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DEVELOPMENT OF MULTIMODE GAS FIRED COMBINED CYCLE CHEMICAL-LOOPING COMBUSTION BASED POWER PLANT LAY-OUTS

Abstract

Operation of power plants in carbon dioxide capture and non-capture modes and energy penalty or energy utilization in such operations are of great significance. This work reports on two gas fired pressurized chemical-looping combustion power plant lay-outs with two inbuilt modes of flue gas exit namely, with carbon dioxide capture mode and second mode is letting flue gas (consists carbon dioxide and water) without capturing carbon dioxide. In the non-CCS mode, higher thermal efficiencies of 54.06% and 52.63% efficiencies are obtained with natural gas and syngas. In carbon capture mode, a net thermal efficiency of 52.13% is obtained with natural gas and 48.78% with syngas. The operating pressure of air reactor is taken to be 13 bar for realistic operational considerations and that of fuel reactor is 11.5 bar. Two power plant lay-outs developed based combined cycle CLC mode for natural gas and syngas fuels. A single lay-out is developed for two fuels with possible retrofit for dual fuel operation. The CLC Power plants can be operated with two modes of flue gas exit options and these operational options makes them higher thermal efficient power plants.

Keywords: chemical looping combustion; lay-out; gaseous fuels; energy balance; multimode; carbon capture;

NOTATION

CLC	Chemical-looping combustion
CC	Combined cycle
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
SMOC	Steam moderated oxyfuel combustion
$h_{Air\ in}$	Enthalpy in air entering into air reactor, kJ/kg
$h_{Dep\ Air}$	Enthalpy of oxygen depleted air reactor leaving the system, kJ/kg
h_{MeO}	Enthalpy in oxygenated carrier, kJ/kg
$h_{Me_{x-1}}$	Enthalpy in enthalpy in reduced oxygen carrier, kJ/kg
$h_{Fuel\ in}$	Enthalpy flow in fuel entering fuel reactor, kJ/kg
$h_{Exhaust}$	Enthalpy flow in exhaust leaving fuel reactor, kJ/kg
ΔH_{Ox}	Heat of oxidation, kJ/mol
ΔH_{Red}	Heat of reduction, kJ/mol
$M_{Exhaust}$	Mass flow of exhaust (containing CO_2 and water vapor) leaving fuel reactor per unit time, kg/s
$M_{O_2 in}$	Mass of oxygen in fresh air, entering to air reactor, kg/s
$M_{Dep\ Air}$	Mass of depleted air at the exit of air reactor, kg/s
$M_{O_2 out}$	Mass of oxygen present in depleated air at the exit of the air reactor, kg/s
$M_{Fuel\ in}$	Mass of fuel entering into fuel reactor, kg/s
$M_{Exhaust}$	Mass of exhaust gas (containing CO_2 and water vapor) leaving fuel reactor respectively, kg/s
M_{MeO_x}	Mass of oxidized oxygen carrier, kg/s
$M_{MeO_{x-1}}$	Mass of reduced oxygen carrier, kg/s
P_1	Compressor inlet pressure, bar
P_2	Compressor outlet pressure, bar
r_p	Compression pressure ratio
T	Temperature at any point, °C
T_1	Temperature of the gas at compressor inlet, K
T_{2s}	Isentropic temperature of gas at compressor exit, K
T_3	Temperature of the fluid at gas turbine inlet and, K
T_{4s}	Isentropic temperature at gas turbine exit respectively, K
γ	Specific heat capacity ratio

1. INTRODUCTION

Emission of greenhouse gas primarily carbon dioxide from power stations is a major concern for energy sectors, climate change and terrestrial ecosystem (IPCC, 2014; IPCC, 2020). At present, carbon dioxide emission from power sectors alone is 35-40 % of the total CO_2 emission and in these sectors fossil fuels accounts for the anthropogenic CO_2 emissions. Carbon dioxide concentration was increased in last one decade with an average growth of 2.4 ppm/year and the 2020 concentration of CO_2 is 415 ppm and CO_2 emissions is about 60 % higher compared to last 160 years (IEA, 2016; IEA, 2021). The various options in reducing emission of carbon to the atmosphere is focused by many advanced combustion technologies and major research and concern is on: (i) increasing efficiency by reducing energy consumption; (ii) use of less carbon emissive fuel; (iii) storage of CO_2 using biological absorption methods in forest and soils (IPCC,2005; IPCC, 2007). The most of combustion technologies involve energy penalty in flue gas cleaning and subsequent carbon capture. This should be minimized to implement CCS with least energy penalty. There are several advantages with gas fuels (for example natural gas and syngas) over high carbon emissive solid fuels to make power generation less CO_2-intensive. The dependency of coal based power generation will continue in countries like India, China and South Africa for the next 40 years (Jayanti et al., 2012).

Emissions of carbon dioxide from the power plants and industries have been great interest in by means of carbon captured and sequestration (CCS) (IPCC, 2014). Three principal way to capture CO_2 from flue gas upon combustion in power plants; these are post-combustion capture, pre-combustion capture and oxyfuel combustion (Ghonieum and Needs, 2011). Comparative analysis of natural gas fired oxyfuel and CLC based power plant lay-outs is made by Basavaraja and Jayanti (2015a) and net efficiency reported for oxyfuel based CC CO_2 recycle and combined cycle steam moderated oxyfuel combustion (CC SMOC) is respectively 30.93 % and 46.57 % and CLC atmospheric and CC CLC is respectively 43.11% and 51.94% after incorporating energy penalty for CO_2 compression to 110bar. Though state of art has been illustrated in these technologies with technical maturity (Wall 2007), many of these involves energy penalty in CO_2 capture. Energy penalty for coal based, post capture and compression is 12%, oxyfuel combustion capture is 11.2%, IGCC Shell is 9.4% and NGCC post combustion capture is 5.8 %(Davison and Thambimuthu, 2009).

Existing power plants needs CCS with well-planned retrofitting. Development of present power plant with the provision of CCS entails additional capital investment. Raymond et al. (2014) studied on retrofitting power

plant for carbon sequestration and problems associated with carbon constrained energy planning (CCEP). Operation of power plant with CCS involves number of factors like fuel type, electricity cost, and geographical area for sequestration and environmental issues (Tola and Pettinau, 2014). A detailed analysis on fuel switching for CLC based power plant layout was made by Basavaraja and Jayanti (2015b) to address alternative fuel as energy source for atmospheric CLC plants by thermodynamic, transport and kinetic factors considerations. Oxy-coal based combustion is gaining attention in research, Jayanti and Kareemulla (2016) studied on the low temperature flashing for simultaneous CO_2 and SO_2 capture in oxy coal combustion based power plants. There is a need for combustion technology that enables power plant is to be operated in both CCS and non-CCS mode. Combustion in power plant based on CLC enables plant to operate with or without capture of CO_2 with minimum retrofit.

The concept of Chemical-looping combustion was proposed in 1954 to produce pure CO_2 and later research work to increase thermal efficiency on reversibility of combustion processes using chemical-looping concept is made (Lewis and Gilliand., 1954; Richter and Knoche., 1983; Ishida et al. , 1987 and Jin and Ishida., 1994). The important parameters of CLC based plants, such as gas-solid contact pattern, oxygen carrier reactivity at different temperatures for various fuels and temperature distribution in reactor system, are now well understood by research (Adanez et al., 2012; Mansoor et al., 2017; Sumana et al. 2020, Jun and Xiang., 2021).

Technically mature Rankine-cycle type oxyfuel-combustion based power plants show 10 to 12% (Jayanti et al., 2012; Jenni et al., 2013; Navajas et al., 2019) energy penalty even though thermal losses can be minimized by proper design and optimization of power cycle. A studies on CLC based power plants show that energy loss will be minimal (Naqvi, 2006; Kvamsdal, 2007; Navajas et al., 2019) in oxygen separation from air and such studies made in integrated gasification combined cycle (IGCC) power plant with and without CO_2 capture (Petrescu and carmos, 2017). Pressurized CLC show higher thermal efficiency and there has been possibility of operating in both CCS and non CCS modes. Jin and Ishida (2006), Abad et al.(2007) and Adanaz et al. (2006) studied on kinetics of oxygen carriers in pressurized CLC environment in lab scale. These results cannot be used to scale-up reactor but these show kinetics in 1 to 15 bar range CLC system will be feasible in case of heavy duty CLC reactors. These studies shows operating CLC based units with high thermal efficiency without much energy consumption for air separation with the feasibility of handling flue gas in CCS and non-CCS mode. While studies on pressurized/combined cycle based CLC system operation (Naqvi 2006; Wolf 2004; Zang

2018) have been reported in literature, detailed combined cycle CLC based power plant lay-out with an option to handle flue gas with CO_2 capture and free let-out have not properly addressed .

The objective of this work is to develop gas fired power plant lay-out incorporating two ways of handling flue gas with a prospective to know heat generation sections and heat utilization to generate electrical power using Brayton and Rankine cycles while still ensuring options of handling flue gas containing CO_2 in CCS and non CCS routes.

This paper aims to study, develop process flow sheet and analyse two gas fired pressurized chemical-looping combustion power plants and their configuration for two modes of operations i.e., one with carbon capture mode and other one is allowing flue gas from plant to atmosphere thereby enabling retrofitting possibility for fuel switch.

Three power plants based on pressurized chemical-looping combustion are considered and are :

(a) a natural gas fueled plant with and without carbon capture modes, (b) a syngas fueled plant with and without carbon capture modes, and (c) a future ready plant operating with and without carbon capture modes with an retrofit for an option to fuel switch.

2. DEPICTION OF MASS AND ENERGY CALCULATION

2.1 Pressurized Chemical Looping Combustion

The principle of pressurized chemical looping combustion is shown in Figure 1. Here, the fuel combustion is split in two stages. Firstly, a solid metal (in a low oxidation state, denoted as MeOx-1) is oxidised by oxygen in the air to form metal oxide (completely oxidized state, denoted as MeOx) in air reactor. In the later stage, the metal oxide gives oxygen to react with the hydrocarbon fuel during fluidization to form carbon dioxide and water vapor in fuel reactor. Two stage combustion of fuel by reactor systems eliminates oxygen separation unit and avoids mixing of N_2 with flue gas. The exit gases from CLC reactor system are taken through gas turbines followed by heat recovery steam generators to generate power and CO_2 separated from the flue gas upon cooling sent for compression.

Pressurised operation of CLC reactor systems enables combined power cycles operated under gas turbine as per Brayton cycle and steam turbine as per Rankine cycle to get improved net thermal efficiency of power plant

(Kehlhofer, 1999; El-Wakil, 2010). In recent years, pressurized CLC is gaining importance from the researches in the view of reactor configuration, solid-gas contact, reaction kinetics, fuel conversion (Abad et al., 2007; Xiao et al., 2010; Xiao et al.,2012; Zheng et al., 2014). Studies made by Adanez et al. (2006) and Garcia-Labiano et al.(2006) shows that reduction of NiO to Ni oxygen carrier conversion remains 100% for CH_4, H_2, CO and O_2 and conversion is reduced at higher pressure. This decrease in the solid conversion is typically in the range of 16-30 bar ranges and therefore in the present work we have chosen 13 bar pressure as highest gas pressure (at depleted air turbine) at Brayton cycle. In the pilot plant studies (Erlach et al., 2011) showed no attrition and no agglomeration when that Ni/NiO can be operated at 1300°C in CLC units. Temperature and pressure for air turbine of the Brayton cycle are fixed at 1200°C and 13bar, respectively.

The heat required for the endothermic metal oxide reduction (by fuel) is supplied from the oxidized metal coming from air reactor. Reaction in two CLC reactors is by gas-solid contact during fluidization. Based on reactive nature of oxygen carrier with air and fuel, air reactor operates in circulating fluized bed mode and fuel reactor operates in bubbling fluidized bed mode. Due to varying type of fluidization in air and fuel reactors results more pressure drop and to account for this pressure in the fuel reactor is assumed to be 11.5 bar (at 1150°C) with the solid conversion of 80%. Similar condition (Naqvi, 2006; Adanez et al. 2006) used in literature for pressurized CLC systems. We have chosen this operating pressure for realistic operation of CLC reactor system. The gases expanded to one bar from gas (air and exhaust) turbine are further cooled by heat recovery steam generators to run steam turbines of Rankine cycle and water preheaters to preheat feed water. Cooled depleted air let to atmosphere. Exhaust gas containing water vapor is separated CO_2 upon cooling in flue gas conditioner and more than 95% pure CO_2 is compressed to a pressure of 110 bar for sequestration. Two possible way of handling flue gas from CLC plant unit is shown in Figure 2, one without capturing CO_2 and another one with power consumption carbon. The energy balance and combined cycle arrangement is discussed in section 2.2.

2.2 Energy balance

In this section mass and energy balance details for the combined cycle CLC system are given. The Nickel oxide (NiO) supported on Nickel di-aluminium tetroxide ($NiAl_2O_4$) in a 60:40 weight ratio is chosen as oxygen carrier. The nickel oxide flow rate calculation is made by considering 25% excess oxygen supply to fuel in fuel

reactor. The CLC-reactors are assumed to be adiabatic with isothermal and homogenous mixing of solids with gases. Air flow rate is calculation is considered in air reactor with an `~ 220% of an excess air. Considering major components of the natural gas and syngas fuels, and their reaction with NiO is given as per reactions (1), (2) and (3) respectively with excess oxygen (Adanez et al., 2012):

$$CH_4 + 4NiO \rightarrow 4\,Ni + 2H_2O + CO_2 \qquad \Delta H = 133.6\ \text{kJ/mol}\ CH_4 \tag{1}$$

$$CO + NiO \rightarrow Ni + CO_2 \qquad \Delta H = -48\ \text{kJ/mol}\ CO \tag{2}$$

$$H_2 + NiO \rightarrow\ Ni + H_2O \qquad \Delta H = -15\ \text{kJ/mol}\ H_2 \tag{3}$$

Nickel is oxidized to nickel oxide in air reactor as per reaction (4) given below

$$2Ni + O_2 \rightarrow 2NiO \qquad \Delta H = -468\ \text{kJ/mol}\ O_2 \tag{4}$$

In reactions (1) to (4), values of heat of reaction shown has been estimated from the values available in literature (Adanez et al., 2012; Linderholm et al., 2008) for the temperature range 1150°C to 1230°C. Based on reactions (1) to (4) stoichiometric oxygen requirement for syngas is calculated and in similar way other components of natural gas is estimated. One can see here that syngas composition consist major portions of carbon monoxide, hydrogen and lessor part of methane. Reaction of CO and H_2 with NiO is exothermic compared to lessor methane gas endothermic reaction with NiO. This make overall syngas reaction with NiO as mildly exothermic.

In this system, power is generated primarily by Brayton cycle and bottoming Rankine cycle. The basis for all CLC calculations is amount of fuel converted in the reduction/fuel reactor. In combined cycle CLC, metal oxidation reaction is taken up by large mass of excess air. With given fuel flow, the amount of oxygen converted is found from reaction stoichiometry, and the heat balance for the air reactor can be solved. Air and fuel reactors heat balance (as per Figure 3) is formulated respectively according to Eqs. (5) and (6):

$$M_{\text{Air in}}h_{\text{Air in}} + M_{MeO_{x-1}}h_{Me_{x-1}} + (M_{O_2\text{in}} - M_{O_2\text{out}})\Delta H_{Ox} = M_{\text{Dep Air}}\,h_{\text{Dep Air}} + M_{MeO}h_{MeO} \tag{5}$$

$$M_{\text{Fuel in}}h_{\text{Fuel in}} + M_{MeO_x}h_{MeO} - M_{\text{Fuel in}}\Delta H_{\text{Red}} = M_{\text{Exhaust}}\,h_{\text{Exhaust}} + M_{MeO_{x-1}}h_{Me_{x-1}} \tag{6}$$

In Eq. (5), terms h_{MeO} , $h_{Me_{x-1}}$, $h_{\text{Air in}}$, $h_{\text{Dep Air}}$ are, respectively, the enthalpy in oxidized metal, reduced metal , air entering and oxygen depleted air leaving the air reactor. In Eq. (6), terms $h_{\text{Fuel in}}$ and h_{Exhaust} are respectively, the enthalpy of fuel entering into fuel reactor and enthalpy of exhaust (stream containing CO_2 and

water vapor). ΔH_{Ox} is the heat of oxidation in kJ/mol i.e,, heat released during reaction of Ni with O_2 to form NiO . The term ΔH_{Red} is heat of reduction in kJ/mol i.e., heat absorbed during the natural gas oxidation or NiO reduction. Ni oxidation is exothermic reaction and therfore the term ΔH_{Ox} associated with molar mass is with plus sign as given in Eq. (5) and NiO reduction in fuel reactor is endothermic for the natural gas fired case and thus the term ΔH_{Red} associated with molar mass is with minus sign as given in Eq. (6) and same will be become plus sign for exothermic NiO reaction with syngas. Here $M_{O_2 in}$, $M_{Dep\ Air}$, $M_{O_2 out}$, $M_{Fuel\ in}$, $M_{Exhaust}$ are respectively mass of oxygen in the fresh air, mass of the depleted air, unreacted or excess oxygen leaving air reactor, mass of fuel entering into fuel reactor and mass of exhaust gas (containing CO_2 and water vapor) leaving fuel reactor respectively. In Eqs.(5) and (6), M_{MeO_x} and $M_{MeO_{x-1}}$ denotes oxidized and reduced states of oxygen carrier respectively.

2.3 Pressurized chemical-looping combustion power cycle

A schematic diagram of the pressurized CLC power cycle is shown in Figure 4. The CLC Brayton cycle consists of air compressor, depleted air turbine and exhaust gas (CO_2+H_2O) turbine. The fuel is assumed to be pressurized. The oxygen depleted air from the air reactor and exhaust stream containing CO_2 and water vapor from the fuel reactor are drawn into two separate Brayton cycles and are expanded in an air turbine and CO_2 turbine. The CLC reactor exit gases after expansion preheats the respective reactor inlet gases using gas-gas heat exchangers or recuperators. The heat left in the exhaust and depleted gas streams is extracted by using series of heat exchangers or heat recovery steam generators (HRSG) to generate steam as per Rankine cycle. Figure 4 shows combined cycle chemical looping combustion power cycle arrangement having two Brayton cycles and a Rankine cycle.

3. RESULTS AND DISCUSSION

Thermal input for natural and syngas fired combined cycle CLC based power plant is considered as 761 MW_{th} and 800 MW_{th} respectively, supplied in continuous fuel flow. The composition in mole % of natural gas (Linderholm et al. 2009) is taken as 89.51% CH_4, 5.92% C_2H_6, 2.36% C_3H_8, 0.40% isobutene, 0.56% n-butane, 0.13% isopentane, 0.08% n-pentane, 0.06% C_6H_{12}, 0.28% N_2 and 0.70 CO_2 with lower heating value of 49.17 MJ/kg. Syngas (that generates almost two times the quantity of CO_2 of that of natural gas upon complete

combustion) molar composition (Winslow 1977) is taken to be 45.7% H_2, 19.6% CO, 6.6% CH_4 and 28.1% CO_2 with the lower heating value of 11.2 MJ/kg.

In both fuel fired case, comprehensive mass and energy balance is made and thermodynamic analysis is carried on the gas preheaters, air reactor, the fuel reactor, gas turbines (depleted air and exhaust gas turbines) of Brayton power cycle and steam turbines of Rankin power cycles. The results from these calculations are discussed below.

3.1 Lay-out of Natural Gas Fired Pressurised CLC

In this section detailed mass and energy balance for power plant and complete process flow sheet of pressurized CLC plant is discussed and details of these are given below.

3.1.1 Mass and Energy Balances

Mass and heat balances are made on CLC reactor system conating five major CLC sub-units. These are the fuel oxidation reactor (operating at 1150°C and 11.6 bar), the air oxidation reactor (operating at 1200°C and 13 bar), the fuel and the air pre-heaters and coolant air flow. Mass flow of individual stream of these sub-units has been found by balancing moles of reactant and product based on the fuel component mole fractions. Using Eqs. (5) and (6) heat (energy) balances have been made for natural gas fueled combined cycle CLC system of 761 MW_{th} fuel input. The resulting energy and mass flow rates in and out of these sub-units are shown in Figure 5.

Compressed air (at 177°C and 13.5 bar) at mass flow of 870.12 kg/s is divides into two streams namely coolant air flow of 58.44 kg/s and the process air of 811.68 kg/s. Air of mass flow 811.68 kg/s (with 215.55 % excess O_2) is drawn to the CLC reactor system and heated air (at 420°C) from recuperator enters air reactor where 59.7 kg/s of oxygen present in the air is selectively reacted with metal (containing of 218.95 kg/s of Ni, 69.66 kg/s of NiO and 232.21 kg/s of $NiAl_2O_4$) to form metal oxide stream (containing of 348.31 kg/s of NiO and 232.21 kg/s of $NiAl_2O_4$). Conversion of NiO to Ni is 80% in the fuel reactor. The Energy produced by exothermic metal oxidation reaction in the air is taken out by N_2 rich air (of flow 751.99 kg/s) and metal oxide streams. The heat absorbed by endothermic metal oxide reduction reaction in fuel reactor is 113 MW. This is supplied by the oxygen carrier. 15.47 kg/s of natural gas is preheated from 30 to 350°C by the exhaust gas of 75.1 kg/s. The O_2-depleted air from the air reactor is 751.99 kg/s at 1200°C. The oxygen depleted air and coolant air (58.44 kg/s at 177°C) mix at the turbine inlet to form a total mass flow of 810.43 kg/s and a temperature of 1132°C at the turbine inlet. The depleted air and coolant bleed mixture gases expand in the gas turbine. The depleted air

turbine exit gas temperature at 1 bar is 497°C. Exhaust gas temperature reduces to 666°C upon expansion. The computed value $\gamma\ (= C_P/C_V)$ for oxygen depleted air and fuel reactor exhaust given are 1.345 and 1.226, respectively. These values are comparable with these reputed literatures (Naqvi et al., 2007; Wolf, 2004) for same inlet gas composition for depleted air and exhaust turbines. Depleted air at the exit of air reactor (at 1200°C) mixes with the coolant air so that turbine inlet temperature is taken to be 1132°C. Turbine efficiency (η_t) is taken in the range of 91-92% (Wolf, 2004) and a value of 92% is used in the present studies. Nearly atmospheric pressure depleted air and exhaust gas streams (after expansion in gas turbines) at low pressure are used for power generation (as per Ranking Cycle) after preheating respective reactor inlet gases. The complete process description for the combined cycle chemical-looping combustion power plant flow diagram is given below (section 3.1.2).

3.1.2 Natural gas Fired Power plant lay-out

Chemical-looping combustion based combined cycle is unique compared to a conventional combined cycle as the depleted air from the air reactor and flue gas containing CO_2 and water vapor from the fuel reactor are drawn into two separate Brayton cycles and are expanded in an air turbine and CO_2 turbine. Combined cycle chemical-looping combustion power cycle consists of four major components namely compressor, recuperators, gas turbine and steam turbine.

Since combustion is divided into oxidation and reduction reactions in two pressurized fluidized bed reactors, therefore two gas turbines are used to expand them in the proposed lay-out. Gases are compressed to desired reactors operation using compressors. Recuperators provide necessary heat to preheat the reactants. Description of the streams in the process plant as shown in Figure 6 is described below.

The terms A1, A2, A3 denote fresh air streams and are respectively air before compression, air after first stage of compression and air at the exit of second compression stage. Major part of the compressed air (A4) is first preheated and then admitted to the air reactor to oxidise the reduced metal oxide (M2). The depleted air (A7) mixes with the cooling air (A5) drawn from air compressor and then expands down. The depleted air from the turbine exit (A8) preheats the fresh air (A4) to (A6). The depleted air from the turbine exit is further cooled from A9 to A10 by water stream (S8) to generate steam (S9). Pressurized fuel (F1) after preheating (F2) reacts with the oxygenated metal carrier (M1) to form CO_2 and H_2O vapour mixture exhaust (E1). The expanded exhaust

(E2) from the turbine preheats the fuel by cooling down to (E3) and further cools down (E4) by giving heat to water stream S2 which form steam S3. The depleted air stream finally cools to 75°C (A10 to A11) while heating water stream (S5) to stream (S6). Thus, the exit gases from air turbine and exhaust gas are drawn into Rankine cycle through heat recovery steam generator to generate subcritical steam at 190°C (1.7 bar). The exhaust gas stream at 128°C is let to the atmosphere through chimney when power plant operates in without CO_2 mode. To operate power plant in carbon capture mode as shown in Figure 7, the exhaust stream from fuel reactor is admitted to flue gas conditioner for further cooling to ~40°C and the condensed water vapour is separated (E6) and CO_2 gas (E7) is compressed to 110 bar (E8) at 35°C. The isentropic efficiency of gas and steam turbines are assumed to be 92%. Thermodynamic analysis of the natural gas fueled CC CLC is shown in the Table 1. The efficiency of water pump and compressor are taken as 75% and 85% respectively.

3.2 Lay-out of Syngas Fired Pressurised CLC

Mass and Energy balance model is same as already presented in Section 3.1.1 for pressurized CLC with natural gas as the fuel has been used to determine the furnace side parameters for syngas firing. Since syngas has higher cost of compression of CO_2, the lay-out has been designed for a 800 MW_{th}, which amounts to 71.43 kg/s of syngas flow and is 4.6 higher than the flow rate of natural gas required for a 761 MW_{th} plant. On the furnace side, the principal sub-systems considered are the air reactor and its preheater, the fuel reactor and its preheater, the gas turbines used to extract power from these exhausts and the compressor to supply air to the air reactors as well as coolant air to the air turbine. Syngas is assumed to be available under pressurized conditions and the cost of its compression is not included in the analysis. As in the case of syngas, the air reactor is fixed to operate at 13 bar and 1200°C, and the fuel reactor is fixed to operate at the pressure of 11.6 bar (at 1226°C). The same oxygen carrier is used and its flow rate has been determined for syngas requirements for an 800 MW_{th} power plant. The operating temperature of the fuel reactor and the inlet and exit temperatures of the recuperators have been adjusted to account for the exothermicity of the reduction reaction in the syngas-fired fuel reactor. The specific heat capacity ratio (γ) is taken as 1.20. The resulting mass and energy flow rates into these subsystems are shown in Figure 8.

The process flow diagram for the CC CLC is shown in the Figure 9. Description of the streams in the process plant is briefly explained below. The inlet and exit streams reactor system is same as natural gas layout. The energy utilization from exit gas of the syngas fired power plant is given below. The expanded exhaust (E2) from

403 the gas turbine gets cooled down to E3 in the processing preheating the fuel and further to E4 and E5 by giving
404 heat to water stream S2 to form high pressure steam S3 which is superheated to S4 by the cooling exhaust gas
405 (E5 to E6). After expansion in the high pressure turbine (S5), the exit steam is reheated (S6) and fed to the
406 medium pressure (20 bar) steam turbine. After expansion to 1.7 bar in the medium pressure turbine, it is mixed
407 with steam generated in various sections (S3, S6 and S16) of process the plant from O_2-depleted air and exhaust
408 gas steams via heat recovery steam generators to produce superheated steam at 1.7 bar at a temperature 190°C.
409 It then finally expands from 190° to 39°C (at 0.069 bar). The exhaust gas (E6) at temperature 128°C leaves the
410 plant through chimney to atmosphere. The thermodynamic properties of the streams at various locations is
411 shown in Thermodynamic analysis of the CC CLC is shown in the Table 2.
412
413 **3.3 Schematic Diagram of the non-CCS and CCS enabled modes Power Plant**
414 A schematic diagram of the proposed power cycle is shown in Figure 4. It is based on pressurized chemical
415 looping combustion of gaseous hydrocarbon fuels such as natural gas, syngas, biogas and shale gas. The
416 combustion of the hydrocarbon fuels occurs in two stages in two separate reactors. In the fuel reactor, the fuel
417 combusts with a metal oxide, e.g., NiO supported on $NiAl_2O_4$ in a 60:40 weight ratio (taken in present work)
418 prepared in the form of micron-sized particles, and gets converted to CO_2 and H_2O. In the process, the metal
419 oxide gets reduced. It is therefore fed to the air reactor where it gets regenerated by reacting directly with air.
420 Both the metal oxidation and the metal reduction reactions are carried in the range of 1150 to 1250°C,
421 depending on the reaction and on the fuel. A circulating fluidized bed type of configuration is envisaged for the
422 cyclic oxidation/ reduction reactions of the metal/metal oxide. It is also proposed that the reactions are carried
423 out at a pressure of 13 bar in the air reactor and at a slightly reduced pressure of 12 bar in the fuel reactor. The
424 high temperature reactions in the reactors thus give rise to high temperature gaseous products at a pressure of 12
425 to 13 bar. These are expanded in separate air or gas turbines to near atmospheric pressure. The expanded gases
426 will still be hot having a temperature of 500 to 700°C depending on the reactor and the fuel. These are then used
427 partly to preheat the gaseous reactants and partly to generate a Rankine cycle to generate further electrical
428 power. In the process of giving up heat for the Rankine cycle, the oxygen-depleted air from the air reactor gets
429 cooled down to ~120°C and is fed to a chimney as it contains little CO_2. The exhaust from the fuel reactor too
430 gets cooled down to ~100°C as it passes through the heat recovery systems. For the CCS mode of operation of
431 the power plant the exhaust stream (E6) is admitted into the flue gas conditioner where it is finally cooled to
432 40°C (E5). The condensed water vapour is separated (E6) and CO_2 gas (E7) is compressed to 110 bar (E8) at

433 35°C if CCS is mandatory or let into the atmosphere through the air chimney when CCS need not be
434 implemented as shown in Figure 10.
435
436 Specific features of the lay-out that make it advantageous and future-ready are:
437 • the use of a combined cycle operation to ensures high power output
438 • The use of chemical looping combustion mode of burning of hydrocarbon fuel enables CO_2 capture as
439 a built-in feature.
440 • The in-built feature of CO_2 capture enables the power plant to be ready for CCS when it becomes
441 mandatory. At that stage, minor changes in the gas flow path, after it gets cooled to ~100°C, are
442 required and a provision to compress CO_2 to 110 bar must be made. Thus, the retrofitting to implement
443 CCS would be minimal.
444 • By proper sizing of the major equipment, it is possible for the plant to be used with as widely different
445 fuels as methane-rich natural gas (or shale gas) and CO/H_2-rich syngas (or biogas).
446
447 These aspects are elaborated further below.
448 A process flow diagram of the proposed power plant lay-out is shown in Figure 9. Based on mass and energy
449 balances discussed in sections 3.1 and 3.2, this has been developed for a 761 MW_{th} plant when fired with natural
450 gas and 800 MW_{th} when fired with syngas. Major have now been identified and the flow paths of the various
451 material streams, such as air, hydrocarbon fuel, steam and metal oxide, have been identified. Process flow
452 sheeting calculations have been done for four different modes of operation, namely, with natural gas firing with
453 and without CCS, and with syngas firing with and without CCS and the pressure, temperature and flow rate at
454 several important locations in the flow paths have been calculated. These are summarized in Table 3. The fact
455 that the same lay-out descriptors can be used for all four configurations highlights the multi-mode capability of
456 the plant design. The two specific features, namely, dual fuel flexibility and readiness for CCS, engender small
457 changes in the process stream flow paths. These have been identified in Figure 9. Fuel switching from syngas
458 to natural gas requires the fuel reactor exhaust stream to go directly from E3 to E5, thus bypassing the high
459 pressure and the medium pressure turbines of the Rankine cycle system. There should be a corresponding
460 bypassing of the relevant heat recovery steam generators by the water on the steam side. Switching from a non-
461 CCS mode (which is the current practice) to CCS mode (which may be required in future) requires the fuel

reactor exhaust to be sent to CO_2 compressor via a exhaust gas cooler to remove steam instead of being sent to the air chimney.

Finally, the overall efficiency of the power plant under various modes of operation is summarized in Table 3. Here, a listing is made of the various processes by which power is produced and those by which power is consumed for the four configurations.

Overall energy analysis is made for power plant lay-outs and net efficiency for each case is evaluated using Eq. (7) considering the energy penalties for gas compression and water circulation.

$$\eta_{Net} = \frac{P_{Net\ CC\ CLC}}{m_{fuel} \cdot Q_{LHV}} \quad (7)$$

In Eq. (7), η_{Net} is net efficiency of power plant, m_{fuel} is mass flow rate of fuel in kg/s, Q_{LHV} is lower heating value (kJ/kg) of the fuel and $P_{Net\ CC\ CLC}$ is net power available for combined cycle chemical looping combustion power plant and $P_{Net\ CC\ CLC}$ evaluated uing Eq. (8)

$$P_{Net\ CC\ CLC} = P_{CO_2+Air+steam} - P_{Air\ comp} - P_{CO_2\ comp} - P_{water\ pump} \quad (8)$$

In Eq. (8), $P_{CO_2+Air+steam}$ is power produced (kW) by CO_2/exhaust, air and steam turbines, $P_{Air\ comp}$ and $P_{CO_2\ comp}$ is respectively power consumed (kW) by air and CO_2 compressors and $P_{water\ pump}$ is power consumed (kW) to pump water.

It can be seen that with CCS, a net thermal efficiency of 52.13% is obtained with natural gas and 48.78% with syngas using Eqs. (7-8). In the non-CCS mode (without CO_2 compression), higher thermal efficiencies of 54.06 % and 52.63% efficiencies are obtained. The lower difference between the natural gas and the syngas in the non-CCS mode is reflective of the higher rate of CO_2 generation in the latter per MW_{th} of the fuel. The high efficiencies obtained in all these cases are partly due to combined cycle operation, partly due to the use of supercritical boilers in the steam cycles and partly due to the use of chemical looping combustion as opposed to oxyfuel combustion. It may be noted that in these calculations, allowance has been made for non-idealities in the expansion, compression and pumping processes involving fluid flow. Allowance has also been made for the power required to compress CO_2 to a pressure of 110 bar so that the nearly pure (purity > 99%) can be sent to a CO_2 sequestration/ storage/ reuse site.

492 Thus, it can be concluded the above power plant, which offers operational flexibility coupled with high
493 efficiency, has the necessary attributes of a future-ready power plant producing power from conventional
494 hydrocarbon fuels in an environmentally friendly way.
495
496 **3.4 Assessment of Possibility of Dual Fuel Operation**
497 In order to assess the possibility of dual fuel operation of the pressurized CLC system, a detailed comparison of
498 several parameters associated with the two systems is made Table 4. It can be seen that most of the parameters
499 are fairly similar; the operating temperature of the fuel reactors are slightly different. Due to the exothermicity
500 of the reduction reaction, the fuel reactor temperature is actually higher than that of the air reactor by about
501 26°C with syngas, whereas it is lower by about 50°C in the case of natural gas firing. Another difference
502 between the two fuels is the calorific value and the fuel gas flow rate. Since syngas contains significant amount
503 of CO_2 as inert, its flow rate is higher and the flow rate of the exhaust gas from the fuel reactor is also higher.
504 This, coupled with the higher exit temperature of the fuel reactor and lesser gas preheating requirement, results
505 in significantly higher amount of thermal power (105.64 MW for syngas vs 51.71 MW for natural gas) retained
506 in the fuel reactor exhaust gas (see Figure 5 and Figure 8) which is available for powering a Rankine cycle. As
507 can be seen from Table 4, the Rankine cycle for syngas has three turbines (a high pressure turbine (150 bar), a
508 medium pressure turbine (20 bar) and a low pressure turbine (1.7 bar)) while the one for natural gas has a single
509 low pressure turbine with a turbine inlet pressure of 1.7 bar.

510 It can be seen that the major part of the power is produced by the low pressure turbine in the syngas case and
511 that its rating is roughly the same (33,216 kW_e to 29,396 kW_e) as that of the low pressure turbine in the natural
512 gas case. The air reactor side parameters are nearly similar and there is hardly 5% change in the heat and mass
513 flow rates of various streams. From the above reasoning, it can be argued that except for minor changes in the
514 lay-out for the Rankine cycle parameters, the lay-outs of the syngas-fired and the natural gas-fired pressurized
515 CLC power plants are similar and a unified lay-out is produced in Figure 10. In this common lay-out, natural
516 gas firing requires by-passing of the fuel reactor exhaust from E3 to E6 directly. Correspondingly, the steam
517 side too bypasses the high pressure and the medium pressure turbines and uses only the low pressure turbine.
518 The stream values corresponding to the unified lay-out are given in Table 1 for natural gas and Table 2 for
519 syngas firing. These represent only minor departures from the normal settings and can be re-engineered without
520 significant difficulty. This means that the thermodynamic compatibility between syngas and natural gas lay-
521 outs for pressurized CLC can be achieved without significant retrofitting. The reaction engineering and

522 transport phenomena considerations are similar to those already as our earlier work (Basavaraja and Jayanti,
523 2015b). While the kinetics of pressurized oxidation/ reduction reactors have not been fully worked out, it
524 appears that the kinetics of all the reactions are slowed down in a similar way in the pressure ranges considered
525 (Adanez et al., 2012; Garcia-Labiano et al. 2006). As demonstrated in our earlier work (Basavaraja and Jayanti,
526 2015b), the fluidization and heat transfer compatibility conditions can be met by careful design of the relevant
527 equipment. Thus, it appears that dual fuel flexibility can be incorporated into pressured CLC lay-out at the
528 design stage itself. In the Table 4, work reported by Naqvi and his co-workers (2007) for 697,545 kW thermal
529 in put natural gas fired pressurised CLC plant operates at 1200°C (13 bar) at air reactor and 980°C (11.6 bar) at
530 fuel reactor. The oxygen carriers, operating pressure (at air and CO_2 turbines), compressor efficiency chosen is
531 same as reported by Naqvi and his co-workers (2007) for the natural gas fired CC CLC plant layout calculations
532 of the present work with 761,000 kW thermal input and the net efficiency is found to be 52.13% and which is
533 comparable net efficiency reported by Naqvi and his co-workers (2007). The detailed analyses of CC CLC
534 reactor operating conditions, power produced at gas and steam turbines, power consumed for air and CO_2
535 compression, net efficiencies are shown in Table 4.
536
537 **4. FUTURE-READINESS OF THE LAY-OUT**
538
539 The lifetime of a thermal power plant is in excess of 50 years. While carbon capture and sequestration is not
540 mandatory right now, it is possible that it may become so in a decade or two. In this scenario, it is necessary to
541 build power plants that are future-ready, i.e., which can be made to operate in a case where CCS becomes
542 mandatory. Extensive retrofitting of the power plant to accommodate carbon capture may not be possible and
543 should be avoided. From the future-compatibility point of view, a chemical looping combustion-based power
544 plant is clearly the superior design. CLC plants can work in either CCS mode or non-CCS mode with very little
545 changes required to make the switch. No special efforts or equipment will be necessary to enable CO2 capture.
546 If CCS is not needed, then the flue gas from the flue gas conditioner need not be compressed and can be sent
547 directly to the chimney. When CCS is required, then this flue gas can be diverted to a CO2 compressor. In the
548 case of a power plant based on oxyfuel combustion, more extensive changes are required as an air separation
549 unit is required for generating pure oxygen. While studies (Jayanti et al. 2012) indicate that retrofitting of
550 atmospheric air combustion coal-fired boilers for working in oxyfuel mode, is possible, the case for pressurized
551 oxyfuel combustion may be different because flue gas compression and recirculation are necessary. In the case

552 of pressurized oxyfuel combustion, the flow rates and composition of the exhaust gas are significantly different
553 from those under air combustion; this may warrant changes in the turbine and heat recovery systems.
554
555 **5. CONCLUSION**
556 In the present study, analysis of two modes of operation of two gas fired pressurised chemical-looping
557 combustion based power plant has been made. The principle conclusions drawn from the study is given:

558 • From the detailed mass and heat balances and thermodynamic analysis, power plant lay-outs have been
559 prepared for pressurised CLC based power plant for fuels natural gas and syngas.
560 • Two modes of power plant operation, one not requiring CCS (the present day mode) and one requiring
561 CCS (in a future scenario), have been considered within the ambit of pressurized CLC-based power
562 plant. It is shown that since CLC generates CO_2-rich flue gas (contains CO_2 and water vapor only)
563 which is ready for sequestration, the power plant can be readily operated in a dual mode with a loss of
564 2% of net thermal efficiency with natural gas and up to 4% for syngas.
565 • A single lay-out of future-ready power plant offering in-built CO_2 capture, high efficiency and fuel
566 flexibility has been developed for power generation using gaseous hydrocarbon fuels.
567 • Oxyfuel combustion based power plants are technically mature in terms of proven commercial scale
568 operation of new elements. They also have competitive net thermal efficiency if pressurised steam
569 moderated oxyfuel combustion (SMOC)-based oxyfuel combustion is used. However, they make a
570 poor choice in terms of future readiness of fuel/equipment flexibility and may warrant significant
571 retrofitting effort to make them CCS-compatible. CLC plants can work in either CCS mode or non-
572 CCS mode with very little changes required to make the switch.
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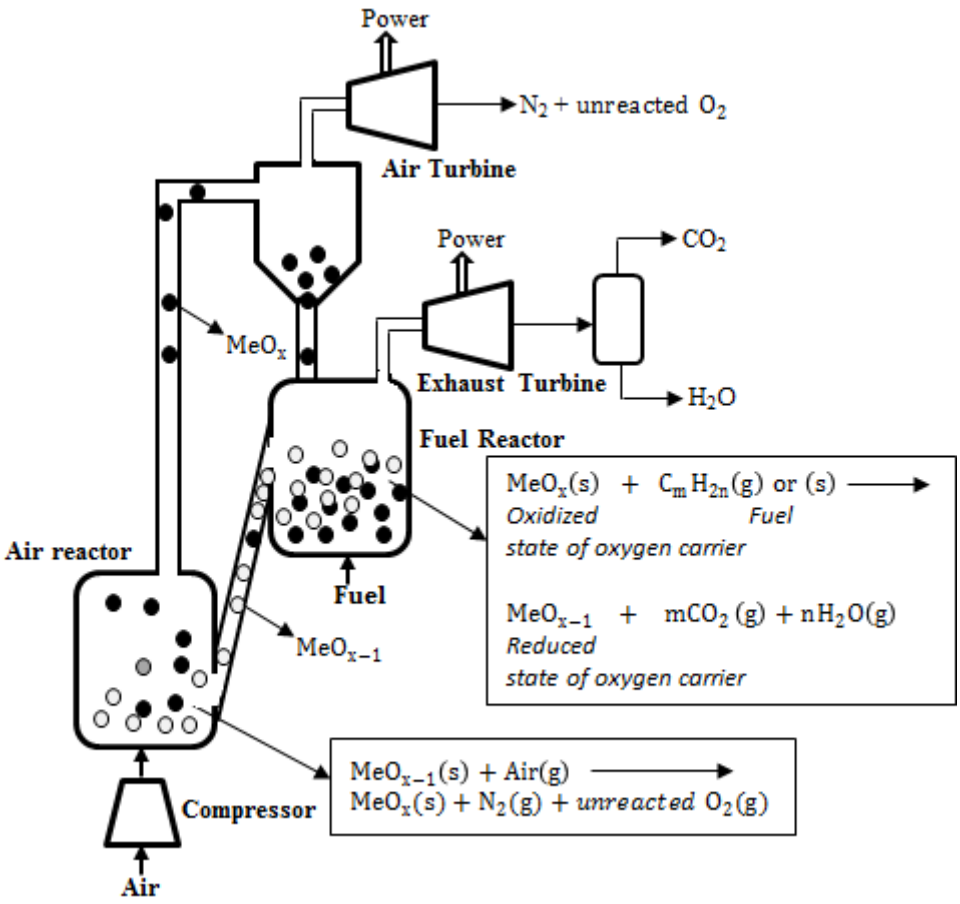

Figure 1: Schematic illustration of pressurized chemical-looping combustion

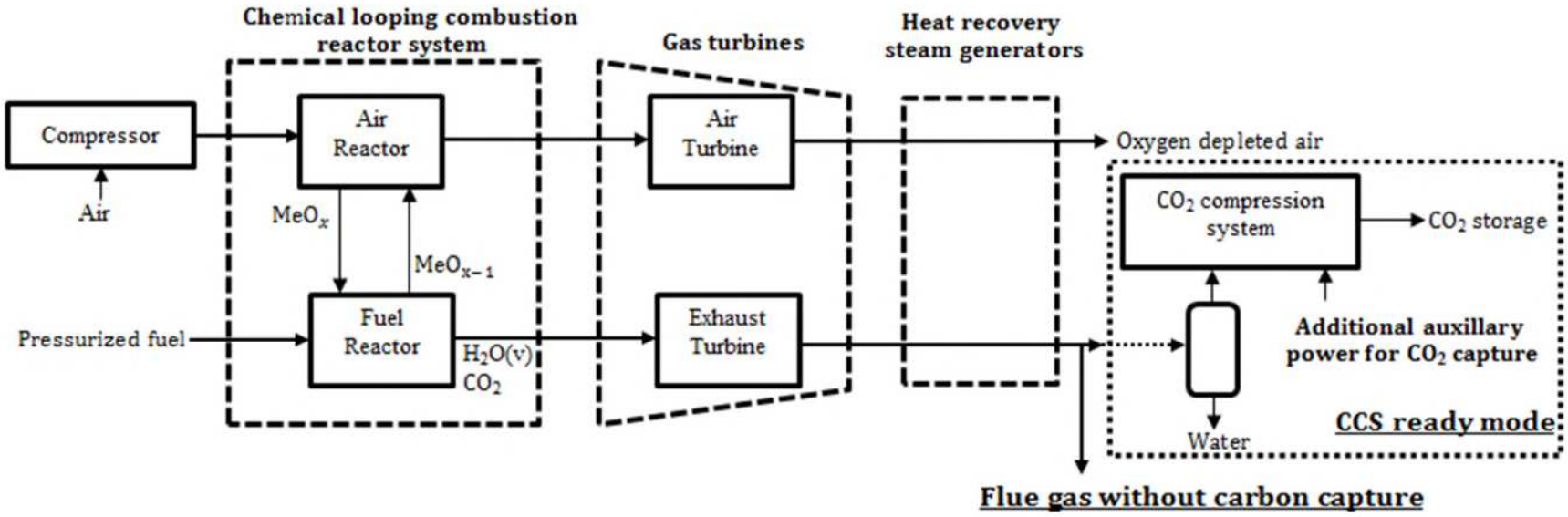

Figure 2: Schematic of flue gas handling in proposed chemical-looping combustion based power plant

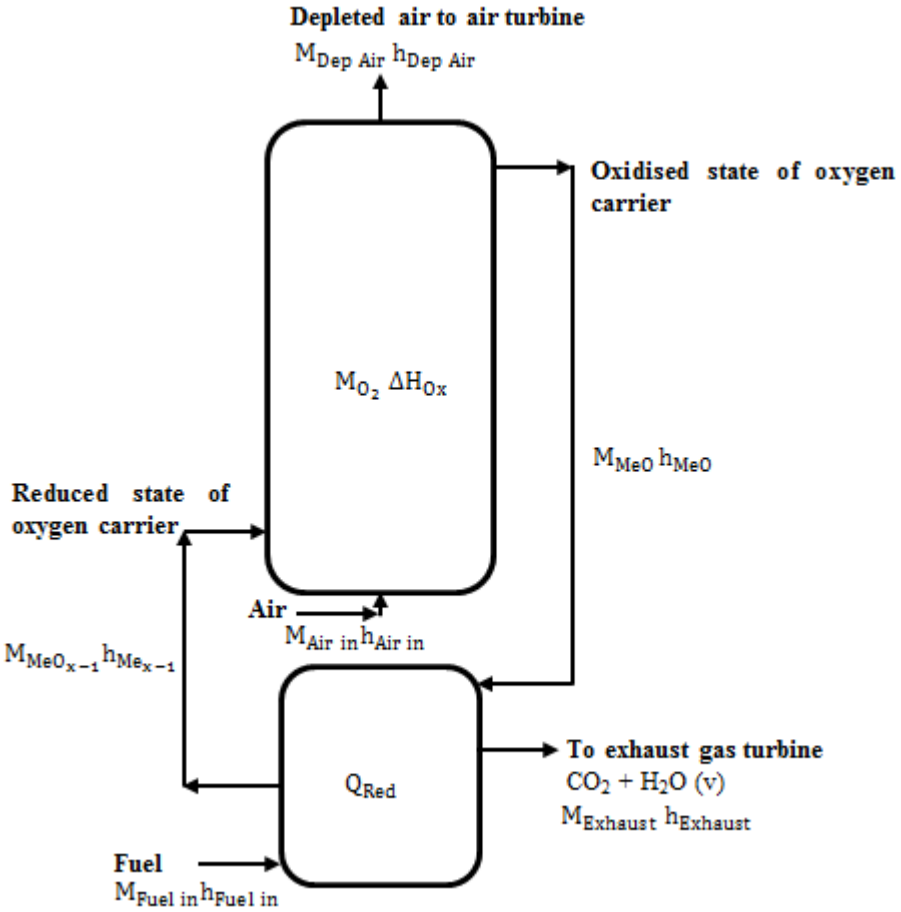

Figure 3: Schematic of energy flow in combined cycle chemical-looping combustion

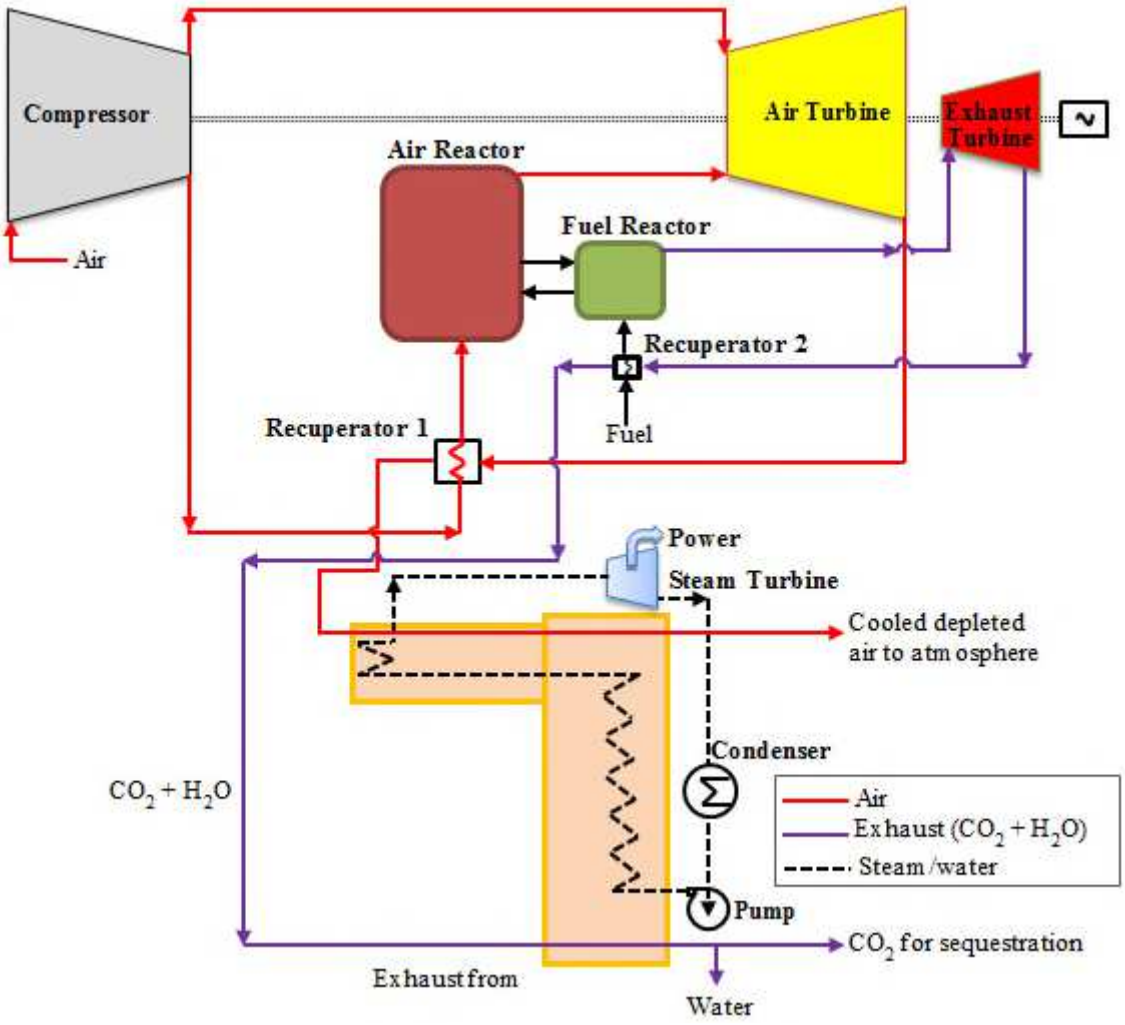

Figure 4: Arrangement of combined cycle CLC power cycle

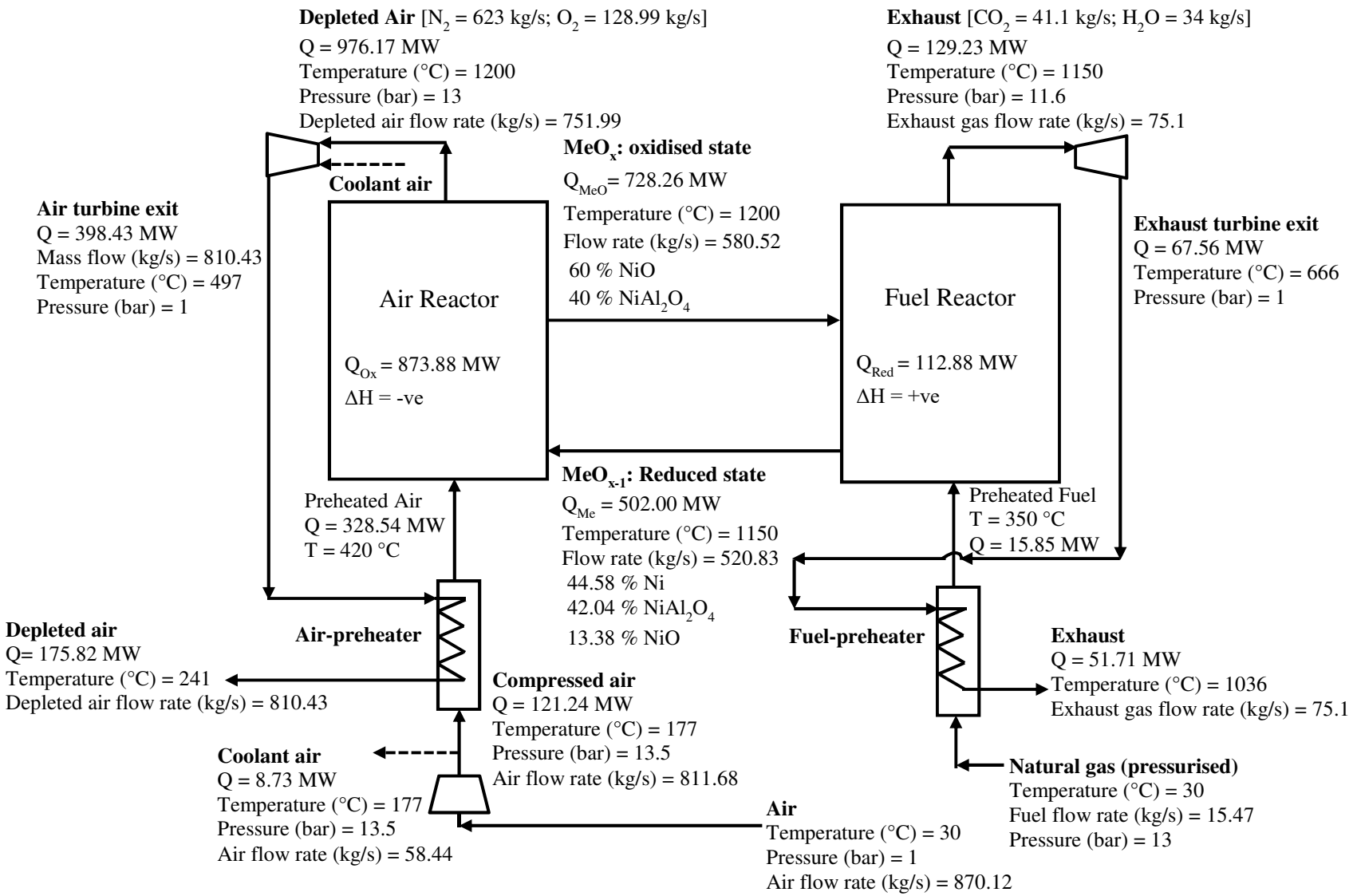

Figure 5 Furnace side heat balance of 761 MW_{th} natural gas fueled combined cycle chemical looping combustion

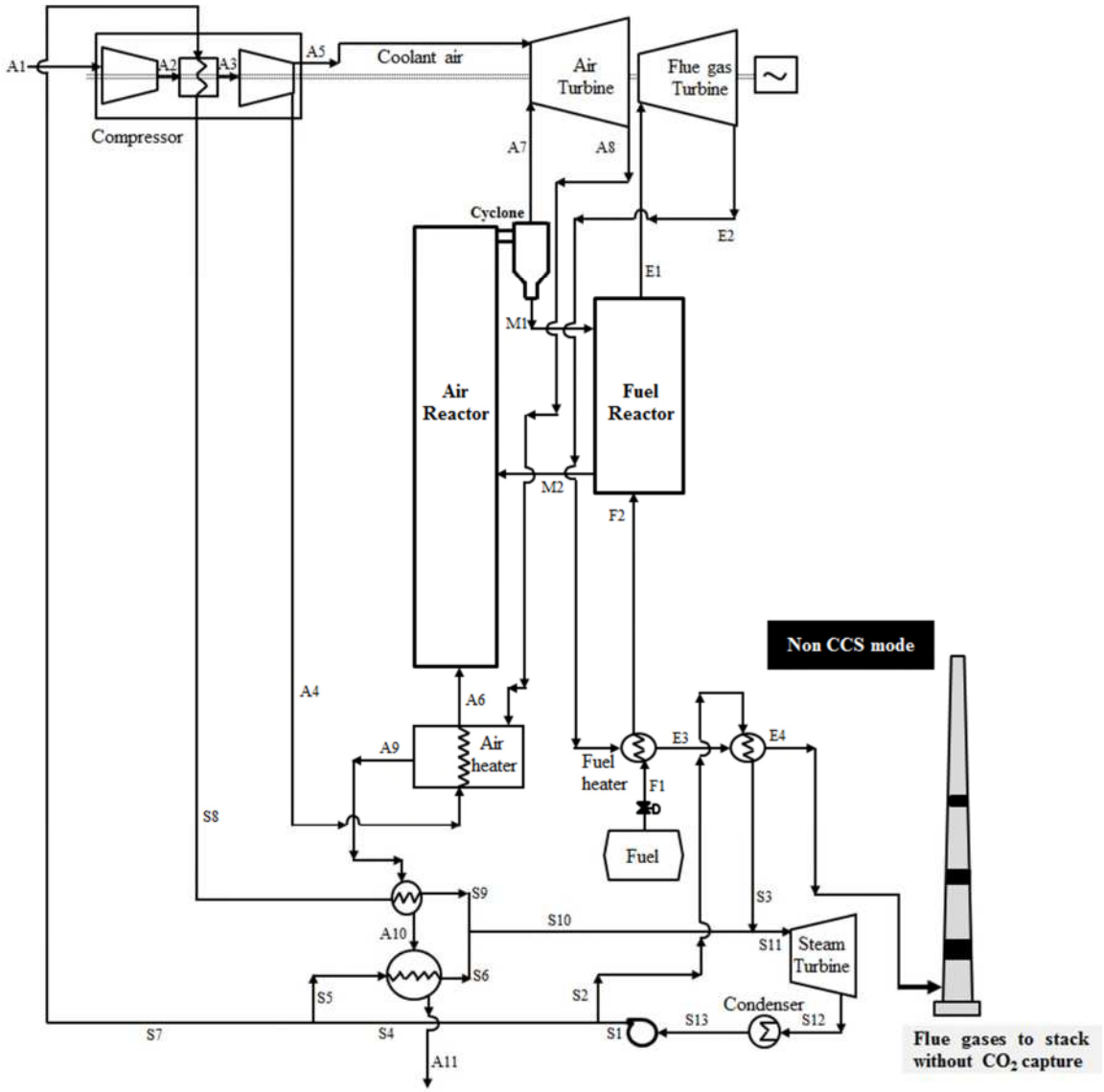

Figure 6: Schematic of natural gas fueled combined cycle chemical-looping combustion power plant without the provision for carbon capture

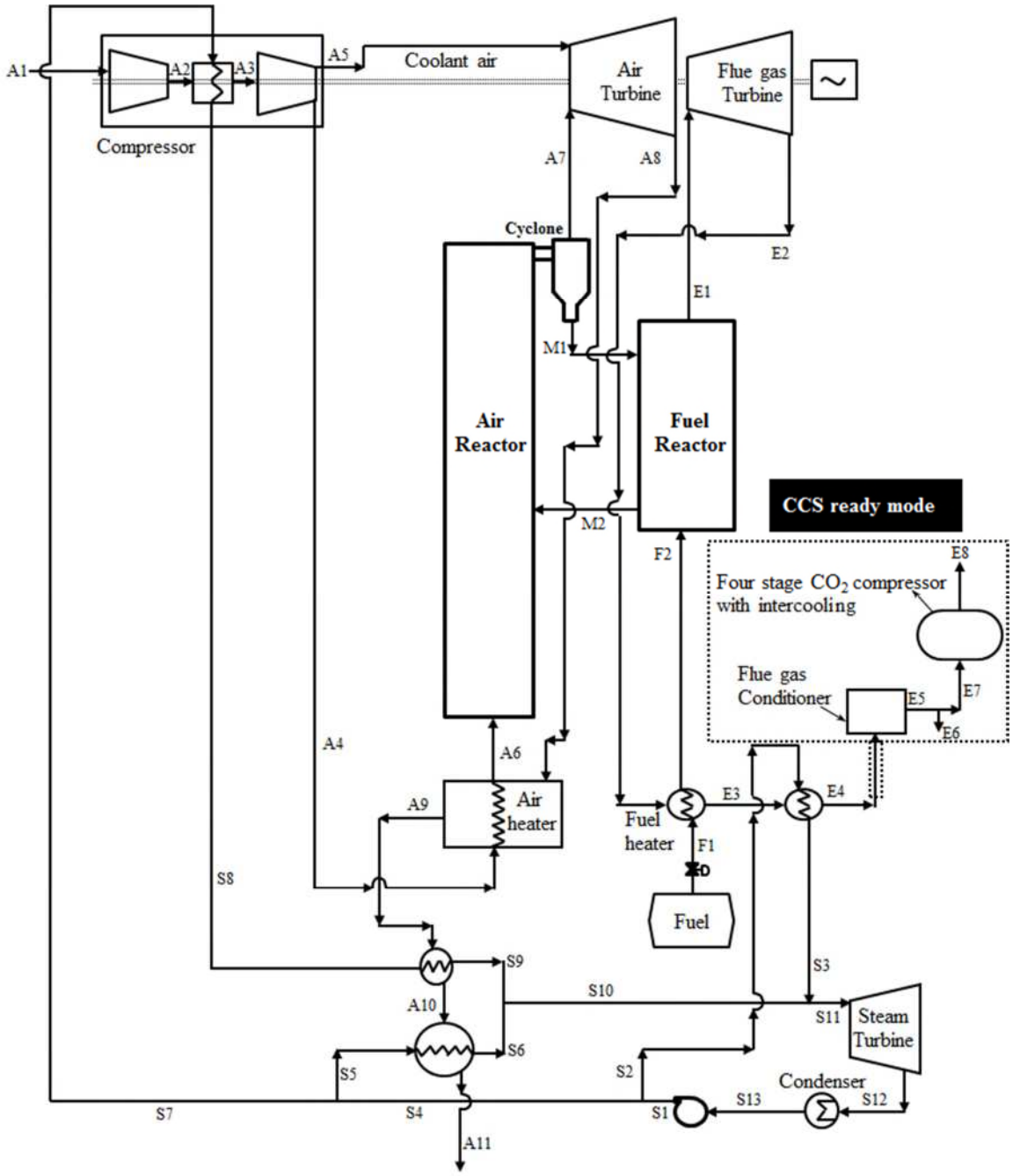

Figure 7: Schematic of natural gas fired 761 MW_{th} combined cycle chemical-looping combustion power plant with provision of carbon capture

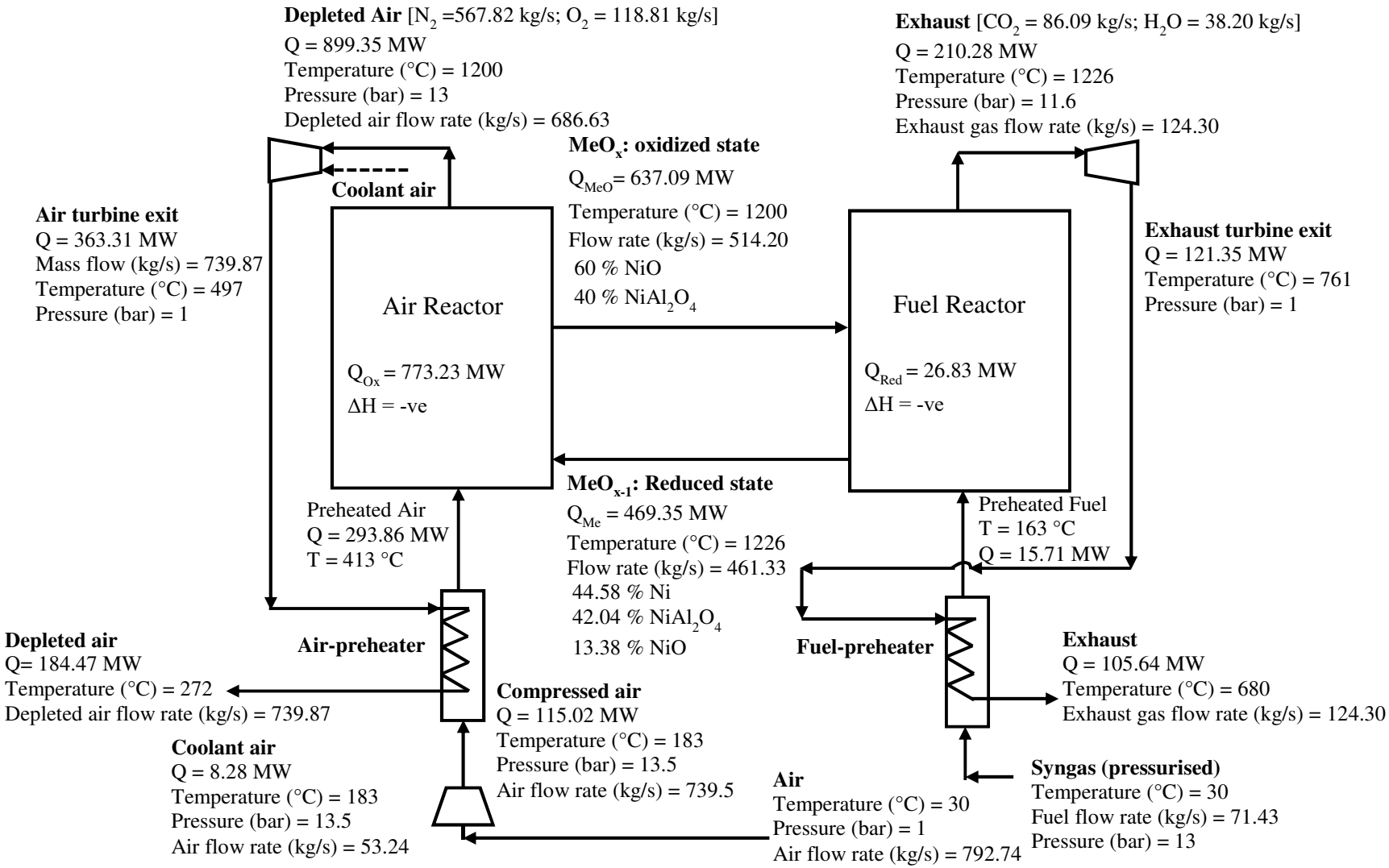

Figure 8: Furnace side heat balance for 800 MW_{th} syngas fueled combined cycle CLC based power plant

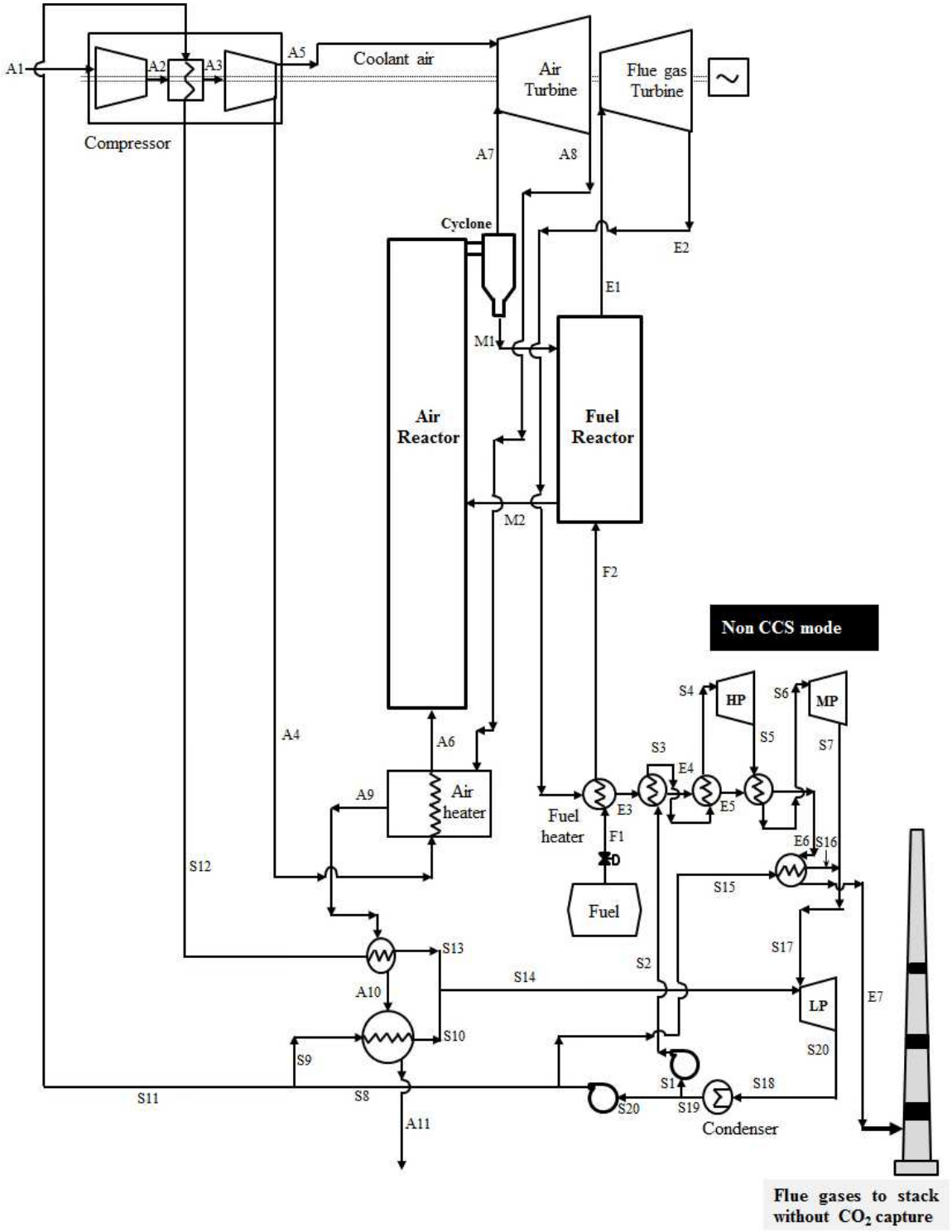

Figure 9: Schematic of syngas fueled combined cycle chemical-looping combustion power plant without the provision for carbon capture

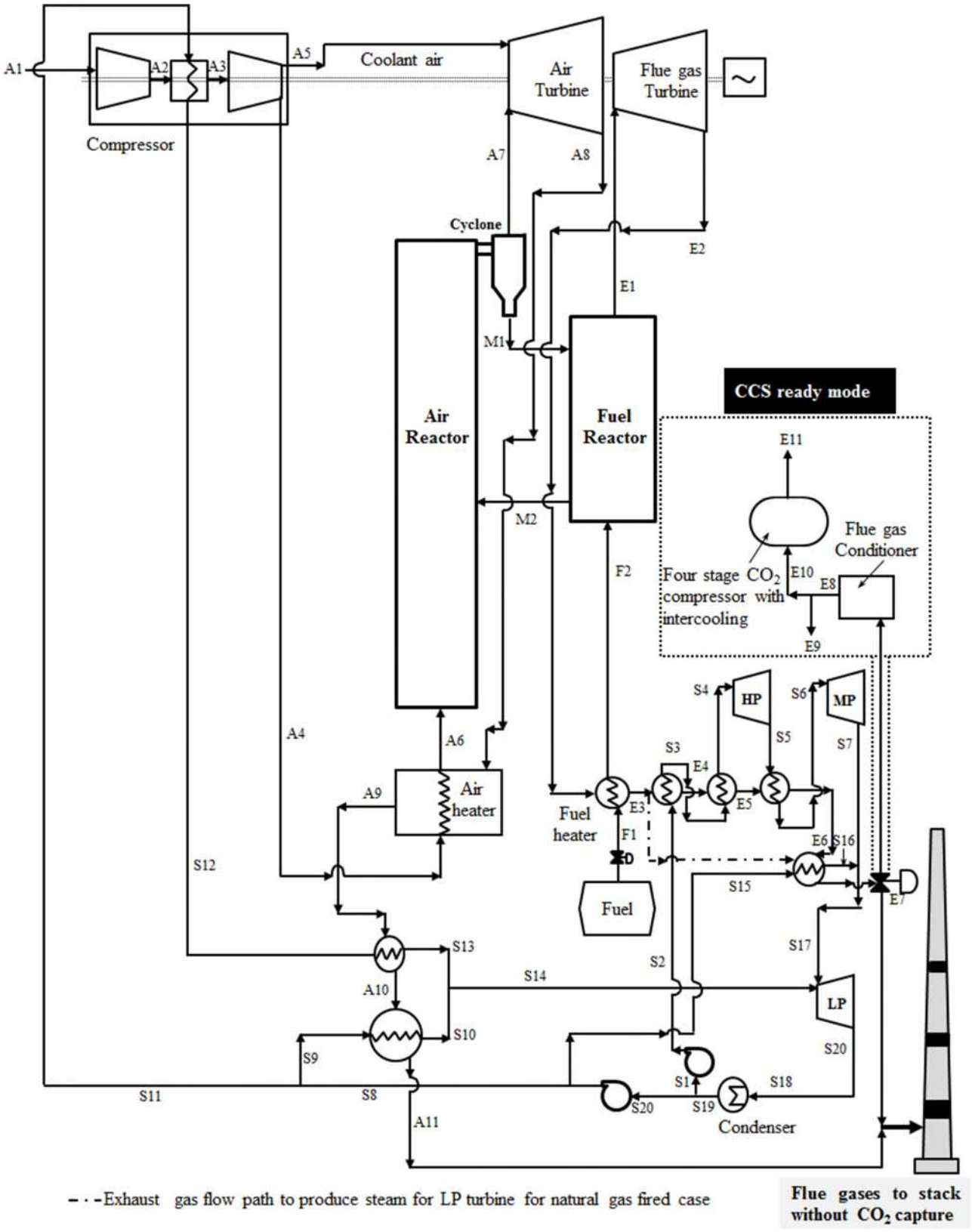

Figure 10: Schematic diagram of multi-fuel compatible combined cycle CLC based power plant lay-out with provisions for, with CCS and, without CCS modes

Table 1: Detailed thermodynamic analysis of natural gas fueled 761 MW_{th} combined cycle chemical-looping combustion power plant

Stream	T (°C)	T (K)	P (bar)	m (kg/s)	h (kJ/kg)
Air					
A1	30	303.15	1.01	870.12	0.00
A2	152	425.15	3.43	870.12	123.71
A3	35	308.15	13.50	870.12	5.02
A4	177	450.15	13.50	811.68	149.37
A5	177	450.15	13.50	58.44	149.37
A6	420	693.15	13.50	811.68	404.77
A7	1200	1473.15	13.00	751.99	1298.12
A8	497	770.15	1.01	810.43	491.62
A9	241	514.15	1.01	810.43	216.94
A10	234	507.15	1.01	810.43	209.92
A11	74	347.15	1.01	810.43	44.34
Fuel					
F1	30	303.15	13.00	15.47	0.00
F2	350	623.15	13.00	15.47	1607.00
Exhaust					
E1	1150	1423.15	11.60	75.1	1720.79
E2	1036	1309.15	1.01	75.1	211.06
E3	463	736.15	1.01	75.1	568.26
E4	128	401.15	1.01	75.1	72.03
E5	40	313.15	1.01	75.1	23.56
E6	40	313.15	1.05	34	41.72
E7	40	313.15	1.05	41.1	8.54
E8	35	308.15	110.00	41.1	4.26
Oxygen carrier					
M1	1200	1473.15	13.00	580.52	1254.49
M2	1150	1423.15	11.60	520.83	963.85
Steam/water					
S1	31	304.15	1.70	104.81	4.17
S2	31	304.15	1.70	18.13	4.17
S3	190	463.15	1.70	13.07	2852.17
S4	31	304.15	1.70	86.68	4.17
S5	31	304.15	1.70	46.95	4.17
S6	190	463.15	1.70	46.95	2852.17
S7	31	304.15	1.70	39.73	4.17
S8	120	393.15	1.70	39.73	2709.16
S9	190	463.15	1.70	39.73	2852.17
S10	190	463.15	1.70	86.68	2852.17
S11	190	463.15	1.70	104.81	2852.17
S12	39	312.15	0.07	104.81	2571.70
S13	30	303.15	1.01	104.81	0.00

Table 2: Detailed thermodynamic analysis of syngas fueled 800 MW_{th} combined cycle chemical-looping combustion

Stream	T (°C)	T (K)	P (bar)	m (kg/s)	h (kJ/kg)	Stream	T (°C)	T (K)	P (bar)	m (kg/s)	h (kJ/kg)
Air						Oxygen carrier					
A1	30	303.15	1.01	792.74	0.00	M1	1200	1473.15	13	514.20	1238.99
A2	152	425.15	3.43	792.74	123.71	M2	1226	1499.15	11.6	461.33	1017.38
A3	35	308.15	13.5	792.74	5.02	Steam/water					
A4	183	456.15	13.5	739.50	155.54	S1	30	303.15	1.01	9.64	0.00
A5	183	456.15	13.5	53.24	155.54	S2	31	304.15	150	9.64	4.18
A6	413	686.15	13.5	739.50	397.37	S3	185	458.15	150	9.64	792.24
A7	1200	1473.15	13	686.63	1309.80	S4	450	723.15	150	9.64	3157.84
A8	497	770.15	1.01	739.87	491.04	S5	325	598.15	20	9.64	3081.50
A9	272	544.94	1.01	739.87	249.32	S6	470	743.15	20	9.64	3402.01
A10	266	539.15	1.01	739.87	243.07	S7	190	463.15	1.7	9.64	2852.17
A11	75	348.15	1.01	739.87	45.71	S8	31	304.15	1.7	86.97	4.18
Fuel						S9	31	304.15	1.7	50.97	4.18
F1	30	303.15	13	71.43	0.00	S10	190	463.15	1.7	50.97	2852.17
F2	163	436.15	13	71.43	219.96	S11	31	304.15	1.7	36.00	4.18
Exhaust						S12	127	400.15	1.7	36.00	2723.90
E1	1226	1499.15	11.8	124.30	1691.73	S13	190	463.15	1.7	36.00	2852.17
E2	761	1034.15	1.01	124.30	976.25	S14	190	463.15	1.7	86.97	2852.17
E3	680	953.15	1.01	124.30	849.85	S15	31	304.15	1.7	21.93	4.18
E4	640	913.15	1.01	124.30	788.41	S16	190	463.15	1.7	21.93	2852.17
E5	517	790.15	1.01	124.30	604.96	S17	190	463.15	1.7	31.57	2852.17
E6	500	773.15	1.01	124.30	580.09	S18	39	312.15	0.069	118.54	2571.79
E7	128	401.15	1.01	124.30	76.98	S19	30	303.15	1	118.54	0.00
E8	40	313.15	1.01	124.30	23.56	S20	30	303.15	1	108.90	0.00
E9	40	313.15	1.05	38.20	41.72						
E10	40	313.15	1.05	86.09	8.54						
E11	35	308.15	110	86.09	4.26						

Table 3: Energy analysis of combined cycle CLC based power plants operating in CCS and non CCS modes

Power produced/consumed	Natural gas CC CLC		Syngas CC CLC	
	CCS Mode	**Non CCS Mode**	**CCS Mode**	**Non CCS Mode**
Power produced				
Air turbine (kW_e)	596,064	596,064	544,302	544,302
Carbon dioxide rich gas turbine (kW_e)	61,674	61,674	88,934	889,34
Steam turbine power (kW_e)	29,396	29,396	39,253	39,253
Power consumed				
Air compression (kW_e)	275,716	275,716	251,197	251,197
CO_2 compression to 110 bar (kW_e)	***14,721***	**-**	***30,842***	**-**
Water pump cost (kW_e)	10	10	202	202
Available power (kW_e)	396,6877	411,408	390,248	421,091
Thermal input (kW_e)	761,000	761,000	800,061	800,061
Net Efficiency (%)	52.13	54.06	48.78	52.63

Table 4: Overall energy analysis for combined cycle CLC

Comparative analyses of Combined Cycle Chemical Looping combustion power plants			
Variants	*Syngas Lay-out*	*Natural gas lay-out*	*Natural gas lay-out (Naqvi, 2007)*
Air reactor operating temperature (°C)	1200	1200	1200
Fuel reactor operating temperature (°C)	1226	1150	980
Temperature of 13 bar pressure oxygen depleted air at air turbine inlet (°C)	1132	1132	1140
Temperature of 1 bar pressure oxygen depleted air at air turbine exit (°C) (at 92% isentropic efficiency)	497	497	492
CLC fuel reactor exhaust gas turbine inlet temperature (°C) at pressure 11.6 bar	1226	1150	980
CLC fuel reactor exhaust exit temperature (°C) at 1 bar (at 92% isentropic efficiency)	761	666	533
Mass flow rate of depleted air at air turbine inlet/exit after addition of coolant air in CC CLC (kg/s)	739.87	810.43	768
Mass flow rate of fuel reactor exhaust gas at exhaust gas inlet/exit in CC CLC (kg/s)	124.30	75.1	70.5
CLC Air turbine inlet/exit gas composition (wt %)	82.7 % N_2 and 17.3 % O_2	82.85 % N_2 and 17.15% O_2	83 % N_2 and 17 % O_2
CLC exhaust gas turbine inlet/exit gas composition (wt %)	30.63 % H_2O and 69.37 % CO_2	45.32 % H_2O and 54.68 % CO_2	45.32 % H_2O and 54.68 % CO_2
CO_2 purity (wt %) for CCS	>99	>99	99
Power produced			
Air turbine (kW_e)	544,302	596,064	477,000
Carbon dioxide rich gas turbine (kW_e)	88,934	61,674	53,600
Steam cycle	150 bar at 450°C (736 kW), 20 bar at 470°C (5,301.5 kW) 1.7 bar at 190°C (33,216 kW)	1.7 bar at190°C	60 bar at 467°C, 5 bar at 258°C
Steam turbine power (kW_e)	39,253	29,396	101,000
Power consumed			
Air compression (kW_e)	251,197	275,716	243,000
CO_2 compression (kW_e) (Compressor efficiency 85%)	30,842 (to 110 bar)	14,721 (to 110 bar)	15,400 (to 200 bar)
Water circulation cost (kW_e) (Pump efficiency 75%)	202 (1 to 150 bar)	10 (1 to 1.7 bar)	-
Available power (kW_e)	390,248	395,267	364,000
Thermal input (kW)	800,061	761,000	697,545
Net Efficiency (%)	48.78	52.13	52.18