Grant agreement no. 884418

C⁴U

Advanced Carbon Capture for steel industries integrated in CCUS Clusters

Innovation Action

D3.1 Report on assumptions, base case technology and methodology for the CO_2 capture integration in the considered industrial application

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Version Management	
Version	**Changes**
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Nomenclature, Greek letters and symbols

CA	CO_2 Avoided (%)
CCA	Cost of CO_2 Avoidance (€/t_{CO2})
C_{CO}	Contingencies Cost (M€)
C_{EPC}	Engineering, procurement and construction cost (M€)
CCR	Carbon Capture Rate (%)
C_{OC}	Owner Cost (M€)
CF	Capacity Factor (%)
C_{fuel}	Fuel Cost (M€/y)
CGE	Cold Gas Efficiency (%)
ΔC_{HRC}	Incremental Cost for HRC (€/t_{HRC})
ΔCO_2	Incremental CO_2 emission HRC (kg_{CO2}/t_{HRC})
ΔT	Temperature difference (°C)
f	Scaling factor
FCF	Fixed Charge Factor (-)
$F_{O\&M}$	Fixed Operating Cost (€/MWh)
LCOE	Levelised Cost of Electricity (€/MWh)
LCODF	Levelised Cost of Decarbonised Fuel (€/t)
LHV_i	Lower Heating Value (MJ/kg)
$\dot{m}_i$	Mass flow rate, kg/s
OEE	Overall Energy Efficiency (%)
$\dot{Q}_i$	Heat rate, (MW)
r	Interest rate (%)
SPECCA	Specific Primary Energy Consumption for CO_2 Capture Avoidance (MJ/kg_{CO2})
T	Time (years)
TAC	Total Annualised Cost (M€/y)
TDPC	Total Direct Plant Cost (M€)
TEC	Total Equipment Cost (M€)
TIC	Total Installation Cost (M€)
TPC	Total Plant Cost (M€)
$V_{O\&M}$	Variable Operating Cost (€/MWh)
W_{net}	Net power output (MW)

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Abbreviations and definitions

BF	Blast Furnace
BFG	Blast Furnace Gas
CASOH	Calcium Assisted Steel-mill Off-gas Hydrogen
CC	Combined Cycle
CCUS	Carbon Capture Utilisation and Storage
COG	Coke Oven Gas
DCF	Decarbonised Fuel
DRI	Direct Reduction of Iron
EAF	Electric Arc Furnace
HP/IP/LP	High-Pressure, Intermediate-Pressure, Low-Pressure
HRSG	Heat Recovery Steam Generator
HRSC	Heat Recovery Steam Cycle
HRC	Hot Rolled Coil
IPT	Intermediate-Pressure Turbine
KPI	Key Performance Indicator
LHV	Lower Heating Value
LPT	Low-pressure Turbine
MDEA	Methyl diethanolamine
S/C	Steam to Carbon ratio
SC	Steam Cycle
TGRBF	Top Gas Recycling Blast Furnace
TRL	Technology Readiness Level
WGS	Water Gas Shift
WP	Work Package

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1. Introduction

The iron and steel industry, along with cement, chemicals and petroleum processes are major sectors that account for 30% of the CO_2 emission globally [1]. Among the sectors mentioned earlier, the iron and steel industry alone contributes to 7% of the global direct CO_2 emissions [2]. Carbon Capture, Utilisation and Storage (CCUS) is a promising technology to reduce the CO_2 emission from three main off-gases from the steel industry, i.e. Blast Furnace Gas (BFG), Coke Oven Gas (COG) and Basic Oxygen Furnace Gas (BOFG) and to make value-added products such as H_2. All these off-gases contain CH_4, CO, CO_2, H_2 and N_2. However, BFG has a higher ratio of CO and CO_2 compared to COG and BOFG. On the other hand, BFG has lower LHV compared to the other two off-gases due to higher N_2 and CO_2 concentration. Therefore, effective CO_2 removal from BFG is (1) more cost-effective than other off-gases, as a result of higher CO_2 content in the BFG [3], and (2) it would meet the need of high calorific BFG which can be further used as a fuel or for conversion to other product/energy carrier as H_2 [4].

The H2020 C^4U project aims to demonstrate the feasibility of two new processes for the decarbonisation and upgrade of the BFG gas from an integrated steel mill with CCUS.

The activity of WP3: Integration of CO_2 capture technologies in steel plant focuses on the industrial applications, feasibility study and techno-economic assessment of the selected technologies and their improvement with respect to the state-of-the art. In this deliverable (D3.1 - Report on assumptions, base case technology and methodology for the CO_2 capture integration in the considered industrial application) the benchmark technology for CO_2 capture from BFG gas has been selected along with the main key performance indicators (KPIs) to compare the performance with the C4U technologies.

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2. Existing research on CO_2 capture from steel mill

Energy efficiency, fuel switching and innovative use of existing technologies can only lead to a reduction of around 15% in CO_2 emissions. Other alternative processes, such as Direct Reduction Iron (DRI) or Electric Arc Furnaces (EAF) are only applicable to certain types of steel and can only reduce emissions by 25%. Blast Furnace Gas (BFG) represents the greatest volumetric flow in a steel plant and has low energy content, consisting of ~50-60 vol% N_2 and ~20-25 vol% CO_2.

Various technologies have been proposed which are currently either at the pre-demonstration or demonstration stage. Their merits and disadvantages, CO_2 avoidance costs and Technology Readiness Levels (TRL) are given in Table 1 and elaborated below on a case by case basis under three categories:

1. **BF with physical/chemical absorption for CO_2 separation (where the CO_2 separation processes are based on commercial technologies):**
   #1 involves the CO_2 separation from the BFG using either chemical absorption, e.g. amine solutions, or physical absorption, and then the CO_2-lean gas is sent to the power plant [5];
   #2 involves the first step of CO conversion into H_2 and CO_2 in a Water Gas Shift (WGS) reactor and a CO_2 separation step using chemical/physical absorption. In this case, deeper decarbonisation is achieved, and an H_2-rich stream is available for different uses;
   #3 is the Top Gas Recycling Blast Furnace (TGRBF) [6]: it comprises injecting pure O_2 or O_2 enriched-air instead of air into the furnace, thereby eliminating (or significantly reducing) the presence of N_2 in the BFG, concentrating more CO_2 in the BFG and therefore reducing the cost of absorption-based CO_2 separation at the expense of the cost of oxygen production. After CO_2 separation, the reducing gases (mostly CO and H_2) are partly recirculated back to the BF and partially used in the steel mill's power plant.

2. **Other BF concepts at the pilot and advanced demonstration stage:**
   #4 relates to the COREX process [7], where lump ore/pellets are first reduced in a reduction zone (reduction shaft) by using gas with high calorific value and then in a second zone called a melter–gasifier, (also) 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 (mostly CO and H_2) is used in the reduction zone, and after that, it can be separated in a CO_2 capture unit (30-40% carbon capture rate) or WGS + CO_2 capture unit (high CO_2 capture, >90%).

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#5, the HIsarna process [8] 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 which is collected at the bottom. The produced gas is a concentrated CO_2 stream, which can be further processed. Both coal and biomass can be used, thus reducing the specific CO_2 emissions of the system by up to 50% (without an additional CO_2 capture system).

Table 1. Blast Furnace Gas CO_2 capture technologies

Case	CO_2 capture technology	Advantages	Disadvantages	CO_2 emissions, t_{CO2}/t_{steel} (CCR)[a)]	CO_2 avoidance cost, €/t_{CO2}	TRL
#1	BF + separation (amine, Selexol)	• Retrofittable • Low impact on interlinked energy system in the steel mill	• High energy consumption • Limited CO_2 separation (approximately 33%)	≈1.4 (15-20%)	40-70	8-9
#2	BF + WGS reactor + amine/Selexol	• Retrofittable • H_2 rich by-product fuel gas produced (≈36% H_2, 64% N_2)	• High electricity demand	≈1 (40%)	≈ 30	9
#3	TGRBF integrated with a CO_2 separation technology	• Retrofittable • 25% less carbon usage • 60% CO_2 reduction with CO_2 storage application	• Increased electric power demand for CO_2 separation	0.8-1 (40-55%)	30-50	7
#4	COREX + separation (amine, Selexol)	• It does not require sinter and coking plants • Non-coking coal can be used • N_2-free high quality gas production	• Non retrofittable • Large oxygen consumption	0.3-1.6 (30-90%)	9-30	7-8
#5	HIsarna technology (smelter technology)	• 20% CO_2 reduction per t_{steel} • 80% CO_2 reduction with CCS	• Non retrofittable • Large oxygen consumption	0.8-1.4 (20-55%)	10-20	7

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3. Assumptions and methodologies

3.1 Assumptions

The properties of the BFG, key assumptions used in modelling, the turbomachinery and the main assumptions for the economic analysis are described in the following tables.

The full plant is based on a 125.1 kg/s (thermal input of 294.67 MW) of BFG gas, which is representative of a steel mill plant that is producing 3.16 Mton/y of hot rolled steel (Table 2).

The simulation has been carried out in Aspen Plus V8.8. In order to estimate correctly the behaviour of the species, ELECNRTL for decarbonisation plant and PENG-ROB for power cycles have been used.

Table 2. Specifications of BFG (dry basis) used in this study and an example in literature [9]

Parameter	This Report	adapted from Manzolini et al. [9]
BFG composition (%mol$_{dry}$)		
CO_2	21.2	22.8
CO	22.7	23
C_2H_4	0.2	0
H_2	2.4	3.7
N_2	53.5	50.4
S compounds[1]	Not considered	Not considered
Flowrate (kg/s)	125.1	155.7
Molecular Weight (kg/kmol)	30.8	30.7
Lower heating value (MJ/kg)	2.35	2.42

The benchmark technology is proposed respectively for partial and high decarbonisation of the BFG gases including the relevant techno-economic numbers. Subsequently, the utilisation of the clean gas has been assessed for the in-situ power generation using the state-of-the-art subcritical steam cycle and combined cycle.

Chemical absorption is the most common and most well-established technology used for industrial-scale acid gas removal. MDEA is remarkably stable and thus more resistant to degradation than other amines such as MEA and DEA. It has a low vapour pressure and low corrosivity. Moreover, MDEA forms weaker bonds with acid gas than other amines, leading to lower stripping energy requirements [10]. Therefore, in this deliver-

[1] The sulfur compound management will be considered on a separate study in order to account for the required treatment downstream the CO_2 separation unit on the basis of the requirement for transport and storage according to WP4

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able CO_2 removal from BFG with MDEA is evaluated extensively. To reach deep BFG decarbonisation, the implementation of the Water Gas Shift (WGS) reactor is considered (enhanced decarbonisation) and compared to the benchmark case (base case) where partial CO_2 removal is obtained (Section 4). Moreover, the possible integration options with the steam cycle and conventional combined cycle are assessed. Aspen Plus® is used to develop the process simulation of all mentioned cases (Section 5). The results obtained from the optimal performance of the cases are used for economic feasibility evaluation and compared in terms of capital cost, levelised cost of decarbonised fuel/electricity production and cost of CO_2 avoidance. The main assumptions used for the simulation of the CO_2 capture unit through MDEA are reported in Table 3 according to the main conditions proposed within the H2020 3DX [11,12] and the CO_2 separation rate and consumption validated with existing literature [13–16]. These assumptions will be revised according to the input provided from industrial partners in due course.

In this deliverable, the cost for CO_2 transport and storage is not considered as this is under study in WP4.

Table 3. Assumptions and initial inputs to simulate the different plant configurations

Parameter	Value
MDEA CO_2 absorption process	
MDEA/water content in the lean solvent (%wt)	25/72
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 regenerative heat exchanger (°C)	10.0
Pump hydraulic/mech efficiency (%) [17]	75/95
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
Turbomachines	
Expander isentropic efficiency (%)	93
Expander delivery pressure, (bar)	1.015
CO_2 compression train	
Number of stages	2
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

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Table 4. Assumptions for the economic analysis [18] and [10]

Parameter	Value
Variable O&M costs (**$V_{O\&M}$**) a fraction of fuel costs (%)	5%
Fixed O&M cost (**$F_{O\&M}$**) as a fraction of total capital cost (%)	5%
BFG price[1] (€/GJ)	5.2
Heat price (€/MWh)	11
Electricity price (€/MWh)	50
Plant lifetime ($\boldsymbol{T}$) (years)	25
Project interest rate ($\boldsymbol{r}$) (%)	11
Capacity factor ($\boldsymbol{CF}$) (%)	80

[1]calculated based on the approach presented in [4]

3.2 Methodology

The key performance indicators (KPIs) used in this work are listed below.

The analysis is distinguished between the simulation of CO_2 capture plant and the analysis in case the CO_2 capture plant are integrated for power generation.

In the case of CO_2 capture unit, the techno-economic assessment is based on:

$$CGE = \frac{\dot{m}_{DCF} \times LHV_{DCF}}{\dot{m}_{BFG} \times LHV_{BFG}} \tag{1}$$

In which the Cold Gas Efficiency (CGE) takes into account the amount of chemical energy that is left in the Decarbonised Fuel (DCF) with respect to the BFG at the inlet of the process.

In order to take into account of the other energy consumptions (associated to the electricity and heat required to operate the process), the overall energy efficiency is considered

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

The CO_2 specific emissions associated to the process are calculated as follow:

$$E_{CO_2}\left[\frac{kg_{CO_2}}{GJ_{LHV}}\right] = \frac{\dot{m}_{CO_2}}{\dot{m}_{DCF} \times LHV_{DCF}} \tag{3}$$

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The resulting CO_2 Capture Rate (CCR), the Specific Primary Energy Consumption for CO_2 Avoided (SPECCA) and CO_2 Avoidance (CA) are calculated as follow:

$CCR[\%] = 1 - \frac{\left(\dot{N}_{CO_2} + \dot{N}_{CO} + \sum \zeta_c \cdot \dot{N}_c\right)_{out}}{\left(\dot{N}_{CO_2} + \dot{N}_{CO} + \sum \zeta_c \cdot \dot{N}_c\right)_{in}}$	(4)
$SPECCA\left[\frac{MJ_{LHV}}{kg_{CO_2}}\right] = \frac{\left(\frac{1}{OEE_{capture}} - \frac{1}{OEE_{no,capt}}\right)}{E_{CO_2,no\ capt} - E_{CO_2,capture}}$	(5)
$CA[\%] = \frac{E_{CO_2,no\ capt} - E_{CO_2,capture}}{E_{CO_2,no\ capt}}$	(6)

The SPECCA is defined as the additional primary energy required (in MJ) to avoid the emission of 1 t of CO_2 producing the same amount of product (fuel or electricity).

In the case of a fully integrated plant, the OEE is replaced with the net electric efficiency.

The economic performance are assessed in terms of levelised cost of products - Levelised Cost of Decarbonised Fuel gas production (LCODF, €/GJ) or Levelised Cost of Electricity (LCOE, €/MWh) - and the Cost of CO_2 Avoidance (CCA, €/t_{CO2}).
To do so, 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.

$TAC\left[\frac{M€}{y}\right] = TPC \times FCF + C_{fuel} + V_{O\&M} + F_{O\&M}$	(7)
$\boldsymbol{LCODF}\left[\frac{€}{\boldsymbol{GJ}}\right] = \frac{\boldsymbol{TAC}\left[\frac{\boldsymbol{M€}}{\boldsymbol{y}}\right]}{\dot{\boldsymbol{m}}_{\boldsymbol{DCF}}\left[\frac{\boldsymbol{kg}}{\boldsymbol{h}}\right] \times \boldsymbol{LHV}_{\boldsymbol{DCF}} \times \boldsymbol{h}\left[\frac{\boldsymbol{h}}{\boldsymbol{y}}\right]} \times \mathbf{1000}$	(8)
$LC\boldsymbol{OE}\left[\frac{€}{\boldsymbol{MWh}}\right] = \frac{\boldsymbol{TAC}\left[\frac{\boldsymbol{M€}}{\boldsymbol{y}}\right]}{\boldsymbol{W}_{\boldsymbol{el}}[\boldsymbol{MW}] \times \mathbf{3600} \times \frac{\boldsymbol{h}}{\boldsymbol{y}}} \times \mathbf{1} \cdot \mathbf{10^6}$	(9)

The TPC (Total Plant Cost) is calculated according to the methodology proposed in Manzolini et al. [9].

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The equipment purchase costs ($\boldsymbol{C_B}$) were calculated based on reference cost data from the literature (Table 5) using Eq. (9) where $\boldsymbol{C_A}$ is the cost of the reference component with the capacity of $\boldsymbol{Q_A}$ and $\boldsymbol{f}$ is the scaling factor. The main economic assumptions used for component purchase cost calculation are presented in Table 5.

$C_B = n \times C_A \left(\frac{Q_B}{n \times Q_A}\right)^f$	(10)

$TEC = \sum_i C_{B,i}$		(11)
$\boldsymbol{TDPC = TEC + TIC}$	Where the *TIC* are assumed to be 66% of *TEC* in case of power generation units and 104% in case of CO_2 capture section [9]	(12)
$\boldsymbol{TPC = TDPC + C_{EPC} + C_{CO} + C_{OC}}$	In which the C_{EPC} are 15% of the *TDPC*, the contingencies C_{CO} and the owner's cost C_{OC} are respectively 10% and 5% of (*TDPC* + C_{EPC})	(13)

The Fixed Charge Factor (*FCF*) is defined using Eq. (13) considering the project interest rate (*r*) and project lifetime (*T*). It is used to annualise the total capital cost over the project lifetime.

$FCF = \frac{r(1+r)^T}{(1+r)^T - 1}$	(14)

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Table 5: Scaling parameters for 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	[19]
CO_2 compressor and condenser	Power (MW)	44	50.5	0.67	[9]
Boiler	Heat duty (MW)	0.25	1	0.67	[20]
Compressor	Power (kW)	0.44	413	0.68	[19]
Pump	Volumetric flow m^3/h	0.017	250	0.14	[21]
WGS	H_2 and CO flow rate (kmol/s)	18.34	2.45	0.65	[22]
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]

Another economic performance indicator is the Cost of CO_2 Avoided (CCA). It compares a plant with CCS to a reference plant without CCS and quantifies the average cost of avoiding a unit of atmospheric CO_2 emissions while providing a unit of electricity.

$$CCA = \frac{LCODF_{Capture}\left[\frac{€}{X}\right] - LCODF_{ref}\left[\frac{€}{X}\right]}{E_{CO_2,ref}\left[\frac{t_{CO_2}}{X}\right] - E_{CO_2,capture}\left[\frac{t_{CO_2}}{X}\right]} \quad (15)$$

In case of a fully integrated steel mill with power generation, the LCOE is used instead of LCODF and the CO_2 specific emissions are expressed in (kg_{CO2}/MWh).

Another index considered in this study is the incremental cost per ton of Hot Rolled coils in case that the BFG is integrated with CO_2 capture with respect to the case where the BFG would be used for power generation. In this case, the total annualised cost (with capture technologies) takes into account also the cost to purchase the electricity required to compensate for the reduction in the power generation with respect to the case with no capture.

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

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4. Description of the CO_2 capture processes

4.1 Base case

The PFD of the process is reported in Figure 1. BFG at 3 bar and 35°C enters the bottom of the absorber column while being contacted counter-current with the lean solvent (MDEA). Decarbonised Clean Fuel (DCF) and CO_2-rich solvent exit from the absorber from the top and bottom of the column respectively. Any trace of H_2S will be separated along with CO_2 since the reaction rates of H_2S with MDEA are effectively instantaneous with respect to the mass transfer rates and enormously higher than the reaction rates of CO_2 with MDEA [23–25].

The CO_2-rich solvent is pumped to 6 bar and then enters the regenerative heat exchanger to heat up to 80°C before entering the stripper. The lean solvent from the bottom of the stripper column, after cooling down in the regenerative heat exchanger, will be sent back to the absorber column after losing its pressure in the valve. The high-purity CO_2 stream leaves the stripper columns after the evaporated water is removed in a condenser. After the CO_2 leaves the capture plant, it is sent to the CO_2 compression and conditioning units prior to being transported elsewhere. The dense phase is regarded as the most energy-efficient condition due to its high density and low viscosity. Consequently, current operating practice for CO_2 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 CO_2 pipeline network is as high as 120 bar. Thus, a compression train is required to pressurise the CO_2 stream from the captured plant to reach a high entry pressure.

The CO_2 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 CO_2-rich stream and pump it to the final delivery pressure to the pipeline.

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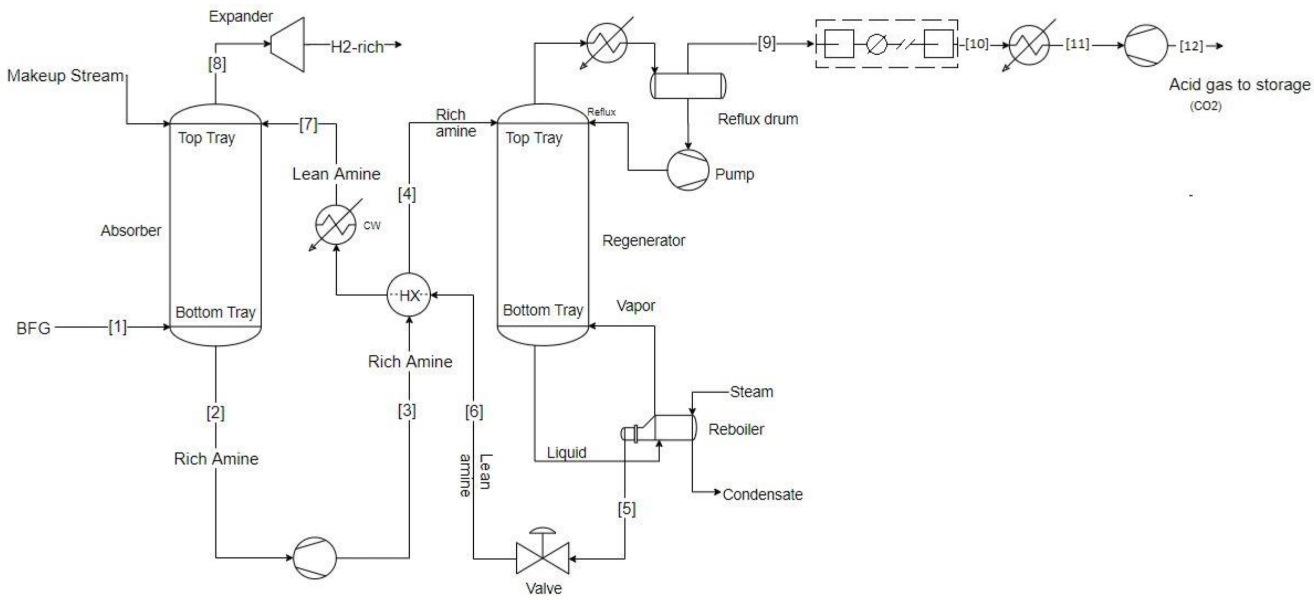

Figure 1: BFG decarbonisation with MDEA

The mass balance of the base case is shown in Table 6.

Table 6: Mass flow, temperature, pressure and composition for the base case according to Figure 1

Stream	m (kg/s)	**T (°C)**	**P (bar)**	**Compositions (%mol)**						
				CO	**C_2H_4**	**CO_2**	**H_2**	**H_2O**	**N_2**	**MDEA**
1	125.1	35	3	22.7	0.18	21.1	2.4	-	53.5	-
2	882.2	57.6	2.7	-	-	-	-	92.4	-	7.3
3	882.2	57.7	6.1	-	-	-	-	92.4	-	7.3
4	882.2	80	6.1	-	-	-	-	92.4	-	7.3
5	845.4	165	6	-	-	-	-	94.7	-	5.2
6	845.4	165	3	-	-	-	-	94.7	-	5.2
7	845.4	40	3	-	-	-	-	94.7	-	5.2
8	90.8	46.5	2.7	27.4	0.2	0.9	2.9	3.7	64.7	-
9	36.8	45	5.9	-	-	98.2	-	1.7	-	-
10	36.8	171	78	-	-	98.2	-	1.7	-	-
11	36.8	25	78	-	-	98.2	-	1.7	-	-
12	36.8	33	120	-	-	98.2	-	1.7	-	-

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4.2 Enhanced decarbonisation (WGS + MDEA)

In this case, the BFG is first converted into H_2+CO_2-rich gas in a single stage WGS, by reacting it with steam. H_2O is available at 3 bar and 145°C which is heated up to 330°C before to enter to the WGS reactor. The shifted gas is cooled down by recovering high temperature heat (from 433°C to 355°C) and then it is used to pre-heat the feed mixture. Further cooling process, along with condensation, is necessary before entering the absorber column at 2 bar and 40°C, Figure 2.

The shifted syngas is then sent to a MDEA process which has been designed according to the same operating conditions in the Base Case (4.1) except for the different inlet gas flowrate and composition. The process flow diagram is represented in Figure 2 and the detailed mass balance of the process is reported in Table 7.

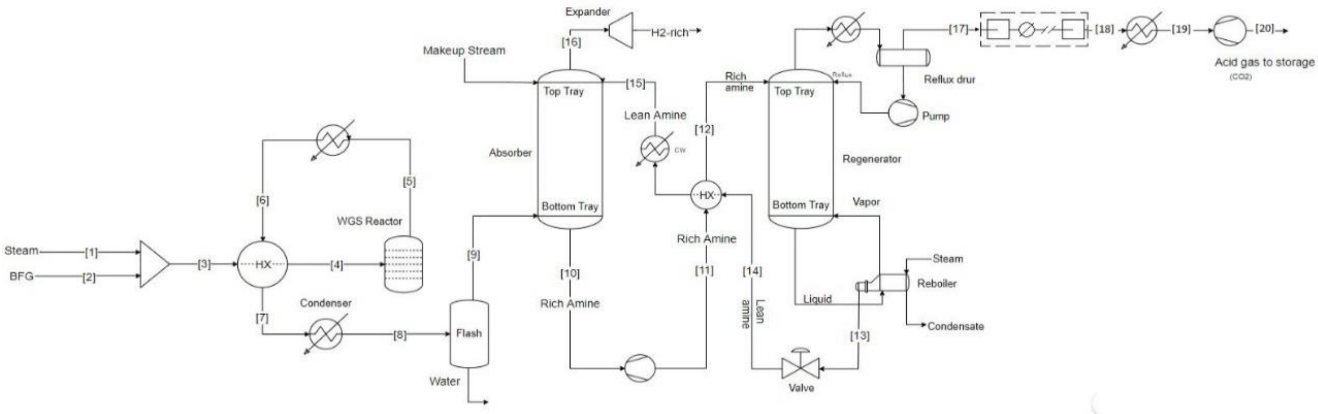

Figure 2: BFG decarbonisation with WGS and MDEA

*This project has received funding from the European Union's Horizon 2020 research and innovation programme under the Grant Agreement No **884418***

Table 7: Mass flow, temperature, pressure and composition for the enhanced decarbonisation case (Figure 2)

Stream	m (kg/s)	T (°C)	P (bar)	Compositions (%mol)						
				CO	C_2H_4	CO_2	H_2	H_2O	N_2	MDEA
1	25	145	3	-	-	-	-	100	-	-
2	125.1	35	3	22.7	0.18	21.1	2.4	-	53.5	-
3	150.1	90.2	3	16.9	0.13	15.7	1.8	25.4	39.8	-
4	150.1	300	2.95	16.9	0.13	15.7	1.8	25.4	39.8	-
5	150.1	432.7	2.54	4.0	-	28.7	15.3	12.0	39.7	-
6	150.1	355	2.51	4.0	-	28.7	15.3	12.0	39.7	-
7	150.1	131.4	2.46	4.0	-	28.7	15.3	12.0	39.7	-
8	150.1	40	2.43	4.0	-	28.7	15.3	12.0	39.7	-
9	141.6	40	2	4.4	-	31.4	16.8	3.7	43.4	-
10	1576.1	59.8	2	-	-	-	-	92.4	-	7.3
11	1576.1	59.9	6.1	-	-	-	-	92.4	-	7.3
12	1576.1	89	6	-	-	-	-	92.4	-	7.3
13	1509.8	164.7	6	-	-	-	-	94.7	-	5.1
14	1509.8	164.7	2	-	-	-	-	94.7	-	5.1
15	1509.8	40	2	-	-	-	-	94.7	-	5.1
16	3.51	48.7	2	6.3	-	2.2	23.9	5.5	61.8	-
17	66.3	45	5.6	-	-	98.1	-	1.7	-	-
18	66.3	173	78	-	-	98.1	-	1.7	-	-
19	66.3	25	78	-	-	98.1	-	1.7	-	-
20	66.3	33	120	-	-	98.1	-	1.7	-	-

4.3 Techno-economic performance

The thermodynamic performance of base case (4.1) and the enhanced case are presented in Table 8.

Table 8: Thermodynamic performance comparison

	Base case	Enhanced case
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

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The assumptions presented in Table 3 are used for the economic assessment of both cases. 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 9.

Table 9: techno-economic performance comparison

	Unit	no capture	Base case	Enhanced
Steel mill size	Mt_{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
Carbon Capture Rate	[%]		46%	83%
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%
ΔCO_2 specific emissions[a)]	[kg_{CO2}/t_{HRC}]	711.9	383.56	120.28
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 avoidance cost	[$€/t_{CO2}$]		39.84	49.38

[a)] These emissions are related to only to this section of the steel mill.

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5. Capture processes coupled with Power Generation in the integrated Steel plant

5.1 Assumptions

In integrated steelworks, the BFG is burned to produce electricity in a conventional power plant. The conventional power plants adopted are a subcritical steam cycle (typical of steel plant applications) and combined cycle. The assumption for the power plant modelling is reported in Table 10.

Table 10: Turbomachinery assumptions for simulation

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

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5.2 Subcritical Steam Cycle

In steam cycle, air and fuel (BFG, or DCF) combust in a boiler to produce steam. Air is pre-heated to 275°C before entering the boiler by cooling the exhaust gas from the combustion chamber. 160 bar and 500°C steam is generated and sent to the HPT. Before the steam is sent to the IPT (operated at inlet pressure of 30 bar), steam is re-heated to 490 °C. LP steam is taken at 6 bar to supply the required heat to the CO_2 capture unit plant as in the case of reboiler and WGS reactants. In the case of enhanced decarbonisation, the heat recovered after the WGS is used to produce high pressure steam that is added to the overall system. The plant is fully integrated as represented in Figure 3.

The main representative points of the process are reported in Table 11, Table 12 and Table 13 for the case in which the fuel used is BFG and decarbonised BFG (as produced from the base case 4.1 and the enhanced one 4.2).

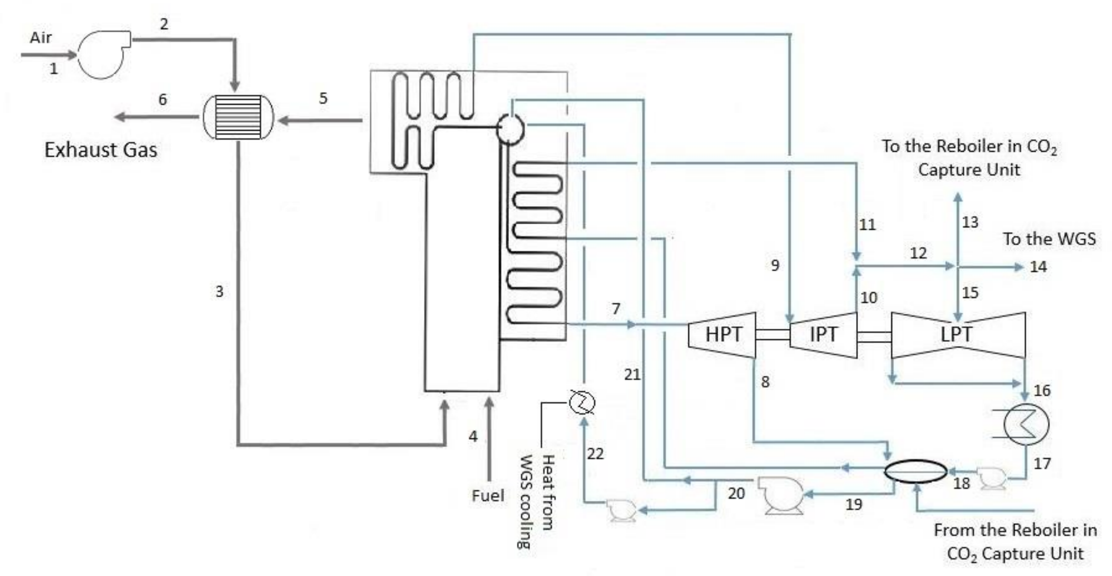

Figure 3: Steam cycle integration with CCS unit

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Table 11: Mass flow, temperature, pressure and composition for the BFG with ST

				Composition (%mol)					
Stream No.	T (°C)	P (bar)	m (kg/s)	H_2O	CO_2	N_2	O_2	Ar	NO
1	15	1.013	130	1	0.03	77	20	0.9	-
2	22	1.08	130	1	0.03	77	20	0.9	-
3	275	1.06	130	1	0.03	77	20	0.9	-
4	35	2.15	125.1	As reported in Table 2					
5	276	1.05	255.1	2	22	70	5	0.5	0.04
6	165	1.04	255.1	2	22	70	5	0.5	0.04
7	500	160	37.09	1	-	-	-	-	-
8	248.96	30.6	37.09	1	-	-	-	-	-
9	490	30.0	63.96	1	-	-	-	-	-
10	167.89	6.1	63.96	1	-	-	-	-	-
11	330	6.1	10.10	1	-	-	-	-	-
12	276.31	6	74.06	1	-	-	-	-	-
13	-	-	-	1	-	-	-	-	-
14	-	-	-	1	-	-	-	-	-
15	276.31	6	74.06	1	-	-	-	-	-
16	35.32	0.048	74.06	1	-	-	-	-	-
17	35.32	0.048	74.06	1	-	-	-	-	-
18	35.38	6.12	74.06	1	-	-	-	-	-
19	147.67	6.12	63.96	1	-	-	-	-	-
20	148.14	31.8	63.96	1	-	-	-	-	-
21	148.14	31.8	26.88	1	-	-	-	-	-
22	149.84	163.2	37.12	1	-	-	-	-	-

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Table 12: Mass flow, temperature, pressure and composition for the BFG with CCS and ST

				Composition (%mol)						
Stream No.	T (°C)	P	m (kg/s)	H_2O	CO_2	N_2	O_2	Ar	CO	H_2
1	15	1.013	130	1	0.03	77	20	0.9	-	-
2	22	1.08	130	1	0.03	77	20	0.9	-	-
3	275	1.06	130	1	0.03	77	20	0.9	-	-
4	9.2	1.015	90.8	3.7	0.9	64.7	-	-	27.5	3
5	304	1.06	210.798	4	13	77	4	0.5	9 PPM	962 PPM
6	165	1.05	210.798	4	13	77	4	0.5	9 PPM	962 PPM
7	500	160	29.51	1	-	-	-	-	-	-
8	249	30.6	29.51	1	-	-	-	-	-	-
9	490	30	50.92	1	-	-	-	-	-	-
10	268	6.1	50.92	1	-	-	-	-	-	-
11	330	6	27.97	1	-	-	-	-	-	-
12	290	6	78.9	1	-	-	-	-	-	-
13	289.9	6	20.55	1	-	-	-	-	-	-
14	-	-	-	1	-	-	-	-	-	-
15	289.9	6	58.35	1	-	-	-	-	-	-
16	35.3	0.048	58.35	1	-	-	-	-	-	-
17	35.3	0.048	58.35	1	-	-	-	-	-	-
18	35.4	6.12	58.35	1	-	-	-	-	-	-
19	152.5	6.1	50.92	1	-	-	-	-	-	-
20	153	31.8	50.92	1	-	-	-	-	-	-
21	153	31.8	21.38	1	-	-	-	-	-	-
22	155.4	163.2	29.51	1	-	-	-	-	-	-

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Table 13: Mass flow, temperature, pressure and composition for the BFG with WGS, CCS and ST

				Composition (%mol)						
Stream No.	T (°C)	P	m (kg/s)	H_2O	CO_2	N_2	O_2	Ar	CO	H_2
1	15	1.013	125	1	0.03	77	20	0.9	-	-
2	15.2	1.08	125	1	0.03	77	20	0.9	-	-
3	275	1.06	125	1	0.03	77	20	0.9	-	-
4	27.6	1.015	75.9	5.5	2.3	62	-	-	6.4	24
5	315	1.06	200.9	14.8	4.2	75	5	0.5	796 PPM	1 PPM
6	165	1.05	200.9	14.8	4.2	75	5	0.5	796 PPM	1 PPM
7	500	160	40.56	1	-	-	-	-	-	-
8	249	30.6	40.56	1	-	-	-	-	-	-
9	490	30	40.97	1	-	-	-	-	-	-
10	267.9	6.1	40.97	1	-	-	-	-	-	-
11	330	6	37.01	1	-	-	-	-	-	-
12	297.4	6	78	1	-	-	-	-	-	-
13	297.4	6	37.34	1	-	-	-	-	-	-
14	297.4	6	25	1	-	-	-	-	-	-
15	297.4	6	15.24	1	-	-	-	-	-	-
16	35.3	0.048	15.24	1	-	-	-	-	-	-
17	35.3	0.048	15.24	1	-	-	-	-	-	-
18	35.4	6.12	15.24	1	-	-	-	-	-	-
19	90	6.12	40.97	1	-	-	-	-	-	-
20	90.3	31.8	40.97	1	-	-	-	-	-	-
21	90.3	31.8	0.41	1	-	-	-	-	-	-
22	91.8	163.2	40.56	1	-	-	-	-	-	-

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5.3 Combined cycle gas turbine

The combined cycle gas turbine (CCGT) comprises a combination of Brayton cycle (gas turbine) and Rankine cycle (steam turbine) for electricity/heat generation as presented in Figure 4. The fuel is compressed to the injecting condition in the combustor in a multistage intercooled compressor. The gas turbine is operated with the pressure ratio of 17 and a temperature inlet temperature of 1180°C.

After the expansion, the exhaust gas enters the heat recovery steam generator (HRSG) by which waste heat of the exhaust gas is recovered in a 2 or 3 pressure levels process.

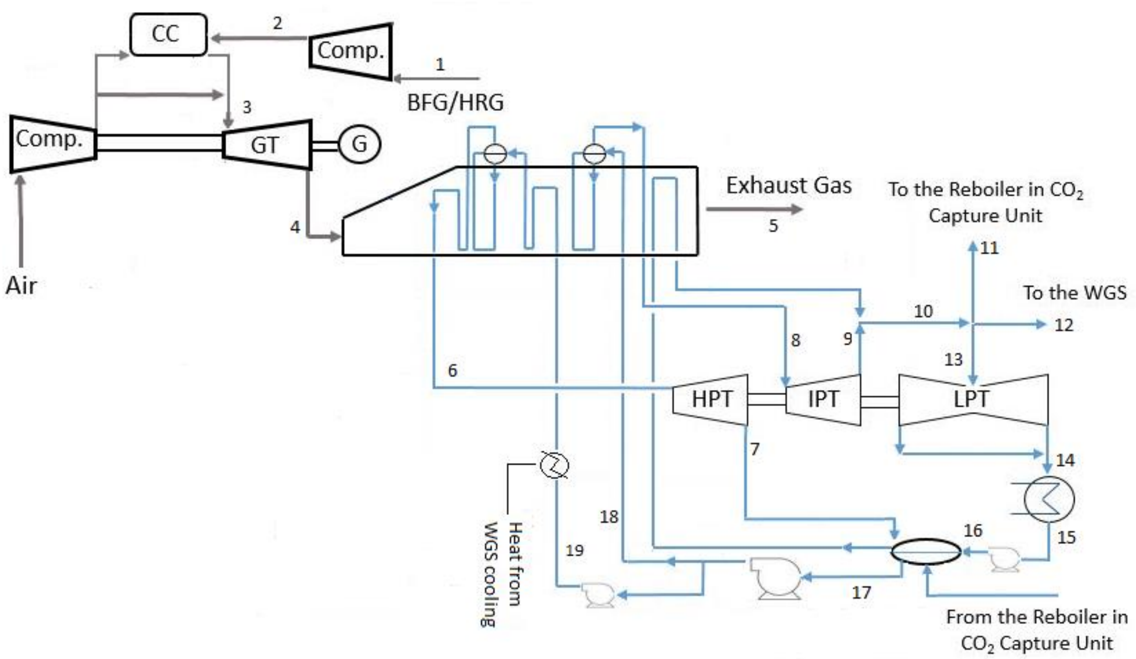

Figure 4. Combined cycle integration with CCS unit

The main representative points of the process are reported in Table 14, Table 15 and Table 16 for the case in which the fuel used is BFG, decarbonised BFG (as produced from the base case 4.1 and the enhanced one 4.2).

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Table 14: Mass flow, temperature, pressure and composition for the BFG with CC

				Composition (%mol)					
Stream No.	T (°C)	P (bar)	m (kg/s)	H_2O	CO_2	CO	N_2	H_2	O_2
1	35	2.15	125.1	-	21	22	53	2.4	-
2	142.2	28	125.1	-	21	22	53	2.4	-
3	1180	17.74	283.36	2	20	71	-	-	6
4	565.5	1.041	283.36	2	20	71	-	-	6
5	164.8	1.041	283.36	2	20	71	-	-	6
6	540.5	130	31.76	100	-	-	-	-	-
7	310.2	29.6	31.76	100	-	-	-	-	-
8	522	28	32.07	100	-	-	-	-	-
9	280	6.1	32.07	100	-	-	-	-	-
10	301.6	6.1	32.38	100	-	-	-	-	-
11	-	-	-	100	-	-	-	-	-
12	-	-	-	100	-	-	-	-	-
13	301.6	6.1	32.38	100	-	-	-	-	-
14	35.3	0.048	32.38	100	-	-	-	-	-
15	35.3	0.048	32.38	100	-	-	-	-	-
16	35.4	6.14	32.38	100	-	-	-	-	-
17	145.8	6.12	32.06	100	-	-	-	-	-
18	146.3	31.9	0.32	100	-	-	-	-	-
19	148	132.6	31.74	100	-	-	-	-	-

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Table 15: Mass flow, temperature, pressure and composition for the BFG with CCS and CC

				Composition (%mol)					
Stream No.	T (°C)	P (bar)	m (kg/s)	H_2O	CO_2	CO	N_2	H_2	O_2
1	46.5	2.7	90.57	3	0.9	27	65	3	-
2	138.4	28	90.57	3	0.9	27	65	3	-
3	1180	17.74	294.9	3	9.8	8 PPM	77	-	9
4	537.9	1.04	294.9	3	9.8	8 PPM	77	-	9
5	165	1.04	294.9	3	9.8	8 PPM	77	-	9
6	513	130	15.2	100	-	-	-	-	-
7	286.9	29.6	15.2	100	-	-	-	-	-
8	510	28	18.54	100	-	-	-	-	-
9	292.2	6.1	18.54	100	-	-	-	-	-
10	296.1	6.1	38.93	100	-	-	-	-	-
11	296.1	6.1	20.24	100	-	-	-	-	-
12	-	-	-	100	-	-	-	-	-
13	296.1	6.1	18.69	100	-	-	-	-	-
14	35.3	0.048	18.69	100	-	-	-	-	-
15	35.3	0.048	18.69	100	-	-	-	-	-
16	35.4	6.12	18.69	100	-	-	-	-	-
17	160.5	6.1	19.11	100	-	-	-	-	-
18	161	31.9	3.44	100	-	-	-	-	-
19	16.8	132.6	15.67	100	-	-	-	-	-

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Table 16: Mass flow, temperature, pressure and composition for the BFG with WGS, CCS and CC

				Composition (%mol)					
Stream No.	T (°C)	P (bar)	m (kg/s)	H_2O	CO_2	CO	N_2	H_2	O_2
1	48.7	2	75.55	5	2	6	62	24	-
2	156.1	28	75.55	5	2	6	62	24	-
3	1180	17.74	254.7	12	3	1 PPM	0.76	1 PPM	8
4	529.2	1.04	254.7	12	3	1 PPM	0.76	1 PPM	8
5	164.7	1.04	254.7	12	3	1 PPM	0.76	1 PPM	8
6	504.2	130	24.8	100	-	-	-	-	-
7	279.4	29.6	24.8	100	-	-	-	-	-
8	500	28	25.06	100	-	-	-	-	-
9	285	6.1	25.06	100	-	-	-	-	-
10	298	6.1	35.24	100	-	-	-	-	-
11	298	6.1	10.24	100	-	-	-	-	-
12	298	6.1	25	100	-	-	-	-	-
13	-	-	-	100	-	-	-	-	-
14	-	-	-	100	-	-	-	-	-
15	-	-	-	100	-	-	-	-	-
16	-	-	-	100	-	-	-	-	-
17	151.5	6.1	25.06	100	-	-	-	-	-
18	152	31.9	0.25	100	-	-	-	-	-
19	153.6	132.6	24.81	100	-	-	-	-	-

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5.4 Techno-economic performance

The overall energy balance of the simulated plants is reported in Table 17. The energy balance is including the energy cost of CO_2 separation and compression as discussed in section 4. The techno-economic comparison is also reported in Table 18.

Table 17: Energy balance of integration options

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
Additional heat to 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	**no capture**	**MDEA**	**WGS + MDEA**
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
Additional heat to 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 CO_2 emission from heat generation is 220 g/kWh [26]

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Table 18: 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
Carbon Capture Rate	[%]		46%	83%		46%	83%
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 (electricity based)	[%]		14.6%	-98.8%		28.3%	65.2%
CO_2 specific emissions	$[kg_{CO2}/t_{HRC}]$	711.9	383.56	120.28	711.90	383.90	120.50
SPECCA	$[MJ_{LHV}/kg_{CO2}]$		14.90	*-40.52*		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 purchased[b)]	[M€/y]		13.11	32.5		14.34	29.73
Δcost of HRC	$[€/t_{HRC}]$		11.92	21.19		12.36	23.65
CO_2 avoidance cost	$[€/t_{CO2}]$		238.03	*-411.58*		93.57	121.55

[a)] This includes the MDEA absorption/desorption plant, CO_2 compression unit, and syngas expander as detailed in Table 9
[b)] This is the cost to purchase the electricity that is not generated in the plant(s) with CO_2 capture with respect to the case of no capture.

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6. Conclusions

Iron and steel industry is amongst the major contributors to anthropogenic CO_2 emissions. This deliverable 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 two power system (steam cycle and combined cycle) integration.

In the case of CO_2 capture processes, the CO_2 avoidance is respectively 42.6% for the base case and 80.8% when CO is also converted into CO_2 and H_2 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 results of the economic analysis, the cost to produce the decarbonised fuel is 9.73 €/GJ with a resulting CO_2 avoidance 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, having been processed using CO_2 capture, it is acceptable only in case of integration with a combined cycle power system given that the SPECCA ranges from 4.3 - 6 depending if the BFG decarbonisation is partial or completed. In the case of steam cycle use, the overall net electric efficiency drops to 19.3% (in the case of partial CO_2 capture) to 2.6% (for enhanced decarbonisation).

From an economic point of view, the CO_2 avoidance 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}.

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