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Abstract

This report is the result of a joint effort of a team of members of the CAESAR, CESAR and DECARBit FP7 projects. It presents three study cases of power plants without and with CO_2 capture. The performance of new cycles proposed within the three projects, incorporating innovative capture technologies, should be compared and referred to the performance of these three cases. The three cases are: an Advanced Supercritical Pulverized Coal plant, an Integrated Gasification Combined Cycle and a Natural Gas Combined Cycle. For each case, a general description of the case is presented, followed by the specification of the process streams, operational characteristics and operational performance.

Public introduction (*)
This report is the result of a joint effort of a team of members of the CAESAR, CESAR and DECARBit FP7 projects. It presents three study cases of power plants without and with CO_2 capture. The performance of new cycles proposed within the three projects, incorporating innovative capture technologies, should be compared and referred to the performance of these three cases. The three cases are: an Advanced Supercritical Pulverized Coal plant, an Integrated Gasification Combined Cycle and a Natural Gas Combined Cycle. For each case, a general description of the case is presented, followed by the specification of the process streams, operational characteristics and operational performance.

(*) According to Deliverables list in Annex I, all restricted (RE) deliverables will contain an introduction that will be made public through the project WEBsite

TABLE OF CONTENTS

Page

1 GENERAL INTRODUCTION

This report is the second deliverable of the European Benchmarking Task Force (EBTF), a team of members of three projects sponsored by the European Commission within the Framework 7 Program. The mission of this task force is to define a comprehensive set of parameters, guidelines and best practices, not only for the three projects but also for future European research and development projects on Carbon Capture and Storage. The three projects are:

CAESAR - Carbon-free electricity by Sorption Enhanced Water Gas Shift (SEWGS): advanced materials, reactor and process design

The scope of CAESAR is the application of the optimized SEWGS process to pre-combustion CO2 capture from natural gas but it also considers the possible application of the process to coal power plants. It is a successor of the CACHET project.

CESAR – CO_2 Enhanced Separation and Recovery

The focus in CESAR is post-combustion capture. Within the CESAR project, Work Package 2 aims at process integration between all the elements of the power plant equipped with CO2 capture (boiler, steam generation system, CO2 capture, CO2 compression). It is a successor of the CASTOR project.

DECARBIT – Enabling Advanced Pre-combustion Capture Techniques and Plants

The objective of DECARBIT is to enable zero-emission pre-combustion capture power plants by 2020 with a capture cost of less than 15 Euros / ton with the highest feasible capture rate. This is to be accomplished by focusing on advanced capture techniques in pre-combustion schemes and key enabling technologies for pre-combustion plants.

The members of the EBTF represent, within these three projects, the following organizations: Alstom, E.ON, NTNU, Politecnico di Milano, Shell, TNO, University of Ulster and Vattenfall.

This report presents three study cases of power plants without and with CO_2 capture. The performance of new cycles proposed within the three projects, incorporating innovative capture technologies, should be compared and referred to the performance of these three cases. The three cases are: an Advanced Supercritical Pulverized Coal plant, an Integrated Gasification Combined Cycle and a Natural Gas Combined Cycle. For each case, a general description of the case is presented, followed by the specification of the process streams, operational characteristics and operational performance. All performance data presented refer to plants operating at nominal base-load, *"new and clean"* conditions. For all considered cases, the energy cost related to CO_2 capture is given by the Specific Primary Energy Consumption for CO_2 Avoided (SPECCA), which is defined as:

$$SPECCA = \frac{HR - HR_{REF}}{E_{REF} - E} = \frac{3600 \cdot \left(\frac{1}{\eta} - \frac{1}{\eta_{REF}} \right)}{E_{REF} - E}$$

where

- HR is the heat rate of the plants, expressed in $kJ_{LHV}/kWhe_l$
- E is the CO_2 emission rate, expressed in $kg_{CO2}/kWhe_l$

- η is the net electrical efficiency of the plants
- $_{REF}$ refers to the value found for the same plant without CCS.

The contents of the following three chapters were, respectively, prepared by CESAR (TNO – Netherlands Organization for Applied Scientific Research, with support from E.ON and Vattenfall), DECARBIT (NTNU – Norwegian University of Science and Technology, with support from Alstom, Shell and University of Ulster) and CAESAR (Politecnico di Milano). Alstom edited the report. Given the objective of the EBTF – benchmarking – the three cases were also calculated, respectively, by the CAESAR, CAESAR and CESAR members. So, for each case, a comparison of configurations and results obtained by two projects is presented. All cases were thoroughly discussed within the EBTF and, with respect to a considerable number of issues, external opinions were sought, so that every effort was made to ensure that this document reflects, as much as possible, the views of the European community of carbon capture researchers. Nevertheless, readers are encouraged to send any comments they may have to any one of the authors listed in the previous pages.

The authors want to clearly state an important caveat about the significance of the presented results. For two out of the three study cases without CO_2 capture, i.e. the Advanced Super-Critical 800 MW steam power plant and the Natural Gas Combined Cycle 834 MWe power plant, their calculations reproduce the actual performance of a large number of existing state-of-the-art power plants. Hence the calculated net electric efficiency and specific power are fully consistent with values reached by the major plant manufacturers. A completely different situation occurs for the Integrated Gasification Combined Cycle 442 MWe study case: the EBTF calculations depict a power generation technology based on the theoretical performance of a large number of state-of-the-art components. This technology is not yet applied in such a large-scale plant that could validate the presented results. A similar situation, i.e., the absence of actual plants to validate the presented calculations, occurs for the three capture study cases: presently, only small-scale pilot plants have been built. Hence the degree of confidence to be assumed in the consideration of the presented results varies significantly from case to case. This caveat holds for the technical results and even more for the economic results, which will be reported in the near future and are not discussed here.

2 ADVANCED SUPERCRITICAL PULVERIZED BITUMINOUS COAL - ASC

2.1 Introduction to the ASC Test Case

This chapter describes the definition of the baseline solvent process for post-combustion CO_2 capture from an Advanced SuperCritical (ASC) pulverized fuel (PF) bituminous power plant. The present test case corresponds to one of the three power plant test cases (two based on solid fuel and one on natural gas) that have been defined for post-combustion capture evaluation in the CESAR project. This solvent process is based on a 30% (by weight) aqueous solution of monoethanolamine (MEA). Regarding the capture technology, a process model has been developed using the ASPEN Plus simulation program where the baseline CO_2-removal has been chosen to be 90%. The results of the process modelling have been used to design the equipment and determine its sizes. This forms the basis for the estimation of the capital investment and the operational costs of the capture plant. Evaluation of power plant performance and integration of capture plant and power plant was a joint effort of Doosan Babcock, E.ON and Siemens. Therefore, the present case has been developed with the contributions of Doosan Babcock, Siemens, E.ON and TNO (capture design).

2.2 ASC Test Case without Capture

2.2.1 Case Description and Flow Diagram

The plant is based on an Advanced SuperCritical (ASC) Boiler and Turbine delivering 819 MWe(gross) without carbon capture. When auxiliary power is taken into account, the final net power plant output is 754.3MWe, yielding a net cycle efficiency of 45.5%. The general arrangement layout for the reference power plant is based on an inland site with natural draft cooling towers and delivery of the coal by rail. Assumptions regarding site conditions (ambient temperature, cooling water temperature, etc), coal properties and equipment efficiency are based on the Common Framework Definition Document of the EBTF (European Benchmark Task Force) [1].

The Block Flow Diagram of 800MW_e Supercritical Power Plant is shown in Figure 2-1. The power plant's power block consists of the steam turbine, steam generator with coal bunker bay and central switch gear. Brief descriptions of each unit and technical data are given bellow.

2.2.1.1 Steam Turbine Plant

The steam turbine plant consists of HP turbine, IP turbine and LP turbine with extraction points for regenerative heating of feed water and condensate. There are nine feed water heaters. The condensers are located beneath the LP turbines. The boiler feed pumps selected are motor driven for base-load power plant, following the suppliers recommendation.

2.2.1.2 Steam Generator Plant

The steam generator is based on state-of-the-art Doosan Babcock Two-Pass single reheat BENSON boiler with Low Mass Flux Vertical Internally Ribbed Tube (LMVT) Furnace to maximize plant performance. To safeguard the furnace, the boiler is equipped with a start-up and low load operation system.

2.2.1.3 Power Plant Auxiliaries

The coal milling plant comprises of 6 vertical spindle, ring and roller slow speed pressurized mills and associated seal air fans. The boiler is equipped with a state-of-the-art combustion system comprising 30 Doosan Babcock Low NOx Axial Swirl burners and in-furnace air-staging system (BOFA) for primary control of NOx emissions. The combustion air and flue gas systems are designed for balanced draught operation based on a two-train system arrangement. Separate primary and secondary regenerative air heaters are used to heat the combustion air to the boiler and provide means of coal drying and pulverized fuel transportation.

For the control of combustion product emissions, the power plant is equipped with selective catalytic reduction (SCR) DeNOx plant located between the boiler's exit and the air heater inlet, electrostatic precipitators and wet limestone based desulphurization plant before exhausting to atmosphere via a flue stack.

For ash handling, a dry ash conveying system is employed for fly ash and a continuous ash removal system with submerged chain conveyer for furnace bottom ash.

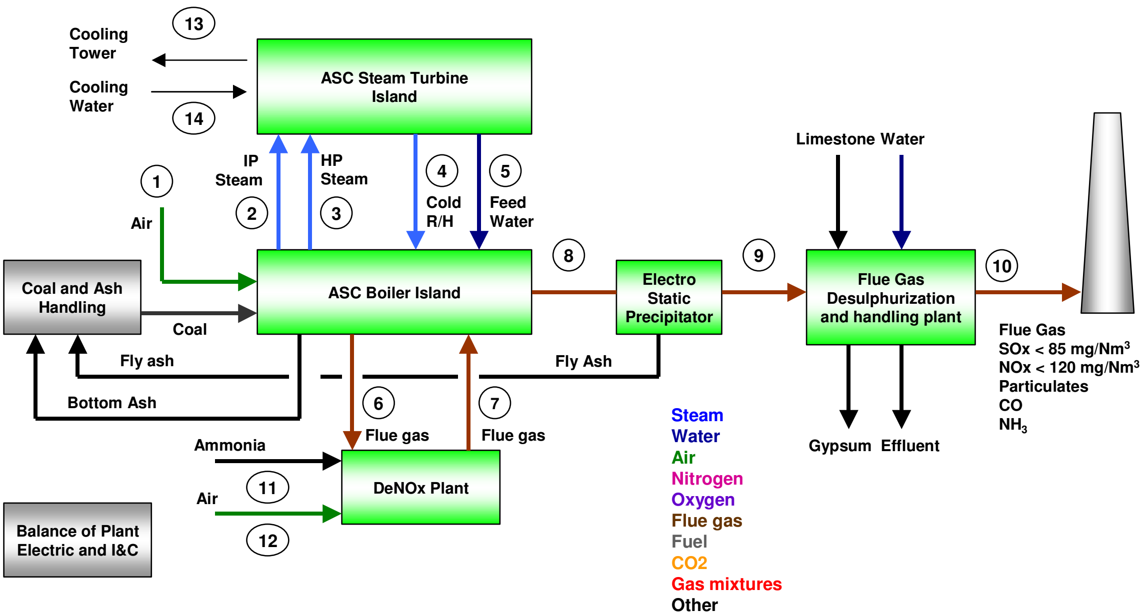

Fig. 2-1 Block Flow Diagram of PF Power Plant without Carbon Capture

2.2.2 Stream Table

Table 2.1 – Stream flows, conditions and compositions												
Stream n°	Mass flow	T	P	x	Composition %v/v, wet							
	kg/s	°C	bara		H2	CO	CO_2	N_2	O_2	Ar	SO2	H_2O
Coal	65.765	15										
1	705.98	15						77.8	20.6			1.6
2	485.2	620	60									100
3	600.0	600	270									100
4	485.2	366	64.01									100
5	600.0	308	320									100
6	730.23	377					14.9	75	2.9		0.04	7.2
7	732.42	377					14.9	75	2.9		0.04	7.2
8	766.9*	128					14.1	75.1	3.8			6.9
9	766.9	128					14.1	75.1	3.8			6.9
10	781	85					13.73	72.9	3.7		0.01	9.7
11	0.11	9										
12	2.19	18						77.8	20.6			1.6
13	16,400	31.8										100
14	16,400	20.7										100

*The increase in mass flow rate and change in composition is due to air leakage over the air pre-heater

2.2.3 Operational Characteristics

The power plant technical data are given in the list below:

- Gross turbine heat rate — 6887 kJ/kWh
- Net full load plant efficiency — 45.5% LHV basis
- CO_2 emissions — 763 g/kWh$_{net}$
- Operation mode — Base load
- Main steam (HP turbine inlet) — 2160 t/h @ 270 bara / 600°C
- Cold reheat (HP turbine exhaust) — 1746.7 t/h @ 64.0 bara / 366°C
- Hot reheat (IP turbine inlet) — 1746.7 t/h @ 60 bara / 620°C

(A reheat temperature of 620°C was chosen to achieve a high efficiency. However, Siemens internal studies suggest that, depending upon anticipated plant operating regime, a lower temperature of 610°C may be preferable. Reference: 'Advanced 800+ MW Steam Power Plants and Future CCS Options', Cziesla *et al*, presented at COAL-GEN Europe 2009, Poland, September 1-4, 2009)

- Final feed water — 320.0 bara @ 308°C
- Boiler feed water pumps — 2 x 50% electric motor driven boiler feed pumps with 30% electric motor driven start-up pump
- Condensate pumps — 2 x 50% motor-driven condensate pumps
- Feed water heaters:- — 5 x LP Heaters + 3 x HP Heaters

	Feed water tank and Deaerator
• Flue gas temperature	120°C at air heater exit
• Furnace exit excess air	17%
• Condensing cooling	Natural draught wet cooling tower
• Condenser pressure	53 / 37 mbar
• Minimum load	30% MCR under stable coal combustion without secondary fuel support
• Steam temperature control point	Rated superheat steam temperatures maintained down to 40% of rated load. Rated reheat steam temperatures maintained down to 70% of rated load
• Steam cycle operation	Sliding pressure in the range 40% to 100% of rated load.
• Design coal	South African Douglas Premium 2
• Environmental measures	State-of-the-art DeNOx, ESP, FGD, 5% unburnt carbon based on design coal.

2.2.4 Operational Performance

• Electrical output	819 MWe (gross)
• Auxiliary power consumption	65 MWe (7.9% of gross output)

2.3 ASC Test Case with Capture

2.3.1 Case Description and Flow Diagram

The key step of any post-combustion CO_2 capture process is the separation stage of the CO2 from the flue gas. This separation can be achieved by a number of different technologies such as absorption, adsorption, and membranes along with other physical and biological methods. In this case, the flue gas is treated using a conventional amine scrubbing post-combustion CO_2-capture process. Main characteristics of this absorption process are listed bellow:

- Basic absorption-desorption process using a 30% wt MEA solvent
- This amine-based process is considered the benchmark technology
- Used in a number of industrial applications

This case includes a new power plant designed for the CO_2 capture operation. The capture plant is designed to function for the whole life of the plant. The capture stage is designed to capture 90% of the CO_2 contained in the flue gas. Operation of the plant at full load conditions is considered. The yearly average load factor of the plant, considering scheduled and unexpected outages, is 85%. Flue gas conditions at the capture plant inlet (equivalent to FGD outlet) are shown in Table 2.2. Fig. 2.2 shows the block diagram of the power plant with capture and Fig.

2.3 shows in detail the flow sheet of the CO_2-capture process that was used for the evaluation of the capture requirements.

In this case, the flue gas is initially cooled to 50ºC and fed to the absorber, where it is contacted with the MEA solvent. With state-of-the art FGD technology, the content of SO_2 can be reduced to 85 mg/Nm^3, which corresponds to 30ppm approximately. The content of SO_2 can be further reduced with the addition of an extra washing step. The final inclusion of this step depends on a close evaluation of solvent degradation and price. For the present study case the degradation of the MEA solvent due to the irreversible reaction with SO2 will be taken into account during the economic evaluation and based on the estimates given by Rubin and Rao, 2002 [ref5]. At the conditions of the absorber, the CO_2 is chemically bound to the MEA solvent.

The reactions that take place are described in Table 2-3. A blower is required to pump the gas through the absorber. After passing through the absorber the flue gas passes through a water wash section to balance water in the system and to remove any solvent droplets or solvent vapour carried over and then leaves the absorber. The "rich" solvent, which contains the chemically bound $CO_{2,}$ is then pumped to the top of a stripper, via a heat exchanger. The regeneration of the chemical solvent is carried out in the stripper at elevated temperatures (120ºC) and a pressure slightly higher than atmospheric pressure. Heat is supplied to the stripper from a reboiler to maintain the regeneration conditions. This heat is required to heat the solvent, generate stripping gas/vapour and provide the required desorption heat for removing the chemically bound CO_2, leading to a significant thermal energy penalty to the host power plant. The steam necessary to supply this heat can be extracted from the steam turbine IP/LP crossover which has a steam pressure of 5.2 bar in the plant without capture. The reboiler requires a steam pressure of 3 bara. A pressure drop of 0.5 bar was assumed between the IP/LP crossover and the reboiler. The minimum steam pressure in the IP/LP crossover is 3.5 bara.

The extraction of steam from the IP/LP crossover in the base plant design causes the pressure to drop beneath 3.5 bara, therefore for the case with capture the LP turbines were redesigned to maintain a pressure of 3.5 bara at full load operation. The steam is then suitably conditioned, through pressure reduction and attemperation, for reboiler use. Attemperation uses condensate from the reboiler to desuperheat the steam, reducing the required mass flow rate of steam to be extracted from the turbine and thus reducing the efficiency penalty of the MEA process on the steam cycle. Steam conditions at the reboiler entrance are 134ºC and 3.05 bar. The condensate is returned into the boiler feed water train.

Stripping steam is recovered in the condenser and fed back to the stripper, whereas the CO_2 product gas leaves the condenser. After the majority of the residual water vapour is removed, the CO_2 product is relatively pure (> 99%), with water vapour being the main other component. The 'lean' solvent, containing residual CO_2 is then pumped back to the absorber via the lean-rich heat exchanger and through a cooler to bring it down to the absorber temperature level.

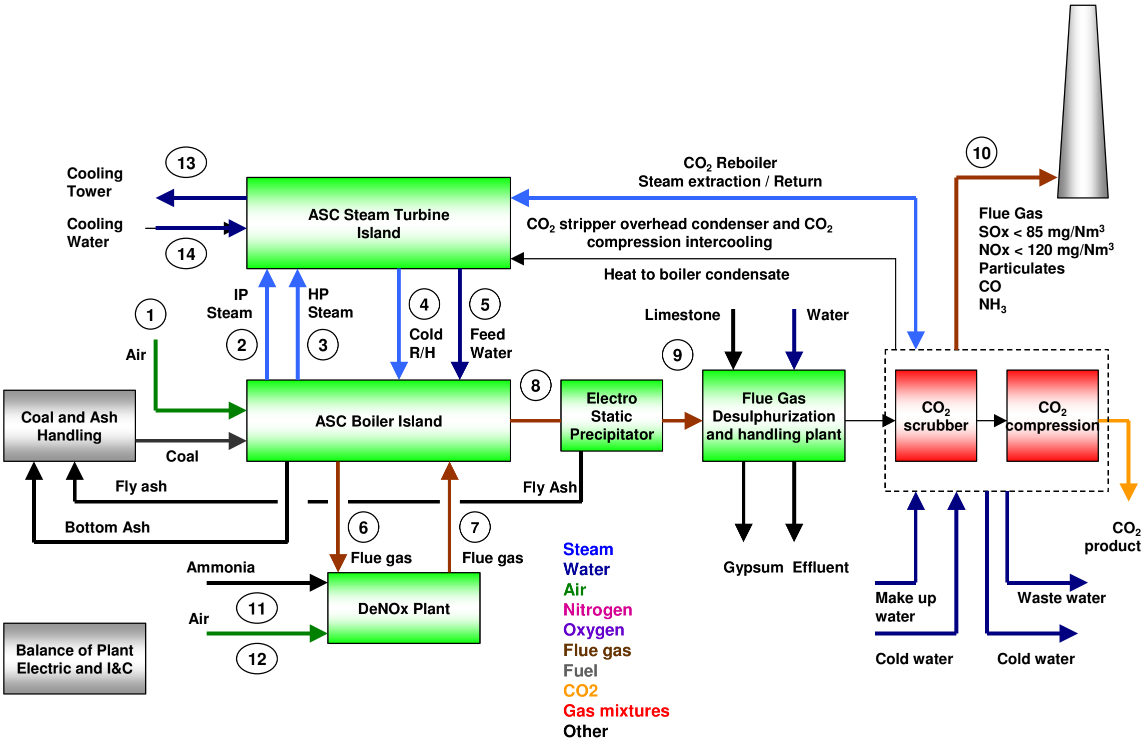

Fig. 2.2 - Block diagram of ASC power plant with capture

Table 2.2 – Post Combustion Capture Plant Inlet Flue Gas Composition		
Parameter	Unit	VALUE
Flue gas flow rate	kg/s	781.77
Temperature	°C	50
Pressure	kPa	101.6
Composition		
O2	Vol. % wet	3.65
CO2	Vol. % wet	13.73
SO2	mg/Nm^3	85 [1]
NOx	mg/Nm^3	120 [1]
H2O	Vol. % wet	9.73
Ar	Vol. % wet	0.005
N_2	Vol. % wet	72.855
Particulate	mg/Nm^3	8 [1]

1 – Estimated, based upon mid point of Best Available Technology (BAT) Reference ranges as recommended in Common Framework Definition Document prepared by the European Benchmarking Task Force (CESAR Deliverable D2.4.1)

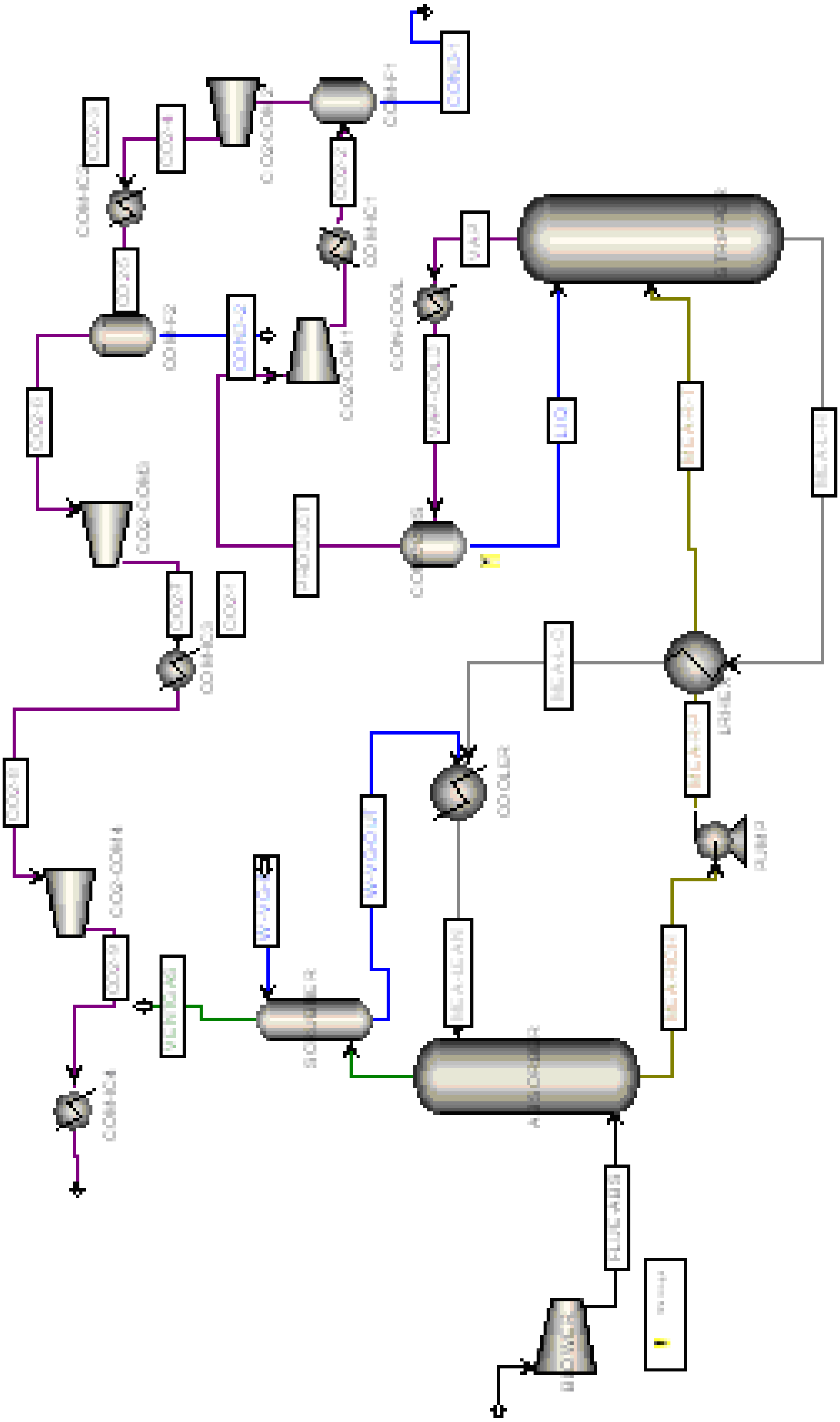

Fig. 2.3 - Process flow sheet for post-combustion capture with MEA 30 wt%

Table 2.3 – MEA reaction chemistry		
Reaction	Type	Stoichiometry
1	Equilibrium	MEA+ + H2O <--> MEA + H3O+
2	Equilibrium	CO2 + 2,0 H2O <--> H3O+ + HCO3-
3	Equilibrium	HCO3- + H2O <--> H3O+ + CO3-2
4	Equilibrium	MEACOO- + H2O <--> MEA + HCO3-
5	Equilibrium	2,0 H2O <--> H3O+ + OH-

Note: Equilibria based upon H_2S and HS are also included within the Aspen model, but are not applicable for flue gas applications.

2.3.2 Stream Table

Table 2.4 – Stream flows, conditions and compositions												
Stream n^o	Mass flow	T	P	x	Composition %v/v, wet							
	kg/s	^oC	bara		H2	CO	CO_2	N_2	O_2	Ar	SO2	H_2O
Coal	65.765	15										
1	705.98	15						77.8	20.6			1.6
2	485.2	620	60									100
3	600.0	600	270									100
4	485.2	366	64.01									100
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11	0.11	9										
12	2.19	18						77.8	20.6			1.6
13	16,400	31.8										100
14	16,400	20.7										100

2.3.3 Operational Characteristics

The capture process technical data and performance are determined by simulation using Aspen Plus ® commercial software. The operating conditions are selected to give an optimal specific heat consumption of 3.7 GJ/ton CO2. This optimum has been checked within the experimental campaigns in the CESAR project.

The absorption process is modelled with two unit operations: absorber and water wash section. Both unit operations are simulated with ASPEN RadFrac® model. This model assumes a sequence of equilibrium stages. Stage efficiencies are considered during sizing of the equipment. The rich solvent coming from the absorber is pumped to the stripper via the lean-rich heat exchanger. This heat exchanger is designed on the basis of a fixed overall heat transfer coefficient and a temperature approach of 5 ºC (cold in-hot out approach). The stripper is simulated again with the ASPEN Radfrac® model. The top two stages serve as a washing section.

Moreover, the stripper is designed at a constant molar recovery ratio. This value is selected to adjust the specific heat consumption to the optimum found in the experimental results of the CESAR project. Therefore, the molar recovery was adjusted to 0.58 in order to give a final heat consumption of 3.7 GJ/ton CO2.

The vapour leaving the stripper is condensed at 40 ºC. The condensate is separated from the gas in a flash vessel (40ºC, 1.6 bara) and recycled back to the stripper at the top stage (water reflux). The CO_2 product gas, once separated from the condensate, is compressed in 3 stages and includes inter-cooling. After the final compression and inter-cooling stage, the CO_2 is already a supercritical fluid. A pump is used to further increase the pressure to 110bara. The final conditions of the product stream are 25ºC and 110 bara. The specification of each unit operation in the process is detailed in Table 2.5.

Electricity requirements for pumping are estimated outside the mass and energy simulations and on the basis of mass flows and densities predicted by Aspen. A first estimate for pump heads is given in Table 2.6. For the columns, the estimate includes the expected height of the column, friction and column pressure.

2.3.4 Operational Performance

Installation of an amine scrubber downstream of the power plant results in a loss in the overall plant performance. The electrical output falls due to the thermal energy requirements of the stripper reboiler (538 MWth), ultimately reducing steam available to the LP cylinders and hence reducing gross electrical output. The auxiliary power consumption is also increased by the compression system, blower and pumps. Table 2.7 shows the main performance parameters of the capture process and Table 2.8 shows the thermal and electrical requirements. Based on the thermal requirements shown in Table 2.8, an evaluation of heat integration with the power plant was done. Results are shown in table 2.9

These results show the effect on power plant efficiency of a benchmark MEA based CO_2 capture process integrated into the power plant with steam extraction optimized for full load, but with no waste heat integration. A variety of suppliers are currently offering proprietary processes with more efficient solvents and capture plant designs. The combination of these advanced designs and increased heat integration, which are not addressed in this report, has the potential to significantly decrease the efficiency penalty from CO_2 capture. However, the MEA capture process considered here provides a transparent and well defined technology benchmark against which new capture processes can be assessed.

Table 2.5 – Specification of unit operations

Name	Aspen Model Type	T [ºC]	P [bar]	Flash options	Specifications
ABSORBER	RadFrac	40-60	1.01	V/L	3 stages, 50mbar pressure drop
BLOWER	Blower	[-]	1.11	V/L	Pressure increase: 100 mbar Type : Isentropic Efficiencies: • Isentropic 0.85 • Mechanical 0.95
CO2-COM1	Compressor	[-]	6.92	V only	Inlet Pressure : 1.5 bara Discharge pressure: 6.92 bara Type : Isentropic Efficiencies: • Isentropic 0.87 • Mechanical 0.95
CO2-COM2	Compressor	[-]	25.72	V only	Inlet Pressure: 6.872 Discharge pressure: 25.72 bara Type : Isentropic Efficiencies: • Isentropic 0.85 • Mechanical 0.95
CO2-COM3	Compressor	[-]	73.72	V only	Inlet pressure :25.65 bara Discharge pressure: 73.72 bara Type : Isentropic Efficiencies: • Isentropic 0.83 • Mechanical 0.95
CO2-COM4	Compressor	[-]	110	L only	Inlet pressure :73.6 bara Discharge pressure: 110 bara Type : Isentropic Efficiencies: • Isentropic 0.82 • Mechanical 0.95
COM-F1	Flash 2	28	[-]	V/L	Pressure drop 0 bar
COM-F2	Flash 2	[-]	[-]	V/L	Pressure drop 0 bar
COM-IC1	Heater	40	[-]	V/L	Pressure in : 6.92 Pressure out : 6.87
COM-IC2	Heater	40	[-]	V/L	Pressure in : 25.72 Pressure out : 25.65
COM-IC3	Heater	65	[-]	V/L	Pressure in : 73.72 Pressure out : 73.6
COM-IC4	Heater	25	[-]	V/L	Pressure in : 110 Pressure out : 110
CON-COOL	Heater	40	1.5	V/L	Pressure drop 0 bar
CONDENS	Flash 2	40	1.5	V/L	Pressure drop 0 bar
COOLER	Heater	40	1.01	V/L	Pressure drop 0 bar
LRHEX	HeatX	NA	3	V/L	ΔT (cold in - hot out) = 5ºC Heat transfer coefficient (U) phase specific values
PUMP	Pump	[-]	3	L only	3 bar Discharge pressure Efficiencies: Pump NA Driver NA
SCRUBBER	RadFrac	40-60	1.01	V/L	2 stages
STRIPPER	RadfFrac	120	1.5	V/L	No. stages: 8 stages Pressure drop: 100mbar

Table 2.6 – Description of pumps						
	Power		Capacity		Head	
Pump	Unit	Value	Unit	Value	Unit	Value
Absorber fluid Pump	kWe	4243	m3/h	12362	m	100
Condenser fluid Pump	kWe	23	m3/h	290	m	20
Stripper fluid Pump	kWe	4526	m3/h	13187	m	100
Cool water Pump	kWe	4443	m3/h	31920	m	42

Note: Cool water pump electricity consumption is equivalent to 0.8% of thermal cooling duty.

Table 2.7 - Specific performance parameters of the capture process		
Parameter	Unit	VALUE
Removal efficiency	%	89
Flue gas flow rate	kg/s	781,77
CO2 feed content	mol. %	13.73
CO2 captured	tonne/hr	518.84
Solvent Concentration	wt-%	30%
Lean solvent flow rate	m3/s	3.43
Solvent specific demand	m3/tonne CO2	23.83
CO2 rich loading	mol CO2/mol MEA	0.47
CO2 lean loading	mol CO2/mol MEA	0.27
Net cyclic loading	mol CO2/mol MEA	0.198
Regeneration energy requirement	MWth	537.6
Regeneration energy specific requirement	GJ/tonne CO2	3.73
Cooling water requirement	m3/hr	32028
Cooling water specific requirement	m3/tonne CO2	62

Table 2.8 - Thermal and electrical requirements of the capture plant	
	VALUE
Thermal (MWth)	
Reboiler Heat	538
Stripper Condenser cooling	208
Lean liquid cooling	260
Flue gas cooling	0
Compressor cooling	87
Electric power (MWe)	
Compressors	48
Pumps	13
Blower	8

Table 2.9 – Comparison of cases with and without capture			
PARAMETER	UNIT	Without capture	With capture
Gross electricity output	MWe	819	684.2
Auxiliary power consumption	MWe	65	135.0
Net electricity	MWe	754	549.2
Efficiency	%LHV	45.5	33.4
CO_2 Emitted	kg/MWh	763	104.7
SPECCA	MJ/kg_{CO2}	N/A	4.35

2.4 Comparison of results found by CESAR and CAESAR for the ASC 800 MW case

A second evaluation of the present case has been carried out by CAESAR, assuming the same steam turbine gross power output of CESAR. Calculations were performed by the code GS (see 4.1). With respect to the test case without capture, the differences between the calculations made by the two projects are:

- Condensing pressure in CAESAR is at 48 mbar instead of two condensers in series at 53 and 38 mbar;
- A temperature drop of 2°C is assumed in CAESAR between the boiler and the steam turbine;
- Auxiliaries consumptions in CAESAR [ref 1,2,3,4]: Coal handling 50 kJ_{el}/kg_{coal}, Ash handling 200 kJ_{el}/kg_{ash}, FGD 5340 kJ_{el}/kg_{SO2rem},

The performance comparison between CAESAR and CESAR results is summarized in Table 2.10. The results show that there are no significant differences between the two models. The higher Gross LHV efficiency of the CESAR case is mostly justified by the different condensing pressure. About auxiliaries, there is a difference of 4.5 MW that almost balances the result in terms of net electrical efficiency. The two results can be considered in good agreement.

The most significant stream flows are summarized in Table 2.11 (stream numbers refer to Figure 2-1).

The capture process flow scheme in CAESAR was similar to the one used in CESAR (also evaluated with Aspen ®) with the following differences:

- The washing section is omitted from the flowsheet. The MEA losses are estimated according to Rao et al, 2002
- Steam for solvent regeneration is taken from steam turbine cross-over and sent back to the steam cycle right before the dearator in order to limit efficiency losses by reducing water preheating;
- The flow scheme includes a MEA outlet and a MEA inlet. Water and MEA balances are controlled by two different design specifications. This makes the lean loading reported at the absorber inlet slightly different from the one reported at the stripper outlet. However the difference is not significant enough (less than 1%) to alter the main process requirements so the extra degree of freedom was accepted in order to speed up simulations. The MEA losses are estimated in the same way as in CESAR.

Table 2.10 – Performance comparison		
	CAESAR	CESAR
Electric power, MW_e		
Steam turbine	819.2	819.0
Feed water pump	-32.05	
Condenser extraction pump	-0.55	
Auxiliaries for heat rejection	-6.32	
Forced fans	-3.50	
Induced fan	-9.60	
Pulverizers and coal handling	-3.33	
Precipitators and ash handling	-1.89	
FGD auxiliaries	-3.32	
Total auxiliary consumption	-60.6	-65.0
Net power output, MW_e	758.64	754.0
Fuel input LHV, MW_{th}	1676.55	1657.1
Boiler LHV efficiency, %	94.5	N/A
Gross LHV efficiency, %	51.38	52.27
Net LHV efficiency, %	45.25	45.5
Specific CO_2 emission, kg/MWh	768	763

Table 2.11 – Stream flows, conditions and compositions in the CAESAR ASC test case												
Stream n°	Mass flow	T	P	x	Composition %v/v, wet							
	kg/s	°C	bara		H2	CO	CO_2	N_2	O_2	Ar	SO2	H_2O
Coal	66.609	15										
1	686.62	15	1.01					77.8	20.6			1.6
2	497.13	620	60									100
3	607.43	600	270									100
4	497.13	364.6	64.0									100
5	607.43	306.1	320									100
6	753.23	350.0	0.99				14.9	75	2.9		0.04	7.2
7	732.42	120.0	0.98				14.9	75	2.9		0.04	7.2

Main results of CO_2 capture section simulations are summarized in Table 2.12. Regeneration energy requirement is equal to the one in the CESAR case. About other electrical and thermal requirements there is no significant difference and, for brevity, they are not reported here.

Compared to CESAR results, the calculated net electrical efficiency is almost the same. About the efficiency penalty, it is slightly lower, mainly because of the CO_2 compressor efficiency difference.

Table 2.12 – Main results of the CO_2 capture section		
Parameter	**Unit**	
Removal efficiency	%	90.43
Flue gas flow rate	kg/s	781.8
CO_2 feed content	mol. %	13.73
CO_2 captured	tonne/hr	523.3
Solvent Concentration	wt-%	30
Lean solvent flow rate	m^3/s	3.27
Solvent specific demand	m^3/t_{CO2}	22.5
CO_2 rich loading	mol_{CO2}/mol_{MEA}	0.4810
CO_2 lean loading	mol_{CO2}/mol_{MEA}	0.2637
Net cyclic loading	mol_{CO2}/mol_{MEA}	0.2173
Regeneration energy requirement	MWth	542
Regeneration energy specific requirement	GJ/t_{CO2}	3.7
Overall plant power balances		
Steam turbine gross power output	MW	686.9
Steam cycle auxiliares	MW	57.1
Capture section	MW	67.4
Blower		8.5
Pumps		14.2
CO_2 Compressor		44.8
Net Power Output	MW	562.4
Thermal power	MW	1676.6
Net electric efficiency	%	33.5
CO_2 specific emissions	kg_{CO2}/MWh	104
CO_2 avoided	%	86.5
Efficiency penalty	%	11.7
SPECCA	MJ/kg_{CO2}	4.16

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3 INTEGRATED GASIFICATION COMBINED CYCLE – IGCC

3.1 Introduction to the IGCC Test Case

This document presents the test case for an IGCC plant, with and without CO_2 capture. The design basis and assumptions are mainly from the EBTF report Common Framework Definition Document [1]. All calculations in this section of the report have been carried out using a combination of Aspen HYSYS and Thermoflow GT Pro.

In choosing technologies for the test case, attempt has been made to choose standard technologies with sufficient references in the open literature. The test case without CO_2 capture is an IGCC plant using a Shell gasifier with flue gas recycle and Selexol for sulphur removal. The test case with CO_2 capture also uses the same gasifier and Selexol for sulphur and CO_2 removal.

3.2 IGCC Test Case without Capture

3.2.1 Case Description and Flow Diagram

A simplified flow diagram of the cycle without capture is given in Fig. 3.1. A detailed flow diagram of the processes of air separation, coal gasification and gas cleaning is shown in Fig. 3.2 and a detailed flow diagram of the power island is given in Fig. 3.3. Details of the process are provided in Section 3.3.

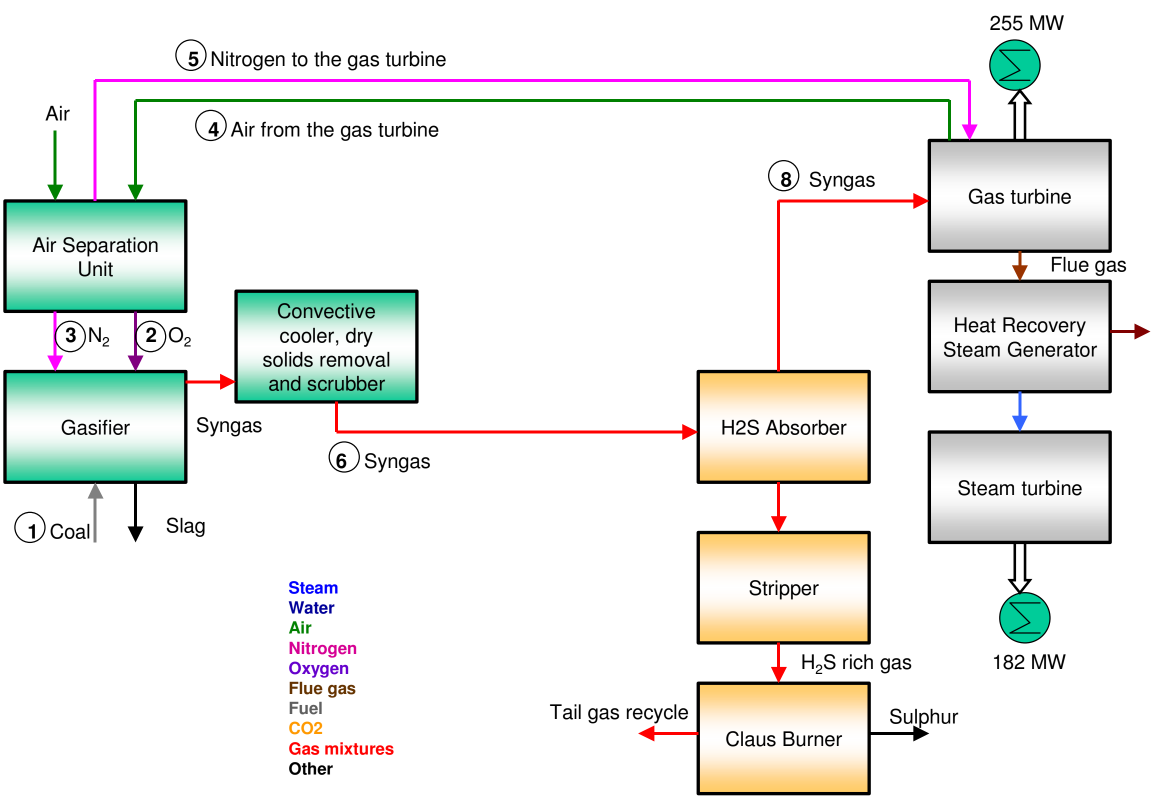

Fig. 3.1 – Simplified flow diagram of the Integrated Gasification Combined Cycle without capture

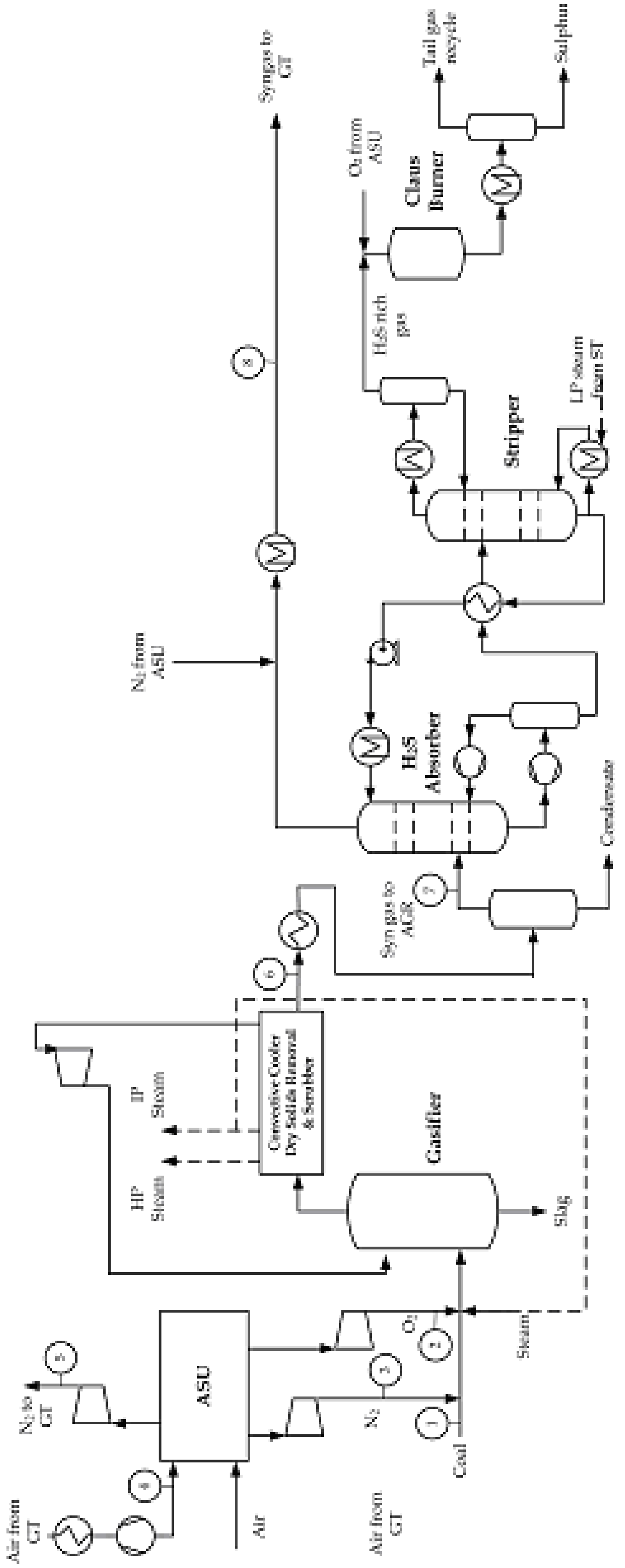

Fig. 3.2 – Detailed flow diagram of the processes of gasification, air separation and gas cleaning

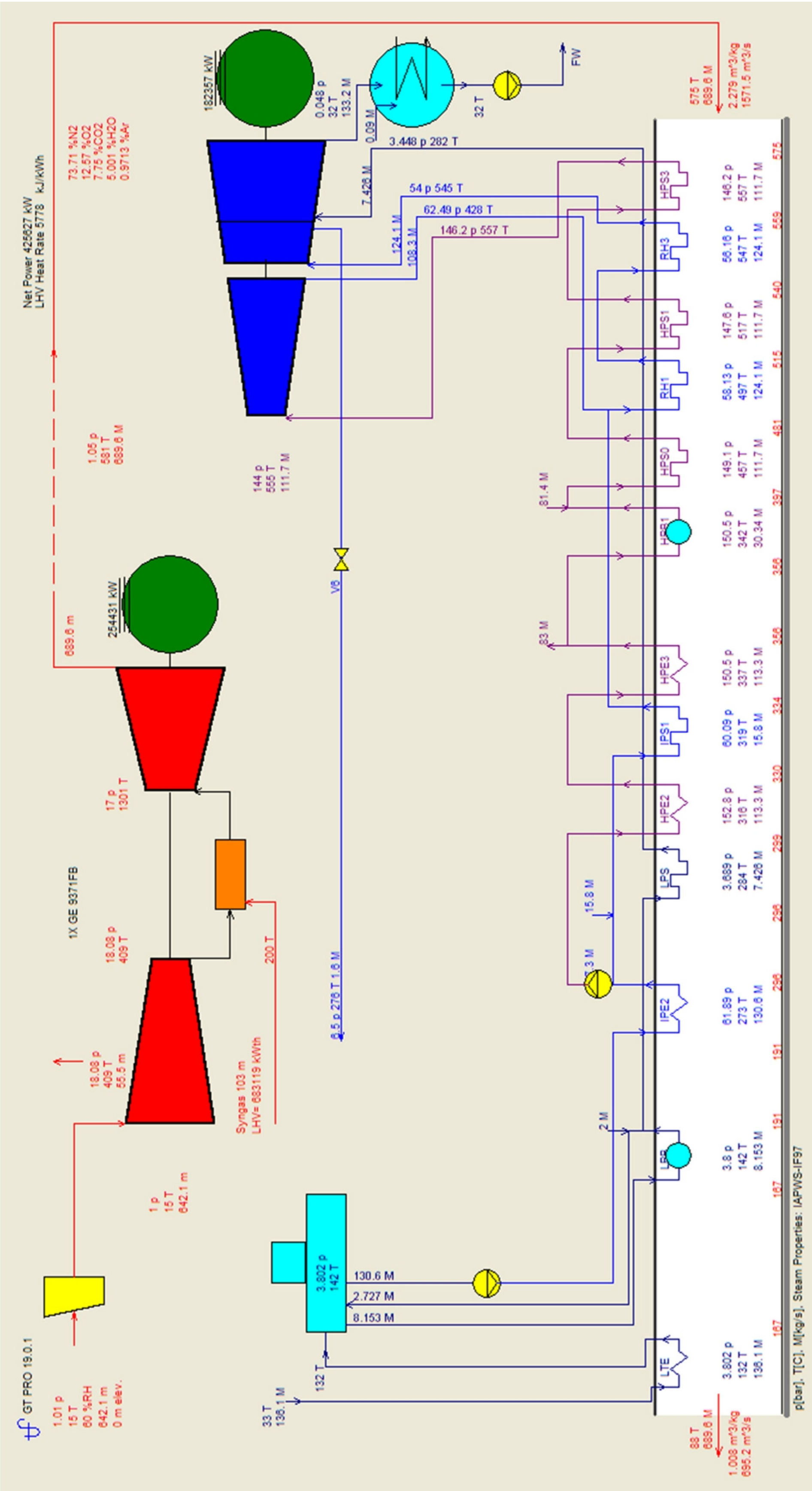

Fig. 3.3 – Detailed flow diagram of the power island

3.2.2 Stream Table

Stream data for important key streams in the test case without capture is given in Table 3.1. Please refer to the process flow diagrams for the stream numbers. The power island is modelled in GTPro.

Table 3.1 – Stream data of the IGCC test case without capture (referred to Figs. 3.1, 3.2 and 3.3)

Stream n^o	Mass flow	Molar flow	T	P	x	Composition mol %							
	kg/s	Kmol/s	°C	bar		H2	CO	CO_2	N_2	O_2	Ar	H_2S	H_2O
1	32.67		Amb	Amb		-	-	-	-	-		-	-
2	26.54	0.83	35	48		-	-	-	2.00	95.0	3.00	-	-
3	7.21	0.26	80	88		-	-	-	99.90	0.10	-	-	-
4	55.54	1.93	45	9.8		-	-	0.04	77.30	20.74	0.92	-	1.01
5	39.49	1.41	144.1	36		-	-	-	99.90	0.10	-	-	-
6	75.26	3.56	170	41		22.02	49.23	3.45	5.77	-	1.20	0.13	18.13
7	63.75	2.92	40	38		26.84	60.00	4.20	7.31	-	1.18	0.16	0.26
8	106.00	4.49	200	35.2		17.45	39.00	2.70	36.15	-	0.77	-	3.91

3.2.3 Operational Characteristics

3.2.3.1 Gasifier

An entrained flow gasifier from Shell with syngas recycle is chosen as the gasifier in the process. The gasification pressure is set at 44 bar and the gasification temperature at 1550 °C. The results for the gasification island in the test case are based on the information package from Shell dated 21.04.2009 for DECARBit.

3.2.3.2 Air Separation Unit (ASU)

The air separation unit is a cryogenic type operating at 10 bar pressure. The air inlet to the ASU is 50% integrated with the gas turbine – i.e. 50% of the air inlet to the ASU comes from the gas turbine. Oxygen is available at 2.6 bar and 20 °C from the ASU.

3.2.3.3 Gas Turbine

The gas turbine is an F class type and is descibed in the EBTF Common Framework Document [1]. The fuel supply temperature is 200 °C. Air is extracted from the compressor exit of the gas turbine to feed 50% of the air input to the cryogenic ASU.

3.2.3.4 Steam Turbine and Heat Recovery Steam Generator (HRSG)

The HRSG and steam turbine cycle is a 3 pressure cycle with reheat.

3.2.3.5 Acid Gas Removal (AGR) and Sulphur Recovery Unit (SRU)

A single stage Selexol process is selected as the AGR. Selexol is a mixture of dimethyl ethers of polyethylene glycol and has the formulation $CH_3(CH_2CH_2O)_nCH_3$ where n is between 3 and 9. The

H_2S is sent to the Claus plant, where the flue gas is recycled. The solvent is regenerated at the reboiler, heated with steam to a temperature of about 150 °C. The heat requirement for the reboiler is 5.82 kWh/kg H_2S and the power consumption for pumps etc. in the AGR is 538.2 kWh/ton H_2S.

3.2.4 Operational Performance

The overall plant performance for the test case is given below:

Table 3.2 – Operational performance		
Coal flow rate	Tph	118.43
Coal LHV	MJ/kg	25.17
Thermal Energy of Fuel (LHV)	**MWth**	**828.02**
Thermal Energy for Coal drying	**MWth**	**7.01**
Gas turbine output	MWe	254.42
Steam turbine output	MWe	182.36
Air expander	MWe	4.96
Gross electric power output	**MWe**	**441.73**
ASU power consumption	MWe	10.30
Syngas compression	MWe	0.92
O_2 compression	MWe	10.08
N_2 to gasifier compression	MWe	4.71
N_2 to GT compression	MWe	13.18
AGR	MWe	0.30
Power island aux.	MWe	8.98
Coal handling	MWe	1.24
Other	MWe	0.58
Total ancillary power consumption	**MWe**	**50.29**
Net electric power output	**MWe**	**391.45**
Net electric efficiency	**%**	**46.88**
Specific emissions	**kg/MWh**	**734.04**

3.3 IGCC Test Case with Capture

3.3.1 Case Description and Flow Diagram

A simplified flow diagram of the IGCC cycle with capture is shown in Fig. 3.4. The detailed diagram of the processes of air separation, coal gasification and gas shifting is shown in Fig. 3.5, the detailed diagram of the gas cleaning processes is shown in Fig. 3.6 and the detailed diagram of the power island is given in Fig. 3.7.

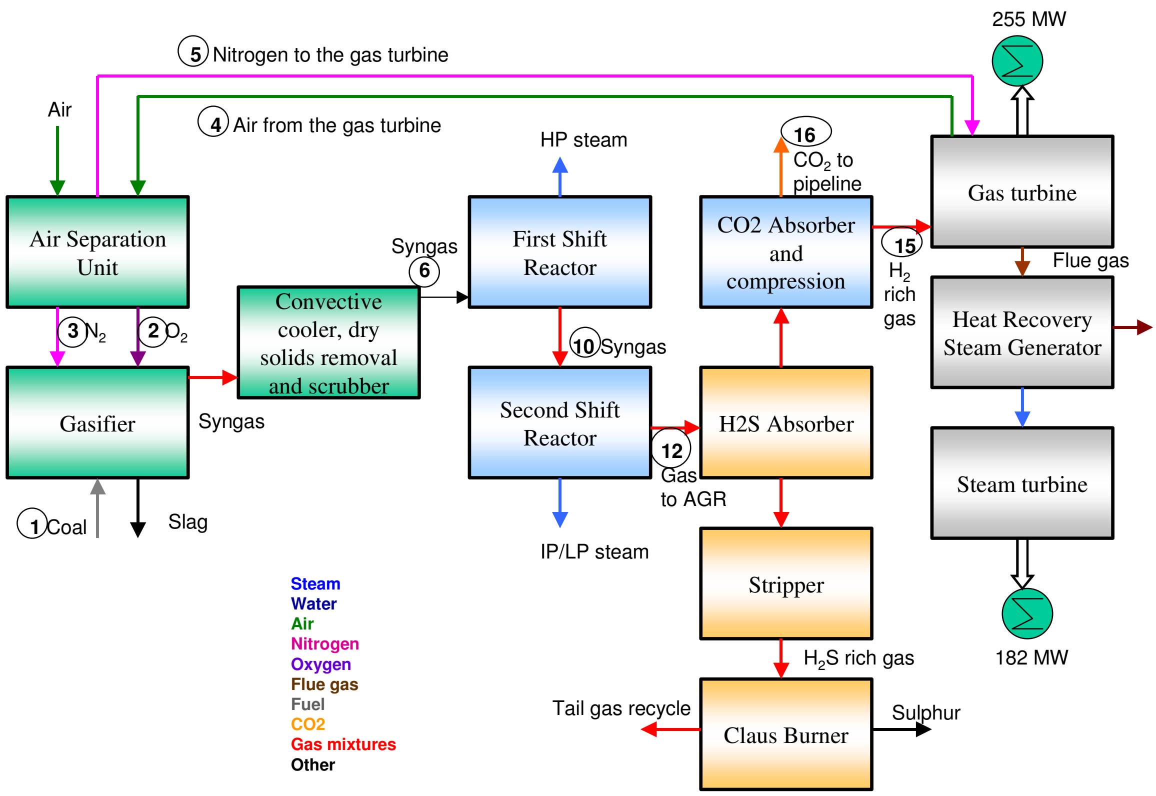

Fig. 3.4 – Simplified flow diagram of the IGCC test case with capture

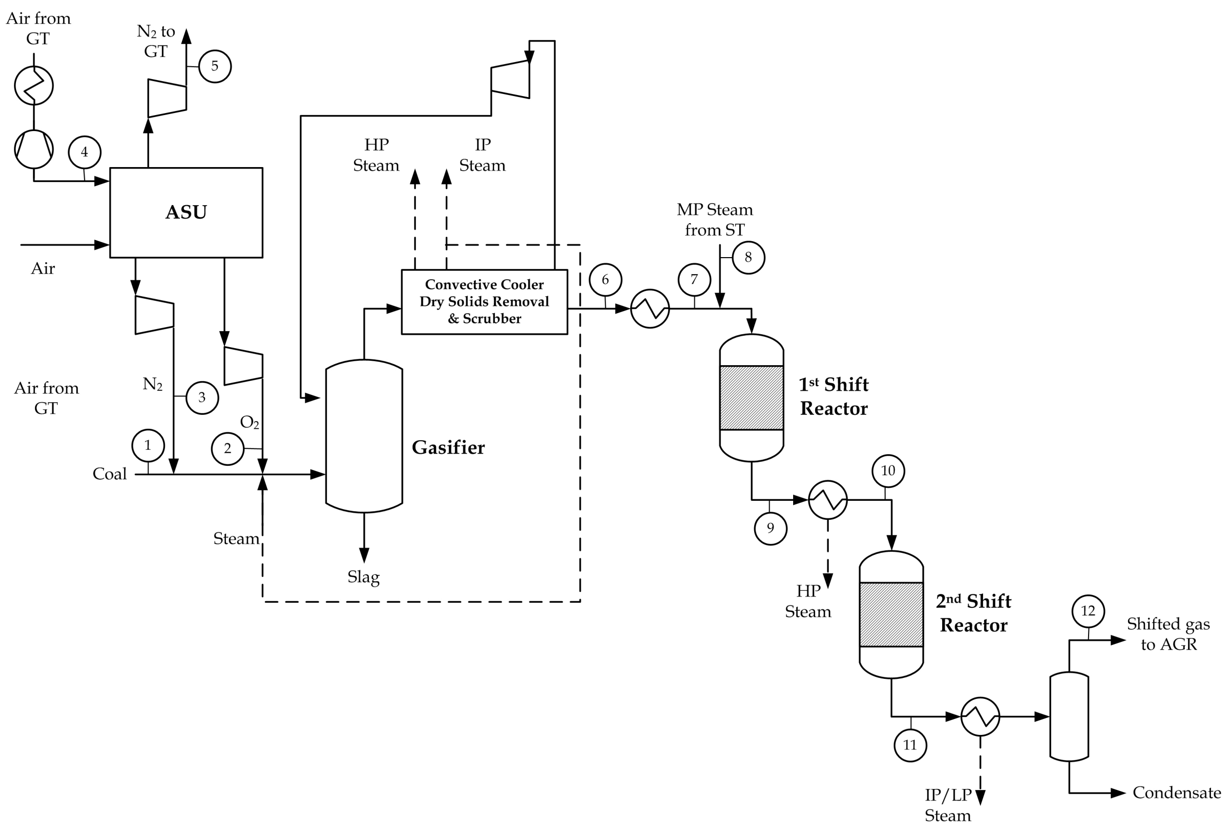

Fig. 3.5 – Detailed flow diagram of the processes of air separation, coal gasification and gas shifting

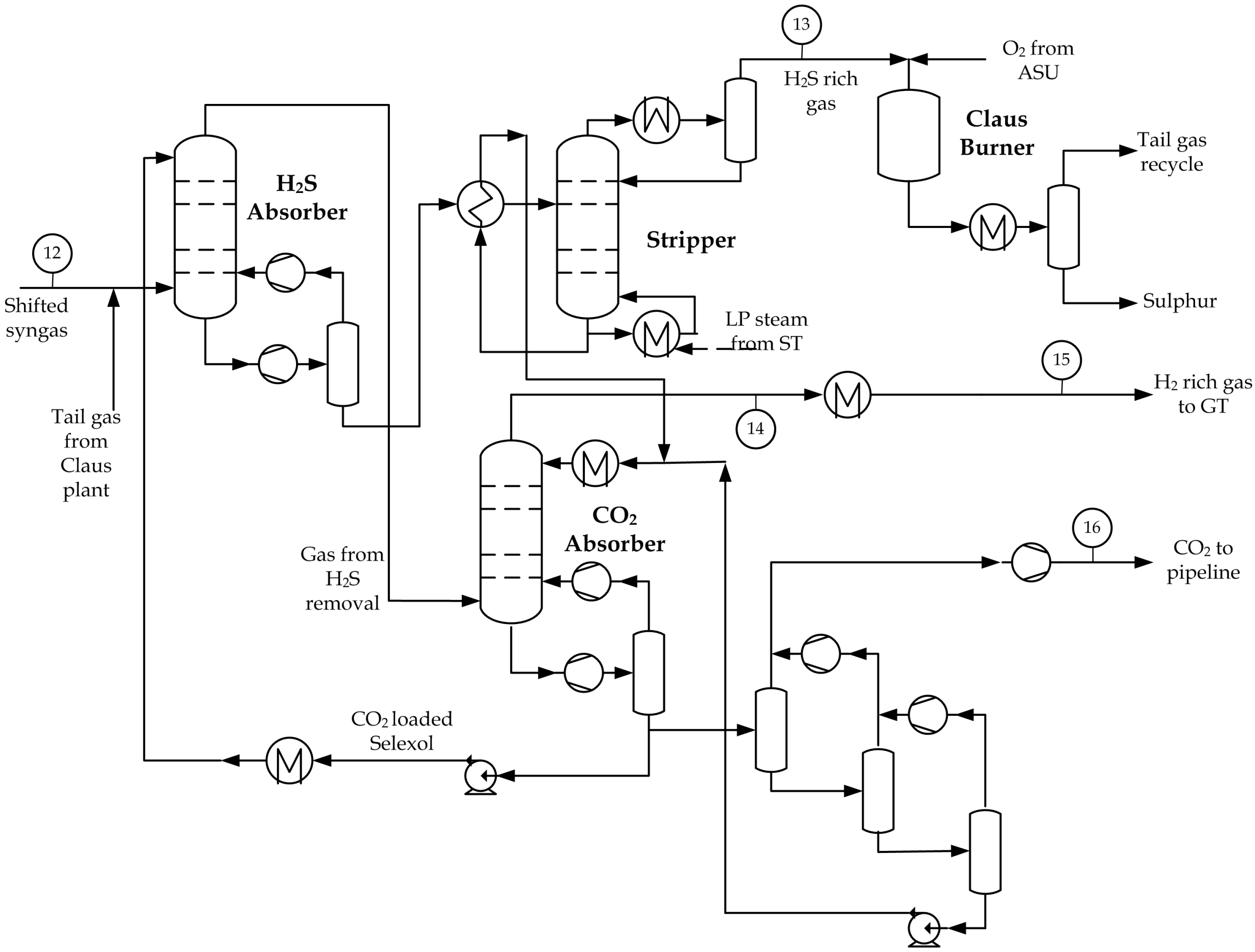

Fig. 3.6 – Detailed flow diagram of the processes of gas cleaning and CO_2 separation and compression

3.3.2 Stream Table

The stream data for important key streams in the test case with capture is given in Table 3.3, referred to the stream numbers of Figs. 3.4 to 3.7. The power island is modelled in GTPro and the cycle flow schematic given in Fig. 3.7 includes stream information.

3.3.3 Operational Characteristics

Most process units and their operational characteristics are similar to those of the IGCC case without CO_2 capture. The IGCC test case with CO_2 capture includes shift reactors for converting carbon monoxide to carbon dioxide and the AGR unit includes a CO_2 capture section.

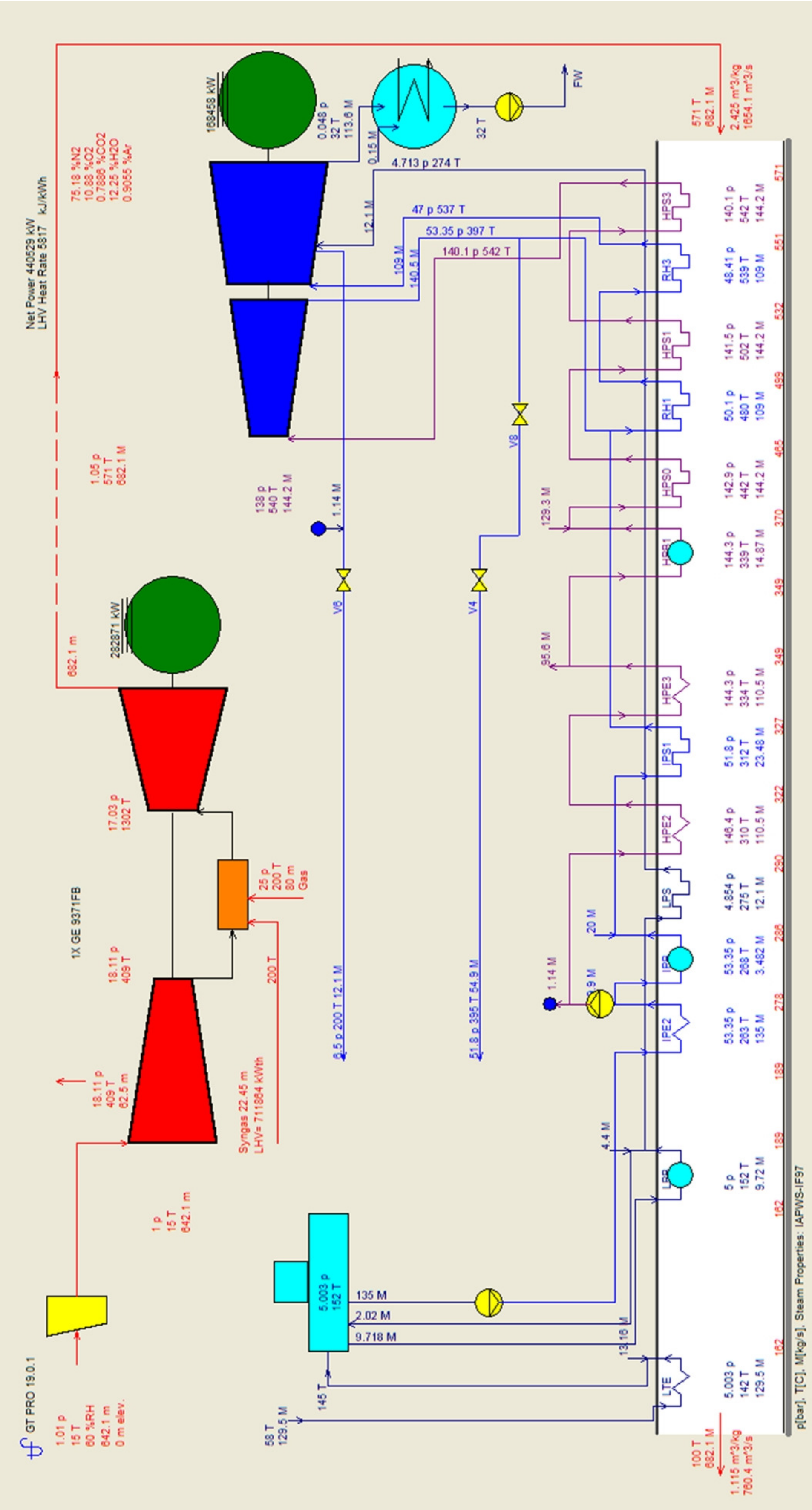

Fig. 3.7 – Detailed flow diagram of the power island

Table 3.3 – Stream data of the IGCC test case with capture (referred to Figs. 3.4 to 3.7)												
Stream n°	Mass flow	Molar flow	T	P	Composition mol %							
	kg/s	Kmol/s	°C	bar	H2	CO	CO_2	N_2	O_2	Ar	H_2S	H_2O
1	38.72		Amb	Amb	-	-	-	-	-		-	-
2	31.45	0.98	35	48	-	-	-	2.00	95.0	3.00	-	-
3	8.55	0.31	80	88	-	-	-	99.90	0.10	-	-	-
4	64.99	2.25	45	9.8	-	-	0.03	77.30	20.74	0.92	-	1.01
5	80	2.86	200	36	-	-	-	99.90	0.10	-	-	-
6	89.21	4.22	170	41	22.02	49.23	3.45	5.77	-	1.20	0.13	18.13
7	89.21	4.22	300	40.7	22.02	49.23	3.45	5.77	-	1.20	0.13	18.13
8	57.72	3.21	395	51	-	-	-	-	-	-	-	100.0
9	146.93	7.42	519.7	39.7	34.19	6.31	23.63	3.41	-	0.55	0.07	31.81
10	146.93	7.42	250	38.1	34.19	6.31	23.63	3.41	-	0.55	0.07	31.81
11	146.93	7.42	304.2	37.6	39.27	1.22	28.72	3.41	-	0.55	0.07	26.72
12	111.04	5.44	35	36.2	53.57	1.67	39.03	4.65	-	0.75	0.1	0.21
13	1.52	0.04	30	4.8	-	0.05	62.21	0.72	-	0.28	36.23	0.51
14	21.70	3.38	1	33.9	85.64	2.66	3.20	7.27	-	1.14	0	0.05
15	21.70	3.38	200	33.2	85.64	2.66	3.20	7.27	-	1.14	0	0.05
16			30	110	0.90	0.03	98.19	0.63	-	0.11	0	0.16

3.3.3.1 Shift Reactors

The shift reactors are used to concentrate the carbon chemical species in the syngas in the form of CO_2 that can be later removed from the gas by physical absorption and produce extra H_2. The shift reaction is accomplished using a "sour shift" or "dirty shift" of CO from the raw gas using two catalytic beds operating at 300 °C and 250 °C respectively. The steam to CO ratio in the first reactor is set to 1.9 and gives a CO conversion around 96%. The pressure drops in both catalytic beds are 1 bar. The shift conversion heat is used to raise HP, MP and LP steam, and preheat streams.

3.3.3.2 Acid Gas Removal (AGR) and Sulphur Recovery Unit (SRU)

The AGR system utilises a two stage Selexol process for CO_2 and H_2S removal. Selexol is a mixture of dimethyl ethers of polyethylene glycol and has the formulation of $CH_3(CH_2CH_2O)_nCH_3$ where n is between 3 and 9. The H_2S is sent to the Claus plant, where the flue gas is recycled. The CO_2 is then captured from the sulphur free syngas.

The Selexol solvent is regenerated by flashing at three different pressures (5, 2.3 and 1.05 bar) and recycled back to absorption stage. CO_2 is compressed to 110 bar and sent through a pipeline to the storage sites.

For capture of the CO_2 the Selexol solvent must be refrigerated to 5°C, but for the H_2S the solvent is regenerated, heated by steam to a temperature of about 150 °C.

The overall power consumption in the AGR is 52.4 kWh/ton CO_2 of which 21.28 kWh/ton CO_2 is for refrigeration and 29.55 kWh/ton CO_2 is for solvent pumping. The heat requirement for the reboiler in the AGR is 84.18 kWh/ton CO_2.

3.3.4 Operational Performance

Table 3.4 – Operational performance		
Coal flow rate	Tph	136.46
Coal LHV	MJ/kg	25.17
Thermal Energy of Fuel (LHV)	**MWth**	**954.08**
Thermal Energy for Coal drying	**MWth**	**8.10**
Gas turbine output	MWe	282.87
Steam turbine output	MWe	168.46
Air expander	MWe	5.84
Gross electric power output	**MWe**	**457.17**
ASU power consumption	MWe	12.13
O_2 compression	MWe	11.61
N_2 to gasifier compression	MWe	5.11
N_2 to GT compression	MWe	27.82
Syngas compression	MWe	1.10
CO_2 capture	MWe	15.11
CO_2 compression	MWe	20.69
Power island aux.	MWe	8.63
Coal handling	MWe	1.43
Other	MWe	0.80
Total ancillary power consumption	**MWe**	**104.43**
Net electric power output	**MWe**	**352.74**
Net electric efficiency	**%**	**36.66**
CO_2 capture rate	**%**	**90.90**
Specific emissions	**kg/MWh**	**85.28**
SPECCA	MJ_{LHV}/kg_{CO2}	**3.30**

3.4 Comparison of results found by DECARBit and CAESAR

This section is dedicated to the comparison between the results obtained by the CAESAR gasification model given by the GS code and those obtained by the DECARBit model. Since there were significant performance differences, mostly related to the different operating conditions assumed for the GT, the CAESAR model of the test case without capture has been set with all the DECARBit assumptions as follows:

- Combustor outlet temperature = 1300 °C
- Air Separation Unit column pressure = 10 bar
- N_2 and O_2 available at 2.6 bar
- Pressure losses at the gas turbine combustor = 1 bar
- Balance of plant auxiliaries 10.2 MW

- Mass flow of coal as received = 32.7 kg/s
- Same N_2 sent to GT combustor
- RH pressure losses = 12%
- Heat recovery steam generator stack outlet temperature = 88°C

As shown in the first two columns of Table 3.5, the performances and the efficiency calculated are similar, if the assumptions are the same. There is a small difference in the ASU power consumption: the CAESAR model simulates it through the air compressor work as suggested by Air Products. The higher power consumption in the power island is related to the higher amount of nitrogen adopted for dilution, thus moving compression power from the GT to the N_2 compressor. A significant difference is in the power island auxiliaries, but because they are not explicitly reported it is difficult to identify the difference. With the same Power island auxiliaries, the efficiency difference between DECARBIT and CAESAR cases would be less than 0.1% points.

Table 3.5 – Comparison of DECARBit IGCC test case and CAESAR test case with and without DECARBit assumptions.

		DECARBit	GS simulation with DECARBit COT =1300°C	GS CAESAR test case TIT=1360 °C
Coal flow rate (*as received*)	kg/s	32.89	32.89	35.05
Coal LHV	MJ/kg	25.17	25.17	25.17
Thermal Energy of Fuel (LHV)	**MWth**	**828.02**	**829.03**	**883.3**
Thermal Energy for Coal drying	**MWth**	**7.01**	**7.24**	**7.71**
Gas turbine output	MWe	254.42	267.35	289.91
Steam turbine electric gross power	MWe	182.36	180.50	193.91
ASU integration air expander	MWe	4.96	5.21	8.47
Gross electric power output	**MWe**	**441.73**	**453.05**	**492.29**
ASU power consumption	MWe	-10.30	-14.98	-11.80
Syngas compression	MWe	-0.92	-0.98	-1.05
O_2 compression	MWe	-10.08	-9.92	-10.73
N_2 to gasifier compression	MWe	-4.71	-4.44	-5.96
N_2 to GT compression	MWe	-13.18	-20.71	-31.94
AGR consumption	MWe	-0.30	-0.35	-0.37
Power island aux.	MWe	-8.98	-3.71	-3.60
Coal handling	MWe	-1.24	-1.55	-1.65
Other	MWe	-0.58	--	--
Total ancillary power consumption	**MWe**	**50.29**	**56.65**	**67.09**
Net electric power output	**MWe**	**391.45**	**396.40**	**425.2**
Net electric efficiency	**%**	**46.88**	**47.36**	**47.68**

Regarding the performances of the IGCC case assumed as reference in CAESAR, the main differences can be explained as:

- Coal flow rate: DECARBit uses the value suggested by Shell in the DECARBit project, while CAESAR assumes a coal flow rate that keeps constant the mass flow out of the GT (i.e. the same geometry and velocity for the GT last stage).
- Gas Turbine performance: a higher net power output was obtained because the GS model, by simulating in detail the turbine coolant flows, allows assuming the same value of TIT used for the NG case.
- Steam turbine gross power: DECARBit achieves higher power with respect to the entering coal flow thanks to the lower stack temperature (88°C against 115°C).

Finally, two IGCC cases with and without carbon capture are presented in Table 3.6. The efficiency penalty calculated for CO_2 capture is equal to 11.2 % points, that's about 1% point higher than the results achieved by DECARBit. The difference is caused by the use of different CO_2 capture section models: the resulting CAESAR consumptions are about 6 MW higher than the DECARBit ones.

Table 3.6 – Cases with and without capture (calculated under CAESAR assumptions – 3rd column of Table 3.5)

	IGCC w/o capture	IGCC Selexol
Gas Turbine output [MW]	289.91	304.95
Steam Cycle Net Power, [MW]	193.91	172.12
ASU integration Air Expander [MW]	8.47	10.12
ASU power consumption [MW]	-10.30	-13.88
O_2 compression [MW]	-10.08	-12.58
Syngas Compression, [MW]	-1.05	-1.23
N_2 to gasifier compression, [MW]	-5.96	-7.18
N_2 to GT compression, [MW]	-31.94	-23.91
AGR consumption, [MW]	-0.37	-19.24
Coal handling, [MW]	-1.65	-1.92
CO_2 compressor, [MW]	N/A	-22.86
Heat rejection auxiliaries, [MW]	-2.40	-2.38
Other Auxiliaries, [MW]	-1.20	-1.88
Net power Output, [MW]	425.20	383.14
Thermal power input, [MW]	883.30	1039.8
Thermal power input for coal drying, [MW]	7.71	9.07
Net Electric Efficiency, [%]	47.68	36.52
Electric Efficiency Penalty,[% points]	N/A	-11.16
Cold Gas Efficiency @ combustor [%]	82.54	74.03
Cold Gas Efficiency post scrubber	82.86	80.12
Emissions [kg_{CO2}/MWh_{el}]	721.4	89.32
CO_2 avoided, [%]	N/A	87.6
SPECCA [MJ_{LHV}/kg_{CO2}]	N/A	3.66

4 NATURAL GAS COMBINED CYCLE – NGCC

4.1 Introduction to the NGCC Test Case

This chapter defines the test case for electricity production from natural gas. The configuration studied here was proposed by CAESAR and is one of possible configurations for a natural gas power plant. Two reference power plants, without and with carbon capture respectively, are proposed to address the efficiency, the power output and the cost penalties related to carbon capture. The technology selected is representative of the present state-of- the-art of large-scale power plants for base-load electricity production without carbon capture.

The reference case adopted for power plant equipped with carbon capture is a NGCC with post-combustion chemical absorption; in particular MEA sorbent is selected. This choice is driven by the simpler integration into the power cycle, (i.e. gas turbine is not modified), and higher reliability than that of other carbon capture routes, as pre-combustion decarbonisation.

It has been chosen to: (i) select large-scale, base-load power plants, representative of the current state-of-the-art, (ii) calculate the performance (in terms of power output, efficiency, specific emissions) for each of these plants under a set of consistent and comprehensive hypotheses, and (iii) present detailed results of the calculations, including energy and mass balances, that could be used as a reference for future simulations. All calculations presented in this report have been carried out by the code GS, developed by the Department of Energy of the Politecnico di Milano. The code is capable to evaluate detailed energy and mass balances of an almost infinite variety of plant schemes. The same code is used to compute performance of all the innovative plant schemes investigated under the CAESAR project, in order to obtain a consistent comparison among the various proposals.

4.2 NGCC Test Case without Capture

4.2.1 Case description and flow diagram

The selected reference NGCC for electricity production without carbon capture is based on two large-scale identical gas turbines, “F class”, following the generic model specified in the EBTF Common Framework Definition Document [1]. Each one is equipped with a heat recovery steam generator (HRSG). A single steam turbine is fed by the two HRSGs. A simplified flow diagram is shown in Fig. 4.1 and a detailed plant layout is shown in Fig.4.2.

The HRSG is a three pressure level + reheat type. Before feeding the gas turbine combustor, natural gas is preheated up to 160°C by means of feed-water extracted from IP drum, with a benefit for the overall plant efficiency. The fuel rate to the combustor is set to keep the same TIT of the case without natural gas preheating.

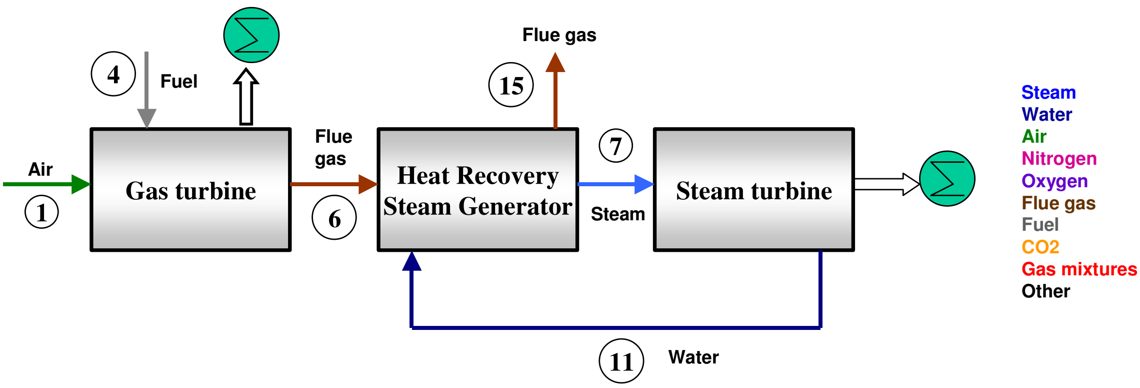

Fig. 4.1 – Simplified flow diagram of the NGCC case without capture

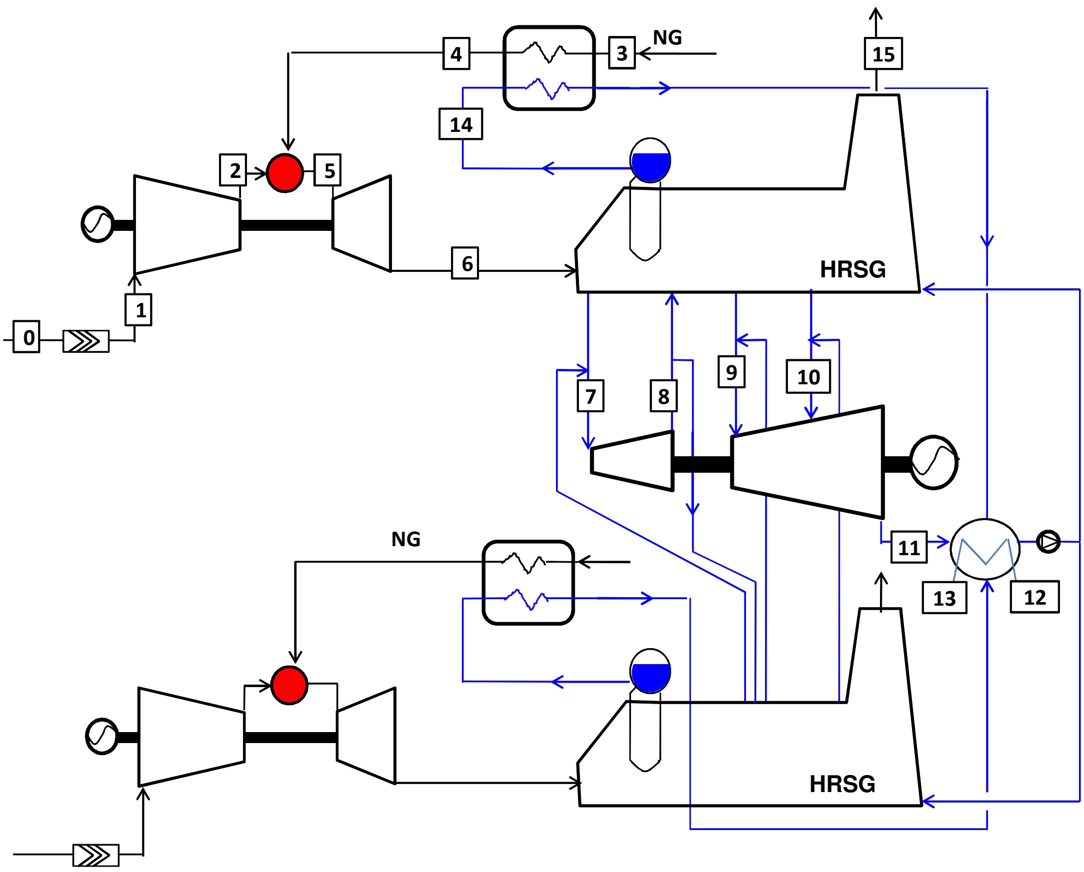

Fig. 4.2 – Detailed flow diagram of the NGCC test case without capture

4.2.2 Stream Table

Table 4.1 - Mass flow rate, temperature, pressure, and composition of the main fluxes of NGCC test case plant (Numbers refer to Figures 4.1 and 4.2)										
Point	G	T	P	x	Composition, %mol.					
	[kg/s]	[°C]	[Bar]		Ar	N_2	O_2	CO_2	H_2O	NO_x
0	650.0	15.0	1.01	--	Air- See EBTF common framework (Table 1)					
1	650.0	15.0	1.00	--						
2	523.4	417.5	18.16	--						
3	15.3	10.0	70.0	--	NG - See EBTF common framework (Table 6)					
4	15.3	160.0	70.0	--						
5	538.7	COT 1443.3	17.6	--	0.88	73.71	10.47	4.87	10.07	$1.4 \cdot 10^{-3}$[1]
		TIT 1360.0	-	-	-	-	-	-	-	-
	665.3	TIT_{iso} 1265.7	-	-	0.89	74.38	12.39	3.96	8.38	$1.4 \cdot 10^{-3}$
6	665.3	608.0	1.04	--	0.89	74.38	12.39	3.96	8.38	$1.4 \cdot 10^{-3}$
7	153.7	559.5	120.9	1	-	-	-	-	100.	-
8	153.7	337.7	28.0	1	-	-	-	-	100.	-
9	185.0	561.0	22.96	1	-	-	-	-	100.	-
10	20.9	299.0	3.52	1	-	-	-	-	100.	-
11	205.9	32.2	.048	0.93	-	-	-	-	100.	-
12	111.7	19.2	1.01	0	-	-	-	-	100.	-
13	111.7	29.2	1.01	0	-	-	-	-	100.	-
14	6.84	230.0	28.00	0	-	.	.	.	100.	-
15	665.3	86.8	1.01	--	0.89	74.38	12.39	3.96	8.38	$1.4 \cdot 10^{-3}$
Net Power Output				**829.9**	**MW**	**Net Electric Efficiency**			**58.3**	**%**

4.2.3 Operational Characteristics

Table 4.2 – Operational characteristics			
Assumptions			
Air	ISO Condition (15°C and 1 atm)		
Pressure loss at inlet	1		kPa
Pressure loss at outlet	1		kPa
Pressure ratio	18.1		-
Air flow rate	650.0		kg/s
TIT	1360		°C
Results	Combined cycle	Simple cycle	

[1] This value is equal to 15 ppm (v.d)

Specific work	418.6	423.6	kJ/kg
Net electric efficiency	38.26	38.43	%
Fuel flow rate	15.30		kg/s
COT	1443.3		°C
TOT	608.0	603.5	°C
TOP	1.043	1.023	Bar
η_{Poly} (cooled stages)	92.15		
η_{Poly} (uncooled stages)	93.15		
Amount of cooling flow	121.9		kg/s
% of cooling flow on air at comp inlet	17.7		%
coolant 1st stage unchargeable	54.5		kg/s
coolant 1st stage chargeable	21.6		kg/s
coolant 2nd stage	33.6		kg/s
coolant 3rd stage	12.2		kg/s

The gas turbine efficiency, the specific work and the TOT are consistent with large scale F-class turbines.

4.2.4 Operational performance

Table 4.3 – Operational performance without capture	
N° of gas turbines	2
Gas Turbine [MW]	272.1
Fuel Temperature [°C]	160.0
Steam Cycle Gross Power, [MW]	292.8
Steam Cycle auxiliaries, [MW]	-3.4
Aux. for heat rejection, [MW]	-3.7
Net Power Output, [MW]	829.9
Thermal Power Input$_{LHV}$, [MW]	1422.6
Net Electric Efficiency (LHV base), [%]	58.3
Emissions [kg_{CO2}/MWh_{el}]	351.8

4.3 NGCC Test Case with Capture

4.3.1 Case description and flow diagram

The post-combustion carbon capture consists of CO_2 absorption by chemical absorption with MEA. The pressure in the absorption column is set at 1.1 bar with a booster fan in front of it, in order to support pressure drops and keep GT exhaust pressure equal to conventional NGCC without carbon capture. The CO_2 captured by MEA in the absorption column is released in the stripper, where heat is required for amine regeneration. The latter is supplied by steam extracted from the steam turbine, de-superheated by LP saturated water. The CO_2 released in the stripper column is compressed in an inter-cooled compressor and, after liquefaction at 80 bar, pumped to the delivery pressure fixed at 110 bar.

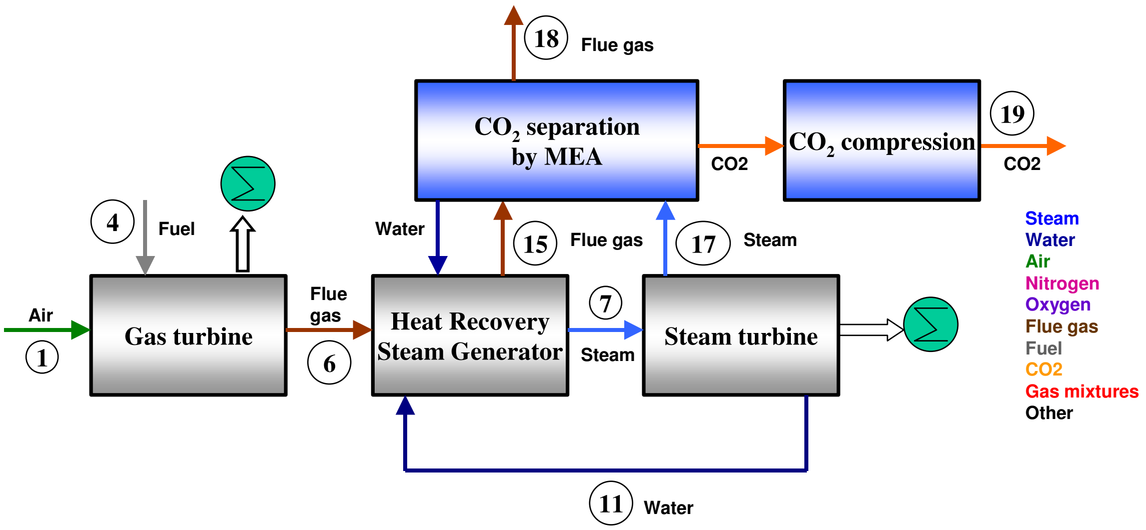

Fig. 4.3 – Simplified flow diagram of the NGCC case with capture

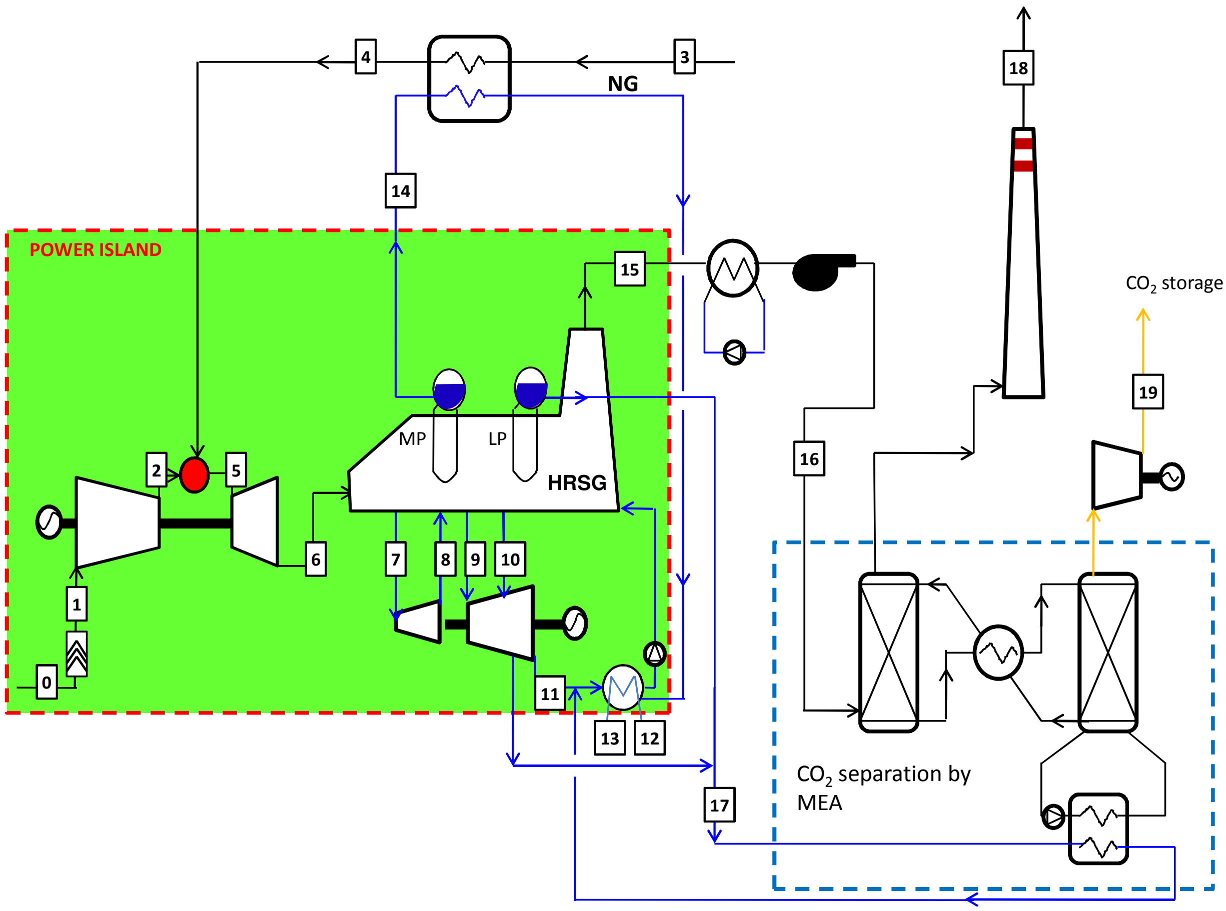

Fig. 4.4 – Detailed flow diagram of the NGCC case with capture

The nominal net output decreases because (i) of the steam required for CO2 regeneration and (ii) of the additional auxiliary power consumption (amine circulation pumps, fans overcoming the gas pressure losses, additional cooling water pumps, CO2 compressor). The amount of energy for regeneration resulting from capture section simulation is 3.95 GJ/tonnCO2. Heat for MEA regeneration is provided with steam at a pressure of 4.0 bar that corresponds to about 1.85 kg of steam every kg of CO_2 captured: steam is bled from the steam turbine at IP-LP cross-over and saturated with water from the LP drum.

4.3.2 Stream table

A summary of the main streams is reported in Table 4.4.

Table 4.4 – Mass flow rate, pressure, temperature and composition of the main fluxes of NGCC reference plant with carbon capture by MEA (Numbers refer to Figure 4.3 and 4.4)										
Point	G	T	P	x	Composition, %mol.					
	kg/s	°C	Bar		Ar	N_2	O_2	CO_2	H_2O	NO_x
0	650.0	15.0	1.01	--	Air - See EBTF common framework (Table 1)					
1	650.0	15.0	1.00	--						
2	523.4	417.5	18.2	--						
3	15.30	10.0	70.0	--	NG - See EBTF common framework (Table 6)					
4	15.30	160.0	70.0	--						
5	538.7	COT 1443.3	17.6	--	0.88	73.71	10.47	4.87	10.08	$1.4\cdot10^{-3}$
		TIT 1360.1								
	665.3	TIT_{iso} 1265.7								
6	665.3	608.0	1.04	--	0.89	74.38	12.39	3.96	8.38	$1.4\cdot10^{-3}$
7	153.7	559.9	120.9	1	-	-	-	-	100.	-
8	153.7	337.7	28.0	1	-	-	-	-	100.	-
9	185.0	561.0	23.0	1	-	-	-	-	100.	-
10	20.7	299.0	3.5	1	-	-	-	-	100.	-
11	90.4	32.2	0.048	0.92	-	-	-	-	100.	-
12	4921	18.2	1.01	0	-	-	-	-	100.	-
13	4921	29.2	1.01	0	-	-	-	-	100.	-
14	6.84	230.0	28.0	0	-	-	-	-	100.	-
15	665.0	101.5	1.01	--	0.89	74.38	12.39	3.96	8.38	$1.4\cdot10^{-3}$
16	659.7	48.7	1.06	--	0.90	75.39	12.56	4.02	7.14	-
17	66.3	154.0	4.0	--	-	-	-	-	100.	-
18	642.4	51.8	1.01		0.89	74.57	12.43	0.38	11.74	
19	36.95	25.0	110.0	0.05	-	0.01	<0.01	99.93	-	-
Net Power Output			**709.9**	**MW**	**Net Electric Efficiency**				**49.9**	**%**

4.3.3 Operational Characteristics

The CO_2 capture section is simulated with ASPEN® adopting RK-SOAVE calculation method. A schematic layout of the carbon capture section simulated in Aspen is reported in Fig. 4.5. In the power plant, there are two absorbers and two stripper lines, one for each HRSG, in order to limit column size and diameter. Nevertheless, it is assumed to adopt only one CO_2 compressor. Exhaust gases are cooled after the HRSG in order to achieve a temperature of 40°C required by the absorber. The absorption and stripper column are simulated, respectively, with 3 and 10 stages at equilibrium of vapour-liquid phase. As shown in Figure 4.5, the MEA loop is broken and a splitter and make-up are introduced on stream from stripper to absorber, but this is just a trick to save computational time. As a matter of fact, in real application, MEA circulates in a closed loop and make-up is necessary only for its degradation process, that's however not simulated here. The operational characteristics are shown in Table 4.5.

Table 4.5 – Operational characteristics of the CO2 capture section	
Mass Flows for each absorber	
Exhaust gases mass flow, kg/s	665.3
CO_2 Captured, kg/s	36.93
Booster Fan	
Pressure ratio	1.1
Isentropic efficiency, %	85
Driver efficiency, %	95
Regenerative Heat exchanger ΔT_{min}, °C	5
Absorption Column	
Column pressure, bar	1.1
Number of stages	3
Stripper Column	
Column pressure, bar	1.8
Number of stages	10
Heat for solvent regeneration, $MJ_{th}/kgCO_2$	3.95
Steam pressure for solvent regeneration, bar	4.0
Absorber and Stripper Pumps	
Head, bar	10
Hydraulic efficiency, %	75
Driver efficiency, %	95
Solution parameter	
Solvent concentration, wt%	30
CO_2 loading rich amine, mol/mol	0.466
CO_2 loading lean amine, mol/mol	0.257
Rich stream regeneration, %	50

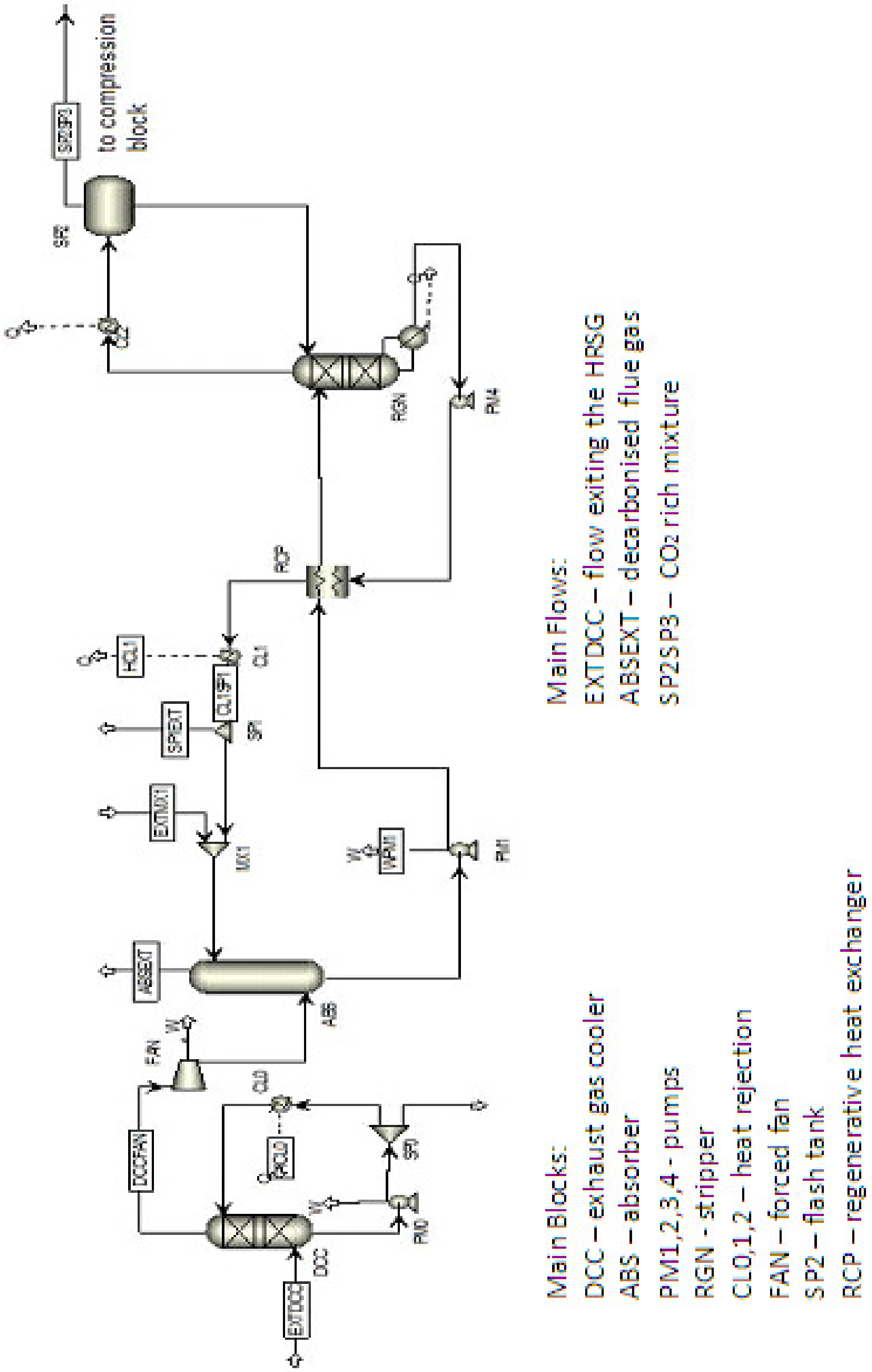

Fig. 4.5 – CO2 capture section

4.3.4 Operational performance

The figures of operational performance of the NGCC with capture are shown in Tables 4.6 and 4.7.

Table 4.6 – Operational performance of NGCC with capture	
	NGCC MEA
N° of gas turbines	2
Gas Turbine [MW]	272.1
Fuel Temperature [°C]	160.0
Steam Cycle Gross Power, [MW]	215.7
Steam Cycle auxiliaries, [MW]	-3.4
CO_2 compressor, [MW]	-22.6
Recirculating pumps [MW]	-4.6
Exhaust gas fans, [MW]	-15.0
Aux. for heat rejection, [MW]	-4.4
BOP capture section [MW]	-0.3
Net Power Output, [MW]	709.7
Thermal Power Input$_{LHV}$, [MW]	1422.6
Net Electric Efficiency (LHV base), [%]	49.9
Emissions [g_{CO2}/kWh_{el}]	36.2
CO_2 avoided, [%]	89.7
SPECCA (MJ_{LHV}/kg_{CO2})	3.30

Table 4.7 – Operational performance of the capture process		
Parameter	**Unit**	
Removal efficiency	%	90.46
Flue gas flow rate	kg/s	665
CO_2 feed content	mol. %	3.961
CO_2 captured	tonne/hr	132.9
Solvent Concentration	wt-%	30
Lean solvent flow rate	m^3/s	0.87
Solvent specific demand	m^3/t_{CO2}	23.5
CO_2 rich loading	mol_{CO2}/mol_{MEA}	0.4655
CO_2 lean loading	mol_{CO2}/mol_{MEA}	0.2573
Net cyclic loading	mol_{CO2}/mol_{MEA}	0.2082
Regeneration energy requirement	MWth	146.0
Regeneration energy specific requirement	GJ/t_{CO2}	3.96

4.4 NGCC 430MW Test Case from CESAR

This section briefly describes the NGCC test case developed within the CESAR project. This case is one of the benchmarking cases used in the CESAR project. The focus is on a newly design power plant with CCS. Possibilities of heat integration are investigated. The focus in this section is on the capture design and requirements estimation. The reader should note that, for internal reasons of the projects, the cases studied by CAESAR and CESAR are different. While two gas turbines and one steam turbine have been considered in CAESAR, one gas turbine and one steam turbine have been considered in CESAR. So, this sub-chapter does not show a comparison but, instead, results for a different configuration from the one dealt with in sub-chapters 4.1-4.3, studied by CAESAR. Also for internal reasons, the gas turbine considered in CESAR does not entirely correspond to the generic gas turbine specified in the Common Framework Definition Document of the EBTF [1].

The reference power plant in the study of this sub-chapter is located inland, assumed 20 meters above sea level. The main equipment, such as gas turbine, steam turbine, generator, HRSG and water treatment is located indoor. Switchyard is included. With respect to the power plant, in this case the main equipment consists of only one gas turbine (Siemens SGT5-4000F) equipped with dry low NOx burners, steam turbine, generator, HRSG and water treatment equipment. Water cooling is done with draft cooling tower. The plant yields 430MWegross. When the auxiliaries are taken into account the net electricity is reduced to 422.5MWenet. CO2 emissions for this case are 354g/kWh (based on net electricity). The overview of heat and mass balances is shown in Table 4.8 and the flue gas composition is given in Table 4.9.

Table 4.8 - Overview of overall heat and mass balance

Parameter	Unit	Value
GT shaft power	**MW**	289.2
ST shaft power	**MW**	145.7
Gross electricity output	**MW**	430.3
Total net power output	**MW**	422.5
HP turbine inlet steam conditions	**bara / °C**	123.8 / 561
IP turbine inlet steam conditions	**bara / °C**	30.1 / 561
LP turbine inlet steam conditions	**bara / °C**	4.2 / 234
Auxiliary power consumption	**%**	1.80
Final feed water temperature	**°C**	33
Fuel flow	**kg/s**	15.0
Net full load plant efficiency	**% LHV**	58.29
CO_2 emissions at full load	**kg/s**	41.54
CO_2 emitted (based on net MWe)	**g/kWh**	354

Table 4.9 - Flue gas composition		
Parameter	**Unit**	**Value**
Gross electricity output	MW	430,3
Flue gas mass flow rate (including moisture)	Kg/s	690.65
Flue Gas Temperature	°C	90.0
Flue Gas Pressure	KPag	
O_2	Vol % wet	12.57
CO_2	Vol % wet	3.88
SO_2	Vol % wet	-
No_x	Vol % wet	
H_2O	Vol % wet	8.20
N_2+Ar	Vol % wet	74.47+0.87

The capture section (depicted in figure 4.6) is similar to the one presented in chapter 2, with the addition of a flue gas cooler to decrease the temperature from 90ºC to 40ºC.

The main operational characteristics of the capture plant are summarized in table 4.10. Table 4.11 shows the thermal and electrical requirements of the capture plant. The electrical output falls due to the thermal energy requirements of the stripper reboiler, ultimately reducing steam available to the LP cylinders and hence reducing gross electrical output. The conditions of the steam going to the reboiler are 134ºC saturated. Steam is extracted from the IP/LP cross over pipe. The auxiliary power consumption is also increased by the compression system, blower and pumps.

Table 4.10 - Specific performance parameters of the capture process		
Parameter	Unit	VALUE
Removal efficiency	%	89
Flue gas flow rate	kg/s	690.65
CO2 feed content	mol. %	3.88%
CO2 captured	tonne/hr	134.07
Solvent Concentration	wt-%	30%
Lean solvent flow rate	m3/s	0.87
Solvent specific demand	m3/tonne CO2	23.41
CO2 rich loading	mol CO2/mol MEA	0.46
CO2 lean loading	mol CO2/mol MEA	0.26
Net cyclic loading	mol CO2/mol MEA	0.209
Regeneration energy requirement	MWth	149
Regeneration energy specific requirement	GJ/tonne CO2	4.01
Cooling water requirement	m3/hr	9864
Cooling water specific requirement	m3/tonne CO2	73.58

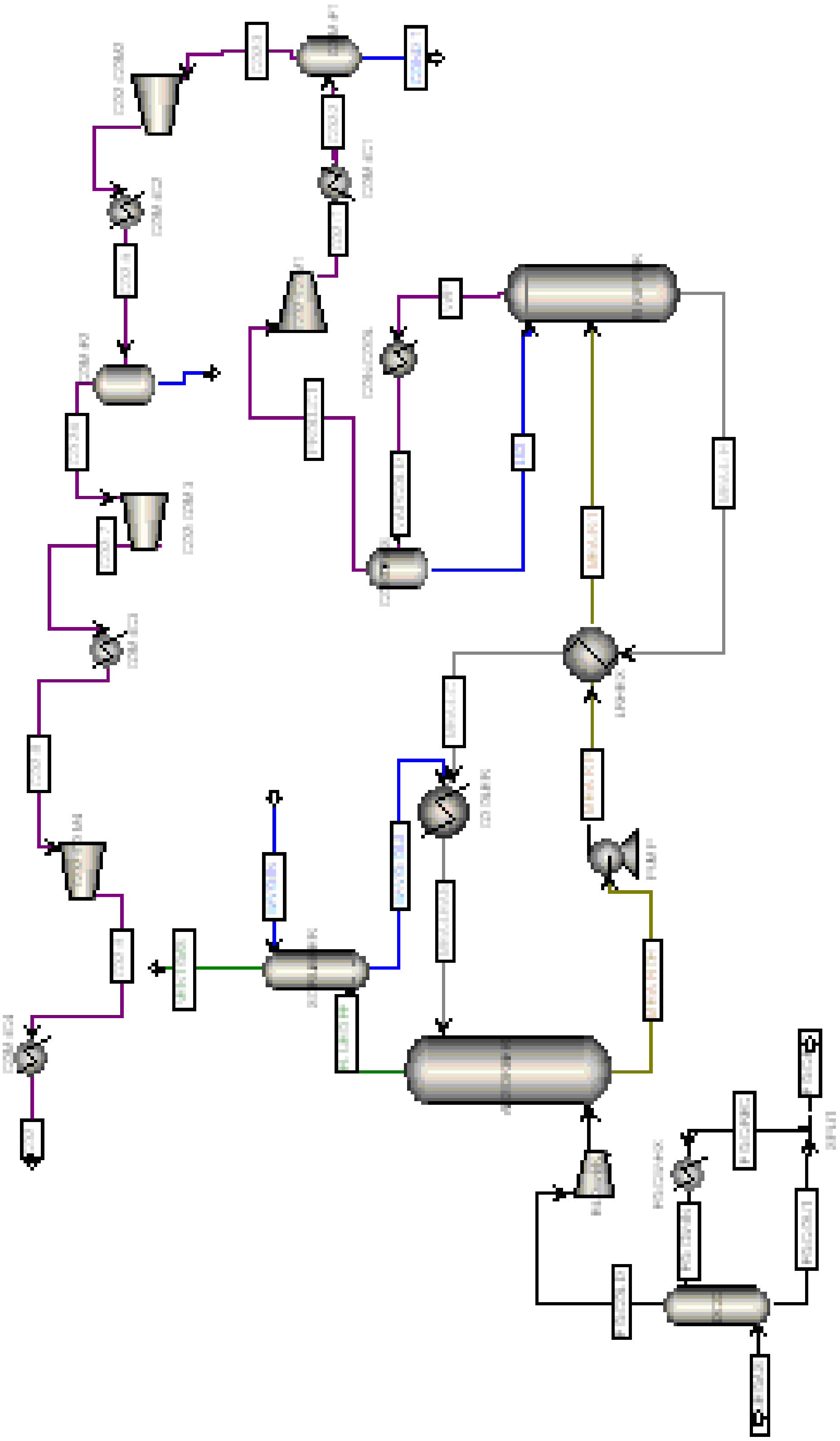

Fig. 4.6 - Process flow sheet for post-combustion capture with MEA 30 wt%

Table 4.11 - Thermal and electrical requirements of the capture plant	
	VALUE
Thermal (MWth)	
Reboiler Heat	149
Stripper Condenser cooling	65
Lean liquid cooling	37
Flue gas cooling	46
Compressor cooling	24
Electric power (MWe)	
Compressors	13
Pumps	3.6
Blower	7.4

Installation of an amine scrubber downstream of the power plant results in a loss in overall plant performance. Based on the thermal requirements shown in Table 4.11, an evaluation of heat integration with the power plant was done. Results are shown in table 4.12.

Table 4.12 – Comparison of cases with and without capture

PARAMETER	UNIT	Without capture	With capture
Gross electricity output	MWe	430.3	388.3
Auxiliary power consumption	MWe	7.7	31.5
Net electricity	MWe	422.5	356.8
Efficiency	%	58.29	48.3
CO2 Emitted	Kg/MWh	354	41.9
SPECCA	MJ/kg_{CO2}	N/A	3.61

5 SUMMARY AND CONCLUSIONS

Chapters 2, 3 and 4 of this report have shown the analysis of three test cases, each one by two of the three projects CAESAR, CESAR and DECARBit. A summary of the results of the three cases, obtained by the three projects, is shown in tables 6.1 to 6.3. In general, the agreement reached by the projects in the main results of these three cases is very good, considering that not only different teams have worked on the calculations but also that these teams have used different computer codes, often involving different models of processes and equipment. In particular, the efficiencies obtained for each case are in remarkable agreement. The work carried out by the European Benchmarking Task Force has achieved its objective in showing that similar results can be reached by different teams with different resources from a similar set of assumptions and parameters. In the work of the EBTF, such set of assumptions and parameters has been mostly presented in [1]. A minor set of assumptions and parameters is explicitly described in some sections of this report.

Table 6.1 gives results for the ASC test case. The high similarity of the parameters and assumptions considered in the two projects has led to a remarkably high similarity of results. The gross electricity productions and the efficiencies are practically the same in the two projects. Also the emissions in the cases without capture are practically the same.

Table 6.1 - Advanced Supercritical Pulverized Coal - ASC				
	CESAR		**CAESAR**	
	Without capture	With capture	Without capture	With capture
Gross electricity output (MWe)	819	684.2	819.2	686.9
Net electric efficiency (%LHV)	45.5	33.4	45.25	33.5
CO_2 emitted (kg/MWh)	763.0	104.7	762.8	104.0
CO_2 avoided (%)		86.3		86.5
SPECCA (MJ/kgCO2)		4.35		4.16

Table 6.2 shows results for the IGCC test case. The numbers from CAESAR shown in the table have been obtained under some assumptions defined in the CAESAR project, not the same as the corresponding ones defined in DECARBit. The consequence is that the gross electricity output is not in as good an agreement as the other results for the case. In chapter 3, however, results obtained by the CAESAR team with the same assumptions of DECARBit have also been included, leading to a better general agreement of results.

Table 6.2 – Integrated Gasification Combined Cycle – IGCC				
	DECARBit		CAESAR	
	Without capture	With capture	Without capture	With capture
Gross electricity output (MWe)	441.73	457.17	492.29	468.6
Net electric efficiency (%LHV)	46.88	36.66	47.36	36.52
CO_2 emitted (kg/MWh)	734.04	85.28	721.4	78.28
CO_2 avoided (%)		88.4		89.2
SPECCA (MJ/kgCO2)		3.30		3.51

For the results shown in Table 6.3, different plant configurations have been considered by CESAR and CAESAR. The gross electricity output is hugely different but easily explained. The efficiencies, specific emissions and CO2 removal percentages are, nevertheless, in very good agreement.

Table 6.3 – Natural Gas Combined Cycle – NGCC				
	CAESAR		CESAR	
	Without capture	With capture	Without capture	With capture
Gross electricity output (MWe)	837.0	759.9	430.3	388.3
Net electric efficiency (%LHV)	58.3	49.9	58.3	49.3
CO_2 emitted (kg/MWh)	351.8	36.2	354	41.9
CO_2 avoided (%)		89.7		88.2
SPECCA (MJ/kgCO2)		3.30		3.61

The results shown in this report allow other teams of other current or future projects to evaluate their own technology propositions in a consistent and well justified way, using the same sets of assumptions and parameters described here and in [1]. Advantages or disadvantages of a technology over another can thus be credibly demonstrated to a good approximation.

6 ACKNOWLEDGEMENTS

A high degree of collaboration and interaction among the members of the European Benchmarking Task Force was required for the completion of its mission. The authors believe that this requirement was fully satisfied, allowing the achievement of the EBTF objectives. As members of the three projects funded by the FP7 program, they are indebted to the European Commission for the opportunity of carrying out such a difficult but very necessary task. They confidently expect that their work will be useful to the carbon capture research and development community.

7 REFERENCES

1. European Benchmarking Task Force, 2009, ‘Common Framework Definition Document’, public report from CAESAR, CESAR and DECARBit European Union Projects.