost	[M€]	59.60	114.63	134.27	99.45	155.76	188.32
Total Direct Plant Cost	[M€]	98.94	212.13	257.77	165.08	278.99	346.43
Total Plant Cost	[M€]	130.85	280.54	340.90	218.32	368.96	458.15
Annualised Plant Cost	[M€/y]	14.92	31.98	38.86	24.89	42.06	52.23
Fuel Cost	[M€/y]	43.49	43.49	43.49	43.49	43.49	43.49
variable O&M	[M€/y]	2.17	2.17	2.17	2.17	2.17	7.85
fixed O&M	[M€/y]	6.54	14.03	17.04	10.92	18.45	22.91
Total Annualised cost	[M€/y]	67.13	91.68	101.58	81.47	106.18	126.48
LCOE	[€/MWh]	94.49	204.54	1681.97	70.32	121.79	224.26
electricity cost ^{b)}	[M€/y]	22.40	35.51	54.90	-0.01	14.33	29.72
Δcost of HRC	[€/t _{HRC}]		19.01	28.28		12.35	23.65
CO ₂ capture cost	[€/t _{CO2}]		238.03	-411.58 ^{c)}		93.57	121.55

^{a)} This includes the MDEA absorption/desorption plant, CO₂ compression unit, and syngas expander.

^{b)} This is the cost to purchase additional electricity from the grid to compensate the power demand of the integrated steel mill (146.94 MW scaled from [9]).

^{c)} The negative value results from higher CO₂ specific emissions compared to the reference case and therefore not meaningful.

42.6% for the base case and 80.8% when CO is also converted into CO₂ and H₂ using a WGS reactor (enhanced decarbonisation). The overall efficiency of the enhanced case drops to 56.7% (from 81.8% in the base case), resulting in an increased SPECCA (1.96 MJ/kg_{CO2} for the base case and 3.54 MJ/kg_{CO2} for the enhanced one). As a result of the economic analysis, the cost to produce the decarbonised fuel is 9.73 €/GJ with a resulting CO₂ capture cost of 39.84 €/t_{CO2} for the base case and 14.78 €/GJ and 49.38 €/t_{CO2} for the enhanced case. When the BFG from the steel mill is used for power generation, the CO₂ capture processes are acceptable only when integrated with a combined cycle. The SPECCA ranges from 4.32 to 6 depending on if the BFG decarbonisation is partial or completed. In the steam cycle, the overall net electric efficiency drops from 19.3% (in the case of partial CO₂ capture) to 2.6% (enhanced decarbonisation). From an economic point of view, the CO₂ capture cost is 93.6 €/t_{CO2} and 121.55 €/t_{CO2} for the combined cycle, while for the steam cycle, it is above 238 €/t_{CO2}.

CRediT authorship contribution statement

Navid Khallaghi: Data curation, formal analysis, validation, writing original draft. **Syed Zaheer Abbas:** formal analysis. **Giampaolo Manzolini:** conceptualisation, formal analysis, supervision, writing -review and editing. **Eric De Coninck:** supervision, funding acquisition, writing-review end editing, conceptualisation, project administration.

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 A. Supplementary data

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