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Sequential supplementary firing in natural gas combined cycle with carbon capture: A technology option for Mexico for low-carbon electricity generation and CO_2 enhanced oil recovery

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ABSTRACT

Combined cycle gas turbine power plants with sequential supplementary firing in the heat recovery steam generator could be an attractive alternative for markets with access to competitive natural gas prices, with an emphasis on capital cost reduction, and where supply of carbon dioxide for Enhanced Oil Recovery (EOR) is important. Sequential combustion makes use of the excess oxygen in gas turbine exhaust gas to generate additional CO_2, but, unlike in conventional supplementary firing, allows keeping gas temperatures in the heat recovery steam generator below 820 °C, avoiding a step change in capital costs. It marginally decreases relative energy requirements for solvent regeneration and amine degradation. Power plant models integrated with capture and compression process models of Sequential Supplementary Firing Combined Cycle (SSFCC) gas-fired units show that the efficiency penalty is 8.2% points LHV compared to a conventional natural gas combined cycle power plant with the same capture technology. The marginal thermal efficiency of natural gas firing in the heat recovery steam generator can increase with supercritical steam generation to reduce the efficiency penalty to 5.7% points LHV. Although the efficiency is lower than the conventional configuration, the increment in the power output of the combined steam cycle leads a reduction of the number of gas turbines, at a similar power output to that of a conventional natural gas combined cycle. This has a positive impact on the number of absorbers and the capital costs of the post combustion capture plant by reducing the total volume of flue gas by half on a normalised basis. The relative reduction of overall capital costs is, respectively, 15.3% and 9.1% for the subcritical and the supercritical combined cycle configurations with capture compared to a conventional configuration. For a gas price of \$2/MMBTU, the Total Revenue Requirement (TRR) – a metric combining levelised cost of electricity and revenue from EOR – of subcritical and supercritical sequential supplementary firing is consistently lower than that of a conventional NGCC by, respectively, 2.2 and 5.7 \$/MWh at 0 \$/t CO_2 and by 4.9 and 6.7 \$/MWh at \$50/t CO_2. At a gas price of \$4/MMBTU and \$6/MMBTU, the TRR of a subcritical configuration is consistently lower for any carbon selling price higher than 2.5 \$/t CO_2 and 37 \$/t CO_2 respectively.

1. Introduction

Annual electricity demand in Mexico is predicted to grow by 72% from 259 to 446 TWh_e between 2011 and 2026 (Mexican Ministry of Energy, 2012). It is expected that this rising demand for electricity would be met by an increase in the use of both coal and gas, with natural gas being the dominant energy source in 2027. In the past 10 years, the fraction of natural gas in electricity generation in Mexico increased significantly from 17.1% (32.9 TWh_e) in 2000 to 50.4% (130.6 TWh_e) in 2011 (Mexican Ministry of Energy, 2012). In this context of rapid electrification dominated by natural gas power plants, Mexico intends in parallel to reduce "its greenhouse gas (GHG) emissions by 50% below 2000 levels by 2050" (CTF/TFC, 2009). In 2012, the Mexican Congress approved the "General Climate Change Law" to reduce GHG emissions, and recent policies recognise the potential for Enhanced Oil Recovery (EOR) and shale gas opportunities. One of the strategies proposed to reach this objective is the application of Carbon Capture and Storage (CCS) on fossil fuel power plants for the purpose of EOR in the oil industry, which relies on the availability of the large amounts of CO_2 (Lacy et al., 2013; Mexican Ministry of Energy, 2012) between 2020 and 2050.

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The triple challenge of rapid electrification through natural gas, reducing CO_2 emissions in power generation and rolling out Enhanced Oil Recovery at national level requires an important R&D effort to develop nationally relevant CCS technology options. The outcome could then be implemented in the current technology roadmap for the design of new build CCS-EOR ready NGCC power plants, to facilitate incorporating CO_2 capture technologies and EOR into the future energy mix. This paper presents the results from a techno-economic study of power plant configurations dedicated to address this triple challenge. It involves the sequential supplementary firing of natural gas in the heat recovery steam generator of a natural gas combined cycle power plant, followed by the removal of carbon dioxide in a post-combustion scrubbing amine-based capture unit to supply CO_2 for EOR. This capture technology has, at the time of writing, been deployed at commercial scale at the Boundary Dam power plant in Canada. It is particularly relevant in the context of a technology roadmap for CCS released by the Mexican Ministry of Energy, recommending actions at national level until 2024 with a particular focus on developing solvent absorption technologies linked to natural gas combined cycle plants (Mexican Ministry of Energy, 2014).

2. Sequential supplementary firing with CO_2 capture

2.1. Introduction to the concept

Non-sequential, single stage, supplementary firing is typically used in Natural Gas Combined Cycle (NGCC) power plants to increase power output by around 30% during times of peak demand of electricity and high electricity selling prices (Kiameh, 2003). Li et al. (2012) proposed to implement supplementary firing in gas-fired power plants with carbon capture. They reported a concentration of O_2 of 5.6% v/v in the exhaust gas, compared to 12.4% v/v without supplementary firing. The temperature difference at the high pressure superheater header of the heat recovery steam generator (HRSG) increases from 50 °C to 800 °C leading to a gas temperature of 1280 °C and large heat transfer irreversibilities, compared to a gas temperature around 530 °C. In both cases, high pressure steam temperature is 480 °C. Single stage supplementary firing requires advanced alloys to cope with the maximum temperature achievable, which then restricts the amount of supplementary fuel that can be used. Modifications to the HRSG design to withstand higher temperatures are, however, compensated by higher CO_2 concentrations at the capture unit inlet.

Sequential combustion effectively makes use of the excess oxygen necessary for gas turbine combustion to generate additional CO_2 and allows to keep temperature around 800–900 °C, an achievable range within a heat recovery steam generator with supplementary firing (Kehlhofer et al., 2009). The last stage of supplementary firing brings oxygen close to stoichiometric limits (1% v/v). This corresponds to an excess air around 5% v/v. Gas and oil fired boilers used in utility and industrial steam generation applications typically operate with an excess air in the range of 5–10% v/v, resulting in oxygen levels in the combustion gas of the order of 1–2% v/v (Steam its generation and use, 2005, pp. 11.4). In the context of sequential combustion in HRSG at low excess oxygen, this suggest that complete combustion with oxygen levels as low as 1% v/v may be practically achievable with good air/fuel mixing with appropriate burner design.

The resulting flue gas of sequential combustion is then more comparable to the flue gas of a coal plant, which facilitates the incorporation of post-combustion CO_2 capture by addressing three specific challenges associated with natural gas flue gas:

A.) CO_2 concentration in the exhaust gas: a low concentration of CO_2 in the exhaust gases affects the electricity output penalty of capture because of a lower driving force for CO_2 absorption and an associated increase in both absorber size and solvent energy of regeneration (Li et al., 2012). CO_2 concentrations in the exhaust gases are typically 10–15% v/v in a coal power plant and 3–4% v/v in a gas turbine. They increase to 9.4% v/v with the configuration with five stages of sequential supplementary firing in this article.

B.) Large exhaust gas volumes leading to higher capital costs: With five stages of supplementary firing, the overall flue gas flow rate entering the capture plant is around 50% of the flow rate of a standard NGCC plant with post-combustion capture with the same power output.

C.) O_2 concentration: large amounts of excess air necessary for gas turbine operation, typically 200%, result in high O_2 concentration in gas turbine exhaust composition, around 12.3% v/v (IEAGHG, 2012), increasing solvent oxidative degradation and operational costs (Goff and Rochelle, 2004). With five stages of sequential supplementary firing, the O_2 concentration is around 1.3% v/v at the inlet of the absorber.

Burning supplementary fuel in consecutive stages increases the heat available in the HRSG and leads to a larger combined cycle power output and a reduction of the number of the GT trains, at constant power output. This also has a positive impact on the number of absorbers and the capital costs of the post combustion capture plant by reducing the total volume of flue gas by half on a normalised basis. It decreases marginally the energy requirements for solvent regeneration and marginally reduces amine degradation. In practice, the overall thermal efficiency of a SSFCC plant is lower than that of a standard NGCC. One useful metric is the marginal thermal efficiency of the additional natural gas combustion, as proposed in Eq. (1). This is defined as the ratio of the increment in power output to the added fuel input in the HRSG:

$$\eta_{\text{marg}} = \left[\frac{W_{SF} - W_0}{M_{SF} LHV}\right] \quad (1)$$

where η_{marg} is the marginal efficiency, W_0 is the power output of steam turbine of conventional NGCC plant (MW), W_{SF} is the power output of the steam turbine of a plant with sequential supplementary firing (MW), M_{SF} is the mass flow of supplementary fuel in the HRSG and LHV is the fuel low heat value (MJ/kg). In principle, Eq. (1) can be used to compare power plants without and with capture.

2.2. Steam cycle and heat recovery design with sequential supplementary firing

A configuration with two stages of supplementary firing with subcritical steam cycle is presented in Kehlhofer et al. (2009). Natural gas fired is burnt at two locations in the primary heat exchange section. Information related to the values of final CO_2 and O_2 concentration in the flue gas is not provided. The flue gas temperature is increased after the gas turbine via a first stage of firing to a maximum temperature around 750 °C and enters a superheater heat exchanger. Natural gas is then fired again in a second stage followed by an evaporator.

The power plant configurations proposed in this article are based on existing patents, manufacturer data and are, to an extent, analogous to the concept proposed by Kehlhofer et al. (2009) and to a concept for supplementary firing with supercritical steam conditions, proposed by Wylie (2004), with the exception that carbon capture is not included. Wylie (2004) proposed to fire supplementary fuel in three stages through a single pressure HRSG with a supercritical steam turbine to improve the efficiency of the cycle. Natural gas fired is fired at three points in the primary heat exchange section in order to mitigate high peak temperatures in the HRSG when generating supplementary power. The peak temperature reached is 760 °C, however, the values of final CO_2 and O_2 concentration in the flue gas are not provided. On the other hand, Ganapathy (1996) suggests that higher maximum temperatures are possible by introducing other modifications in the HRSG. For instance, a temperature of 927 °C is achievable with the use of insulated casings and up to 1316 °C when equipped with water-cooled furnaces. In order to avoid including advanced alloys, boiler design consisting of water-cooled furnaces and excessive capital expenditure, exhaust gas temperatures can be kept at a maximum of 820 °C, a typical temperature in a conventional NGCC with supplementary firing (Thermoflow, 2013). Both the subcritical and supercritical configurations proposed here are based on this concept.

Two steam cycle configurations are possible with sequential supplementary firing: Supercritical steam conditions: 630 °C, 295 bar (McCauley et al., 2012; Salazar-Pereyra et al., 2011; Satyanarayana et al., 2011; Cziesla et al., 2009) and subcritical steam conditions: 601.7 °C, 172.5 bar (IEAGHG, 2012). In both cases, the maximum design temperature is a critical parameter for the design of the HRSG.

3. Sequential supplementary firing with a subcritical combined cycle

A techno-economic study of a subcritical combined cycle configuration is first compared to a reference plant consisting of a new-build NGCC plant with post-combustion capture in this section. The next section of the article examines the benefits of a supercritical combined cycle over a subcritical configuration. Both configurations examined here are equipped with a conventional HRSG, where the maximum temperature achievable is 820 °C. A model of the power cycle integrated with the capture plant is used to optimise performance and provide the basis for the techno-economic study. Appendix A lists the parameters used in the modelling of the power plants for all case studies.

3.1. Modelling and optimisation of subcritical SSFCC cycle alternative

The parameters involved in the optimisation of the overall thermal efficiency and the marginal thermal efficiency of the additional natural gas combustion in the HRSG are:

- the number of additional firing stages
- the amount of fuel burnt
- the pinch point temperature
- number of pressure levels in the HRSG, and steam pressure
- the stack temperature

Power plants configurations are simulated using Aspen HYSYS®. Setting the maximum HRSG temperature achievable allows for a given number of stages of supplementary firing with a minimum level of excess O_2 content in the flue gas for complete combustion. After the final firing stage the oxygen content in the flue gas is 1% v/v (Steam its generation and use, 2005, pp 11.4), which is sufficient to achieve complete combustion. The optimisation in Aspen HYSIS consists of maximising marginal efficiency and reducing heat transfer irreversibilities as much as possible by analysing different pressure levels of steam produced in the HRSG (triple, double or single pressure). The integration between the combined cycle and the capture plant consists of solvent regeneration steam being extracted from the crossover pipe between the intermediate pressure (IP) and the low pressure (LP) turbines of the steam cycle at a pressure 3 bar in order to allow optimum solvent regeneration of a 30% wt MEA solvent.

3.2. Modelling and optimisation of the CO_2 capture plant and compressor unit

All case studies have been integrated with a standard CO_2 capture plant using 30% wt MEA, as shown in Fig. 1. The CO_2 capture plant is simulated in Aspen plus® using a rate-based approach. The capture plant was validated by several authors based on various data sets from different pilot plants (Razi et al., 2013; Sanchez Fernandez et al., 2014). The performance of the absorber is estimated to find the optimum parameters such as lean loading, rich loading, absorber and stripper packing height, heat transfer area, and energy removed from the condenser, and the electricity output penalty (*EOP*) to achieve 90% CO_2 capture rate.

The electricity output penalty can be calculated from the net power output without capture; the net power output with CO_2 capture, which includes loses for steam extraction and electrical energy for CO_2 compressors and other archilleries; and the CO_2 captured as shown in Eq. (2).

$$EOP = \frac{MW_{\text{without/capture}} - MW_{\text{with/capture}}}{CO_2\ \text{captured}} \quad (2)$$

where *EOP* is the electricity Output Penalty (kWh/t CO_2), $MW_{\text{without/capture}}$ is the net power output without capture (kW), $MW_{\text{with/capture}}$ is the net power output with CO_2 capture and compressor unit (kW), and CO_2 captured is the amount of CO_2 capture (t/h).

The lean solvent loading of the MEA is varied to find the minimum *EOP* for a given CO_2 concentration in the flue gases. While studying the effect of different lean loading on the capture process, the stripper reboiler pressure is varied to change the values of the lean loading and the temperature is kept constant. The recommended temperature of the reboiler for MEA is 120 °C (Kohl and Nielsen, 1997; IEAGHG, 2010; Rochelle, 2009). It was verified to be optimal in the experimental results of Knudsen (2011) in a pilot plant with capacity to capture 1 t/h of CO_2 from the flue gas generated at the coal fired power plant operated by Dong in Esbjerg, Denmark (Sanchez Fernandez et al., 2013 after Knudsen, 2011). For each lean loading specified, the height of the absorber is then varied. At a given absorber height, the absorption solvent circulation rate is varied to achieve the same CO_2 removal capacity (90%).

The configuration of the compressor is selected with two trains of a gear-type centrifugal compressor with 7 stages and intercooling after each stage. It is designed for a nominal pressure ratio 80 and a CO_2 temperature of 40 °C after the intercoolers based on Liebenthal and Kather (2011) and Siemens (2009).

3.3. Conventional natural gas combined cycle configuration

The conventional case is a NGCC plant integrated with MEA-based CO_2 capture. The configuration and operating parameters for the conventional case is been taken from Parsons Brinckerhoff (IEAGHG, 2012). The configuration of the NGCC consists of two gas turbines and three steam turbines. Each train comprises of one GE 937 IFB gas turbine with flue gas exiting into a HRSG. The total steam generated in both HRSG's supply steam to a subcritical triple pressure steam cycle comprising of three steam turbines, as shown in Fig. 2.

The pinch diagram for the hot gas turbine exhaust and the steam cycle water/steam flow rates for the conventional case is shown in Fig. 3. The pinch temperature in the evaporator is 10 °C for the standard reference plant (Kehlhofer et al., 2009).

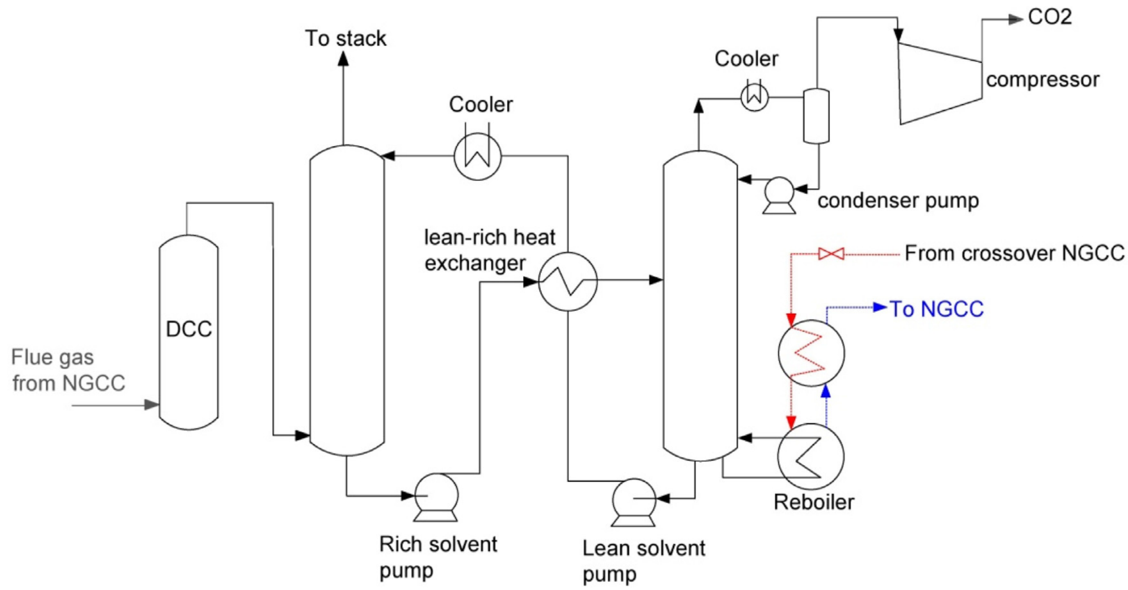

Fig. 1. Process flow diagram of the CO_2 capture process. DCC – direct contact cooler.

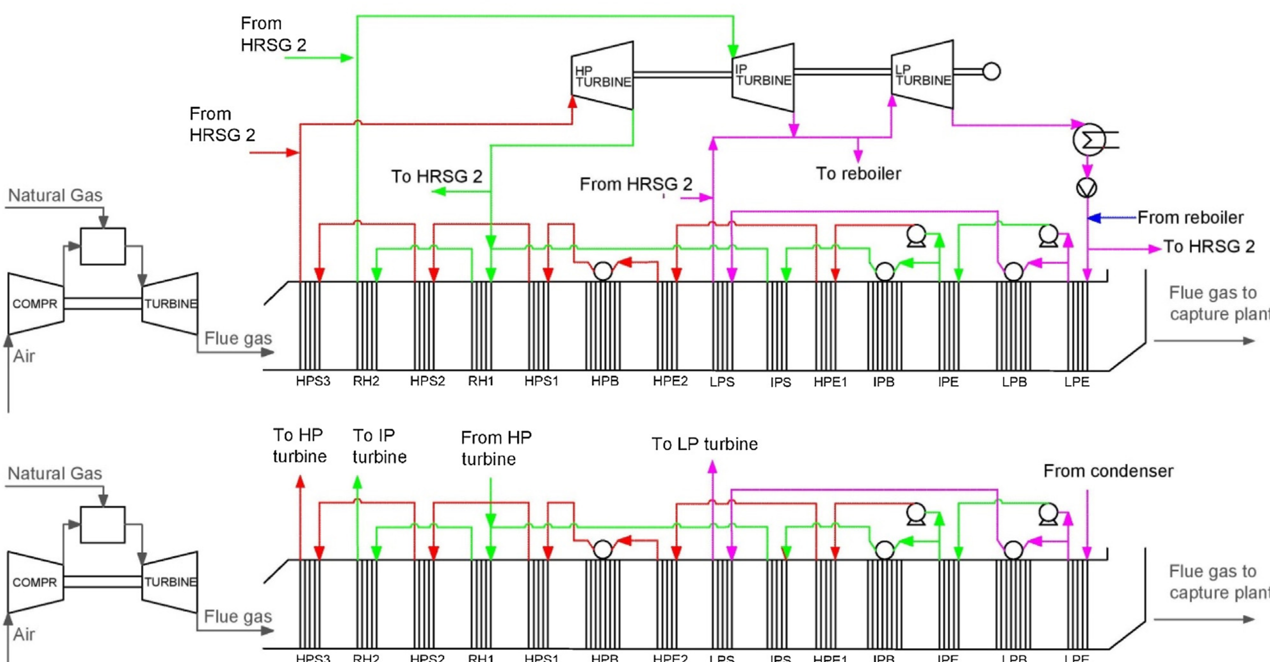

Fig. 2. Schematic process flow diagram of the conventional natural gas combined cycle configuration with two GE 937 IFB gas turbine, two triple pressure HRSGs and one subcritical steam turbine.

3.4. Subcritical SSFCC power plant configuration

Fig. 4 shows the pinch diagram for a configuration where the total amount of supplementary fuel is burnt using a single duct burner to reach 1% v/v O_2 in the flue gas, representing by a black dashed line. The temperature rises up to 1700 °C. With sequential supplementary firing, the total amount of natural gas is divided into five stages through the HRSG. As a result, the peak temperature is dropped to around 820 °C as shown in Fig. 4 representing by a black continue line. The total amount of natural gas burned in five stages in the HRSG is 22.3 kg/s. This corresponds to 57% of the total fuel input of the gas turbine and the HRSG.

The schematic process flow diagram shown in Fig. 5 is the optimum subcritical SSFCC configuration and consists of a single GE 937 IFB gas turbine followed by a single HRSG unit. The HRSG operates with a single pressure and provides steam to a single reheat steam cycle. Similar materials to that of a conventional HRSG (stainless steel 304) can be used.

Table 1 shows the inlet and outlet temperature, and the O_2 and CO_2 concentration in each duct burner. The inlet temperature, velocity, turbulence of the exhaust gas, and the burner configuration can lead to increasing the efficiency of combustion in a situation of low concentration of oxygen (Ditaranto et al., 2009). The main challenge may lay in the design of the last two duct burners (4th and 5th duct burners) where lower levels of oxygen compared

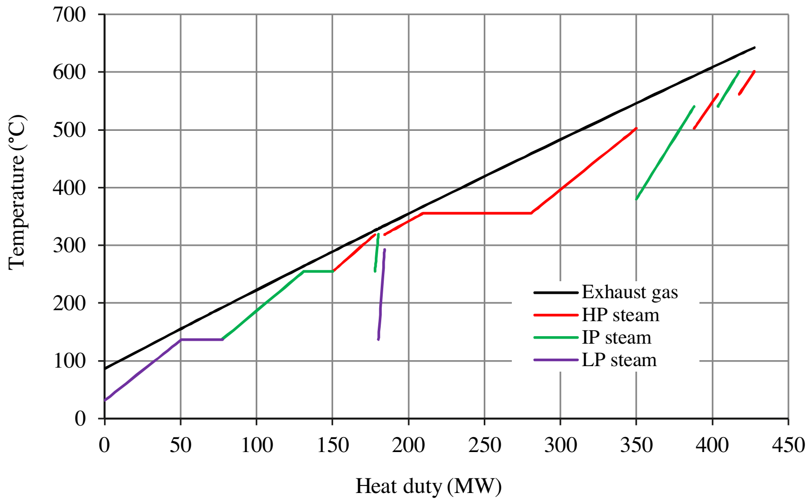

Fig. 3. Temperature/heat diagram for the Heat Recovery Steam Generator of the Natural Gas Combined Cycle plant (Fig. 2) with subcritical steam conditions (601.7 °C, 601.5 °C, 172.5 bar).

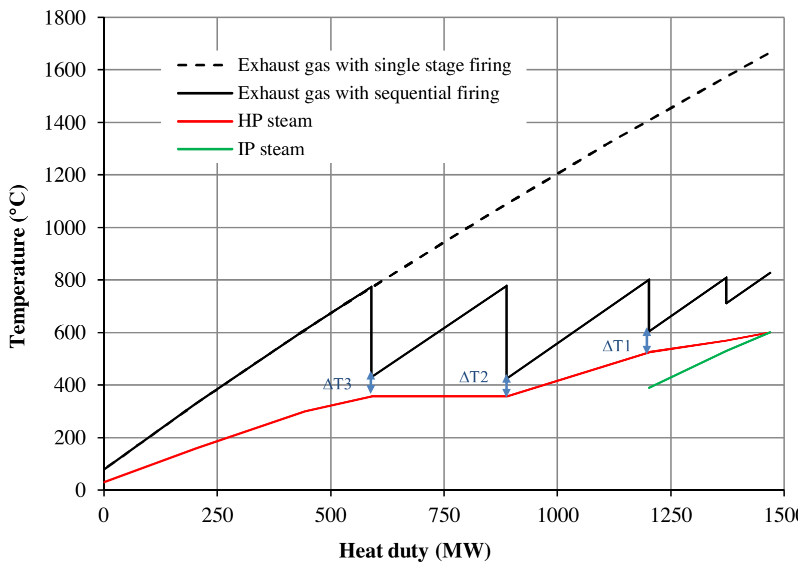

Fig. 4. Temperature/heat diagram of the Heat Recovery Steam Generator of a five stage sequential supplementary firing configuration with a single pressure HRSG, with a single reheat combined cycle and subcritical steam conditions (601.7 °C, 601.5 °C, 172.5 bar). The three pinch temperatures ΔT1, ΔT2, ΔT3 are respectively 76 °C, 70 °C, 79 °C.

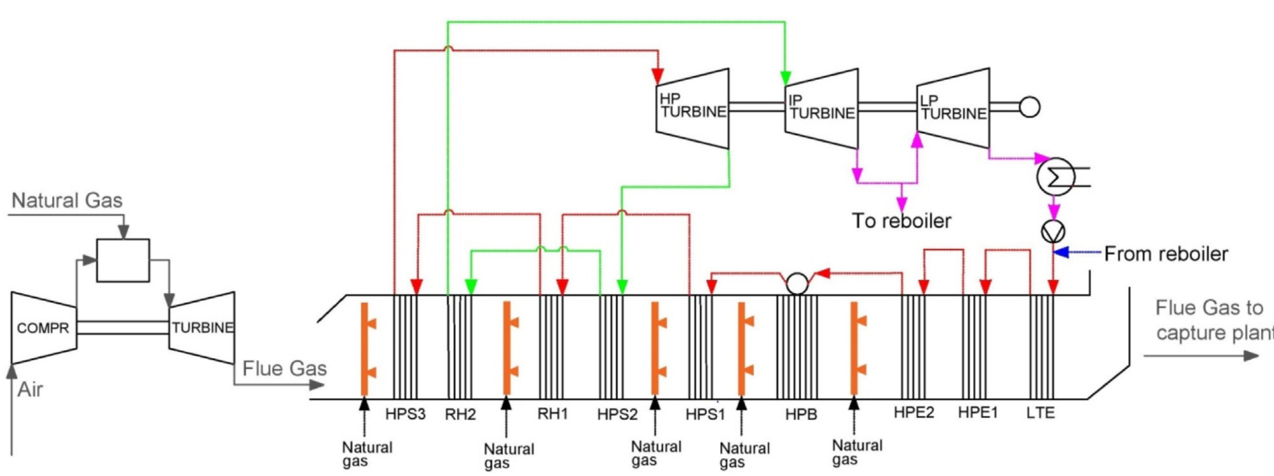

Fig. 5. Schematic process flow diagram of a subcritical sequential supplementary firing configuration with one GE 937 IFB/single pressure HRSG train combined with a single reheat steam cycle.

Table 1
Temperature, O_2 concentration, CO_2 concentration at the inlet of each duct burner for a subcritical sequential supplementary firing power plant.

	Temperature		Inlet O_2 concentration	Inlet CO_2 concentration	Exit equivalent excess Air
	Inlet (°C)	Outlet (°C)	% v/v	% v/v	% v/v
Duct burner 1	643	820	11.9	4.2	100
Duct burner 2	712	809	10.2	5.01	69
Duct burner 3	608	802	8.0	5.45	39
Duct burner 4	453	778	5.8	6.33	26
Duct burner 5	480	774	4.0	7.85	6

to the first three burners are present. High temperature can compensate for the low levels of oxygen and the combustion can be stabilised with simple burner ramps (Li et al., 2012). It is also worth reiterating that gas and oil fired boilers used in utility and industrial steam generation applications typically operate with an excess air in the range of 5–10% v/v (Steam its generation and use, 2005, pp 11.4), comparable to the 6% v/v of equivalent excess air at the inlet of the last burner.

Although the specific design of duct burners to operate within this range is outside the scope of this study, it is worth noting that the presence of higher levels of CO_2 compared to conventional gas and oil boilers requires further investigation of combustion stability and efficiency. If satisfactory combustion proved to be challenging in the final duct burner, this could lead to removing the burner and optimise the configuration to operating with one fewer burner, with possible higher outlet temperature to maximise natural gas usage.

3.5. Effect of sequential supplementary firing on power plant performance

Key parameters for the conventional NGCC configuration and subcritical SSFCC with CO_2 capture are described in Table 2. When supplementary fuel is burnt sequentially in a single one HRSG attached to a 295 MW gas turbine, the capacity of the steam cycle increases from 245 MW to 545 MW. The corresponding total net power of the SSFCC is 781 MW, similar to the conventional NGCC configuration with 794 MW. As in SSFCC only one gas turbine is used, the total volume of the exhaust gases is reduced by half. It has a positive impact on the number of direct contact coolers (DCC) and absorbers of the capture plants.

Although the efficiency of the subcritical SSFCC configuration is of the order of 43.1% LHV, compared to 51.3% LHV for a standard NGCC plant with capture, there are significant capital cost implications for the gas turbine, the heat recovery steam generator, the steam cycle, the absorber trains and the stripper/compression part of the capture plant and the potential for additional revenue from EOR:

- The SSFCC configuration makes use of a single gas turbine/HRSG train compared to two gas turbine/HRSG trains for a standard configuration.
- The number of absorber trains is reduced from four to two, as previously discussed.
- The capacity of the stripper and the compression train is increased by around 17.7%.

3.6. Effect of increased CO_2 concentration on solvent energy of regeneration and absorber column design

The combustion of additional natural gas in the HRSG increases the CO_2 concentration in the flue gas from 4.2% v/v to 9.36% v/v, whilst reducing the excess oxygen to 1.3% v/v. The optimum lean loading for a NGCC configuration with capture reaches 0.27 mol CO_2/mol MEA and 0.26 mol CO_2/mol MEA for a SSFCC configuration. The higher rich loading achieved with higher CO_2 concentration leads to an increase in solvent capacity and the specific reboiler duty decreases from 3.56 to 3.42 GJ/t CO_2 for a configuration with 21 m of structured packing height in the absorber columns as shown in Fig. 7. This is illustrated in Fig. 6 where the optimisation of the overall electricity output penalty with solvent lean loading is reported.

Columns with very large diameters are not recommended. There is a maximum volume flow rate of 300,000 m^3/h (292.5 t/h approximately) which could be treated in an absorber column due to economic limits of the size of the absorber (Desideri and Paolucci, 1999; Yagi et al., 1992). For systems that require the processing of a larger flow, a modular design with several trains operating in parallel is adopted. Rezazadeh et al. (2015) after Reddy et al. (2003) reported that the maximum diameter for an absorber column under operation is 18.2 m. In subcritical SSFCC, the total flue gas flow rate is 696 kg/s containing 93 kg/s of CO_2 compared with a conventional NGCC where total flue gas flow rate is 1347 kg/s which contain 79 kg/s that can be seen in Table 2. Then based on the argument described previously related to the capacity of the absorber, the flue gas flow rate of one train of SSFCC is 348 kg/s which contain 46.5 kg/s of CO_2 and the flue gas flow rate of one train of the NGCC is 336.8 kg/s which contain 19.75 kg/s. The final configuration of SSFCC is: two DCC and two absorbers; and two stripper columns and two rich/lean heat exchangers. For NGCC: four DCC and four absorbers; and two stripper columns and two rich/lean heat exchangers.

The reduction by approximately 50% of the overall gas flow rates has a positive impact on the capital costs of the DCC and absorber columns which are reduced from four to two columns. The height of the absorber for SSFCC and the NGCC are optimised, based on the reduction of the reboiler duty, for the CO_2 content in flue gas and 90% capture and both arrive at the same height of 21 m of packing in each absorber column.

3.7. Comparison of cost of electricity

The main objective of this economic study is to compare the expected cost of electricity, taking into account revenues from EOR, of a SSFCC configuration with a conventional NGCC. There are important differences between both configurations, such as thermal efficiency, size of critical pieces of equipment, operational costs. In this study, the direct comparison of the expected costs of sequential supplementary firing with a conventional configuration, using consistent sources of information ensures that error and inaccuracies in capital costs are mitigated. A sensitivity analysis is also provided to examine the robustness of the findings over a range of capital cost estimates to account for the associated estimate uncertainties.

Cost estimation for all configurations is based on a methodology proposed in Rubin et al. (2013). Appendix B describes the methodology and the sources of information in more details. Capital costs of the MEA-based CO_2 capture and compression system for NGCC are not calculated and are based on the estimation given by IEAGHG (IEAGHG, 2012). In that report, the cost is given for different sections of the plant, which makes it possible to determine the

Table 2
Summary of key parameters of a SSFCC with single pressure subcritical steam cycle with CO_2 capture (Saturated vapour at 3 bar is used in the reboiler).

Concept	Unit	NGCC	SSFCC subcritical
LHV net electric efficiency[a]	%	51.3	43.1
Gas turbine power output GT	MW	590	296
Steam cycle power output	MW	245	545
Total LHV gross power output	MW	835	840
Total LHV net power output (including CO_2 compression and other ancillaries)	MW	794	781
Mass flow rate of natural gas to gas turbine	kg/s	33.2	16.6
Mass flow rate of natural gas for supplementary firing	kg/s	NA	22.2
Marginal efficiency of natural gas fired in HRSG (LHV)	%	NA	36
Marginal efficiency of natural gas fired in HRSG (LHV) without post-combustion capture (for comparative purpose purposes only)	%	NA	44.7
Electricity output penalty (*EOP*)	$kWh_e/t\ CO_2$	408	362
Carbon intensity of electricity generation	$kgCO_2/MWh$	39.8	47.5
Flue gas mass flow rate	kg/s	1347	696
Flue gas composition after direct contact cooler			
Water (H_2O)	% vol	4.29	4.29
Carbon dioxide (CO_2)[b]	% vol	4.37	10.87
Oxygen (O_2)	% vol	12.5	1.3
Nitrogen (N_2)	% vol	78.8	83.5
CO_2 mass flow to pipeline	kg/s	79	93
Capture level	%	90	90
Solvent energy of regeneration	$GJ/t\ CO_2$	3.56	3.42
Steam mass flow to solvent reboiler	kg/s	145	146
Number of absorber trains		4	2
Diameter	m	15.5	15.5
Absorber height	m	21	21
Flue gas mass flow rate at each absorber inlet	kg/s	337	348
Volume of packing used for CO_2 capture (not including water wash sections)	m^3	16,260	8130

[a] LHV net electric efficiency includes CO_2 compression and parasitic losses and transformed losses.
[b] The concentration of the CO_2 presented in Table 2 is the concentration of the exhaust gas after the direct contact cooler. It is higher than in the HRSG after condensation of a fraction of the water contained in the flue gas.

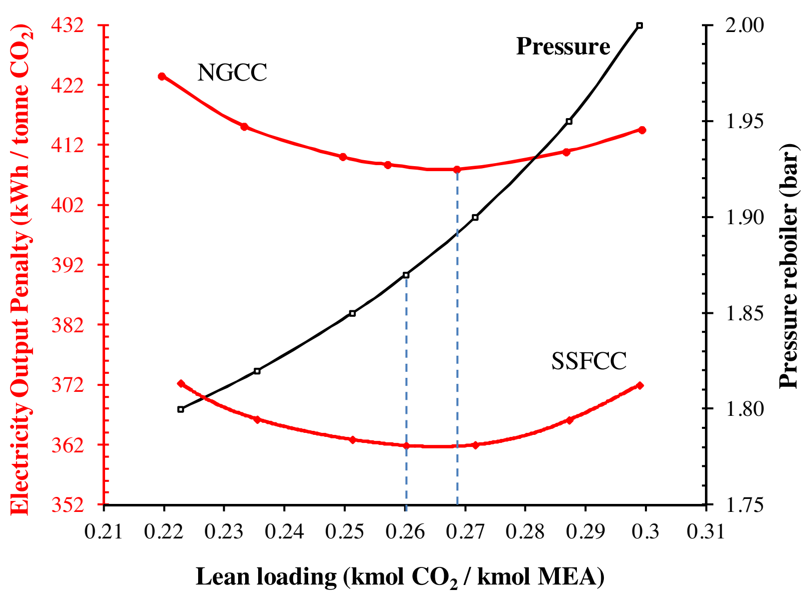

Fig. 6. Optimisation of electricity output penalty for a natural gas combined cycle (NGCC) and for sequential supplementary firing combined cycle (SSFCC) as a function of solvent lean loading, with a CO_2 removal rate of 90% and stripper temperature of 120 °C. The CO_2 concentration in the flue gas is, respectively, 4.2 mol% and 9.4% for a NGCC configuration and a SSFCC configuration. The blue dotted lines indicate the optimum solvent lean loading. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

cost of capture plant for a SSFCC configuration. The total volume of packing of the absorber and the stripper and the area of heat exchangers are used to analyse the implications on the required capital expenditure (CAPEX).

The specific investments of the conventional NGCC and subcritical SSFCC cases have been evaluated and are reported in Table 3. The net specific investment estimated for the NGCC case is 773 $/kW, which increases to 1698 $/kW when the CO_2 capture unit is incorporated. The results of the NGCC are in good agreement with other published sources (Gas Turbine Handbook, 2013; IEAGHG, 2012; Franco et al., 2012), and with the predictions of the commercial software PEACE/GT-PRO (Thermoflow, 2013). Table 3 shows a reduction in total specific investment for the subcritical SSFCC with CO_2 capture configuration of 15.32%, from 1698 $/kW to 1438 $/kW. This is due to a reduction in the cost of the absorption part of the capture unit and in a reduction of the cost of the HRSG caused by a reduction in the total volume of exhaust gas. The reduction of the volumetric flow leads a reduction in cross sectional area. Also,

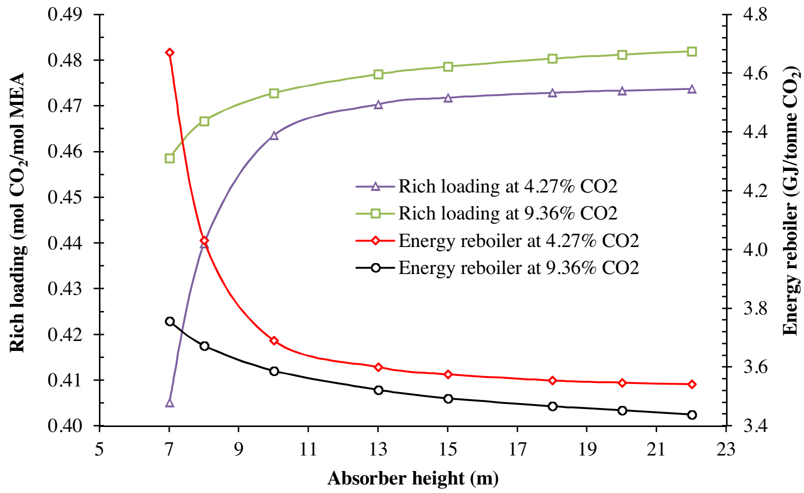

Fig. 7. Effect of CO_2 concentration in the flue gas on solvent energy of regeneration for a range of absorber column heights. The capture rate is 90%. The lean loading and pressure in the reboiler are, respectively, 0.27 and 1.9 bar for the NGCC configuration and 0.26 and 1.9 bar for the SSFCC configuration.

Table 3
Estimated specific investment for the natural gas combined cycle with and without capture and subcritical sequential supplementary firing combined cycle with capture.

Plant component	Unit	NGCC	NGCC w/capture	Subcritical SSFCC w/capture
Gross power output	MW	928	835	839.7
Net power output	MW	909	794	781
Power plant main items				
Gas turbine, generator and auxiliaries	M$	137	137	68
HRSG, ducting and stack	M$	65	65	33
Duct burner	M$	0	0	2
Steam turbine generator and auxiliaries	M$	66	55	88
Cooling system and miscellaneous, Balance of Plant (BOP) system	M$	69	36	68
Subtotal	M$	336	293	260
Total Installation cost[a]	M$	163	142	126
Bare Erected Cost (BEC)	M$	499	434	386
Indirect cost[b]	M$	70	61	54
Engineering Procurement and Construction (EPC)	M$	569	495	440
Contingencies, owner's costs[c]	M$	134	116	103
Total Capital Requirement (TCR) power plant	M$	703	611	544
Capture plant main items				
Flue gas cooling	M$	NA	21	11
CO_2 absorber & flue gas re-heater	M$	NA	110	55
Rich/lean amine circulation	M$	NA	6	6
Stripping section	M$	NA	139	139
Ancillaries	M$	NA	5	5
Suporting facilities & labor (direct and indict)[d]	M$	NA	61	47
Subtotal	M$	NA	342	262
Installation cost[e]	M$	NA	128	98
BEC	M$	NA	470	361
EPC, Contingencies and owner's costs[f]	M$	NA	216	166
TCR capture plant	M$	NA	687	527
TCR CO_2 compression[g]	M$	NA	49	53
Specific investment – Gross	$/kW	757	1614	1337
Specific investment – Net	$/kW	773	1698	1438

[a] 49.8% of subtotal cost (IEAGHG, 2012).
[b] 14% of BEC cost (Franco et al., 2012).
[c] 23.5% of EPC (IEAGHG, 2012).
[d] 2.7% of the total equipment cost (IEAGHG, 2012).
[e] 37.5% of subtotal cost (IEAGHG, 2012).
[f] 46% of BEC (IEAGHG, 2012).
[g] Hendriks et al. (2003) includes installation, indirect costs, contingencies and owner's costs.

the complexity and the number of heat exchangers is smaller as the HRSG is a single pressure system instead of a triple pressure system. The contribution of the gas turbine to the overall power output is much lower than in the NGCC. Effectively, the number of gas turbine trains is reduced from 2 to 1. The additional investments in the steam cycle are compensated by the reduction in the gas turbine train, leading to 11% lower power plant specific investment than NGCC with capture. The investment in the steam part of the power cycle (steam turbines, cooling system and BOP) increases to generate more power from the heat recovered in SSFCC. In all the cases, as the power plants are designed to operate with CO_2 capture, the LP steam turbine size is smaller than if it would operate without capture.

The operating and maintenance costs (O&M) for NGCC and subcritical SSFCC are provided in Table 4. The operating costs of a conventional NGCC configuration increase by 70.17%, from 30.9

Table 4
Operating and maintenance cost (O&M) of the power plant and CO_2 capture plant for the natural gas combined cycle and subcritical sequential supplementary firing combined cycle.

	Unit	NGCC	NGCC with capture	Subcritical SSFCC
Power plant	M$		M$	M$
Fixed O&M costs[a]	M$	13.3	11.6	11.4
Variable cost[a]	M$	17.6	15.4	15.2
CO_2 capture and compression				
Fixed O&M costs[b]	M$	NA	14.7	11.6
Variable cost[c]	M$	NA	10.9	7.4
Total	M$	30.9	52.6	45.5
Total O&M – net	$/kWh	4.85	9.46	8.32

[a] COPAR (2013).
[b] 2% TCR CO_2 capture plant including compression (IEAGHG, 2011).
[c] Solvent make up is estimated as 2.4 kg MEA/t CO_2 for the NGCC case with 13% v/v O_2 in the flue gas (Gorset et al., 2014) and 1.5 kg MEA/t CO_2 for the SSFCC cases for O_2 concentrations similar to coal flue gas (below 4% v/v) (Rubin and Rao, 2002; DOE, 2007).

Table 5
Total cost of CO_2 transport for the natural gas combined cycle and subcritical sequential supplementary firing combined cycle.

	Unit	NGCC	NGCC with capture	Subcritical SSFCC
CO_2 transport[a]	M$	NA	7.0	8.2
	$/kW	NA	8.9	10.5

[a] 3.65 $/t$CO_2$ in 2011 dollar (DOE/NETL, 2013a,b) is updated to 3.51 $/tCO2 in 2013 dollar using the Chemical Engineering index (2013).

to 52.6 M$ (million dollar), when capture is added. The variable operating costs of the capture unit decrease for the SSFCC configuration compared to the NGCC with capture. Mainly it reflects the benefits of having lower solvent degradation with lower oxygen concentrations in the flue gas.

The total cost of CO_2 transport is provided in Table 5. The Cost of geological storage is not included as the CO_2 produced is considered for EOR. The CO_2 conditions considered in this study are at a pressure of 150 bar and 95% CO_2 purity for the purpose of EOR projects (DOE/NETL, 2012) with 100 km from the power plant to the oil field, as indicated in the DOE study.

3.8. Total revenue requirement and decision diagram

The values provided in Tables 2–4 are used to estimate the levelised cost of electricity (*LCOE*) using Eq. (B_2) in Appendix B and then calculate the total revenue requirement (*TRR*). The TRR is defined as the total revenue necessary for the project to break even. It is quantified at different CO_2 selling prices using Eqs. (3) and (4).

$$TRR = LCOE - EOR \text{ revenue} \tag{3}$$

where *TRR* is the total revenue requirement in $/MWh, *LCOE* is the levelised cost of electricity $/MWh. *EOR revenue* is the revenue for selling CO_2 in $/MWh and is calculated using the Eq. (4).

$$EOR \text{ revenue} = \frac{CO_2 \text{ selling price} \times \text{levelised flow of } CO_2 \text{ captured}}{\text{net power output}} \tag{4}$$

where CO_2 selling price is in $/t CO_2, levelised flow of CO_2 capture in t/h, and net power output in MW.

The following underlying assumptions are used in this analysis:

- There is no carbon price associated with the residual carbon emissions
- It is financially worth building a new NGCC plant with capture in the electricity market where all the possible configurations of plants would operate
- Therefore the electricity selling price averaged over the life of a plant is at least higher than the LCOE of the NGCC plant with capture

The cost impacts of CO_2-EOR sales are investigated with a sensitivity analysis of the capital of the SSFCC configuration in Fig. 8. The subcritical SSFCC configuration is naturally more sensitive to variation of the CO_2 selling price because of the additional revenue from selling CO_2 for EOR, normalised per unit of energy. With respect to the price of crude oil, the commercial CO_2 price decreased within the range from 25 to $65/t when the crude oil price is $100/barrel to 45 $/t CO_2 at oil price of $70/barrel (Zhai and Rubin, 2013; National Energy Technology Laboratory, 2012, 2010). In our analysis, the CO_2 sale price covers a range from 0 to $50/t CO_2 and the gas price from 2 to 6 $/MMBTU, indicating that:

- For a gas price of 6 $/MMBTU (5.69 $/GJ), the total revenue requirement lines of the subcritical SSFCC configuration intersect with the total revenue requirement line of the NGCC configuration at a breakeven CO_2 selling price of 37 $/t CO_2, as shown in Fig. 8. With a relative reduction of capital cost of 10% of the SSFCC configuration, the lines intersect at 7.5 $/t CO_2. For a CO_2 selling price above the breakeven value in the intersection, the subcritical SSFCC plant with CO_2-EOR has a smaller TRR than the NGCC plant and would generate additional revenues if both configurations receive the same electricity selling price.
- For a gas price of 4 $/MMBTU (3.79 $/GJ), the two total revenue requirement lines intersect at a breakeven CO_2 selling price of 2.5 and 33.5 $/t CO_2 for variations of the capital costs of the SSFCC configurations of 0 and 10%.
- For a gas price of 2 $/MMBTU (1.896 $/GJ), the current price at the time of writing in Mexico (Regulatory Commission of Energy, 2016), the subcritical SSFCC configuration presents the lowest total revenue requirement for all CO_2 selling price and for capital costs varying from −20% to 10%. At an increment of 20% relative, the lines intersect at a breakeven CO_2 selling price of 30 $/t CO_2.

This analysis is summarised in a decision diagram in Fig. 9 for a difference range of capital cost estimates for the subcritical SSFCC configuration and a range of gas prices.

4. Sequential supplementary firing with a supercritical combined cycle

4.1. Performance assessment

This second configuration is a supercritical SSFCC configuration and consists of one train of GE 937 IFB gas turbine, the HRSG is a single pressure Once Through Steam Generator type supplying heat to a double reheat combined cycle with four steam turbines, as shown in Fig. 10. An HRSG design for supercritical steam conditions is a once-trough steam generator with the main advantages of size reduction, a simplified control system, and fast start up

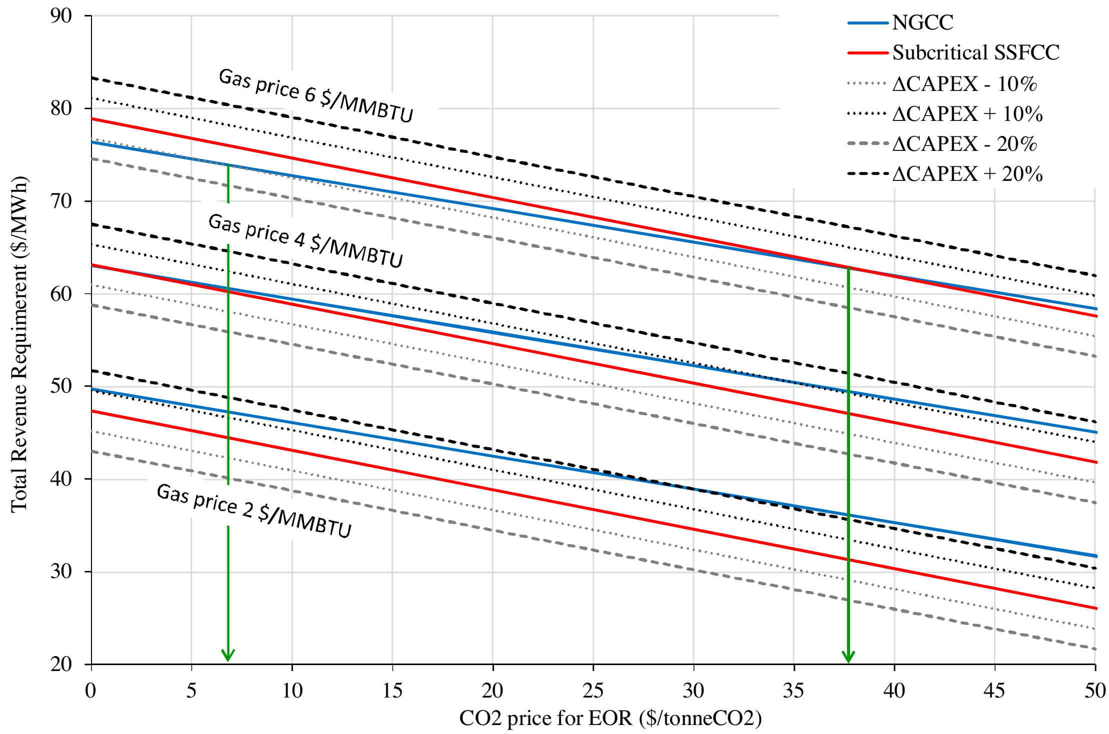

Fig. 8. Total revenue requirement for a subcritical sequential supplementary firing configuration and a conventional natural gas combined cycle configuration for a range of representative CO_2 price for EOR and fuel prices. The relative variation in capital costs of the subcritical sequential supplementary firing configuration (ΔCAPEX) ranges from −20% to 20%. The vertical lines indicate the breakeven CO_2 price of equal total revenue requirements.

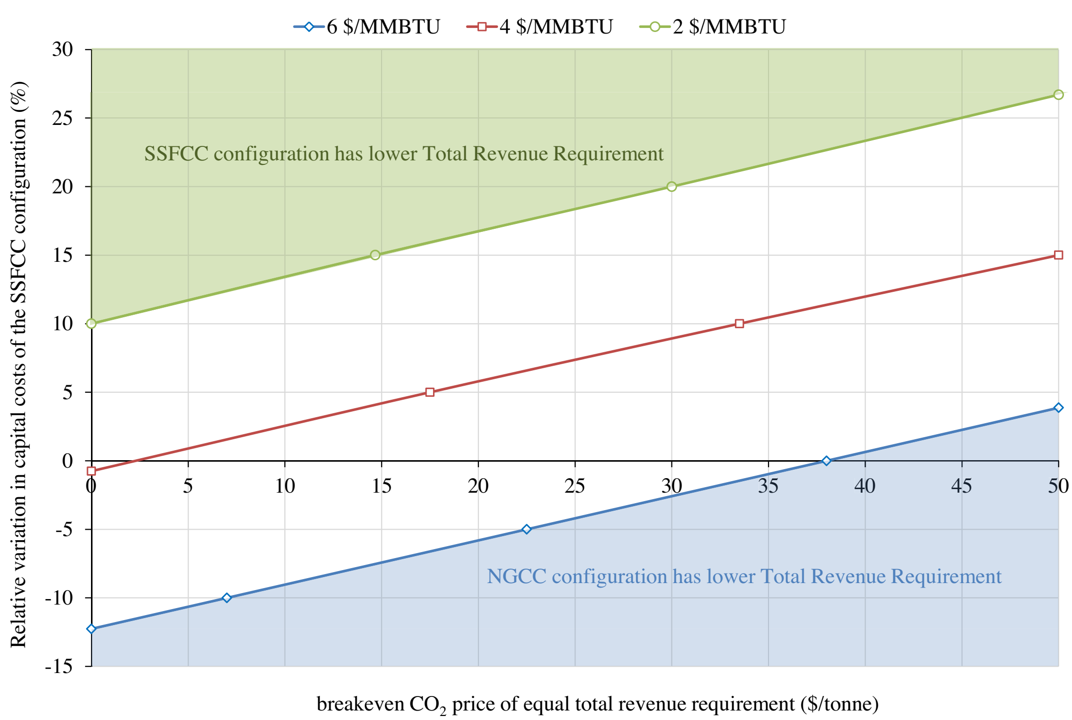

Fig. 9. Decision diagram for a range of capital cost estimates and gas prices.

(Innovative Steam Technologies Company, 2012). Nevertheless, advanced alloys, such as Incoloy Alloy 800 & 825, a nickel and iron-chromium enriched alloy with additions of molybdenum and copper, are required compared to a conventional HRSG, with Stainless Steel 304 (Innovative Steam Technologies Company, 2012).

The gas turbine is identical to the gas turbine of the conventional NGCC and of the subcritical SSFCC configurations. The capacity of

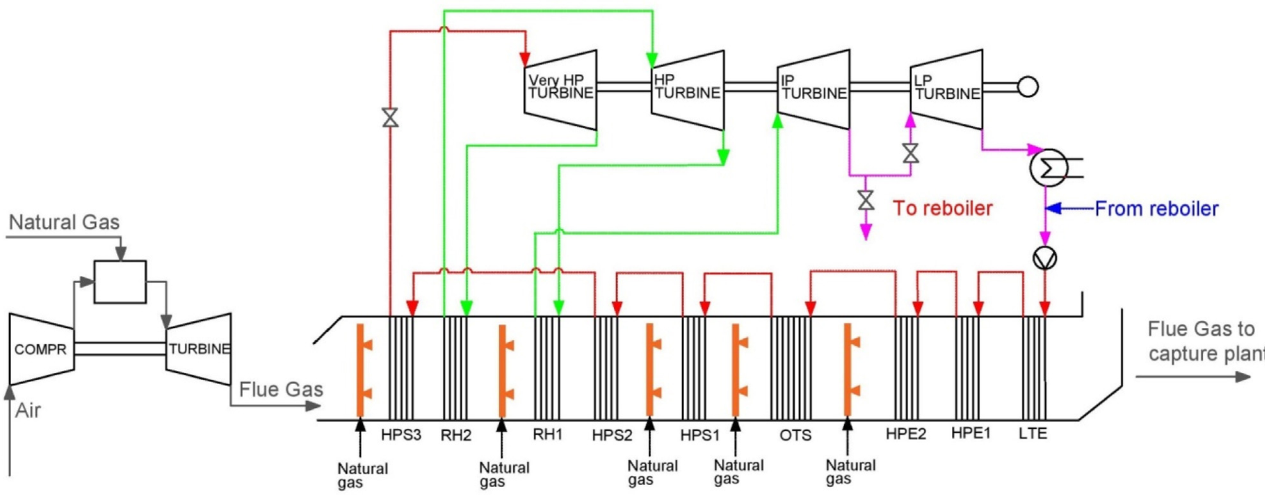

Fig. 10. Schematic process flow diagram of a supercritical sequential supplementary firing configuration with one GE 937 IFB/single pressure HRSG train combined cycle with a double reheat steam cycle.

the combined cycle is higher than the subcritical configuration since there is an increment in the marginal thermal efficiency of the additional gas usage with supercritical steam conditions. The configuration of the steam turbines is adapted from a configuration described by Kjaer (1993) for a pulverised coal power plant. As in the subcritical SSFCC configuration, supplementary gas is burned in 5 stages throughout the HRSG to reduce the excess O_2 down to a concentration of 1% v/v.

With sequential supplementary firing, supercritical steam conditions of 630 °C, 601.5 °C, 290 bar (McCauley et al., 2012; Salazar-Pereyra et al., 2011; Satyanarayana et al., 2011; Cziesla et al., 2009) increase the average temperature of heat addition to the steam cycle. The absence of phase change between the evaporator to the superheater allows for a reduction in heat transfer irreversibilities with lower temperature difference between the flue gas and the turbine working fluid. The pinch point of the HRSG is reduced with supercritical conditions from 70 °C to 27 °C seen in Fig. 11 and the marginal thermal efficiency of natural gas usage is increased from 36 to 40.2% shown in Table 6.

For completeness, Fig. 12 shows the expansion lines of the supercritical double reheat combined cycle and the subcritical single reheat combined cycle on an enthalpy-entropy diagram. In the supercritical Rankine cycle with double reheat, steam is expanded from 295 bar to 80 bar in the Very High Pressure (VHP) turbine and sent back to the HRSG where it is reheated in Reheater RH2 of Fig. 10. Steam then expands in the HP steam turbine down to around 42 bar and is sent back to the HRSG where it is reheated in Reheater HR1. The steam temperature rises to 601 °C before it is expanded in the IP steam turbine.

Table 6 presents the performance assessment of the supercritical SSFCC configurations and compares it to the equivalent subcritical configuration. With additional fuel being burnt in one HRSG with supercritical steam conditions, the capacity of the steam turbine increases from 245 MW to 589 MW compared to the conventional NGCC configuration. The total net power of the supercritical SSFCC configuration is 824 MW, compared to 794 MW with a NGCC and 781 MW with subcritical SSFCC. The thermal efficiency of the supercritical SSFCC configuration with post-combustion capture is 45.6% LHV, compared to 43.1% for a subcritical SSFCC plant, as shown in Table 6. However, there are cost implications: The HP part of the combined cycle, including the HP steam turbine, valves, pipework, and the HP superheater requires being of supercritical design.

Table 8
Operating and maintenance cost (O&M) of the power plant and CO_2capture plant for the supercritical sequential supplementary firing combined cycle.

	Unit	Subcritical SSFCC
Power plant	M$	M$
Fixed O&M costs[a]	M$	12.0
Variable cost[a]	M$	16.0
CO_2 capture and compression		
Fixed O&M costs[b]	M$	11.6
Variable cost[c]	M$	7.4
Total	M$	47.0
Total O&M – net	$/kWh	8.14

[a] COPAR (2013).
[b] 2% TCR CO_2 capture plant including compression (IEAGHG, 2011).
[c] Solvent make up is estimated as 2.4 kg MEA/t CO_2 for the NGCC case with 13% v/v O_2 in the flue gas (Gorset et al., 2014) and 1.5 kg MEA/t CO_2 for the SSFCC cases for O_2 concentrations similar to coal flue gas (below 4% v/v) (Rubin and Rao, 2002; DOE, 2007).

4.2. Cost estimation of supercritical SSFCC

The methodology used to estimate the cost of the supercritical SSFCC configuration is identical to the subcritical one described in Section 3.6. For supercritical steam conditions, the cost estimate of the HRSG in sections with high temperature is based on Eq. (B_1) in Appendix B, where a factor is used to account for the use of more expensive alloys to support supercritical conditions (World steel prices, 2013).

The specific investment of supercritical SSFCC is reported in Table 7. When compared with the conventional NGCC configuration, there is a reduction in the total specific investment of 9.1%, equivalent to 75 M$, lower than for the subcritical configuration with 15.3% and 264 M$ respectively. The operating and maintenance costs (O&M) are provided in Table 8. Since the fuel thermal input is the same for both configurations with sequential firing, the amount of CO_2 generated is the same. Total cost of CO_2 transport is provided in Table 5.

4.3. Total revenue requirement and sensitivity to gas price and CO_2 selling price

The TRR of the supercritical configuration is evaluated and then compared with the corresponding subcritical configuration.

Fig. 13 shows a reduction of the total revenue requirement of supercritical with respect to subcritical SSFCC at 0–50 $/t CO_2

Table 6
Summary of key parameters of a SSFCC with single pressure HRSG and a double reheat supercritical steam cycle with CO_2 capture (Saturated vapour at 3 bar is used in the reboiler).

Concept	Unit	Supercritical SSFCC	Subcritical SSFCC
LHV net electric efficiency[a]	%	45.6	43.1
Gas turbine power output GT	MW	296	296
Steam cycle power output	MW	589	545
Total LHV gross power output	MW	884	834
Total LHV net power output (including CO_2 compression and other archillaries)	MW	824	781
Mass flow rate of natural gas to gas turbine	kg/s	16.6	16.6
Mass flow rate of natural gas for supplementary firing	kg/s	22.2	22.2
Marginal efficiency of natural gas fired in HRSG (LHV)	%	40.2	36
Marginal efficiency of natural gas fired in HRSG (LHV) without post-combustion capture (for comparative purpose purposes only)	%	49.1	44.7
Electricity output penalty	$kWh_e/t\ CO_2$	350	362
Carbon intensity of electricity generation	$kgCO_2/MWh$	45	47.5
Flue gas mass flow rate	kg/s	696	696
Flue gas composition after direct contact cooler			
H_2O	% vol	4.29	4.29
CO_2	% vol	10.87	10.87
O_2	% vol	1.312	1.3
N_2	% vol	83.52	83.5
CO_2 mass flow to pipeline	kg/s	93	93
Capture level	%	90	90
Solvent energy of regeneration	$GJ/t\ CO_2$	3.42	3.42
Steam mass flow to solvent reboiler	kg/s	157	146
Number of absorber trains		2	2
Diameter	m	15.5	15.5
Absorber height	m	21	21
Flue gas mass flow rate at each absorber inlet	kg/s	348	348
Volume of packing used for CO_2 capture (not including water wash sections)	m^3	8130	8130

[a] LHV net electric efficiency includes CO_2 compression and parasitic losses and transformed losses are included.

Table 7
Estimated specific investment for the supercritical sequential supplementary firing combined cycle with capture.

Plant component	Unit	Supercritical SSFCC w/capture
Gross power output	MW	884
Net power output	MW	824
Power plant main items		
Gas turbine, generator and auxiliaries	M$	68
HRSG, ducting and stack	M$	88
Duct burner	M$	2
Steam turbine generator and auxiliaries	M$	108
Cooling system and miscellaneous, Balance of Plant (BOP) system	M$	64
Subtotal	M$	331
Total Installation cost[a]	M$	161
Bare Erected Cost (BEC)	M$	492
Indirect cost[b]	M$	69
EPC	M$	561
Contingencies, owner's costs[c]	M$	132
Total Capital Requirement (TCR) power plant	M$	693
Capture plant main items		
Flue gas cooling	M$	11
CO_2 absorber & flue gas re-heater	M$	55
Rich/lean amine circulation	M$	6
Stripping section	M$	139
Ancillaries	M$	5
Suporting facilities & labor (direct and indict)[d]	M$	47
Subtotal	M$	262
Installation cost[e]	M$	98
BEC	M$	361
EPC, Contingencies and owner's costs[f]	M$	166
TCR capture plant	M$	527
TCR CO_2 compression[g]	M$	53
Specific investment – Gross	$/kW	1439
Specific investment – Net	$/kW	1544

[a] 49.8% of subtotal cost (IEAGHG, 2012).
[b] 14% of BEC cost (Franco et al., 2012).
[c] 23.5% of EPC (IEAGHG, 2012).
[d] 2.7% of the total equipment cost (IEAGHG, 2012).
[e] 37.5% of subtotal cost (IEAGHG, 2012).
[f] 46% of BEC (IEAGHG, 2012).
[g] Hendriks et al. (2003), includes installation, indirect costs, contingencies and owner's costs.

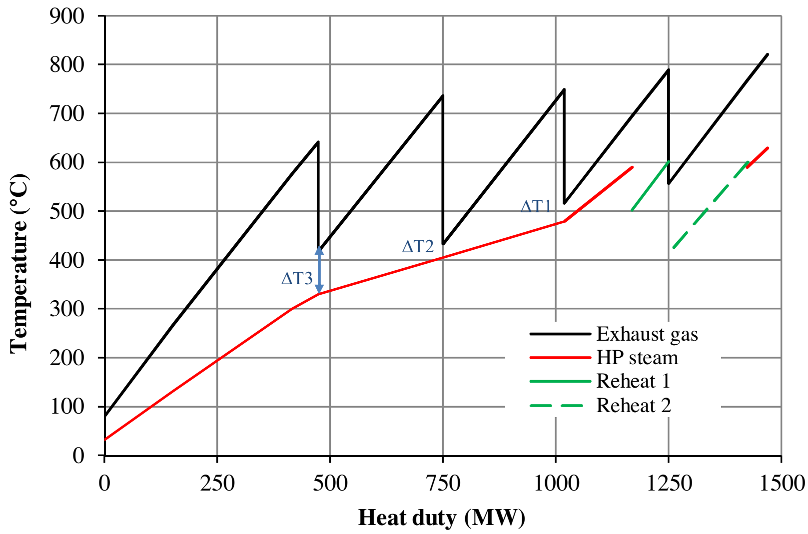

Fig. 11. Temperature/heat diagram for the Heat Recovery Steam Generator of a five stage sequential supplementary firing configuration, with a double reheat combined cycle and supercritical steam conditions (630 °C, 601.5 °C, 295 bar). The two pinch temperatures ΔT1, ΔT2, ΔT3 are respectively 27 °C, 36 °C, 88 °C.

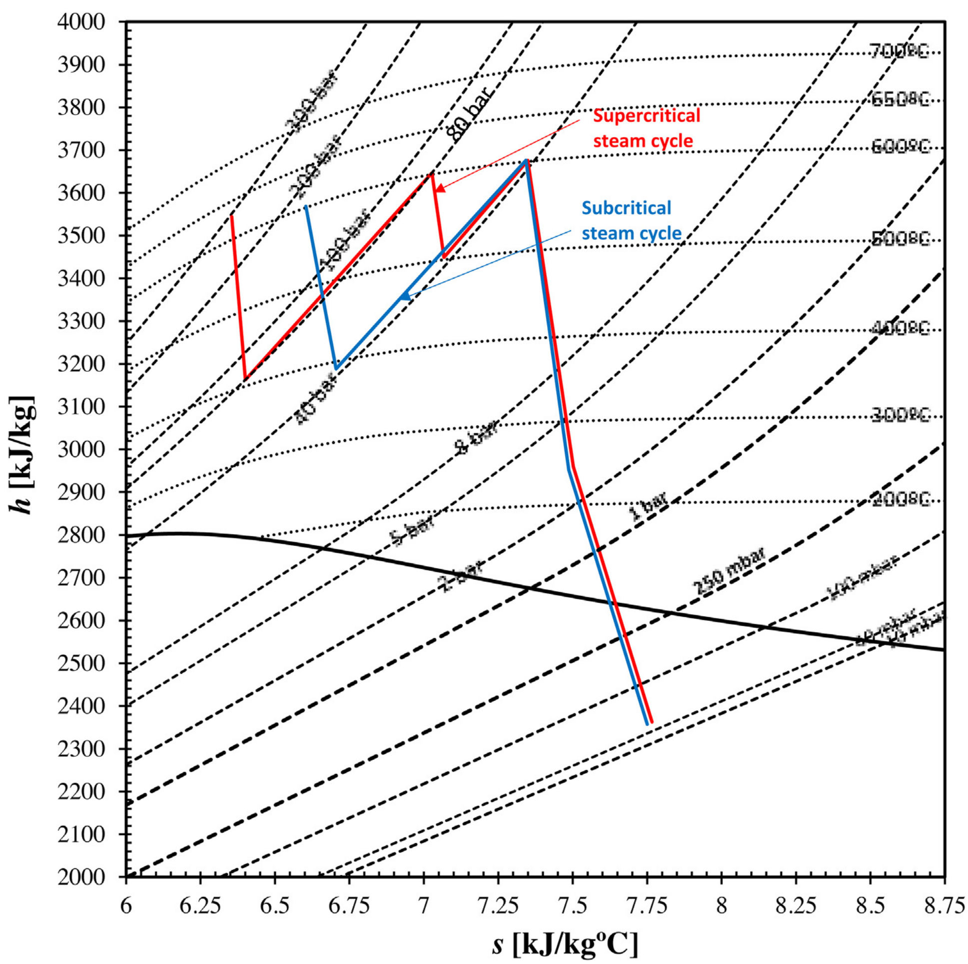

Fig. 12. Enthalpy-entropy diagram of the supercritical Rankine cycle with double reheat and the subcritical Rankine cycle with single reheat.

selling price and gas price in a range from 2 to 6 $/MMBTU. The supercritical SSFCC configuration presents overall a lower TRR than a subcritical configuration. This is due to an improvement in efficiency associated with supercritical steam conditions and the fact that revenue from CO_2 sales are identical to the subcritical configuration. If both configurations of CCS power plants were receiving the same electricity price and the same CO_2 price, the supercritical configuration would receive higher revenue over the economic life chosen for this analysis. It can be concluded that a supercritical combined cycle is an improvement to a subcritical

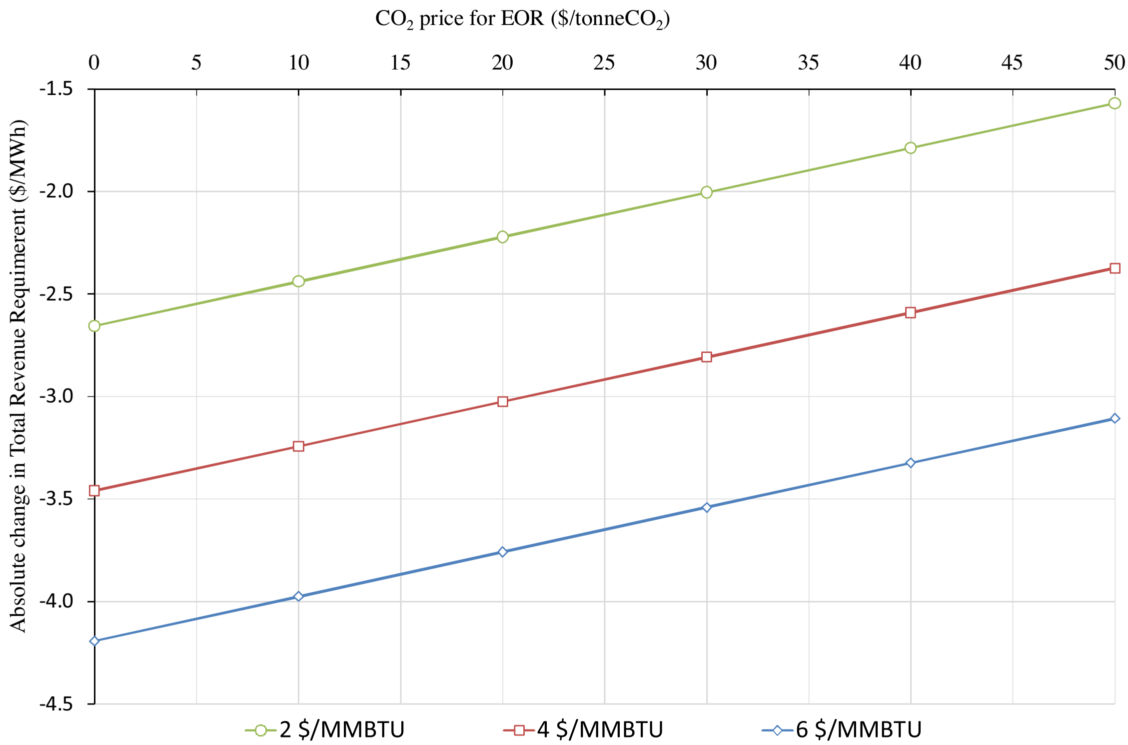

Fig. 13. Reduction in total revenue requirement for sequential supplementary firing combined cycle plant with supercritical steam conditions compared to a subcritical configuration, for a range of representative CO_2 price for EOR and fuel prices.

combined cycle in this context, as it presents consistently a lower TRR in a range of gas price from 6 to 2 \$/MMBTU and when the CO_2 captured is utilized for EOR at commercial prices from zero to 50 \$/t CO_2.

5. Conclusions

The integration of sequential supplementary firing combined cycle plants is examined in the context of deploying CCS with Enhanced Oil Recovery in Mexico. A new design of heat recovery steam generator is proposed where additional fuel is combusted to increase the volumes of carbon dioxide available for EOR. The maximum amount of CO_2 is produced by reducing excess oxygen levels as low as practically possible (of the order of 1% v/v). The total power output of a sequential supplementary firing configuration with CO_2 capture, consisting of a single gas turbine and heat recovery steam generator train, is 824 MW with a supercritical combined cycle, 781 MW with a subcritical combined cycle, compared to 794 MW for a conventional NGCC configuration with capture with two gas turbines and two HRSGs. The difference in the power output is due to the design of the heat recovery steam generator where additional fuel burnt increases heat available for steam generation in the combined cycle. This allows a reduction by half of the number of GT/HRSG trains and of the total volume of flue gas. This has a positive impact on the number of direct contact cooler and absorbers required in the post combustion capture plant. The reduction of overall capital costs is, respectively, 9.1% relative and 15.3% relative for the supercritical and the subcritical configurations compared to the conventional configuration with capture. Both sequential supplementary firing configurations also present a reduction in the electricity output penalty compared to a conventional NGCC plant with capture.

The sensitivity of total revenue requirements for low-carbon electricity generation, a metric combining levelised cost of electricity and revenue from EOR, to CO_2 prices and fuel prices is used to compare configurations. Since capital cost estimates are bound to include large biases and uncertainties, we perform a sensitivity analysis showing that our conclusions are robust over a range of gas prices and CO_2 prices for EOR, and that sequential supplementary firing is advantageous in the context of North American gas prices.

A comparison between a subcritical and a supercritical SSFCC configurations show that improvements in power plant efficiency with supercritical steam conditions consistently result in a lower TRR. At gas prices ranging from 2 to 6 \$/MMBTU, supercritical SSFCC may receive additional revenues ranging from 1.5 to 4 \$/MWh for CO_2 prices ranging from 0 to 50 \$/t CO_2 compared to subcritical configurations.

Further work is needed to include site specific considerations and detailed capital estimates beyond the work included in this article, which is effectively a very first attempt at assessing the feasibility and validity of the concept, with access to affordable natural gas prices and likely revenues from Enhanced Oil Recovery.

Acknowledgements

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Appendix A.

The flue gas inlet absorber at 44 °C and 1.13 bar; 40 °C the temperature in the stripper condenser, and lean/rich stream heat exchanger approach temperature 10 °C (Sanchez Fernandez et al., 2013), and 30% MEA were kept constant (see Table A1, A2 and A3

Table A1
Ambient conditions and modelling basis for all case studies.

Concept	Unit	Value
Ambient temperature	°C	15
Ambient pressure	bar	1.013
Relative humidify	%	60
Cooling water temperature	°C	25
Cooling water maximum temperature rise	°C	10
Fuel calorific value (LHV)	kJ/kg	46,510
Pressure ratio compressor		19.5
Pressure in condenser	bar	4.38
Adiabatic/polytropic efficiency compressor	%	87.4/82
Adiabatic/polytropic efficiency gas turbine	%	88/83.2

Table A2
Input data for all case studies.

Concept	Unit	NGCC	SSFCC Supercritical	SSFCC subcritical
Pressure supercritical steam	bar	NA	295.0	NA
Temperature supercritical steam	°C	NA	630.0	NA
Pressure HP steam	bar	172.5	80.0	172.5
Temperature HP steam	°C	601.7	601.0	601.0
Pressure IP steam	bar	41.4	42.6	42.6
Temperature IP steam	°C	601.5	601.0	601.0
Pressure LP steam	bar	3.0	3.0	3.0
Temperature LP steam	°C	292.4	229.5	229.5
Isentropic efficiency supercritical steam turbine[a]	%	NA	92.0	NA
Isentropic efficiency HP steam turbine	%	86.0	86.0	86.0
Isentropic efficiency IP steam turbine	%	90.0	90.0	90.0
Isentropic efficiency LP steam turbine	%	87.6	87.6	87.6

[a] Franco et al. (2012).

Table A3
Summary of key assumptions for the evaluation of plant revenues and CAPEX.

Capture level for post-combustion capture plant	%	90
Power plant fixed cost (COPAR 2012)	\$/MW-year	14,594
Power plant variable cost (COPAR 2012)	\$/MWh	2.77
Annual fixed capture plant related to CAPEX	%	2.0
Interest rate or discount rate	%	10
Plant life (COPAR 2012)	years	30
Load factor for new plant, assumed to be all at full output (COPAR 2012)	%	80
Running hours per year for retrofit load factor	h/yr	7008
Variable costs for new plant, before capture basis	\$/MWh	2
CO_2 emission price	\$/tCO_2	0

Table B1
References of capital cost for power and CO_2 capture, CO_2 compressor plants.

Equipment	Reference
Gas turbine, generator and auxiliaries 9 F 5-series model	Gas Turbine Handbook (2013)
HRSG, steam turbine, and balance of plant BOP	Franco et al. (2012)
In duct firing	Thermoflow (2013)
Supercritical steam turbine	DOE/NETL (2013a,b)
Capture plant	IEAGHG (2012)
CO_2 compressor	Hendriks et al. (2003)
CO_2 transport	DOE/NETL (2013a,b)

list the basic parameters used in the modelling of the power plants for all case studies).

Appendix B.

1. CAPEX estimate

Sources of information for capital costs are shown in Table B1. The Chemical Engineering Plant Cost Index 2013 is used to update the cost of equipment to 2013 and a currency exchange of 0.8 EUR/USD in 2014 is used.

The sum of all equipment costs, together with the balance of plant (BOP), cooling water system, and installation costs is, as it is described by Rubin et al. (2013), the bare erected cost (BEC). Following the methodology, the BEC including indirect costs, engineering procurement and construction (EPC) costs, contingencies, and owner's costs gives the total capital requirement (TCR) for the power plant as well as for capture plant and compression system.

The cost of the HRSG for all three cases is calculated using the Eq. (B_1) proposal by Franco et al. (2012):

$$C = C_0 \left[\frac{UA}{U_0 A_0} \right]^f \tag{B1}$$

where C_0 is the reference erected cost component (\$), U_0A_0 (MW/K) is the reference size component, UA is the scaling parameter (MW/K) (U heat transfer coefficient and A is the heat transfer area), f is the scale factor (−). For supercritical SSFCC, Eq. (B_1) is used to estimate the cost of the HRSG in sections with low temperature, and for sections with high temperature Eq. (B_1) is multiple by $N = 3.3$. N is the factor for using more expensive material to support supercritical conditions (World steel prices, 2013).

2. Operation and maintenances cost O&M

Information for the operation and maintenance fixed and variable costs (O&M) for case studies for the power plant section are provided by Costs and benchmarks for the development of investment projects in the Mexican electricity sector (COPAR, 2013), which gives information for Mexico regarding new power plant projects in Mexican Federal commission of electricity. The estimation includes the expenses for consumables and chemical solvent make-ups (variable) as well as costs for maintenance and labor.

Variable of O&M costs for CO_2 capture plant studies are calculated and considerer make up of water and chemicals such as soda ash, corrosion, inhibitor, activated carbon, molecular sieve, and diatomaceous. The variation of these chemicals varies according to the amount of MEA make up reported in DOE/NETL (2007). Solvent make up is estimated as 2.4 kg MEA/t CO_2 for the NGCC case with 13% v/v O_2 in the flue gas (Gorset et al. (2014) and 1.5 kg

MEA/t CO_2 for the SSFCC cases for O_2 concentrations similar to coal flue gas (below 4% v/v) (Rubin and Rao (2002), DOE (2007)).

3. Levelised cost of electricity

The levelised cost of electricity (LCOE) is calculated by annualizing the total capital cost and the total operating and maintenance costs and variable costs in \$/MWh. The net electricity produced and sold, the operating, maintenance and fuel cost are considered constant over the life of the plant based on constant dollar. Carbon prices are not included in this analysis. Then, the simplified equation for these conditions is expressed by Eq. (B_2) reported by Rubin et al. (2013).

$$LCOE = \frac{TCR \times FCF + FOM}{\text{Power output} \times \text{CF} \times 8760} + VOM + HR \times FC + TCO_2 \quad \text{(B2)}$$

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

where

TCR is the total capital requirement (\$), *FCF* fixed charge factor, *FOM* is the fixed *O&M* costs (\$), Power output is the net power generated by the power plant (*MW*), *CF* capacity factor (−), *VOM* is the variable *O&M* costs (\$/MWh), *HR* net power heat rate (MJ/MWh), *FC* fuel cost per unit of energy (\$/MJ), and TCO_2 CO_2 transport cost (\$/MWh). r (−) is the interest rate and T is the economic life of the plant (30 years in this study).

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