On the retrofitting and repowering of coal power plants with post-combustion carbon capture: An advanced integration option with a gas turbine windbox

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ABSTRACT

Retrofitting a significant fraction of existing coal-fired power plants is likely to be an important part of a global rollout of carbon capture and storage. For plants suited for a retrofit, the energy penalty for post-combustion carbon capture can be minimised by effective integration of the capture system with the power cycle. Previous work on effective integration options has typically been focused on either steam extraction from the power cycle with a reduction of the site power output, or the supply of heat and electricity to the capture system via the combustion of natural gas, with little consideration for the associated carbon emissions.

This article proposes an advanced integration concept between the gas turbine, the existing coal plant and post-combustion capture processes with capture of carbon emissions from both fuels. The exhaust gas of the gas turbine enters the existing coal boiler via the windbox for sequential combustion to allow capture in a single dedicated capture plant, with a lower flow rate and a higher CO_2 concentration of the resulting flue gas. With effective integration of the heat recovery steam generator with the boiler, the existing steam cycle and the carbon capture process, the reference subcritical unit used in this study can be repowered with an electricity output penalty of 295 kWh/tCO_2 – 5% lower than a conventional steam extraction retrofit of the same unit – and marginal thermal efficiency of natural gas combustion of 50% LHV – 5% point higher than in a configuration where the gas turbine has a dedicated capture unit.

1. A novel configuration for carbon capture retrofits of existing coal plants

The contribution of post-combustion capture (PCC) technology to retrofit existing coal plants could play an important role in the deployment of CO_2 capture and storage (CCS) for a fast-track emission mitigation strategy (IEA, 2012). It has been shown that many technical and economic factors have an influence on the feasibility of retrofitting capture to an existing pulverised coal power plant (Specker et al., 2009; Dillon et al., 2013; IEAGHG, 2011).

Two issues are considered to be major obstacles for retrofits: the location of the plant if it results in a lack of access to viable geological CO_2 storage sites, and space restriction around the existing site. The latter may, for example, include lack of space for the capture and compression plant, and/or lack of space or access for the

equipment associated with the integration of the Post-Combustion Capture (PCC) Plant, e.g. if a flue gas desulphurisation (FGD) unit is required. In a context of a decarbonisation of electricity generation, these barriers may result in either shutting down an existing plant, and possibly building new low-carbon electricity generation capacity instead, or reducing the load factor of the plant.

Other important considerations determine the viability of a scenario where a pulverised coal plant is retrofitted. They include:
- Changes in revenue from electricity sales.
- Strategies for mitigating reduced power output.
- The additional investment and the associated running costs of new plants built elsewhere in the event of a reduction in electricity output.
- New additional capacity built within the boundaries of the existing site to restore or increase the power output.
- Thermodynamic integration with the power plant system, notably the energy requirement to provide electricity and heat for capture and compression, and

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Nomenclature

CAV	Cavity
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
ECO	Economiser
EOP	Electricity output penalty
FGD	Flue gas desulphurisation
FEGT	Furnace exit gas temperature
FSH	Final superheater
GHG	Greenhouse gases
GT	Gas turbine
GTCC	Gas turbine combined cycle
H_2O	Water
HP	High pressure
HRSG	Heat recovery steam generator
IP	Intermedium pressure
LHV	Lower heating value
LP	Low pressure
MEA	Monoethanolamine
O_2	Oxygen
PCC	Post-combustion CO_2 capture
PSH	Primary superheater
RHB	Reheater bank
RHOL	Reheater out leg

- The availability of water, additional cooling requirements, the return temperature of water to the environment, and whether air-cooling is a viable alternative option.

A widely-proposed way to retrofit coal-fired power plants with PCC is a configuration referred, in this article, as a 'Standard Integrated Retrofit' where all the electricity and heat required to operate the capture and compression plant is supplied within the boundaries of the existing plant, at expense of a reduction in site power output. In particular, thermal energy for solvent regeneration is provided by steam extraction from the power cycle.

There are, however, situations where a reduction in net output with capture is not necessarily desirable, e.g in a context of growth of electricity demand in markets aiming for electrification and decarbonisation simultaneously, for plants operated in a regulated environment with a nominal output, or if the alternative to build low-carbon make-up capacity is not practical.

In order to avoid the loss of net output of 'Standard Integrated Retrofit' options, it is possible to supply all, or a large part of, the heat and electricity required for capture and compression with a dedicated combined heat and power (CHP) plant built within the boundaries of the existing plant (IEAGHG, 2011; Singh et al., 2003; Romeo et al., 2008; Bashadi and Herzog, 2011). Efficient operation of the CHP plant can be achieved with good thermodynamic integration with the existing plant.

Gibbins et al. proposed six rules to maximise the effectiveness of post-combustion capture systems (Gibbins et al., 2004), which were later updated in (Lucquiaud, 2010). Importantly, they state that it is advantageous to "produce as much electricity as possible from the power cycle [...] and from any additional fuel used", and that "rejecting heat at the required temperature for solvent regeneration" also ensures effective thermodynamic integration. For CHP plants, this suggests the use of the highest possible power to heat to power ratio and the lowest steam supply temperature to the solvent reboiler, at any given regeneration temperature. Consequently, this article discards gas ancillary boilers retrofits on the basis of low thermal efficiency and high electricity output

penalties with capture, as shown for example in (Lucquiaud and Gibbins, 2012)

It focuses instead on the retrofit of exiting coal plants with Gas Turbine (GT) CHP units. A novel configuration, referred as a 'gas turbine windbox carbon capture retrofit' is proposed where

> the sequential combustion of the exhaust gas of a gas turbine in the boiler of an existing coal plant retrofitted with carbon capture allows for repowering the existing site with the gas turbine and the combined capture of carbon emissions from the combustion of coal and natural gas.

When hot flue gas from the GT feeds the coal boiler and replaces a portion of the combustion air from the original fans, the term hot-windbox repowering is employed, as described in detail in (GE Power Systems, 1994). It is an option available to existing coal plants to increase generation capacity whilst reducing emissions. This was also proposed, for example, by Romeo et al. 2008 as a carbon abatement strategy for coal plants (Romeo et al., 2008). Unlike in conventional repowering projects (without carbon capture), we propose to achieve effective integration with the capture plant with the addition of a heat recovery steam generator (HRSG) after the gas turbine, using thermal energy in the flue gas to generate steam for power generation and heat for the capture plant. Effectively, the gas turbine flue gas enters the boiler via the windbox, a 'gas turbine windbox retrofit', but at a temperature similar to an air firing case.

The article examines further the effects on boiler operation and proposes options for effective thermodynamic integration between the steam cycle of the existing plant, the GT, the HRSG and the PCC plant.

Scenarios where 'gas turbine windbox carbon capture retrofits' may be attractive to power plant owners are then proposed, supported by a comparison with other 'power matched' retrofit configurations where the output of the gas turbine combined heat and power plant unit is sized specifically to compensate for the loss of output associated with a carbon capture retrofit. Particular attention is given to

- Space around and access to the existing power cycle for steam extraction
- The possibility for a fully integrated retrofit, e.g. if the plant is built as CCS ready (also termed carbon capture ready)
- The transmission capacity of the existing site
- The integration between the existing coal plant and the gas turbine cycle with a fraction, possibly all, of the thermal energy for solvent regeneration supplied by the gas Combined Heat and Power (CHP) plant.
- The capture of emissions from the combustion of natural gas.
- Marginal thermal efficiency of the natural gas combustion in the CHP unit
- Electricity output penalty
- The carbon intensity of electricity generation.

The latter is an important consideration in the context of decarbonisation of all fossil fuel use (as opposed to coal only), and notably whether CO_2 emissions from both natural gas and coal are captured, or from the latter only. We compare 'gas turbine windbox carbon capture retrofits' with configurations where 90% of the CO_2 emissions from both fuel sources are captured.

The structure of the paper is as follows: The next section of the paper presents an overview of the reference power plant data and the modelling methodology of the gas turbine windbox carbon capture retrofit. Additional details on the modelling methodology are provided in the Supplementary material. It then discusses the implications of replacing a fraction of the air supplied to the boiler of an existing plant with natural gas flue gas. The following

Table 1
Design basis of the gas turbine windbox retrofit.

Pulverised coal power plant	
Coal plant performance specifications	The coal plant configuration is based on Case 9 of the "Cost and Performance Baseline for Fossil Energy Plants" report (DOE/NETL, 2013)
	The steam generator consists of a water wall furnace, a platen secondary superheater and a final superheater in the upper region of the furnace and a primary superheater, reheater, and economizer in the parallel pass convection section, as represented in Fig. 1
Design coal specifications	High volatile bituminous coal, Illinois N°6 (DOE/NETL, 2012)
Gas Turbine Combined Cycle	
Gas Turbine[a]	GT is sized to provide the electrical power required for the capture process and to cover any loss in power output to restore the net power output of the plant. Performance characteristics are based on the PG 7251 FB General Electric (GE) gas turbine (GE Power Systems, 2000)
Heat Recovery Steam Generator	HRSG is sized to supply HP and IP steam to the steam cycle of the retrofitted plant and LP saturated steam to the stripper of the PCC plant. Design specifications:
	- Pinch point temperature difference: 8 °C
	- Approach point temperature difference: 5 °C
	- Operating gas temperature at the HRSG outlet: 100 °C (in order to avoid corrosion problems the metal temperature of the heat-transfer-surfaces must be above the gas dew-point temperature)
Design Natural Gas Specifications	Natural Gas specifications based on Case 13 of the "Cost and Performance Baseline for Fossil Energy Plants" report (DOE/NETL, 2013)
Carbon Capture Plant and CO_2 compression system	
Carbon Capture Plant	PCC plant is sized for a typical MEA scrubbing post-combustion capture process with two absorber trains, stripper and lean-rich heat exchanger. Boundary conditions are:
	- MEA concentration in solution: 30%
	- Stripper pressure (1st stage): 1.8 bara
	- Rich-lean heat exchanger temperature difference: 8 °C
	- Absorber inlet temperature: 40 °C
	- Reboiler temperature difference: 5 °C
	- Pump efficiency: 75%
	- Blower isentropic efficiency: 90%
CO_2 Compression System	Three-stage centrifugal compressor:
	- Compression rate of 2.6 to compress the CO_2 to 13 bara
	- Compressor adiabatic stage efficiency: 75%
	- Inter-coolers are designed to cool the CO_2 to 50 °C
	- Propane refrigeration system
	- Heat exchanger approach temperature: 5 °C
	- Heat exchanger minimum subcooling: 8 °C
	- Compressor adiabatic stage efficiency: 75%
	- Cryogenic pump hydraulic efficiency of 75%
	Economiser:
	- Approach temperature: 5 °C

[a] For this conceptual study, the characteristics of an off-the-shelf gas turbine are implemented, although the maximum output of 184 MW of a PG 7251 FB gas turbine is higher than the 127 MW required to restore the power output of the reference site (600 MW). Because of the wide range of output and configurations of existing coal plants, GT sizing would need to be examined on a site-by-site basis and is left outside the scope of this article. It is worth noting that the GT could either be operated at part-load in a power-matched retrofit configuration or, if it is possible to increase the power output of the site, it could be operated at full load. Alternatively, one GT could be added to repower and retrofit two units of the same site.

section discusses the effective integration between the heat recovery steam generator of the gas turbine and the coal plant steam cycle. Finally, the last section provides a comparative performance of 'power matched' retrofit options.

2. A performance assessment of the gas turbine windbox retrofit

2.1. Design basis of the gas turbine windbox retrofit

Table 1 gives an overview of the basic engineering data used for the study basis.

2.2. Modelling methodology of the gas turbine windbox carbon capture retrofit

Models of the boiler, the steam cycle and the ancillaries of a pulverised coal plant and of a combined cycle gas turbine were first developed in Mathcad and then validated by the process simulator Aspen Plus V8. Models of the combined cycle gas turbine, the CO_2 capture plant and the CO_2 compression system also use the process simulator Aspen Plus V8. The following sections will present the modelling results obtained from Aspen Plus V8.

2.2.1. Boiler modelling

The first stage of boiler performance calculations is the rating process which sizes the geometry of the various heat transfer equipment with the aim of matching the specifications for the design basis with air firing.

Once the surface areas of the heat exchangers are known, off-design performance of the retrofitted boiler can be studied. Retrofit options where gas turbine flue gas is introduced to the boiler to replace a fraction of the combustion air are examined taking into account changes in flame temperature, radiative and convective heat transfer with the new gas composition, and the associated
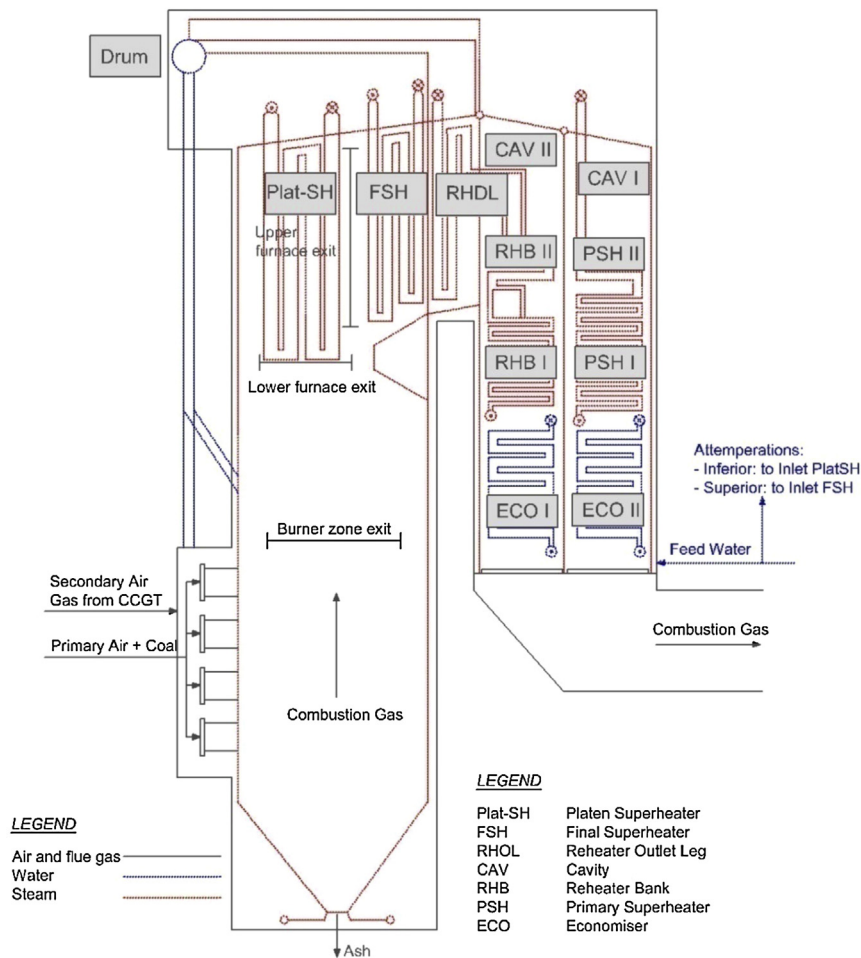
Fig. 1. Process flow diagram of the subcritical boiler.

changes in mass and energy balances to determine steam temperature and flow rates.

Fig. 1 illustrates the process flow diagram of the subcritical boiler.

The semi-empirical method suggested by I.E. Dubovsky (Blokh, 1988) is used to assess the heat transfer in the boiler furnace. This method estimates the furnace exit gas temperature based on equations of radiative transfer and energy balance in the furnace combined with empirical data and practical experience of boiler operation.

The heat absorbed by the furnace is computed as a fraction of the difference between the total heat available in the furnace and the sensible heat of the flue gas leaving the furnace section. The heat absorbed by the water walls, platen superheater and exit plane is determined based on the ratio of the effective areas of each type of surface to the total furnace area.

Due to the wide spacing between tubes, the heat radiated by the flame to the exit plane reaches the banks of tubes located at the top of the convection pass. An effectiveness factor is used to determine the amount of furnace radiation absorbed by a specific bank based on its configuration; the remainder is then sent to the next bank. The effectiveness factor used in this work is assumed to be the direct view factor proposed by Hottel for the first row of tubes from an infinite plane (Hottel and Sarofim, 1967).

The heat transferred by direct radiation does not affect the flue gas temperature drop across the mixed bank; however, it represents a fraction of heat absorbed by the steam/water inside the bank tubes. Therefore, the total heat absorbed by the steam takes into account the convection and intertube radiation and the direct radiation from the flame.

2.2.2. Feedwater heaters modelling

The feedwater heaters and condenser used in the steam cycle of pulverised coal plants are shell-and-tube exchangers which are generally built of a bundle of tubes mounted in a cylindrical shell with the tube axis parallel to that of the shell. One fluid flows inside the tubes and the other flows across and along the tubes.

Three different zones are distinguished in the feedwater heat exchangers: desuperheating, condensing and drain cooling zone, and only one zone in the condenser, the condensing zone. In this project, each zone is studied as a separate heat exchanger and heat transfer coefficients are evaluated separately.

2.2.3. Steam turbines modelling

Each turbine is represented by a series of block of expansion stages with n + 1 expansion block of stages for a turbine with n extractions. Steam temperature and pressure at the inlet and outlet of each block stages is consistent with the steam cycle of the US Department of Energy (DOE) and extraction points of the steam turbine (DOE/NETL, 2012). By neglecting, the difference between inlet and outlet kinetic energies, a common assumption used for modelling non-condensing steam turbine, the isentropic efficiency of every block of stages can be calculated.

The method of Stodola is used to assess the off-design operation of the steam turbines (Cooke, 1983). It treats each block of stages as if it were a single nozzle and this equivalence is known as Stodola's

Ellipse. The swallowing capacity, K, is determined for each block of stages at designed conditions. It is then used to predict the steam turbines behaviour when mass flow and/or pressure change.

In this work, the small stage efficiencies of the steam turbine are assumed to be the same as the designed value, since the off-design mass flow permits a normal turbine operation.

2.2.4. Carbon capture plant modelling

The capture plant was validated by Sanchez Fernandez (2014) based on various data sets from different pilot plants (Razi et al., 2013).

RadFrac columns are selected for both the absorber and the stripper. In the rate-based approach, actual rates of multi-component mass and heat transfer as well as chemical reactions are considered directly.

The rate based approach is based on the two-film model. This model divides liquid and gas phases into two regions, the bulk and the film. It assumes that all the mass transfer resistance is concentrated in the films, and that the only mass transfer mechanism is steady state molecular diffusion. Additionally, as the model selected for the bulk region is the mixed option, there is no concentration gradient in the bulk region due to the high level of mixing.

The mathematical model behind the rate based calculations, developed in Aspen Plus®, consists of material balances, energy balances, mass transfer, energy transfer, phase equilibrium, and summation equations.

The reader is referred to the Supplementary material (Appendix A1) for additional details on the modelling methodology of the gas turbine windbox carbon capture retrofit.

2.3. A performance assessment of the gas turbine windbox carbon capture retrofit

Replacing a fraction of the air supplied to the boiler of an existing plant with natural gas flue gas has obvious implications, discussed next. Effective integration between the heat recovery steam generator of the gas turbine and the coal plant steam cycle is discussed in the second part of this section.

2.3.1. Boiler flue gas composition

Once the heat transfer equipment of the boiler is sized to reach the specifications of the design basis with air firing, it becomes possible to examine the behaviour of the retrofitted boiler with a new gas composition and flow rate, when a fraction of the combustion air is replaced by gas turbine flue gas.

A fraction of the oxygen supply for combustion occurs via the gas turbine flue gas with a concentration of 15% on a volume basis, i.e. significantly lower than 21% in air. A larger amount of combustion agent per kg of fuel, i.e. the combined mass flow rate of flue gas, primary and secondary air, is then required, compared to an air-firing case, in order to maintain the excess oxygen level after the combustion of coal in the air/flue gas mixture. The resulting increase in average gas velocity may, however, lead to the erosion of heat exchangers banks if the plant was operated with an abrasive high ash content coal. In practice, the limit on gas velocity depends
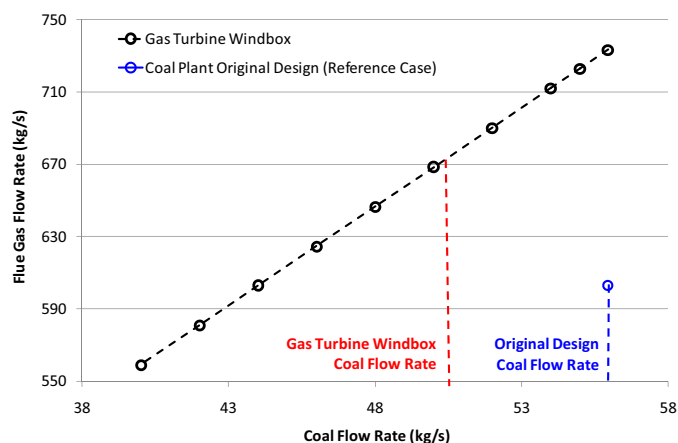

Fig. 2. Change in gas flow rate in boiler furnace for a range of coal feed rate.

on the amount of ash and on the proportion of abrasive constituents in the ash. Typical limits used for boiler design are 19.8 m/s for relatively non-abrasive low ash content coals, and 13.7 m/s, or less, for abrasive high ash content coals (Kitto and Stultz, 2005). In this work the heat exchangers of the coal boiler were designed to reach a maximum gas velocity of 13.7 m/s.

The coal input to the boiler has then to be reduced, as indicated in Fig. 2, to maintain appropriate gas velocities. The increase in gas velocity is nonetheless of the order of 7.5% (maximum gas velocity of 14.7 m/s) in this case, compared to the design basis, and results in an increase of fan power. The existing fans may need to be replaced to accommodate the additional flow, although this would need to be determined on a site by site basis.

Overall, the reduction in coal flow rate leads to lower heat release rates and, consequently, to a reduction in boiler steam flow rates and steam temperature.

'GT Windbox carbon capture retrofit' may also have an effect on the operation of the burners. Although the primary air velocity is identical to the air firing case, the secondary air velocity is higher since a fraction is replaced by a larger portion of flue gas with lower oxygen content, as indicated in Table 2. In practice, this would require tuning for all the burner settings, such as cone-damper opening, swirler position, etc. in order to obtain a suitable flame shape of the flame.

Fig. 3 illustrates the alteration to boiler flue gas composition and shows that the higher the gas turbine flue gas flow rate the lower the CO_2 concentration and the higher the H_2O concentration. It is worth noting that the oxygen concentration is kept constant by design to maintain 3% of excess air.

2.3.2. Furnace characteristics and heat transfer

Since both water vapour and carbon dioxide absorb significant amount of radiation at every point throughout the furnace, it is important to account for their effect on steam production. On the other hand, the presence of CO and SO_2 can be neglected since they

Table 2
Boiler coal, combustion air and flue gas mass flow rates.

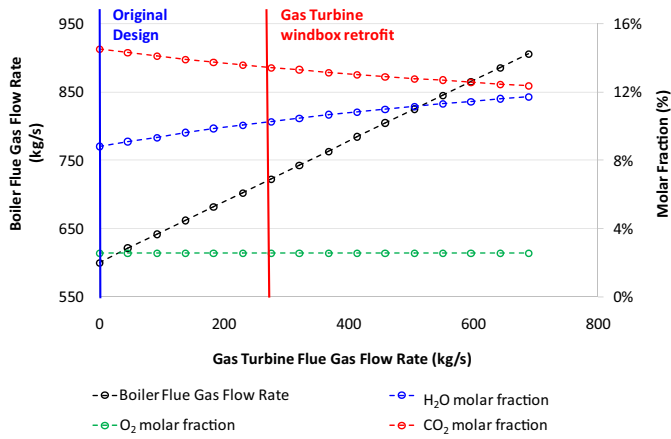|		Air-firing	Gas Turbine windbox carbon capture retrofit
Coal flow rate	kg/s	55.9	49.7
Primary air flow rate	kg/s	127.6	129.2
Secondary air flow rate	kg/s	415.4	208.2
Gas turbine flue gas flow rate	kg/s	0.0	280.7
Total of secondary air and gas turbine flue gas flow rates	kg/s	415.4	488.9
infiltration air flow rate	kg/s	9.6	9.6
Furnace exit gas flow rate	kg/s	607.2	676.2

Fig. 3. Change flue gas composition over a range of gas turbine flue gas flow rates.
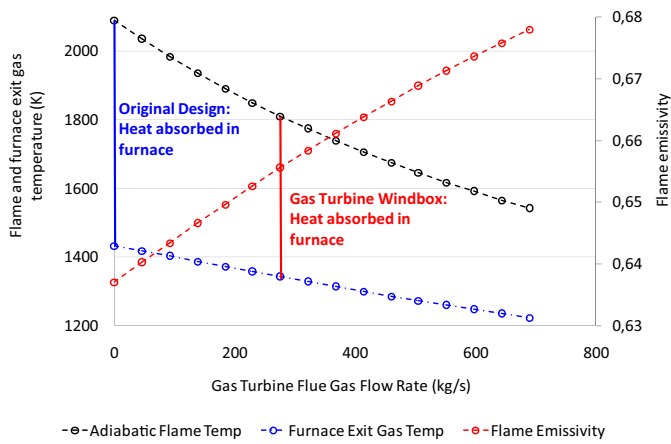

Fig. 4. Gas temperature and flame emissivity.

are weakly participating and overlap with the infrared spectrum of H_2O and CO_2.

In addition to the gas radiation from the products of combustion, the presence of suspended ash particles also cause an attenuation of the radiation due to absorption and anisotropic scattering. The equation of the flame emissivity proposed in (Basu et al., 2000) is used here to study the influence of CO_2, H_2O and solid particles in the furnace radiation.

$$a_{fl} = 1 - e^{-k \cdot p \cdot s} \qquad (6)$$

Where:

a_{fl} = Flame emissivity
k = Coefficient of radiant absorption in the furnace
P = Pressure of gases in the furnace
S = Mean beam length.

The combined coefficient of radiation absorption, k, takes into consideration the contribution of these three contributions.

$$k = k_{gas} \cdot x_{gas} + k_{ash} \cdot w_{ash} + 10 \cdot C_1 \cdot C_2 \qquad (7)$$

Where:

w_{ash} = Concentration of fly ash particles in the furnace
k_{ash} = Coefficient of radiant absorption due to fly ash particles
x_{gas} = Total volume concentration of tri-atomic gases
k_{gas} = Coefficient of radiant absorption due to tri-atomic gases
C_1 = Constant determined by the type of fuel
C_2 = Constant determined by the type of firing method.

Fig. 4 shows changes in adiabatic flame temperature, furnace exit gas temperature and flame emissivity with gas turbine flue gas flow rate and the associated changes in boiler flue gas composition.
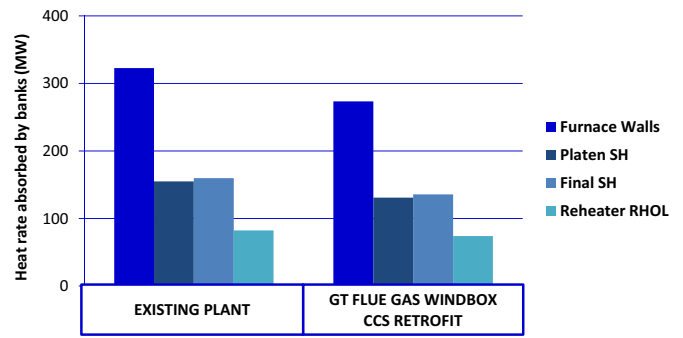

Fig. 5. Effect of flame radiation reduction on the total heat absorbed by the banks.

The water concentration of the flue gas rises to 10% v/v, in comparison to 8.8% v/v for the original design of the coal plant with air-firing, as indicated in Fig. 3. This 18% relative increase modifies the heat transfer characteristics of the furnace of the boiler: flame emissivity is increased; the adiabatic flame temperature, the furnace exit gas temperature and the gas temperature at the inlet of the superheater are reduced (Table 3). These effects have a wide range of consequences on heat transfer.

A smaller difference between the adiabatic flame temperature and the furnace exit gas temperature, as shown in Fig. 4 for the retrofit case, result in a decrease of the amount of heat absorbed in the furnace.

The lower flue gas temperature to the superheater would cause a reduction in the temperature of superheated steam generated in the boiler if the HRSG were not efficiently integrated to the steam cycle to provide high pressure high temperature steam to the existing steam cycle, as discussed in more details in Section 3.

The analysis of heat transfer in the boiler banks also reveals a reduction in radiation and an increase in convective heat transfer. The increase in the flame emissivity and the reduction in the adiabatic flame temperature and furnace exit gas temperature, alter furnace heat transfer characteristics and reduce the furnace direct radiation absorbed by heat exchangers. Additionally, the reduction in the temperature of the gas flowing around the tubes of the heat exchangers also alters the intertube radiation and reduces the amount of heat radiated from the gas to the surface of the tubes. Nevertheless, the flue gas flow rate of the boiler is increased by 10%, from 607.2 kg/s (original design of the coal plant) to 676.2 kg/s, as noted before in Table 2, and consequently, the amount of heat transferred by convection is also increased.

Fig. 5 shows the reduction in overall heat transfer in the furnace walls, platen superheater, final superheater and reheater outlet leg due to the reduction in flame and intertube radiation. The variation in the amount of heat absorbed by the different banks of the reheater, the outlet leg, the second bank of tubes, and the first bank of tubes, is plotted in Fig. 6. A large fraction of the total heat transfer shifts from convective heat transfer in the first bank to radiative heat transfer in the last bank of tubes.

As far as emissions are concerned, the reduction in coal flow rate is likely to result in lower total fuel NOx emissions, while a reduction in thermal NOx emissions is likely with a lower adiabatic flame temperature.

To maintain output and thermal efficiency, it is important to achieve high superheated and reheated steam temperatures. If they were not maintained with the 'gas turbine windbox retrofit', this could lead to a reduction in output of the steam turbines and to an increase in wetness at the back end of the low pressure turbine and increase blade tip erosion with an increase number of water droplets.

Attemperators located between the platen superheater and the final superheater in Fig. 1 are used to control the steam temperature

Table 3
Furnace characteristics.

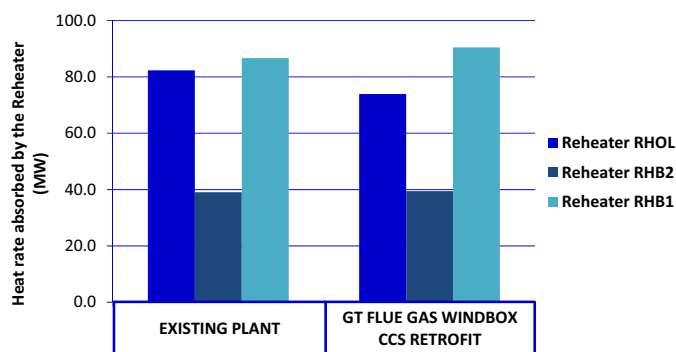| Furnace Characteristics		Air firing	Gas turbine windbox carbon capture retrofit
Adiabatic Flame Temperature	K	2121	1876
Burner Zone Exit Gas Temperature	K	1803	1631
Upper Furnace Exit Gas Temperature	K	1499	1398
Heat absorbed by Water Walls	MW	323	277
Heat absorbed by Platen Super Heater	MW	155	133

Fig. 6. Total heat absorbed by reheater banks.

at the final superheater outlet with the injection of a subcooled liquid. Likewise, a set of dampers installed at the exit of the boiler are used to control steam temperature at the reheater outlet by adjusting the proportion of gas flow between the two convection paths.

3. Effective integration of capture, compression and the gas turbine system with the existing power cycle

In order to maintain the net output of the site when capture is added, and effectively execute a 'power matched retrofit', three important factors for the sizing and the configuration of the gas turbine and heat recovery steam generator are:

a) Supply additional steam to the turbines of the existing plant to compensate for the 'partial derating' of the boiler, caused by a change in heat transfer characteristics.
b) Supply thermal energy via low pressure to the reboiler of the carbon capture plant
c) Supply power for the CO_2 compression train and ancillary equipment (blowers, fans, pumps, etc.).

Unlike in conventional 'hot-windbox' retrofit configuration, the addition of a dedicated HRSG allows these to be achieved for the purpose of carbon capture and repowering. Effective thermodynamic integration is achieved by appropriately sizing an unfired triple pressure HRSG to supply steam for power generation to the existing power cycle, and low pressure steam to the reboiler of the stripper column of the capture plant. The gas turbine supplies the electricity necessary to restore the power output of the site. This integration maintains steam production and allows reaching adequate steam temperatures in the steam cycle, as represented in Fig. 7.

3.1. Gas turbine and heat recovery steam generator

It is worth noting that the range of power output of off-the-shelf open cycle gas turbines may not necessarily exactly match what would be required for a 'power matched retrofit' of a large number of existing plants. Existing coal power stations vary widely in output and in boiler configuration, and the selection of a dedicated gas turbine system would, in practice, need to be made on a site per site basis. Most retrofits tend to be unique, and this would

certainly be the case when 'gas turbine windbox carbon capture retrofits' are implemented. Effectively, power plant developers are left with a range of options: if power output export capacity is constrained by the grid, an oversized gas turbine could be operated marginally below its maximum output, otherwise, for sites where the grid capacity allows increasing net output, it is possible to select the output of the gas turbine beyond the size required for a 'power matched retrofit'. There is a continuum of sizes and output possible, with the upper limit being determined by either the maximum grid capacity, or by the heat supply to the capture plant in 'heat matched retrofit' configuration where all steam required for solvent regeneration is generated in the heat recovery steam generator.

For the reference site, the 184 MW of a PG 7251 FB General Electric gas turbine would, for example, be higher than the 127 MW associated with capture and compression. The present paper do not include these site specific considerations and does no evaluate the off design behaviour of the gas turbine. The main focus is instead on the feasibility of the retrofit concept with a gas turbine system appropriately sized for the configuration of the reference site.

Effective thermodynamic integration is achieved with a Heat Recovery Steam Generator (HRSG) design specifically suited for the existing steam cycle and the capture process:

- A High Pressure (HP) circuit in the HRSG takes boiler condensate to generate high pressure, high temperature superheated steam entering the HP turbine inlet and compensating for the reduction in steam flow rate of the boiler superheaters.
- An intermediate Pressure (IP) circuit takes cold reheated steam from the outlet of the HP turbine to generate intermediate pressure (IP) reheated steam entering the IP turbine and compensating for the reduction in steam flow rate of the boiler reheaters.
- A Low Pressure (LP) circuit takes boiler condensate to generate LP saturated steam matching the pressure and temperature requirement of the solvent reboiler of the stripper column, which, together with steam extracted from the existing steam cycle, is used for solvent regeneration.
- The existing turbines and the HRSG effectively constitute the combined cycle of the gas turbine, which does not have a dedicated 'standalone' combined cycle.

Unlike in conventional HRSG designs, the IP economiser, the IP evaporator and the LP superheater typically found in a triple pressure HRSG are here redundant, as illustrated in the temperature profile of the HRSG in Fig. 8.

The flow rates, temperature and pressure and important design considerations of this purposely designed HRSG are provided in Table A3.1 of Appendix C.

3.2. Integration and operation of the steam cycle with carbon capture

With effective integration of the HRSG, the operation of the steam cycle remains unchanged in terms of mass flow rate, pressure and temperature, except for the low pressure part of the steam cycle; in particular the low pressure turbine and low pressure feed water heaters.
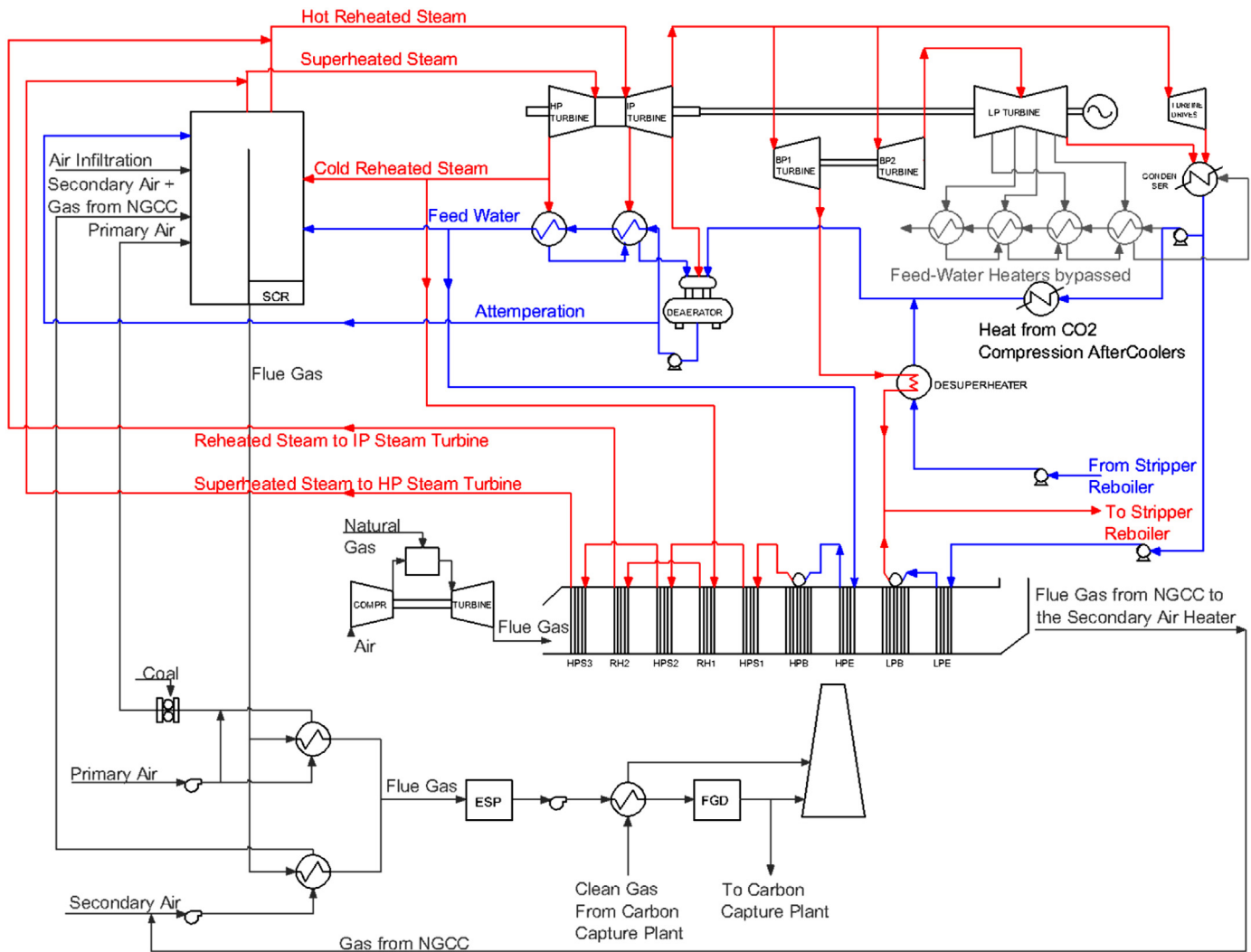
Fig. 7. Process flow diagram of a gas turbine flue gas windbox retrofit.
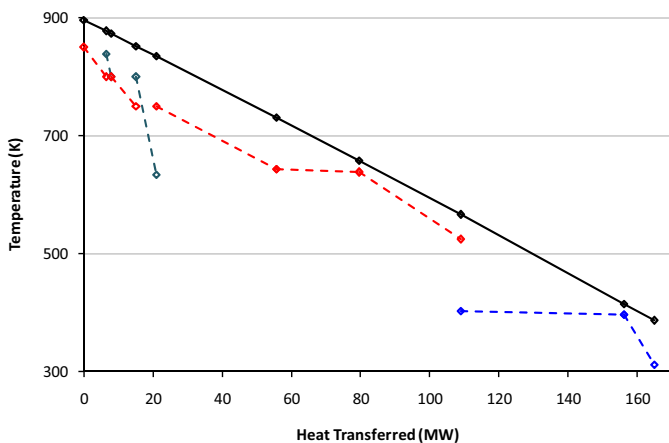

Fig. 8. Temperature profile of the HRSG.

The integration of capture to the existing steam cycle of the reference plant relies on well established principles, described for example in (Lucquiaud, 2011b, int J GHG Control):

- Steam is extracted for solvent regeneration from the crossover pipe between the intermediate and low pressure turbine, reducing the steam flow entering the LP turbine

- Steam extraction from the LP turbine for condensate water heating is substituted by heat recovered from the CO_2 compressor intercoolers
- A back pressure turbine, BP Turbine #1 in Fig. 9, generates 46 MW from steam extracted for solvent regeneration. It takes 46% of the IP turbine outlet flow to the lowest pressure that satisfies the operation of the solvent reboiler. The number of turbine stages is specific to the crossover pressure of the existing plant and the solvent regeneration temperature
- A second back pressure turbine, BP Turbine #2 in Fig. 9, recovers 34 MW from steam expanded from the crossover pressure to the new low pressure turbine inlet pressure. It avoids the thermodynamic losses associated with a valve system throttling the inlet of the LP turbine to maintain the crossover pressure. Although this is rarely proposed in the literature for carbon capture retrofits, it is worth noting that an working example of the addition of a back pressure turbine in from of the LP turbine to an existing steam cycle is currently in use at Wilhelmshaven coal-fired power plant in Germany (E.ON Kraftwerke GmbH, 2010).

3.3. Post-combustion capture process

For the purpose of assessing effective integration strategies, a typical post-combustion capture scrubbing process with two absorber trains, stripper and lean-rich heat exchanger is used as
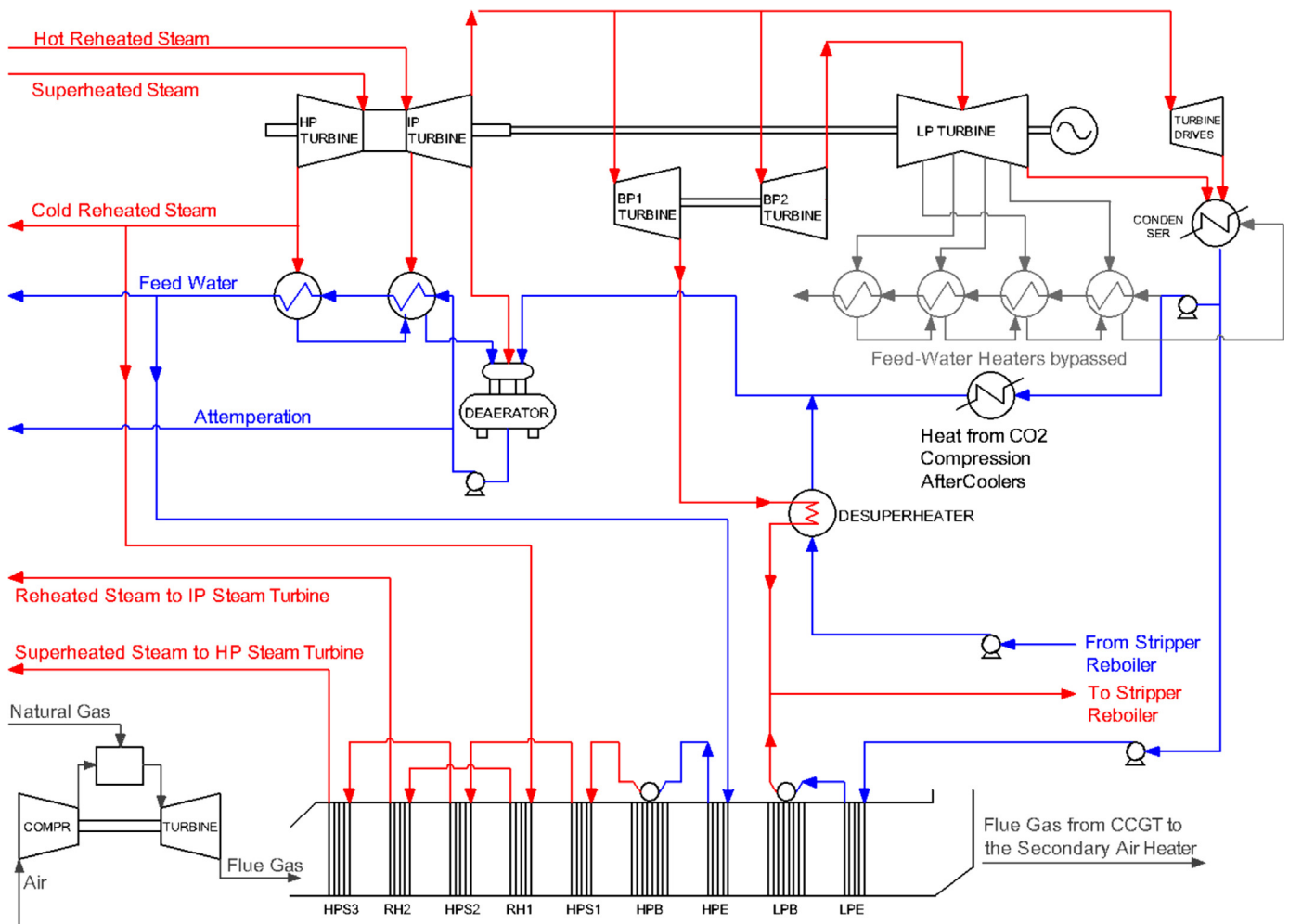
Fig. 9. Steam Cycle of the GT flue gas windbox carbon capture retrofit.

an illustrative example of post-combustion capture technologies. it is worth noting that the integration with the power plant proposed here is generic and can be easily expanded to other solvents, by appropriately tailoring the HRSG to match the temperature of regeneration and the thermal energy of regeneration of any given solvent.

The absorber island is specifically sized for the gas flow rates and CO_2 concentration of the 'gas turbine windbox carbon capture retrofit' by performing a sensitivity analysis of both absorber packing height and solvent loading on reboiler thermal duty and stripper pressure, with the objective of minimising the reboiler thermal duty.

For two absorber trains of 13 m diameter and a packing height of 17 m, reboiler duty is minimised to 3.5 MJ/kgCO_2 with a stripper pressure of 1.8 bar, when the solvent lean loading is around 0.25 mol/mol for a 30%wt MEA solvent, as indicated in Figs. 10 and 11.

The sizing of absorber packing height for the 'gas turbine windbox carbon capture retrofit' is illustrated in Fig. 12, where it can be seen that, for packing height above 17 m and for values of lean loading respectively lower and higher than 0.25 mol/mol, the rich loading is close to the equilibrium value and further increases in height do not improve significantly the reboiler duty.

Important design considerations of the optimised PCC plant are provided in Table A3.2 of Appendix C.
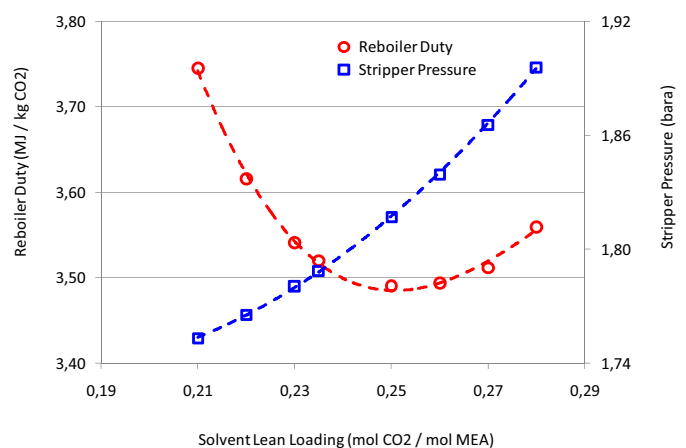

Fig. 10. Optimum MEA lean loading depending on Reboiler duty and Stripper pressure at a 407 K Reboiler Steam Temperature.

4. A comparative performance assessment of 'power matched' retrofit options

The novel 'Gas Turbine Windbox Carbon Capture Retrofit' configuration proposed in this article compares favourably to 'Standard
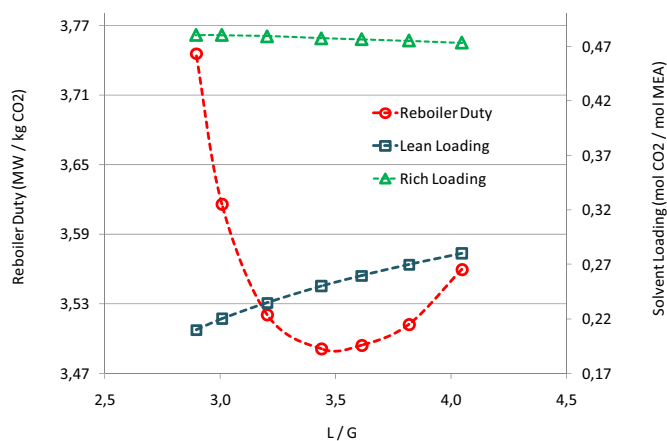
Fig. 11. Optimisation of solvent flow rate at 90% CO_2 removal rate and 17 m packing height.
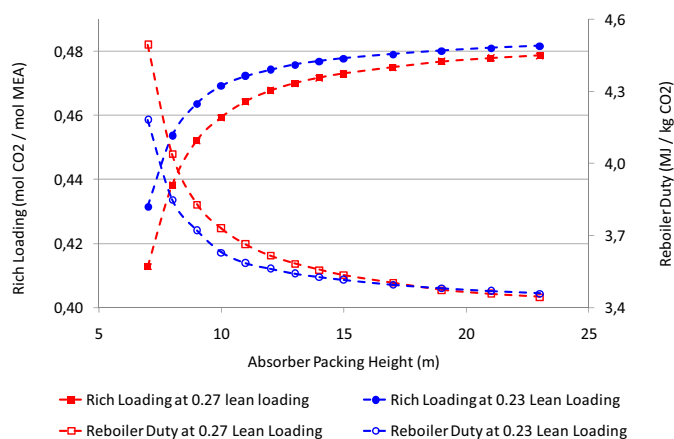

Fig. 12. Effect of absorber height on reboiler duty and rich loading at 90% CO_2 removal rate, 407 K Reboiler Steam Temperature and 3.5 L/G.

Integrated Retrofit' options and to other 'power matched' options where gas turbine power cycles are implemented for retrofitting, with post-combustion carbon dioxide capture, as well as repowering existing coal plants.

For configurations with minimal integration between the coal boiler and the gas turbine, one option to address carbon emissions from natural gas is to add a dedicated capture plant or, if efficient mixing of large gas volumes can be achieved, to treat the flue gas of the coal boiler and of the gas turbine in the same capture plant. The process flow diagram of this type of power matched retrofit is represented in Fig. 14. It consists of a CCGT where the HRSG is a triple pressure system and the steam cycle comprises a High Pressure and an Intermediate Pressure turbine, but not a Low Pressure turbine, and the IP steam turbine exits into the solvent reboiler and, supplemented by saturated steam generated in the low pressure part of the HRSG, supplies a fraction of the thermal energy for solvent regeneration. Steam is also withdrawn from the IP/LP crossover pipe of the existing steam plant.

Table 4 compares the high capture level 'power matched' retrofit options analysed in this article and, for completeness, with a 'Standard Integrated Retrofit' configuration, illustrated in Fig. 13. The main metric used are the electricity output penalty of capture and compression (kWh/t CO_2) and the marginal thermal efficiency of natural gas (% LHV). They are rigorously described in Appendix B.

It is worth keeping that the outcome of this scoping study are obviously, to a certain extent, predicted by the choice of the reference coal plant and the solvent selected for capture. The size of

the gas turbine and the HRSG effectively depends on a range of factors: coal composition, steam cycle configuration, solvent energy of regeneration etc. The general trends are, however, robust for useful conclusions to be drawn.

For all the gas turbine power cycle retrofits of Table 4, the natural gas calorific value is utilised as effectively as practically possible, as suggested in the rules for thermodynamic integration of the PCC plant with the power cycle (Gibbins et al., 2004; Lucquiaud, 2010), to produce power in the gas turbine and high temperature high pressure steam to generate extra power in the steam turbines of the combined cycle. The high natural gas marginal efficiency indicates a very effective use of the natural gas, an important fraction of the calorific value of the natural gas is recovered as power.

4.1. Standard integrated retrofit

For consistency, the 'Standard Integrated Retrofit' configuration with steam extraction supplying all of the thermal energy required for solvent regeneration follows the same integration principles as the steam cycle of the 'Gas Turbine Windbox Carbon Capture Retrofit'. The addition of two back pressure turbine ensures that the best possible scenario for thermodynamic integration is achieved and that the electricity output penalty is close to that of a retrofitted carbon capture ready plant. The electricity output of the retro-fitted site is reduced by 20% and the thermal efficiency drops by 8% points. It is important to note that this level of integration may not necessarily be always achievable if general access, extraction from the existing turbines or space is a limiting factor.

4.2. Gas turbine windbox carbon capture retrofit

The effective thermodynamic integration of the novel retrofit configuration reaches the lowest electricity output penalty and the highest marginal thermal efficiency of natural gas combustion, since:

- The lower gas flow rate entering the capture plant, compared to other gas turbine power matched retrofits, results in a lower power consumption of the flue gas blowers.
- The HP and IP steam generated by the HRSG is fed to existing Rankine cycle, which benefits from feedwater heating from the compressor intercoolers, unlike the combined cycle of conventional configurations.
- Lower irreversibilities in the HRSG: the heat addition for steam generation from the gas turbine exhaust gas is more reversible than in a standard HRSG, since the dedicated HRSG has no IP evaporator, as shown in the pinch diagram of Fig. 8.
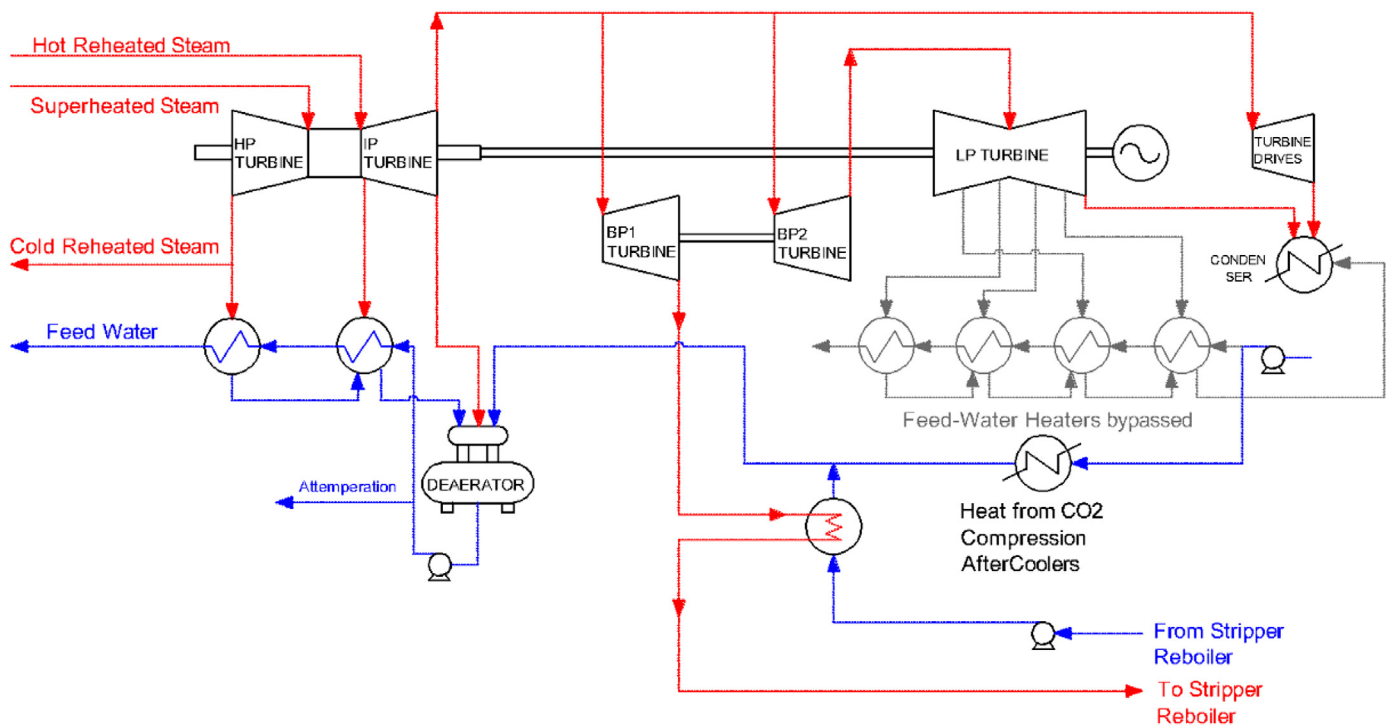
4.3. Gas turbine power matched retrofits

The two specific retrofit configurations include a configuration with two capture units, one for coal flue gas and one for gas flue gas, and a configuration where both flue gas are mixed and treated in a single capture unit. The way the carbon generated by natural gas combustion is abated has an impact on performance, since the electricity output penalty of a CCGT with post-combustion capture is significantly higher, at 430 kWh/tCO_2, than for coal. This is mostly due to the lower flue gas CO2 concentration and the fan power associated with a high flow rate of the exhaust gas. The counterfactual plant in Table 4 does not use the best in class gas turbine available, 60–61% LHV thermal efficiency at the time of writing, but, for consistency, the off the shelf gas turbine (PG 7251 FB) used for a windbox retrofit of the reference coal plant, with a thermal efficiency of 53.6%, due to its smaller size. As noted earlier, the thermal efficiency is independent of the electricity output penalty (Lucquiaud and Gibbins, 2011a,b)

Table 4
A comparative performance assessment of gas turbine power cycles for repowering existing coal plants and retrofitting with post-combustion capture.

	Existing coal plant w/o capture	Standard Integrated Retrofit	GT Windbox Carbon Capture Retrofit	CCGT Power Matched Retrofit	CCGT Power Matched Retrofit (mixing flue gases)	Counter- factual CCGT
Coal thermal input (MWth)	1517.9	1517.9	1348.6	1517.9	1517.9	0.0
Gas thermal input (MWth)	0.0	–	358.4	269.6	265.3	1290.1
Net Power output (MWe)	600.3	473.9	600.3	600.3	600.3	600.3
Carbon intensity of electricity generation (gCO2/kWh)	765.3	96.9	79.5	84.7	84.6	39.2
Thermal efficiency (% LHV)	39.5	31.2	35.2	33.6	33.7	46.5
Carbon capture rate from coal combustion (w/w)	–	0.9	0.9	0.9	0.9	0.9
Combined carbon capture rate (w/w)	–	N/A	0.9	0.9	0.9	N/A
Total gas flow rate (kg/s)	632.8	632.8	697.9	851.0	847.5	1044.2
Gas flow rate to coal capture unit (kg/s)	–	632.8	697.9	632.8	847.5	–
Gas flow rate to gas turbine capture unit (kg/s)	–	–	–	218.2	–	1044.2
Flue gas CO2 concentration from coal combustion (v/v)	0.14	0.14	0.13	0.14	0.11	–
Flue gas CO2 concentration from gas combustion (v/v)	–	–	–	0.04	–	0.04
Solvent energy of regeneration – coal (GJ/t CO2)	–	3.49	3.49	3.49	3.51	–
solvent energy of regeneration – gas (GJ/t CO2)	–	–	–	4.0	–	4.1
CO2 compression power (kWh/t CO2)	–	111.0	111.0	111.0	111.0	111.0
Electricity output penalty (kWh/t CO2)	–	305.8	291.5	315.8	311.3	431.2
Gas Turbine Combined cycle thermal efficiency, if without capture (% LHV)	–	–	53.6	53.6	53.6	53.6
Marginal thermal efficiency of additional gas combustion (% LHV)	–	–	50.0	46.9	47.7	N/A

Fig. 13. Process flow diagram of the Standard Integrated Retrofit configuration with steam extraction from the main steam cycle providing all of the heat for CO$_2$ capture and power requirements from the main generator.

For gas turbine power matched retrofits with limited integration, i.e. no sequential combustion of the gas turbine exhaust gas in the coal boiler, there is an detrimental effect on reboiler duty since the CO$_2$ concentration of 'Gas Turbine Windbox Carbon Capture Retrofit' is closer to that of coal plant, as opposed to capturing from two streams at respectively 13.6% v/v and 4.0% v/v. The other important factor is the ancillary power for the flue gas blower, which is proportionally higher per unit of CO$_2$ captured for natural gas flue gas than for coal.

5. Summary of findings and conclusions

Sequential combustion of the exhaust gas of a gas turbine via the windbox of the boiler of an existing coal plant allows
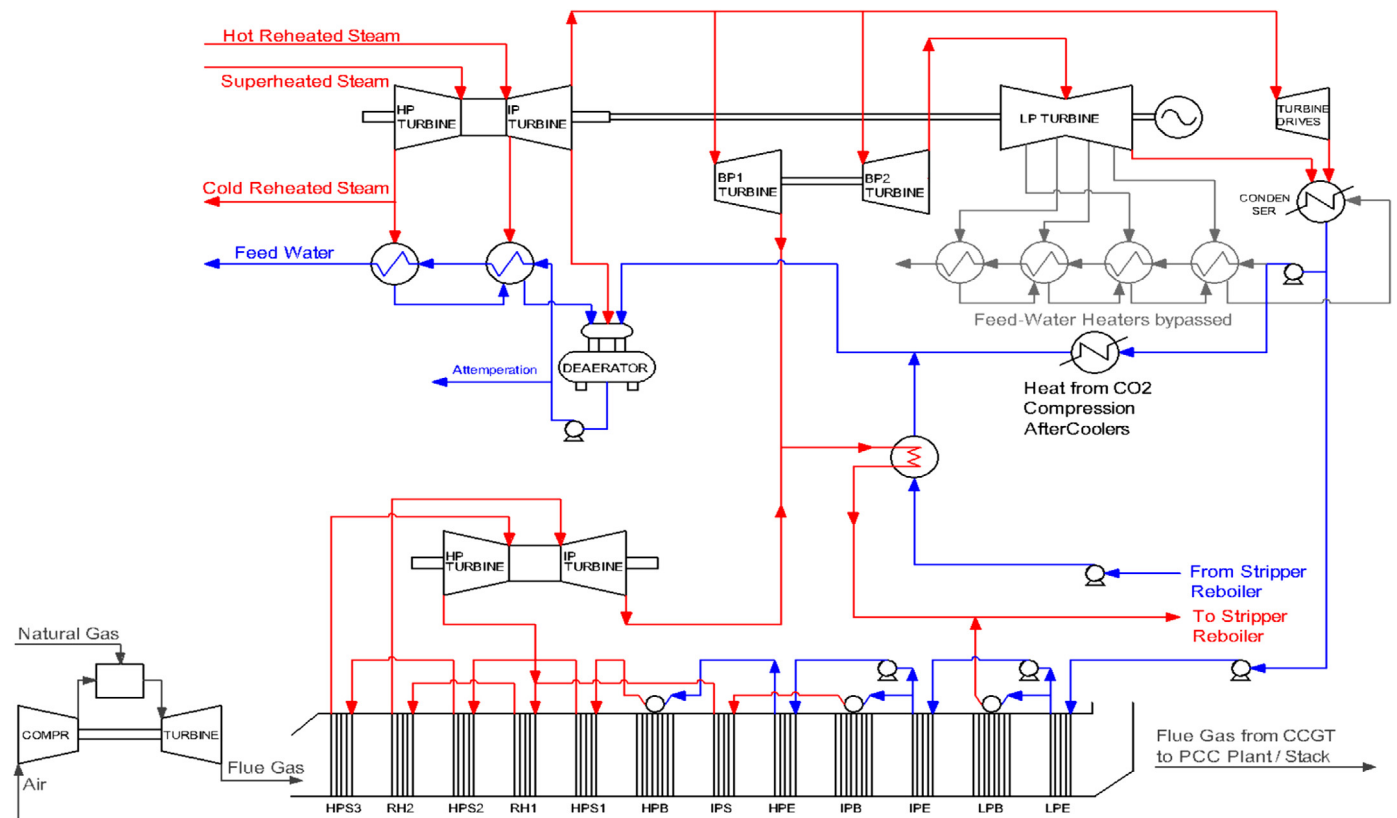
Fig. 14. Process flow diagram of a power matched carbon capture retrofit with a combined cycle gas turbine. The heat for CO_2 capture and the power requirements are supplied from both the combined cycle gas turbine and the main steam cycle.

repowering and facilitates post-combustion capture of carbon emissions from both fuels. In addition, the necessary reduction by 10% of coal flow rate combined with the effective integration of the heat recovery steam generator with the existing steam cycle and the capture process presents several advantageous features:

- Number and sizing of absorber columns

The resulting flue gas can be treated in the same post-combustion capture plant. If an equivalent power output and carbon intensity of electricity generation were to be achieved with a retrofit with an additional gas turbine, this would require capturing carbon from the gas turbine in a dedicated capture plant, with a much higher flue gas flow rate and more absorber columns. If the flue gas of gas turbine and a coal boiler were to be treated in the same capture plant, stratification issues may occur in the absorber, since efficient mixing of large volumes of low temperature gas with different composition is difficult to achieve. Corrosion may also occur because of condensation of acid flue gases, when flue gas from both fuel sources are mixed. The temperature of the mixture may drop below the dew point and sulphuric acid may condense as small fog droplets and on the fly ash particles.

- Effective integration with the existing power cycle

Since the heat recovery steam generator supplies steam directly to the existing steam cycle, the gas turbine does not have a dedicated combined cycle. The existing steam turbines effectively operate as the combined cycle of the CCGT and without being derated.

It is also important to note that, although it has not been studied in extensive details here, an array of possible off-the-shelf gas turbine sizes can complement most existing plants, and, if desirable, achieve a varying degrees of repowering.

A lower electricity output penalty and a higher marginal efficiency of the combustion of additional natural gas can be achieved compared to other gas turbine power cycle retrofit options, and to integrated steam extraction retrofits.

- Associated capital cost savings

The absence of a dedicated combined cycle for the gas turbine result in capital cost savings, compared to alternative 'power matched' retrofit options. Likewise, the reduction in total volume of CO_2 to be treated in the carbon capture plant, compared to other retrofit options at equivalent output and carbon intensity of electricity generation is associated with large capital cost savings.

- Energy penalty of solvent regeneration

Lower energy requirements of the post-combustion capture process, compared to options at equivalent output and carbon intensity, are also beneficial. The specific reboiler duty is close to that of a coal unit since the CO_2 concentration at the inlet of the absorber at 0.13 v/v is comparable to the concentration of 0.14 v/v of the coal plant with air-firing and since the additional irreversibilities of scrubbing flue gas at 0.04 v/v directly from a gas turbine are avoided.

- Other operational issues

Most of the issues associated with hot-windbox repowering, i.e. erosion problems, are avoided with a 'gas turbine windbox carbon capture retrofit' since the increase in the overall boiler gas flow rate is somehow limited to 10%.

Implications for other combustion pollutants than carbon dioxide are a reduction in thermal and fuel NOx emissions due to a lower flame temperature and a reduced coal flow rate. SOx emissions are expected to decrease as well.

Solvent degradation is expected to be improved, compared to options with a capture unit dedicated to a gas turbine. A lower O_2 concentration at the inlet of the carbon capture plant of 3,2% v/v, in comparison to 12.5% v/v at the exhaust gas of the turbine or 5.6% v/v if flue gas from coal and gas are mixed, would result in

lower operating costs for solvent replacement and lower corrosion of carbon steel equipment.

- Repowering existing coal plants built with CCS

Repowering existing coal plants with CCS makes the 'GT windbox carbon capture retrofit' a promising alternative for adapting integrated capture retrofits that are initially designed for operation with zero to ~90% capture (as at the Boundary Dam 3 unit) for subsequent operation only with full capture. In this case the addition of a GT flue gas windbox retrofit will restore the full power output of the site with full CO_2 capture and using the original capture plant.

- Considerations for future work and conclusions

This work shows that 'GT windbox carbon capture retrofit' can be a viable option for repowering and retrofitting coal plants with post-combustion capture. A case study of a subcritical boiler unit has not identified any major technical barriers. Although existing coal power stations vary widely in output and in boiler configuration, it is possible to widen the conclusions of this study to generic conclusions to existing coal plants.

One important consideration to assess the potential for deployment is coal to gas price ratio. It is obvious that 'GT windbox carbon capture retrofit' are likely to be compare favourably to other coal plant retrofit options in regions of affordable natural gas prices, e.g. in North America at the time of writing, since a retrofitted unit would consume proportionally a larger amount of natural gas per unit of low carbon electricity compared to other gas turbine power cycle retrofit options. Site specific factors will ultimately dominate the effect on capital costs and determine what series of existing plants may benefit greatly 'gas turbine windbox carbon capture retrofit', notably with respect to any modifications of the base power plants, e.g. heat transfer area in the boiler. Further work is now required to assess the full implications on the cost of abatement and the cost of low carbon electricity generation and include relevant site specific parameters, such as the remaining life of existing coal power generation asset, coal to gas price ratio, load factors, etc.

Acknowledgments

Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.ijggc.2016.09.015.

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