

Operational flexibility options in power plants with integrated post-combustion capture



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ABSTRACT

Flexibility in power plants with amine based carbon dioxide (CO₂) capture is widely recognised as a way of improving power plant revenues. Despite the prior art, its value as a way to improve power plant revenues is still unclear. Most studies are based on simplifying assumptions about the capabilities of power plants to operate at part load and to regenerate additional solvent after interim storage of solvent. This work addresses this gap by examining the operational flexibility of supercritical coal power plants with amine based CO₂ capture, using a rigorous fully integrated model. The part-load performance with capture and with additional solvent regeneration, of two coal-fired supercritical power plant configurations designed for base load operation with capture, and with the ability to fully bypass capture, is reported. With advanced integration options configuration, including boiler sliding pressure control, uncontrolled steam extraction with a floating crossover pressure, constant stripper pressure operation and compressor inlet guide vanes, a significant reduction of the electricity output penalty at part load is observed. For instance at 50% fuel input and 90% capture, the electricity output penalty reduces from 458 kWh/tCO₂ (with conventional integration options) to 345 kWh/tCO₂ (with advanced integration options), compared to a reduction from 361 kWh/tCO₂ to 342 kWh/tCO₂ at 100% fuel input and 90% capture. However, advanced integration options allow for additional solvent regeneration to a lower magnitude than conventional integration options. The latter can maintain CO₂ flow export within 10% of maximum flow across 30–78% of MCR (maximum continuous rating). For this configuration, one hour of interim solvent storage at 100% MCR is evaluated to be optimally regenerated in 4 h at 55% MCR, and 3 h at 30% MCR, providing rigorously validated useful guidelines for the increasing number of techno-economic studies on power plant flexibility, and CO₂ flow profiles for further studies on integrated CO₂ networks.

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1. Introduction

Reducing carbon dioxide emissions to prevent climate change has become one of the key priorities for the energy sector. One route to achieve decarbonised electricity systems within the targets highlighted by the latest IPCC report (IPCC, 2013) will entail expanding renewable energy supply and using nuclear energy and fossil fuel plants with carbon capture and storage (CCS). Given the current installed capacity and expansion plans for electricity generation from variable renewable sources, future power systems will favour resources that provide system flexibility (ability to follow

changes in variable energy plant output). In this respect, fossil fuel power plants with integrated CO₂ capture (for transportation and storage) could also play an important role in balancing low carbon electricity grids.

Post-combustion capture based on amine scrubbing is a mature technology that has been proven at small to medium scales and is the technology of choice for the first fossil fuel power plants with CO₂ capture (Boot-Handford et al., 2014). In future electricity systems, power plants with integrated amine-based post-combustion capture (here referred to as CCS power plants) are expected to operate at variable load to balance the intermittent supply from renewable sources (depending on net electricity demand) and produce low carbon intensity electricity by capturing most of the CO₂ emitted (Bruce et al., 2015). Understanding of operating flexibility is an important step in the development of amine

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scrubbing technology since they were typically designed as a base load continuous operation separation technology for natural gas treating (Kohl and Nielsen, 1997).

Flexible operation of the capture unit is widely suggested as a way to improve the economics of CCS power plants (Chalmers and Gibbins, 2007; Chalmers et al., 2009; Cohen et al., 2010, 2012; Delarue et al., 2012; Haines and Davison, 2014; Oates et al., 2014; Van der Wijk et al., 2014). For instance, the capacity to vary steam extraction levels from the power cycle to adjust both power output and capture level is a valuable option to increase/decrease power output rapidly to meet grid requirements, maintain the output of the power plant in case of a failure either in the CO₂ capture, transport or storage part of the system, generate revenue in response to price signals in the electricity spot market or generate revenue in the reserve market.

A key assumption when assessing the implications of CCS power plant flexibility is how the CO₂ capture plant is operated, which is influenced by legislation for CO₂ emissions. The CO₂ capture plant could be operated flexibly around the power plant if an annual emission tonnage is implemented instead of emission concentration limits or removal rates. Therefore, strategies for part-load operation and/or flexible operation of capture units can be classified according to their objective. There are strategies for part-load operation of the capture unit that aim to maintain the capture level, normally referred as load-following, which have been described by several authors (Kvamsdal et al., 2009; Ziaii et al., 2009; Van der Wijk et al., 2014; Brasington, 2012). Other strategies aim to provide fast power augmentation by stopping solvent regeneration temporarily (Haines and Davison, 2014) or pursue additional profitability. Capture by-pass, also referred as venting (Chalmers and Gibbins, 2007; Gibbins and Crane, 2004), consists in turning down/off the capture and compression unit and diverting the steam extracted for solvent regeneration back to the power cycle bringing it to its full net power output. When the capture unit is supplied with amine solvent storage capacity followed by delayed solvent regeneration (Chalmers and Gibbins, 2007; Gibbins and Crane, 2004), the power plant has the ability to reduce considerably the energy penalty for a set period of time and regenerate rich solvent later time.

This flexible strategy is associated with an increase in plant revenues when electricity prices are high and/or from balancing services (Chalmers and Gibbins, 2007; Chalmers et al., 2009; Cohen et al., 2010, 2012; Delarue et al., 2012; Gibbins and Crane, 2004; Oates et al., 2014). However, profitability is highly dependent on the differential in electricity prices and the amount of wind generation in the electricity system considered. Brasington (2012) showed that flexibility with amine solvent storage does not increase profitability under the set of electricity price spreads that were considered. Patiño-Echeverri and Hoppock (2012) showed that flexibility with amine storage may be marginally cost-effective for retrofitted plants by taking advantage of arbitrage opportunities present in electricity markets with large price differentials.

Van der Wijk et al. (2014) recently carried out a comprehensive study integrating a capture unit with an electricity system model of the North West part of Europe, including revenue from some ancillary services. By comparing the revenues of different options for flexible CCS power plants to a non-flexible counterfactual they showed that the main benefit of flexible CCS is an increase in reserve capacity. They also concluded that solvent storage could be a viable option independent of the carbon price if solvent can be regenerated during hours of low demand, when the plant generator operates regularly at part-load when it is displaced by wind generation. The work of Oates et al. (2014) concluded that solvent storage could be used for capital cost gain by undersizing the regenerator to smooth out compressed CO₂ flow throughout the day.

Mac Dowell and Shah (2013, 2015) have proposed a flexible solvent regeneration strategy. Using a multi-period design approach, they show that, with perfect foreknowledge of electricity prices and a specific set of electricity price distribution, time varying solvent regeneration approach has the potential to generate electricity that has, on average, a lower carbon dioxide intensity and to be more profitable than the options of either capture bypass or solvent storage (Mac Dowell and Shah, 2014).

Despite this prior art, the value of flexibility strategies in CCS power plants is still unclear, and conclusions from various authors are sometimes contradictory, perhaps due to the complexity of the networks and systems involved. The assumptions about part-load performance and the capabilities of the plant when operated with solvent storage and delayed solvent regeneration have a large influence on the outcome of flexibility studies. Besides the influence of the selected assumptions, which is not always reported transparently, most of the previous studies simplify parts of the systems involved in power generation and capturing and compressing CO₂. For instance, the performance of the capture unit is simplified (Lucquiaud et al., 2007), the interface between the power cycle and the capture is not described (Van der Wijk et al., 2014) or is simplified (Ziaii et al., 2009), the effects on compression power of changes in the volumetric flow rate of CO₂ at part-load are not included (Van der Wijk et al., 2014), or they focus on the operation of one part of the system only (Kvamsdal et al., 2009). This work builds on these studies and examines the full implications of important parameters, such as power plant efficiency at part-load and impact of additional solvent regeneration on overall efficiency. Parameters related to flexible operation such as capture level, availability of steam extraction and steam pressure, compressor efficiency, are included to evaluate the extent of the sensitivity of the value of flexibility to these parameters.

In addition, future CCS power plants, beyond initial demonstration from a single source to a single CO₂ sink, will have to operate within the constraints of a second network, namely the downstream CO₂ transport and storage system. The latter presents its own constraints on variations in CO₂ flow and conditions, CO₂ phase change, injection rates and gas composition. CCS power plant flexibility may become valuable to control CO₂ flows, possibly independently of electricity generation, to meet the requirements of transport networks or storage sites by adjusting compressed CO₂ flow in response to signals from the transport network and storage operators.

This study contributes to the existing literature on CCS power plant flexibility by providing an engineering analysis of part load and flexible operation of CCS power plants using a rigorous fully integrated modelling approach of the CCS power plant system. The part-load operation of a supercritical coal power plant is evaluated taking into account the main factors that influence the performance of capture units integrated into flexible power plants:

- (1) Power plant part load strategy,
- (2) Power plant and capture unit integration philosophy,
- (3) Capture unit configuration and operation strategy, and
- (4) Compression unit operation.

For this purpose, a detailed model is used to characterise the operating envelope, the performance and the corresponding CO₂ output of supercritical coal power plants with post-combustion capture for a range of loads, varying from 20% to 100% of the power plant maximum continuous rating (MCR), with or without voluntary by-pass of the capture unit. The performance of two power plant configurations is evaluated. The first configuration illustrates the case of a CCS power plant designed with limited consideration for part-load operation and flexibility, with the exception of oversizing the low pressure turbine, which is a minimum requirement

to by-pass the capture unit and generate additional power. The second configuration includes advanced integration options in the boiler, steam turbine and CO₂ compressor that provide considerable efficiency improvements at part load. For both configurations, an optimised part-load operating strategy of the capture unit is proposed to improve performance at reduced fuel input by minimising the electricity output penalty associated with capture and compression. A direct comparison on the basis of net power output, thermal efficiency and electricity output penalty demonstrates the benefits of each configuration over a range of fuel input and power plant loads. It is worth noting that the dynamic response of the integrated power plant is not considered in this work, which is concerned with steady-state efficiency.

Two flexible operation strategies, capture by-pass and amine solvent storage with delayed solvent regeneration, are evaluated for both configurations. Novel insights into the capabilities of CCS power plants to interact with emerging CO₂ networks are provided. This takes into account the capability of the steam cycle, capture unit and the compression train to deliver compressed CO₂ to the network under different conditions of load and flexible operating strategy. The results of this study can be fed into studies on the economic assessment of power plant flexibility, and also into the growing field of integrated CO₂ networks.

2. Engineering aspects of part-load and flexible operation of CCS plants

Various aspects in the design of coal power plants with post-combustion capture influence their behaviour at part load. These are related to the control philosophy of the boiler, the type of integration of the capture unit into the steam cycle, the turndown strategy at capture plant level and compressor options to accommodate CO₂ flow variations. This section describes the key points to consider for effective integration between supercritical steam cycles, amine based post combustion capture and compression that can significantly improve plant efficiency across the entire range of plant load, as shown by the results of this work. Although subcritical plants are not considered here, it is expected that many of the conclusions of this work would hold.

2.1. Boiler operation in coal power plants with supercritical Rankine cycles

The load of the boiler of coal power plants is adjusted to increase or decrease power plant output as a response to electricity demand. This leads to variations in steam flow rates and steam parameters (pressure and temperature) that are controlled at steam turbine level to adjust power output. The most common methods to change power output control these steam parameters for a given plant load or adjust the swallowing capacity of steam turbines, i.e. their capacity to expand steam across a range of volumetric flow rates:

- (1) Fixed boiler pressure control and steam throttling: The steam pressure in the boiler is maintained constant. The control valves located upstream of the HP turbine section are actuated to adjust the degree of throttling to decrease/increase mass flow. This method has significant efficiency disadvantages in continuous operation but provides fast dynamic response (Cotton, 1994; Wechsung et al., 2012).
- (2) Sliding boiler pressure control: The boiler pressure is reduced by controlling the discharge pressure of the boiler feed pump. This method allows faster start-up procedures (Vitalis, 2006) and by eliminating the valve control and maintaining the pressure ratio across the turbine improves plant efficiency at part-load (Cotton, 1994).
- (3) Partial-arc admission or control stage: A control stage is located at the inlet of the HP turbine. Steam enters the first rotating blade through a set of control valves, usually 4 but up to 8 control valves, which are opened in sequence with increasing output, each valve supplying a separate arc of the first stationary blade row. This type of control adjusts the swallowing capacity of the turbine to specific steam parameters and is especially advantageous where the boiler has to be operated at fixed pressure since it does not incur in throttling losses. However, the facts that the inlet flow is not rotationally symmetrical and homogeneous has disadvantages of mechanical nature that result in increased plant costs and lower operating reliability (Wechsung et al., 2012).

In practice, coal plants tend to use fixed or sliding pressure boiler control philosophies to trade-off between fast start-up, fast dynamic response at full load and part-load efficiency. Partial-arc admission is a turbine control philosophy, which can be combined with both boiler control methods (Silvestri, 1989; Vitalis and Hunt, 2005) to improve further part-load efficiency. However, this control strategy has only been realised by a few manufacturers for outputs above 600 MW (Wechsung et al., 2012). This study considers a supercritical plant with a combination of sliding pressure boiler control and steam throttling and a plant with only sliding pressure boiler to demonstrate improvements in part-load efficiency.

2.2. Integration of between power cycle and capture unit

For carbon capture, steam turbines are designed and operated at nominal load (with capture) to meet the pressure requirements on the steam side of the reboiler in the capture unit. Meeting pressure requirements at part load might not be possible, depending on the design of the steam extraction. An extensive review of steam turbine options to supply the necessary steam for post-combustion capture operation can be found in Lucquiaud (2013) and Lucquiaud and Gibbins (2011). In flexible operation strategies, power output is increased when the capture unit is by-passed, turndown or partially stopped. This requires accommodating larger steam flows than base load operation with capture into the low pressure turbine of the steam cycle. Two integration options have been considered based on their relevance for flexible steam extraction (Lucquiaud and Gibbins, 2009, 2011):

- (1) Throttled LP turbine (controlled steam extraction): In this option, the IP/LP crossover pressure is set at the desired value for a specific solvent regeneration temperature. The crossover pressure is controlled with a throttling valve upstream the LP turbine. When the capture unit is by-passed, the valve is fully opened and the pressure in the crossover pipeline is dictated by the discharge conditions of the IP turbine at full load. When the capture unit is in operation and steam is extracted at the IP/LP crossover, the LP turbine inlet is throttled using the valve to maintain the crossover pressure. This creates a thermodynamic loss when the steam is expanded in the valve by reducing pressure.
- (2) Floating IP/LP crossover pressure (uncontrolled steam extraction): Unlike the previous option, the extraction pressure is not controlled by a throttle valve but rather determined by the amount of steam extracted. This system eliminates the thermodynamic losses when the plant operates at base load. The initial IP/LP crossover pressure is set so that, when the predicted amount of steam is extracted for solvent regeneration, its pressure falls or 'floats' to the desired value.

After extraction, steam needs to be conditioned to saturation conditions by subsequent de-superheating steps. The control

philosophy for steam extraction needs to comply with safety considerations (it should minimise the risks to the power plant hardware or the capture plant hardware or solvent), flexibility (it needs to accommodate variable steam load and steam conditions) and efficiency (it should be designed to minimise the impact on power generation efficiency). The typical options for steam de-superheating are inline spray de-superheaters and indirect contact de-superheaters. The spray type has less pressure drop but its turn-down ratio and capacity to accommodate variable steam flow and conditions is limited (SpiraxSarco, 2015). For this reason, indirect contact de-superheating is used in this work.

2.3. Capture unit operation at part load

Amine scrubbing technology was originally developed to work at a constant load. The overall turndown capability of the unit depends on the turndown characteristics of two main components, namely the absorber and reboiler. For part load operation, different operating modes can be applied to maintain or provide the most economical capture level:

- (1) Constant liquid-to-gas ratio (L/G) in the absorber: This strategy is widely proposed for load following (Kvamsdal et al., 2009; Mechleri et al., 2014; van der Haar, 2013; Van der Wijk et al., 2014) and relies on maintaining the ratio between lean solvent and flue gas streams entering the absorber approximately equal to the design value at full load. The capture plant has basic controls to maintain the conditions in the stripper column. The pressure is controlled by a valve downstream of the condenser following the stripper, and temperature is controlled by adjusting the steam extraction flow. The capture level is controlled by adjusting the solvent flow in order to keep the L/G ratio in the absorber constant. In practice, a constant ratio of gas and liquid generally results in slightly higher CO_2 removal rates due to higher residence times in the absorber column, therefore in order to achieve the same capture rate as full load the L/G ratio is slightly reduced. This effect has also been verified experimentally at pilot plant operation (Knudsen, 2011; Knudsen et al., 2009).
- (2) Constant solvent flow rate (L): The strategy is investigated by Kvamsdal et al. (2009) and it consists on maintaining the flow of the lean stream entering the absorber constant. The steam flow rate needs to be reduced to maintain the capture level, which implies operating at higher lean loadings than designed at full load operation. This has implications to the operation of the absorber and stripper. Mainly the reaction kinetics are affected by the lean loading.

Both strategies are considered in this work but they had to be modified to take into account the integration with the steam cycle, which is lacking in the studies where they have been described.

2.4. Compressor unit operation at part load

The CO_2 released at the stripper head needs to be cooled to ca 40°C to separate water and then compressed to a suitable pressure for transportation. Generally, the CO_2 is compressed to 110 bar which is a pressure commonly used in capture and transportation studies in Europe (EBTF, 2011).

At reduced flows, there is a risk of surge flow that can be damaging for the compressor. For this reason all compressors have an anti-surge control unit that prevents surge by recycling a part of the compressed fluid. This control action decreases compressor efficiency at part load substantially. Other option to control compressor performance is variable speed drive, which consists in adjusting the rotating speed of the compressor to

change swallowing capacity. This option is analysed by Ziail (2012) concluding that a variable speed drive compressor is advantageous with respect to part load efficiency. However, from the mechanical perspective, variable speed drive compressors may have issues with vibrations (Sanchez Fernandez et al., 2015).

Rost et al. (2009) provide a generic study of integrally geared centrifugal compressors with inlet guide vanes that investigates the influence of selected main operating conditions on the compressor design and cost. Their work covers a set of criteria that includes relevant parameters of the mechanical design. This approach is advantageous due to the fact that concepts developed based on a thermodynamic analysis in isolation might lead to the development of a tailor-made compressor design for the application, which are effectively not available.

In this work, flow control based on recycling part of the compressed fluid and the use of inlet guide vanes has been considered. The inlet guide vane system (IGV) manipulates the angle between the inlet flow and the impeller and, therefore, the relative speed of the inlet gas. This allows for the optimisation of power consumption when operational parameters such as pressure, temperature or flow change. Both operational strategies are compared to show the improvements of the IGV system.

3. Methodology

3.1. Description of studied configurations: conventional integration options (CIO) vs. advanced integration options (AIO)

In order to demonstrate the improvements of different integration options on the flexible operation of CCS power plants, a reference power plant configuration that illustrates the scenario of a power plant designed with limited consideration for part-load performance has been modelled. This configuration is based on a series of conventional integration options: a supercritical boiler controlled by a combination of sliding pressure and throttling of the superheated steam flow, a throttled LP turbine for steam extraction, a compressor with CO_2 recycling to control performance at reduced load. It is referred to as conventional integration options (CIO) power plant, and is compared to a configuration with advanced integration options (AIO) that improve part-load efficiency: sliding pressure for boiler control without throttling at the HP turbine inlet, an IP turbine and an LP turbine designed to operate with a floating crossover pressure, and a compressor with inlet guide vanes (IGV) for load control.

Fig. 1 illustrates the process flow diagram of a standard supercritical coal power plant, which applies to both power plant configurations. The boiler is a state-of-the-art supercritical boiler designed to operate with bituminous coal and light oil for start-up and flame stabilisation. The minimum load without oil support is 40% of the MCR (boiler Maximum Continuous Rating). The boiler is fitted with sliding pressure control and/or throttling for part load operation between 40% MCR to 100% MCR. The temperature of the superheated steam is controlled within this load range by 2-stage spray attemperation maintaining live steam temperature at 603°C . The reheated steam temperature is controlled at 623°C by adjusting the proportion of gas flow between two convection paths (the superheater and reheater) at a minimum load of 50% MCR. At lower boiler loads the reheated steam temperature drops to a minimum of 601.4°C . The performance data for boiler operation are in agreement with a typical supercritical boiler design (Panesar et al., 2009).

The steam cycle is supercritical with single reheat. It comprises a single flow HP turbine, a double flow IP turbine and a series of double flow LP turbine (note that only one LP turbine is represented in Fig. 1), with 50% reaction turbine stages. The degree of reaction of the turbines is representative of modern units. It is well suited

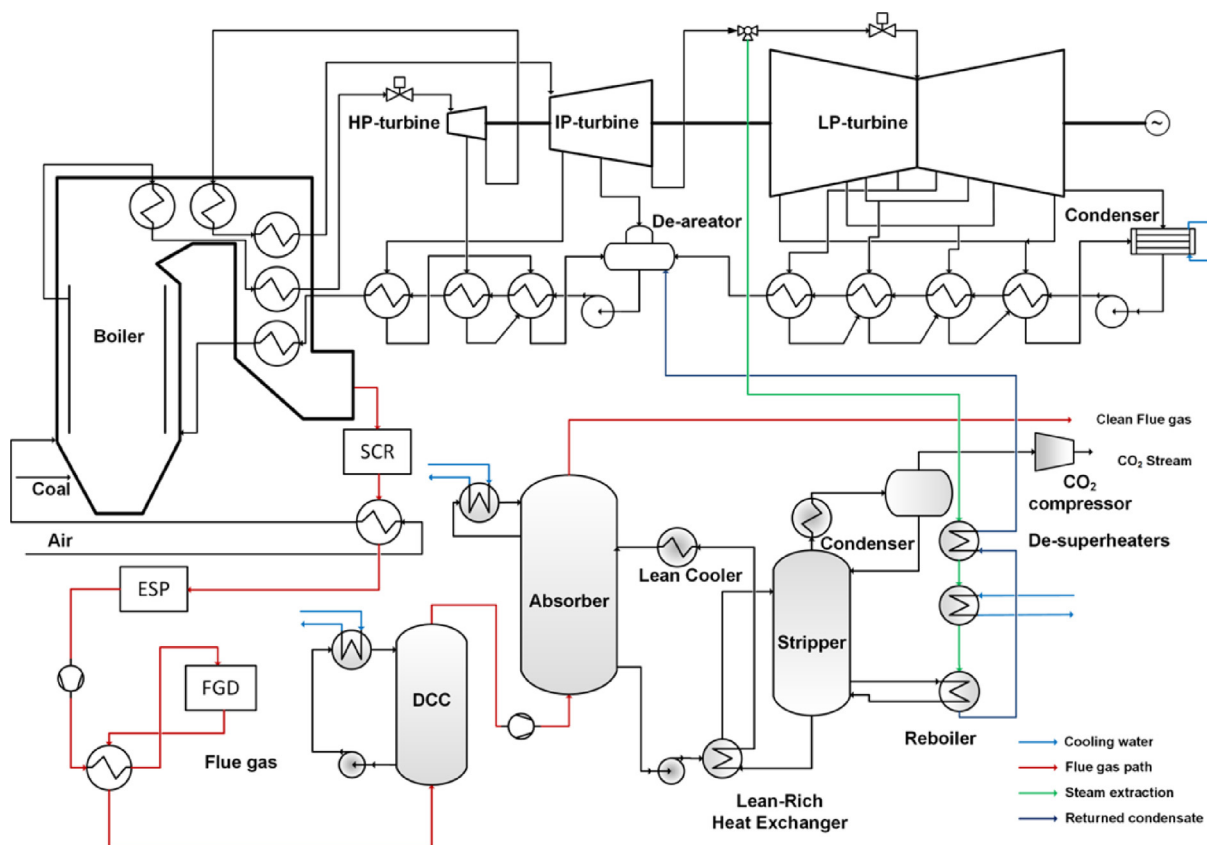


Fig. 1. Process scheme of the power plant configurations investigated: conventional integration options (CIO) and advanced integration options (AIO). The configurations only differ in the integration of capture unit with the steam cycle, the compressor control philosophy and, to a less extent, the boiler control philosophy (Table 1). The capture and compression plant is divided into two identical parallel trains, but only one is shown in the figure.

for steam cycles integrated with carbon capture where the pressure ratio across the IP turbine suits the pressure requirement of solvent regeneration. The double flow design handles variation of the pressure ratio with boiler load and steam extraction level by ensuring that the thrust on the balancing pistons at the end of each turbine cylinder counteract each other.

Table 1 lists the main options selected for the conventional integration options (CIO) power plant configuration and the advanced integration options (AIO) power plant configuration. Both are integrated with a MEA based capture unit, which consists of two identical capture and compression trains (only one train is shown in Fig. 1) and have the capability of by-passing the capture unit to produce a net power of 583 MW. The capture plant consists of a standard MEA flowsheet configuration: the CO₂ present in the exhaust flue gas is chemically bond to the solvent in the absorber, the solvent enriched in CO₂ is then sent to the stripper column via the lean-rich heat exchanger to desorb the CO₂, the stripper column is fitted with a kettle reboiler where the solvent is heated up to the operating temperature and partially vaporized. The required steam for regeneration is taken from the IP/LP crossover in superheated conditions. The IP/LP crossover pressure is designed at 4 bar for both power plant configurations and operation at full load with 90% capture. This value is chosen to deliver steam at a pressure as closed as possible to the requirements of the MEA solvent (ca 3 bar), allowing sufficient margin to cover the pressure losses of the extraction line. The power plant configurations differ on the value of the IP/LP crossover pressure when the capture unit is by-passed, as shown in Table 1.

The steam is brought to saturated conditions by passing through two indirect contact de-superheaters of the tube bundle type, one

using returned condensate from the reboiler and the other cooling water, which ensures that steam is saturated at all loads and does not exceed the maximum temperature for the MEA solvent. The capture load is controlled, as discussed in the previous section, by either maintaining the *L/G* ratio in the absorber, or by maintaining/increasing the solvent flow rate to the absorber.

The desorbed CO₂ leaves the stripper from the top with water vapour, which is condensed in the overhead condenser at 40 °C. The remaining CO₂ stream is then compressed to 110 bar for transportation and storage. The CO₂ compression system consists of two trains of a 7-stage integrally geared centrifugal compressor. The design includes intercooling after the 2nd, 4th, and 6th stage to achieve low power consumption for the compressor drive (Rost et al., 2009). The operating strategy is difference for the two power plant configurations. In the CIO configuration, the compressor load is controlled by the anti-surge control (i.e. part of the compressed CO₂ is recycled to ensure operation within the operating range of the compressor). In the AIO configuration, the compressor load is controlled with inlet guide vanes that adjust the operating window of the compressor at lower loads.

3.2. Modelling methodology

A fully integrated model of the power plant, capture plant and compression (Fig. 1) developed in Aspen Plus® is used to estimate the steady state thermal efficiency of the configurations in Table 1, at design and off-design conditions. The main parameters of the steam cycle at full load are listed in the appendix. The following sections describe the modelling procedure and implementation.

Table 1
Power plant configurations description of options for part-load operation evaluation. The design parameters for the power plant cases without carbon capture can be found in Appendix A.

Power plant case	Boiler control	Capture plant integration	Capture plant part load operation	Compression part load operation
Conventional integration options case (CIO)	Sliding pressure & throttling	Throttled LP turbine: (1) Full load capture by-pass: $P_{IP/LP} = 4$ bar. (2) Full load with 90% capture: $P_{IP/LP} = 4$ bar (controlled by throttling) (3) Part load with 90% capture: $P_{IP/LP} = \text{variable}$	Ratio L/G constant: $L/G = \text{constant}$ $T_R = \text{variable}$ $P_S = \text{variable}$ Constant stripper pressure: $L/G = \text{variable}$ $T_R = \text{variable}$ $P_S = \text{constant}$	Recycling: $P_1 = \text{variable}$ $P_O = \text{constant}$ $m_{CO_2} = \text{constant}$ Recycling: $P_1 = \text{constant}$ $P_O = \text{constant}$ $m_{CO_2} = \text{constant}$
Advanced integration options case (AIO)	Sliding pressure	Floating pressure LP turbine: (1) Full load capture by-pass: $P_{IP/LP} = 7.6$ bar ^a . (2) Full load with 90% capture: $P_{IP/LP} = 4$ bar (not controlled) (3) Part load with 90% capture: $P_{IP/LP} = \text{variable}$	Ratio L/G constant: $L/G = \text{constant}$ $T_R = \text{variable}$ $P_S = \text{variable}$ Constant stripper pressure: $L/G = \text{variable}$ $T_R = \text{variable}$ $P_S = \text{constant}$	IGV: $P_1 = \text{variable}$ $P_O = \text{constant}$ $m_{CO_2} = \text{variable}$ IGV: $P_1 = \text{constant}$ $P_O = \text{constant}$ $m_{CO_2} = \text{variable}$

T_R , reboiler temperature; P_S , stripper pressure; L/G , liquid to gas ratio in the absorber; $P_{IP/LP}$, crossover pressure; P_i , suction pressure in the compressor; P_O , discharge pressure in the compressor; IGV, inlet guide vanes; m_{CO_2} , CO_2 flow to the compressor (100 kg/s at full load).

^a Based on the minimisation of the electricity output penalty (EOP) at full load operation.

3.2.1. Supercritical boiler performance

The operation of the boiler is characterised by regressing performance data (Panesar et al., 2009) of streams entering and leaving the boiler to simple functions, which describe the relationships between boiler performance (efficiency, fuel consumption, flue gas conditions and composition), live steam and reheated steam parameters (temperature, pressure and flow) and feed water conditions (temperature, pressure and flow). These relationships are programmed in Aspen using a Fortran subroutine. The pressure drop for both boiler and reheater is estimated from the performance data and fitted to the following density–velocity relationship:

$$\Delta P = K \cdot F_S^2 \cdot \left(\frac{1}{\rho} \right)_{av} \quad (1)$$

where ΔP is the pressure drop, F_S is the mass flow of steam and ρ is the density at the inlet and outlet of the boiler and K is a constant.

3.2.2. Modelling of the steam turbines

Each group of turbine stages, located between the inlet, outlet and the various steam tapping points shown in Fig. 1, is modelled with a constant isentropic efficiency taken from (EBTF, 2011). Turbine stages with a 50% degree of reaction exhibit relatively flat profile of efficiency over the range of turbine stage loading encountered in this work (Dixon, 1966) if, for a first order approximation, secondary losses (e.g. vortexes, recirculation and tip leakages) are ignored.

As shown in the supplementary information provided with this paper, the isentropic efficiency of the IP turbine for the AIO configuration varies by less than 1% point, for a 50% degree of reaction blade design. The stage efficiency of a 50% reaction stage is close to the design value, provided that the stage loading (the ratio of the blade speed to the steam velocity at rotor inlet stays within a 0.6–1.4 range) (Dixon, 1966).

The method of Stodola is then used to predict the off-design operation of the steam turbines (Cooke, 1985; Stodola, 1927). This method treats each block of stages in the steam turbine as a single nozzle. The application of nozzle conservation energy equation leads to:

$$\frac{m_{in}}{\sqrt{P_{in}/vol_{in}}} = K \cdot \sqrt{1 - \left(\frac{P_{out}}{P_{in}} \right)^{(n+1)/n}} \quad (2)$$

where vol_{in} is the inlet specific volume to the first stage nozzle of any block of stages, m_{in} is the inlet flow to the first stage nozzle of any block of stages, P_{in} is the inlet total pressure to the first stage nozzle of any block of stages, P_{out} is the exit static pressure from the last stage of any block of stages, n is the polytropic exponent and K is the swallowing capacity.

The swallowing capacity, K , is determined for each block of stages at design conditions (full load) and is then used to predict steam turbine behaviour when mass flow and/or pressure change.

Changes in crossover pressure and the amount of throttling occurring in the LP turbine inlet valve depend on plant load and the amount of steam extracted. The pressures throughout the cycle are estimated by using Eq. (2).

It is worth noting that at low flow rates, e.g. at reduced boiler load and/or increased steam extraction for solvent regeneration, the last stages of the LP turbine may be subject to increased mechanical vibrations and recompression close to the blade tip. It is also possible that choked flow conditions may be incurred in the steam vane of turbine stages at low flow. However, for modelling purposes, the applicability of Stodola ellipse law stands for choked nozzles (Cooke, 1985).

3.2.3. Modelling of the capture and compression units

The capture plant is modelled using the ENRTL model from Aspen Plus®. This thermodynamic model, fully described in numerous references (Sanchez Fernandez et al., 2014), is extensively used in modelling carbon capture and is validated with various data sets from different pilot plants (Razi et al., 2013, 2014).

The pressure drop of the steam extraction line is mainly due to the de-superheaters. Experience based rules of thumb suggest a pressure drop between 0.2 and 0.68 bar per heat exchanger (Branan, 1998). The pressure drop in the extraction line is assumed to be 1 bar to account for the pressure drops in the de-superheaters and to allow sufficient margin for the necessary length of pipework to the reboiler. This pressure drop is re-estimated at part load operation based on an expression similar to Eq. (1).

The operating conditions of the compressor at off-design are scaled up to the correct volumetric flow and incorporated into Aspen Plus® as compressor performance maps. This enables the prediction of discharge conditions, efficiencies and work at part-load conditions and different angles of the IGV system.

The part-load performance of the heat exchangers (for the steam cycle and the capture plant) can be estimated based on correlations of the Nussel number:

$$Nu = a \cdot Re^b \cdot Pr^c \quad (3)$$

where Nu is the Nussel number, Re is the Reynolds number and Pr is the Prandtl number and a , b , c are empirical coefficients that depend on the geometry and the heat transfer mechanism. The model uses the default coefficients available in Aspen Plus®. This is strictly accurate only when convection is the main transfer mechanism in shell and tube heat exchangers. However, the feedwater heaters normally present three different zones (superheated, condensing and subcooled). For the actual performance of the feedwater heaters the default values from Aspen Plus® are used for parameter b in Eq. (3). This approach is considered sufficient because it results in a good fit of the operational data available of the power plant without capture.

3.2.4. Overall modelling procedure

The initial step of the modelling procedure consists of validating the power plant performance against the available operating data. At this stage the equipment in the power cycle is fixed. The swallowing capacity of the series of groups of turbine stages, the heat transfer area of the feed water heaters and condenser and the capacity of the pumps are sized to enable operation with by-pass of the capture unit. The next step consists of integrating the capture unit so that the steam cycle is operated with 100% boiler load and 90% capture. For this purpose, the capture unit is designed to provide the minimum electricity output penalty (EOP) as defined in the following equation:

$$EOP = \frac{W_{no\ CCS} - W_{CCS}}{\dot{m}_{CO_2}} \quad (4)$$

where $W_{no\ CCS}$ is the net power output of the power plant without capture, W_{CCS} is the power output of the power plant with capture and W_{CCS} is the flow of CO_2 captured.

The amount of steam extracted at the LP turbine inlet optimised by varying the stripper pressure and solvent flow rate to maximise total power output, and reduce the EOP to a minimum at 90% capture. At this stage, the equipment pieces in the capture unit (heat transfer area of heat exchangers and de-superheaters, stripper diameter, etc.) are re-optimised at each operating point. Once a minimum in the EOP is found, the design of the capture unit is fixed and the equations and procedures described are used to estimate the overall performance of the CCS power plants at part load. The crossover pressure was not re-optimised at part-load, therefore the pressure in the crossover decreases as the power plant load decreases.

4. Results and discussion

This section commences with a study of the behaviour of the conventional and advanced configurations without carbon capture, analysing efficiency and pressure implications at part load when the capture unit is by-passed. Subsequently, the optimisation of capture operation at full load is described. The implications for part load operation when the capture unit is in operation are addressed next. Part-load specific operating strategies are proposed and evaluated. The final part of this evaluation investigates the possibility to regenerate additional solvent and analyses the limitations to additional solvent regeneration.

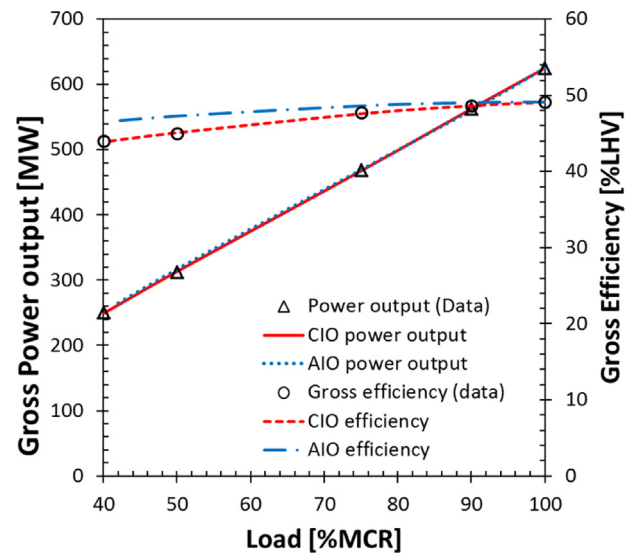


Fig. 2. Gross power output and gross efficiency estimated for the CIO (conventional integration options) and AIO (advanced integration options) power plant cases and comparison with literature data (Panesar et al., 2009).

4.1. Power plant operation at part load and capture unit integration

Fig. 2 represents the gross power output of both power plant configurations without carbon capture as a function of load, represented as a percentage of the boiler maximum continuous rating (% MCR), and compares them to the available boiler data. The AIO power plant configuration deviates from the efficiency of the conventional configuration at lower loads, since control of the boiler load with sliding pressure is more efficient at part-load than the combination of sliding pressure and throttling of the live steam flow at lower loads, which is the control strategy that best fits the boiler data of (Panesar et al., 2009).

The behaviour of the condenser of the steam cycle also plays a role at part-load. Since the flow rate of feed water to the boiler is reduced; consequently the amount of steam leaving the LP turbine exhaust into the condenser is reduced. By maintaining the cooling water flow at part load, the vacuum is reduced in the condenser due to the lower heating capacity of condensing steam and the smaller pinch point in the condenser. This effect, illustrated in the enthalpy–entropy diagrams in Fig. 3, is more significant in the configurations with steam bleed to supply the capture unit. Fig. 3 shows the steam cycle performance for the AIO configuration (pure sliding pressure in the boiler) with and without CO_2 capture. For the configuration with capture, the condenser pressure changes, for example, from 45 to 30 mbar when the load is decreased to 50%.

The optimisation of steam extraction for solvent regeneration at 100% boiler load and 90% capture is illustrated in Fig. 4. For the two power plant configurations, Fig. 4 shows the variation of the EOP with different operating solvent lean loading conditions in the stripper and the pressure drop across the LP turbine inlet valve necessary to maintain steam extraction pressure constant in the CIO configuration. With advanced integration options, the exit conditions of the IP turbine when the capture unit is by-passed are selected in such way that the EOP is minimised when the capture unit is in operation. As a consequence of the complexities of the model, which considers a minimum design pressure drop for the valve of 0.2 bar, the results reported here include a moderate amount of throttling at full load with 90% capture. It is important to highlight that this is not significant to alter the results of the optimisation.

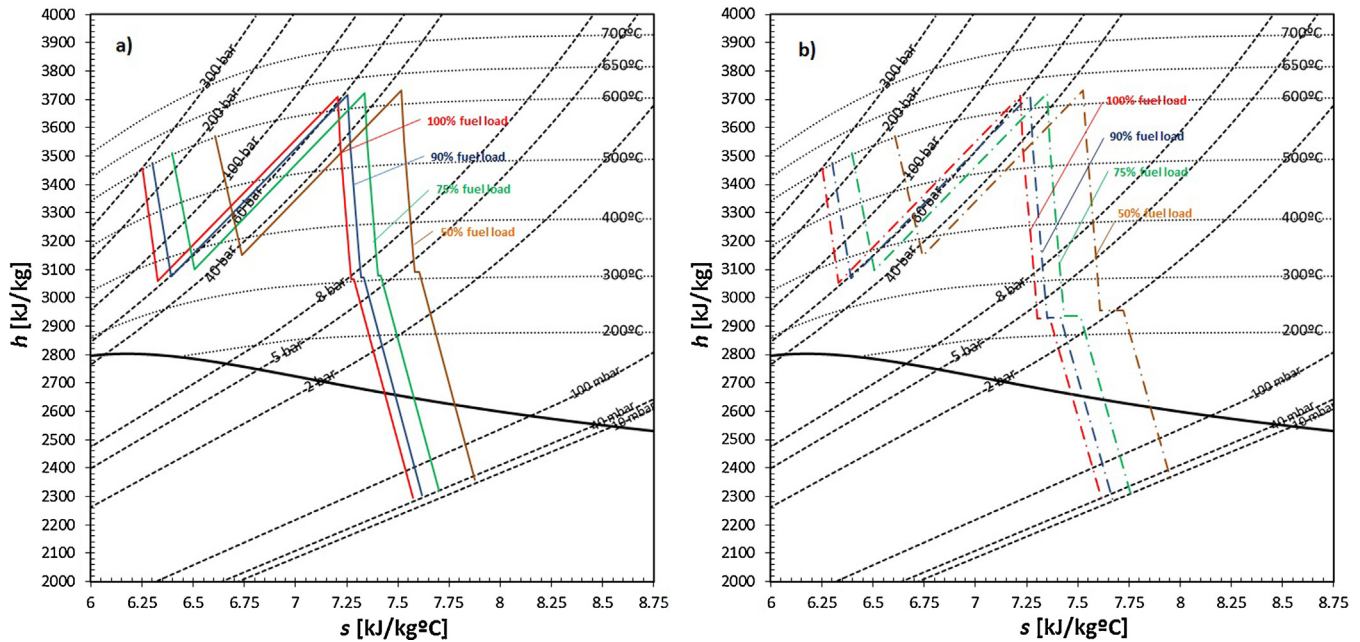


Fig. 3. Enthalpy-entropy diagram for the AIO (advanced integration options) case (a) without capture and (b) with 90% CO₂ capture.

At part load, the boiler pressure and the operating pressures across the turbines decrease. The IP/LP crossover pressure reduces accordingly. Fig. 5 shows the decline in crossover pressure as a function of load (% MCR), when the capture unit is by-passed, and notably that the pressure in the AIO configuration (floating pressure integration) declines more rapidly compared to the CIO configuration (fixed pressure integration).

With capture switched on, the choice of design pressure of steam supplied to the capture unit has important implications for the operation of the AIO configuration, given that, with uncontrolled extraction, the reduction in pressure also depends on the amount of steam extracted. The latter is directly linked to the solvent energy of regeneration, and to the pressure drop in the extraction line,

which is dependent on the volumetric flow rate of extracted steam. Solvent energy of regeneration can vary slightly upon the operation of the capture unit but always decreases, in absolute values, at part load due to the lower flow of treated flue gas. The pressure drop in the extraction line decreases with the square of the steam flow rate, however, since steam density is substantially reduced at lower loads, it partially attenuates that effect by contributing to the pressure loss. At part load, the steam effectively condenses at lower temperature in the capture unit reboiler deviating from design conditions. The impact on the overall performance of the capture unit is analysed in the following section.

4.2. Analysis of part-load strategies for power plants with integrated CO₂ capture

When the power plant boiler operates at part load, the mass flow of flue gas treated in the capture unit decreases almost

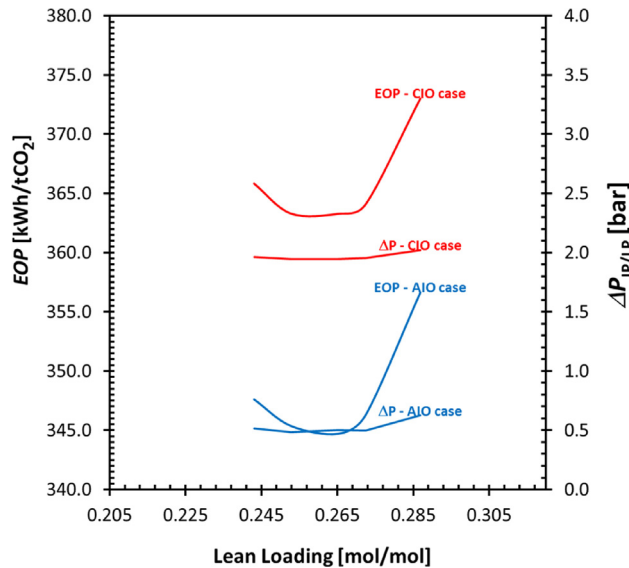


Fig. 4. Optimisation of the integration of the capture unit in the two power plant cases investigated, CIO (conventional integration options power plant configuration) and AIO (advanced integration options power plant configuration). (Left axis) Variation of energy output penalty (EOP) with lean solvent loading. (Right axis) Pressure drop applied in the LP turbine inlet valve ($\Delta P_{IP/LP}$) to maintain steam pressure at 4 bar at different lean solvent loadings.

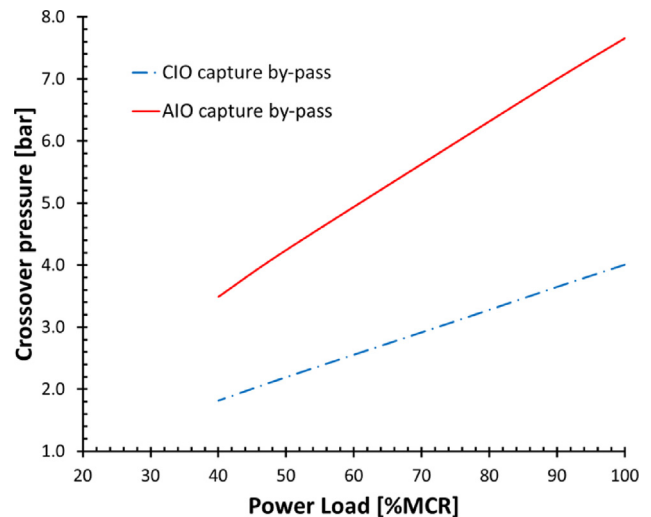


Fig. 5. Reduction in crossover pressure for the two power plant configurations, conventional integration options (CIO) and advanced integration options (AIO), when the capture unit is by-passed as a function of load shown as fraction of the boiler maximum continuous rating, MCR).

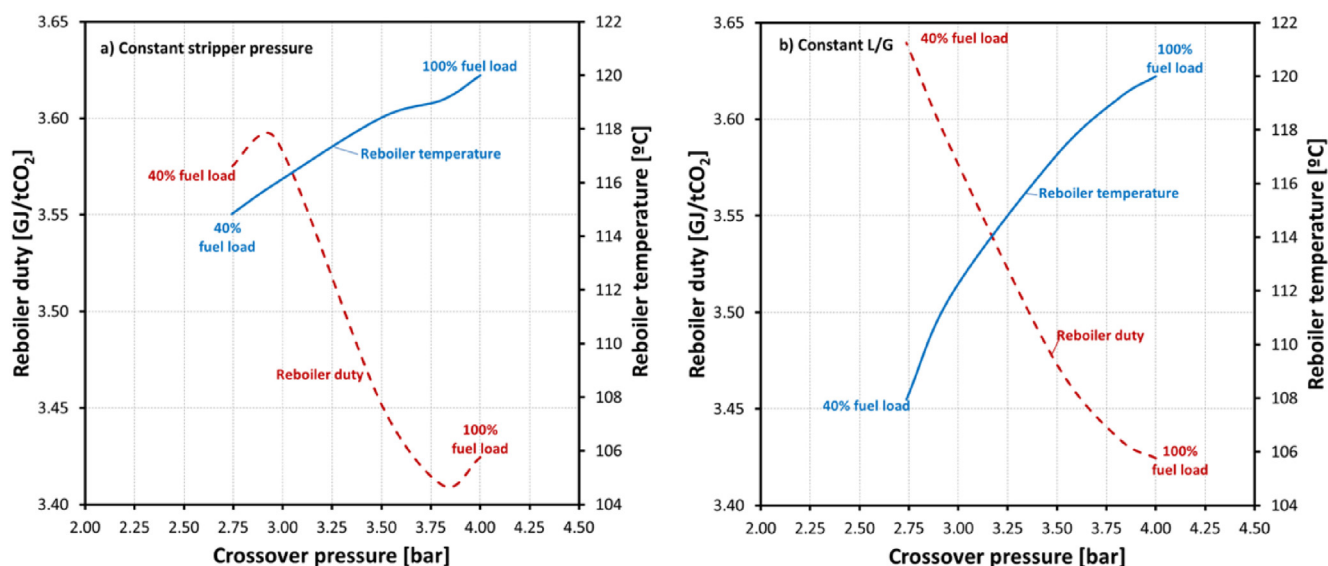


Fig. 6. Performance of the capture unit with (a) constant operating pressure in the stripper column and (b) constant L/G in the absorber column. Reboiler duty and reboiler solvent temperature vary with changes in crossover pressure, caused by the reduction of steam cycle flow rate. The figure shows the performance for load following from 100% to 40% MCR with 90% capture in the conventional integration options (CIO) case.

proportionally to boiler load. The capture unit operation needs to be adjusted to maintain the capture level under different loads. However, due to the decrease in pressure in the IP/LP crossover line the steam pressure that is available to the capture plant is lower than that at full load. This effect leads to operating solvent temperatures that are substantially lower than 120°C, the design temperature. The overall performance of the capture unit is affected as lower reboiler temperatures are linked to a less favourable vapour–liquid equilibrium for desorption, which reduces the extent of solvent regeneration and leads to higher CO₂ loadings in the regenerated solvent.

Given the reduction in crossover pressure shown in Fig. 5, it is evident that the solvent cannot be regenerated at part load to the same extent as at design conditions, while maintaining the operating conditions in the stripper column constant, as suggested by the literature (Section 2.3). Two part load strategies for load following are proposed that take into account the lower regeneration capabilities of the capture unit:

- (1) Constant Stripper pressure for load following: This option consists in maintaining the stripper pressure at design value. The solvent flow to the absorber column is adjusted to maintain capture level.
- (2) Constant L/G ratio in the absorber for load following: In this turn down strategy the solvent flow is adjusted at lower loads in order to keep a constant L/G ratio in the absorber. Unlike in the previous option, the solvent lean loading is maintained constant by releasing stripper pressure.

Fig. 6 shows the non-linear behaviour of solvent regeneration energy requirements across a range of boiler load, in relation to the IP/LP crossover pressure and the reboiler temperature for part load strategies in the CIO case. In our analysis, we take into account the effect of steam volumetric flow on the pressure drop across the extraction line and on the heat transfer coefficient in the reboiler.

In the first option (Fig. 6a) the stripper pressure is at design value. Due to lower reboiler temperatures, the lean loading increases at part load compared to full load operation. Achieving 90% capture in this case is possible by increasing both the solvent circulation rate and the L/G ratio in the absorber. The increase in

pressure drop in the absorber column leads to a higher specific blower power consumption. On the other hand, the suction pressure at compressor inlet is maintained at its base load value, reducing the power required for compression.

As shown in Fig. 6a, the decay in the crossover pressure causes lower operating temperatures in the reboiler. For small reduction from base load, a modest decrease in reboiler duty is observed as the drop in crossover pressure is partially compensated by lower pressure drop in the extraction line, resulting in the reboiler temperature being close to its design value. As the load and the crossover pressure gradually decrease, the drop in extraction pressure dominates. Although lower mass flows of steam are extracted, steam density decreases with lower pressure and higher degrees of superheating. Effectively, a reduction in solvent temperature is observed, which results in an increase in specific reboiler duty. At very low loads and crossover pressure, there is a marginal decline in reboiler duty, related to a slight improvement in the heat transfer coefficient, due to the fact that the volumetric flow of steam relative to the amount of CO₂ desorbed increases at this point.

Maintaining the L/G ratio as turndown strategy, implicitly constrains the lean loading to a value approximately equal to the design value, which was chosen to maximise power output at full load boiler operation and 90% CO₂ removal rate, but is not necessarily the optimum for any other given load. The lean loading at part load is maintained constant by releasing stripper pressure to extend the regeneration degree of the solvent. Fig. 6b shows the solvent regeneration requirements for this strategy and its relation to the steam extraction pressure. Lower pressures and temperatures in the stripper require more energy per unit CO₂ to achieve the same degree of solvent regeneration as in the design case due to a less favourable CO₂ to steam ratio. To provide this energy, more steam is extracted from the IP/LP crossover, resulting in lower steam pressures and higher pressure drops in the extraction line. Nevertheless, the latent heat of steam increases with decreasing condensing pressures and a final energy balance is achieved in the reboiler. Comparing the two turndown strategies (Fig. 6a and b), the final operating temperatures in the reboiler are lower for the constant L/G strategy and the reboiler duty is higher. Moreover, this turndown strategy has a negative impact on the downstream compressor operation.

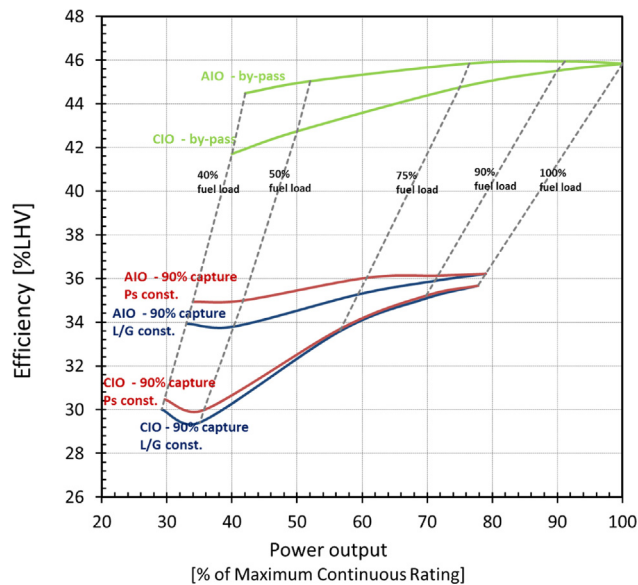


Fig. 7. Performance map for part-load operation of the two cases investigated in this study: (CIO – conventional integration options power plant configuration with throttling and boiler sliding pressure, AIO – advanced integration options power plant configuration with boiler sliding pressure only) and two capture unit part load strategies (Ps const – constant stripper pressure, L/G const – constant Liquid-to-gas-ratio in absorber). The figure represents net power plant efficiency versus net power load.

4.3. Part-load operation performance maps

Based on the integrated models described in Section 3, the overall plant power output and efficiency is evaluated for the following operating modes: (1) capture by-pass, (2) 90% capture with constant L/G and (3) 90% capture with constant stripper pressure. Fig. 7 shows the performance map for the two power plant configurations investigated, the CIO case and the AIO case. Performance is represented as net power plant efficiency versus net power load,

which is represented as percentage of the maximum continuous rating (MCR). The dashed straight lines indicate the points that have constant fuel input.

4.3.1. Performance map for the conventional integration power plant case (CIO)

The performance map of the CIO power plant configuration is shown in Fig. 7. This configuration has 45.8% LHV efficiency at 100% MCR without capture. When the power output is decreased gradually the efficiency of the plant decreases gradually to 41.7% LHV at 40% MCR, which is assumed to be the minimum stable boiler load without burning additional fuel.

When the capture unit is in operation, the gross power of the steam turbine is reduced due to steam extraction for solvent regeneration. In addition, the compressor and ancillaries of the capture unit decrease the net power output of the plant. At full load with 90% capture, plant efficiency is 35.7% LHV. With respect to part load strategies for the capture unit, our results show that there is a benefit in operating the stripper at constant pressure rather than maintaining the L/G ratio in the absorber. On one hand, the reboiler temperature achievable with constant stripper pressure is higher than with L/G constant (Fig. 6), which improves solvent regeneration. The additional power consumption of the blower at higher L/G ratios is compensated by lower compression work. This is more evident as power plant load decreases and is mainly due to the loss of compression efficiency at part load. The compressor is operated by recycling part of the compressed CO₂ in order to maintain the suction conditions. This operation imposes a very high penalty to the power plant efficiency at power plant loads lower than 60% MCR. At 40% fuel input (around 30% MCR) one of the compressor trains is disconnected, resulting in an increase in power plant efficiency compared to 50% fuel input in Fig. 7.

4.3.2. Performance map for the power plant configuration with advanced integration options (AIO)

The efficiency at full load for this configuration in capture by-pass mode (Fig. 7) is the same as the CIO power plant configuration (45.8% LHV).

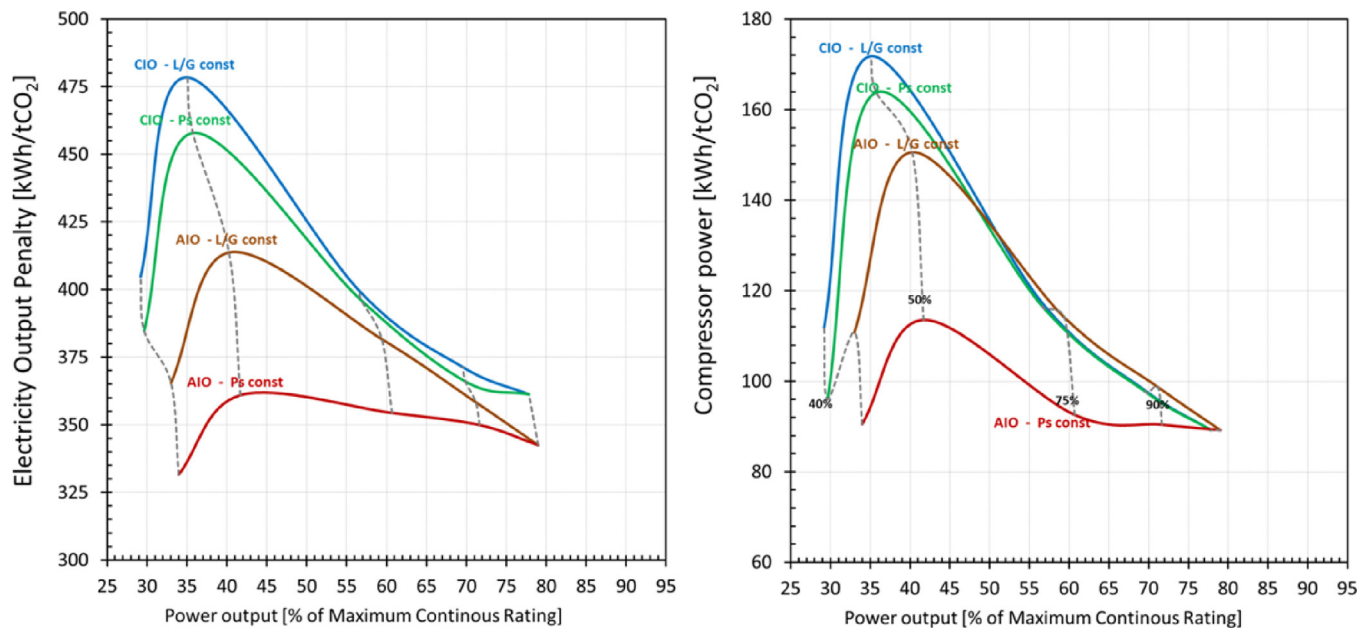


Fig. 8. Electricity output penalty and the corresponding specific compressor power for part-load performance with 90% capture. The figure shows the two power plant configurations investigated, the power plant configuration with conventional integration options (CIO) and the configuration with advanced integration options (AIO), and two capture turn-down strategies, constant liquid-to-gas ratio in the absorber (L/G const.) and constant stripper pressure (Ps const.).

The performance at full load with 90% capture is 36.2% LHV, whilst the part-load efficiency is substantially higher than with conventional integration options. This is due, on one hand, to a lower penalty in the steam extraction (there is no throttling at the LP turbine inlet in this case) and on the other hand, to a substantially improved compressor performance. When the operation of the compressor is controlled by inlet guide vanes (IGV), it improves efficiency compared to CO₂ recycling, especially at lower loads. Similarly to the previous case, at 40% fuel input one of the compressor trains is disconnected, which results in an increase in power plant efficiency compared to 50% fuel input in Fig. 7.

As in the previous case, turning down the capture unit with constant stripper pressure is more efficient than maintaining the *L/G* ratio constant because compressor power increases when the suction pressure decreases.

4.3.3. Electricity output penalty and compressor performance at off-design conditions

The compressor is normally designed to operate around specific conditions of flow, suction pressure and temperature. When these conditions are changed, compressor power generally increases. Fig. 8 shows the electricity output penalty with 90% CO₂ capture at variable load and the contribution of the compressor power to the electricity output penalty. As the power load decreases from 80% to 30% MCR, compressor power has a markedly impact on the electricity output penalty at part load in both power plant configurations. It increases at lower loads and finally decreases when one compressor train is disconnected. The performance map used for the two configurations is shown in Fig. 9. Unlike the CIO configuration, where suction conditions are controlled by recycling a fraction of the compressed CO₂ stream back to compressor inlet, the AIO configuration controls load with the use of inlet guide vanes (IGV). By adjusting the guide vanes angle, it is possible to maintain compressor efficiency (expressed as isothermal efficiency) above 75% without recycling. Nevertheless, the operation at 50% and 75% boiler load and 90% capture falls above the region where the anti-surge control will actuate (part of the compressed CO₂ will be recycled automatically). These points need to be given especial consideration to investigate the possibility of designing an anti-surge control system that is safe and does not penalise substantially the efficiency at this point (e.g. designing the anti-surge control line closer to the surge line or allowing lower discharge pressure in the 75% fuel input case).

4.4. Analysis of additional solvent regeneration for operational flexibility

In this section, the limits to solvent regeneration for the power plant configurations evaluated in this work are investigated to enable the implementation of flexible operation strategies.

An additional operating strategy is included in the performance map of the power plant configurations in Fig. 10. This flexible strategy, referred to as maximum solvent regeneration, represents the operation of the capture unit with 90% capture level for all loads and the maximum possible rich solvent flow regeneration. For this purpose, a combination of the capture unit part load strategies has been used (*i.e.* releasing stripper pressure and increasing the *L/G* ratio in the absorber). It is of importance to highlight that only the LP turbine and the power plant condenser are oversized in both power plant configurations, principally for the purpose of capture by-pass. The other equipment in the capture unit (compressor or stripper column) is designed for 90% capture at full load, imposing limits on the amount of additional regeneration. Other than solvent storage tanks and associated ancillaries, the maximum solvent regeneration strategy does not require additional investment in oversizing components and can be considered as in-built flexibility.

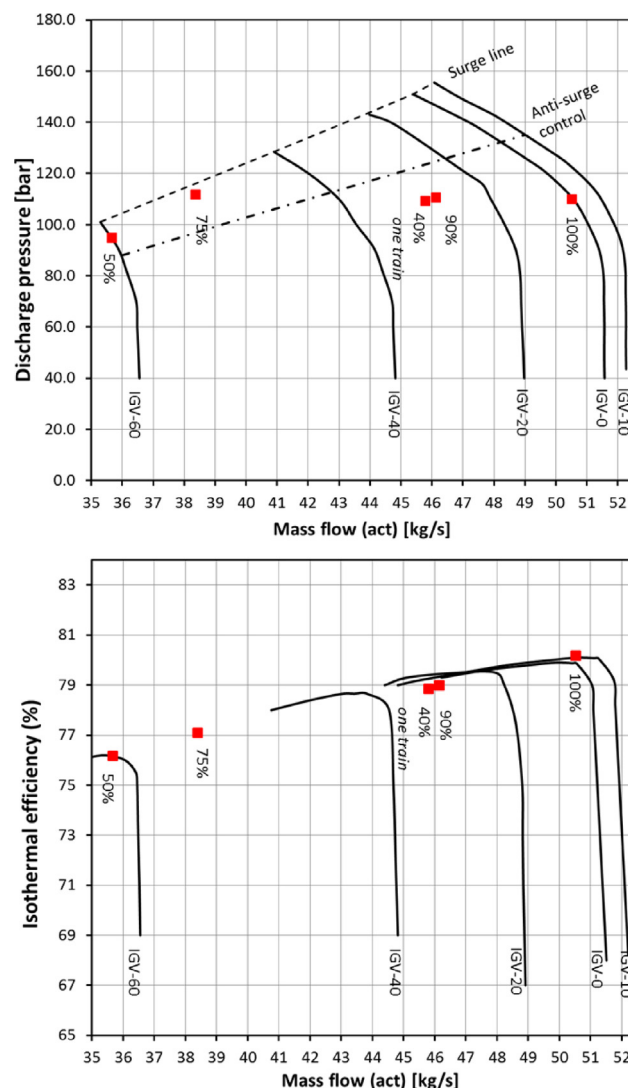


Fig. 9. Performance map for part-load operation of the compressor for the AIO (advanced integration options) power plant configuration. The figure represents discharge pressure and isothermal efficiency as a function of the actual mass flow (at inlet conditions). The power plant has two identical compressor trains (only one is shown in the figure). At 40% fuel input one of the trains is disconnected. The numbers next to the performance curves indicate the angle position of the guide vanes. ■ indicates the operating conditions at different fuel loads.

Therefore, the additional regeneration is limited by the capabilities of the given equipment. Limitation to additional regeneration may be imposed by the following equipment:

- (1) CO₂ compressor: when there is not capacity to compress additional CO₂.
- (2) LP steam turbine: when there is not enough steam to operate the turbine. The minimum steam flow is assumed to be at least 10% of the design steam flow (Cotton, 1994), to avoid excessive overheating of the turbine casing, an effect often encountered at conditions of low flow in turbine when trapped steam gases inside the casing are exposed to frictional heat caused by blade velocity, and referred as churning.
- (3) Steam pressure/solvent regeneration: when the steam pressure is very low, the solvent cannot be regenerated. This is a combination of effects, as discuss in Section 4.2, which include the extraction pressure, the pressure drop in the extraction line and the heat transfer coefficient in the reboiler.

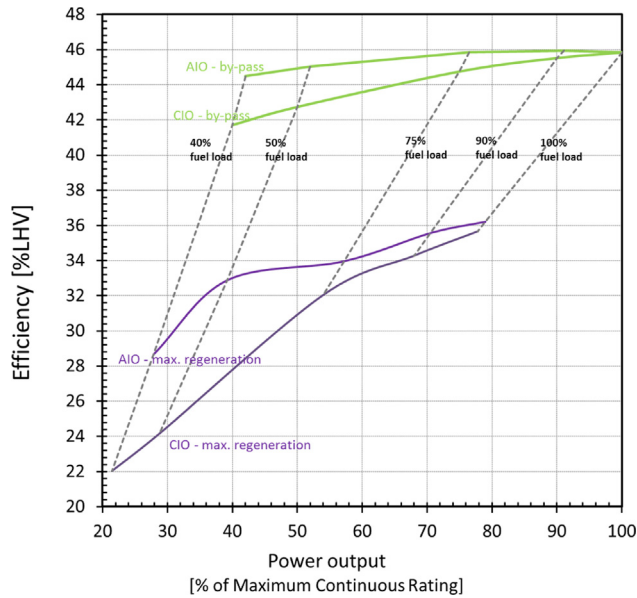


Fig. 10. Performance map for flexible operation of the two configurations investigated in this study (CIO – conventional integration options power plant, AIO – advanced integration options power plant). The capture unit operates by capturing 90% of the CO₂ in flue gas and regenerates the maximum possible solvent (max. regeneration). The figure represents net power plant efficiency versus net power load. Dashed lines represent constant fuel input operation.

(4) Stripper flooding: additional stripping steam and liquid flow to the stripper might limit the operation when the flooding point is reached.

Other minor equipment such as pumps and flue gas blower are sized with enough capacity to compensate pressure drops.

The limits to additional solvent regeneration are illustrated in Fig. 11 for the CIO and AIO configurations. It was found that the stripper size does not impose a limitation. With CIO configuration, additional regeneration is limited only by compressor capacity at higher loads up to 75% of the boiler fuel input, or approximately 55% of MCR. At lower loads, below 30% of MCR, limitations are

related to the minimum flow necessary to operate the LP steam turbine.

The AIO configuration is mainly limited by the steam pressure available for solvent regeneration at reboiler inlet. Although it has better part load efficiency, operational flexibility via additional solvent regeneration is more limited than in the previous case.

In either configuration, it is not possible to maintain a constant flow to the pipeline without addressing the hardware limitations to additional regeneration, although CO₂ flow could always be maintained above 70% and 50% of the base load value for the CIO and the AIO configurations respectively, as long as stored solvent is available. In the CIO configuration, it is possible to maintain the CO₂ flow to the pipeline within a 10% of the base load value for power plant loads between 30% MCR and 80% MCR. This could be useful to smooth CO₂ flow variations to the transport system. Further enhancement of flexibility in power plants needs to address the issue of providing steam for solvent regeneration (e.g. electrical steam generators, steam ejectors, etc.).

Efficiency at maximum solvent regeneration at part load should also be considered to estimate any additional revenues from flexible operation. As shown in Fig. 10, power plant efficiency decreases to just 22 and 28% LHV for the CIO and AIO configurations respectively at the lower end of power plant load.

Unlike typically assumed in the literature, the time necessary to regenerate a solvent inventory equivalent to 1 h of interim solvent storage varies with the fuel input into the plant, due to the limitations previously described (Fig. 11). For instance, the CIO configuration requires 4 h at 55% MCR or 3 h at 30% MCR to regenerate a solvent inventory equivalent to 1 h of interim solvent storage while capturing 90% of fuel CO₂ emissions. Power plant efficiency also decreases during additional regeneration as shown in Fig. 10. The electricity output penalty for the regeneration of stored CO₂ is calculated as:

$$EOP_{ad} = \frac{EOP_{\max, \text{reg.}} \cdot \dot{m}_{\text{CO}_2 \max, \text{reg.}} - EOP_{90\%} \cdot \dot{m}_{\text{CO}_2 90\%}}{\dot{m}_{\text{CO}_2 \max, \text{reg.}} - \dot{m}_{\text{CO}_2 90\%}} \quad (5)$$

where $EOP_{\max, \text{reg.}}$ and $EOP_{90\%}$ are the electricity output penalties for boiler loads with maximum regeneration and 90% capture respectively, and $\dot{m}_{\text{CO}_2 \max, \text{reg.}}$ and $\dot{m}_{\text{CO}_2 90\%}$ are the CO₂ flows leaving the capture unit for boiler loads with maximum regeneration and 90% capture respectively.

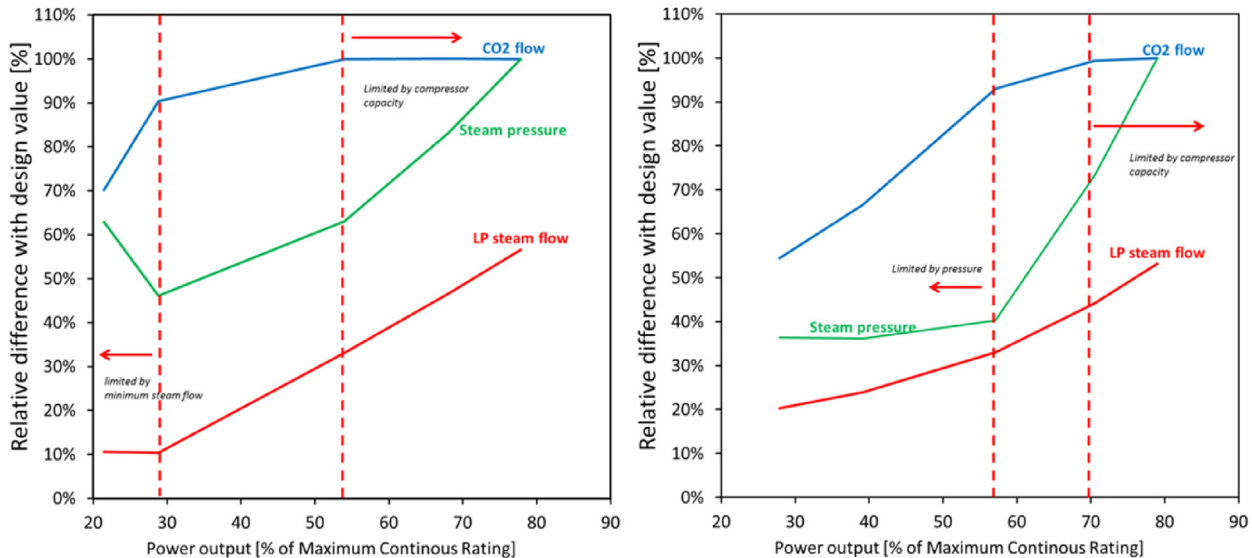


Fig. 11. Limitations to additional solvent regeneration for the CIO power plant configuration (left) and the AIO power plant configuration (right). Steam pressure indicates the pressure at the inlet of the capture unit reboiler.

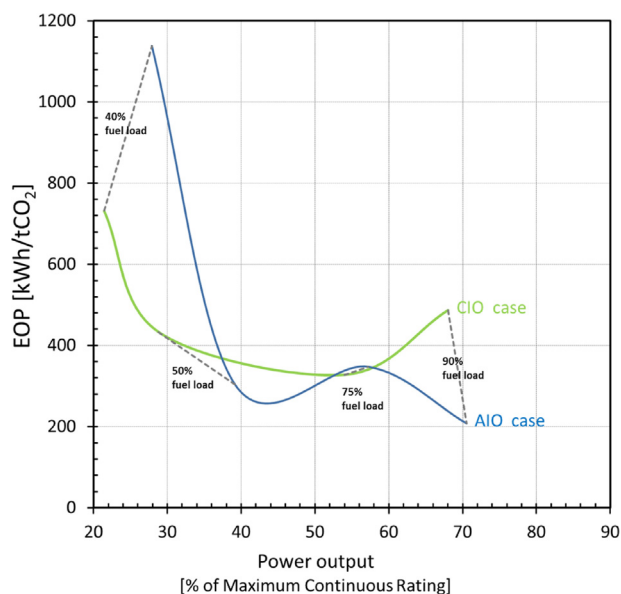


Fig. 12. Electricity output penalty for the regeneration of 1 tonne of stored CO₂ for the CIO and AIO power plant configurations. The dashed lines represent constant fuel input lines.

Fig. 12 shows that, with respect to electricity output penalty, the CIO configuration is more suited for the implementation of additional solvent regeneration than the AIO configuration. Minimisation of the electricity output penalty occurs at 75% fuel load for the CIO configuration and 90% fuel load for the AIO configuration. Oversizing the solvent regeneration part of the capture unit (as proposed in Van der Wijk et al., 2014) and the compression train for additional solvent regeneration will not add any benefit to these cases.

The inflection point in the EOP of the AIO configuration in Fig. 12 is due to the fact that, at 75% fuel input the decline in available steam pressure for the reboiler is most substantial (as reflected in the shape of the steam pressure in Fig. 11) due to additional steam extraction, pressure drop in the extraction line and poor solvent regeneration. At 50% fuel input, the crossover pressure is slightly lower than at 75% fuel input but the pressure drop in the extraction line decreases further since much less steam is required to maintain the capture level, resulting in steam pressure for solvent regeneration similar to that at 75% fuel input.

Although these results are, to some extent, specific for the configurations investigated, the general principles and guidelines for the design of CCS power plant systems can be of use to clarify the feasibility of strategies proposing to bring additional flexibility.

5. Conclusions

This work examines the steady state part-load operation of supercritical coal power plants with MEA based CO₂ capture and enhanced operational flexibility options with capture bypass and maximum solvent regeneration. The performance maps for a power plant with conventional capture integration options, mainly based on a throttled LP steam turbine and a CO₂ compressor with recycling for flow control, and a power plant with advanced integration based on floating pressure LP turbine and CO₂ compressor

with inlet guide vanes for flow control, are provided for a range of fuel loads (40–100%) based on rigorous integrated model of the boiler, steam cycle, post-combustion capture and compression system. Unlike in previous studies, where simplifying assumptions are made about the power plant and/or the compression system, it can be concluded that the electricity output penalty of capturing CO₂ increases at part load, due to efficiency losses not only in the power plant but also the capture unit and CO₂ compressor. It is possible to optimise for better part-load efficiency, without compromising base load efficiency, by considering jointly the design aspects of the whole system, such as boiler control philosophy, integration of the capture unit in the steam cycle (floating pressure versus fixed pressure), capture plant off-design operation and control philosophy of the CO₂ compressor.

With respect to the operation of the capture process, it is more beneficial to turn down load by increasing the solvent flow rate to the absorber and keeping stripper pressure constant. This strategy is more efficient than maintaining the liquid to gas ratio (*L/G*) in the absorber because the suction pressure at the CO₂ compressor inlet is maintained as close as possible to its base load value, reducing power requirements.

The electricity output penalty occurred during additional solvent regeneration is also evaluated and used to analyse the feasibility of interim solvent storage as a flexible strategy to operate power plants with CO₂ capture. In both power plant configurations examined, it was found that additional solvent regeneration would be limited by either steam flow or steam pressure to supply the reboiler of the capture unit.

A key aspect of the flexible operation of post-combustion capture plants is steam availability and conditions, necessary to regenerate the solvent. The results of this work show that part load operation inhibits solvent regeneration in the capture unit. Uncontrolled steam extraction (or floating pressure integration) to supply the capture unit is preferred over controlled extraction by throttling the low pressure turbine inlet since it improves full and part load performance. It is, however, associated with limitations for regeneration at part load, since the floating pressure integration leads to steam pressures at part load that are too low for additional solvent regeneration. Following this analysis, further work is needed to evaluate the commonly proposed flexible strategies on case by case basis so that changes in efficiency associated with flexible operation can be included in optimisation and techno-economic studies. Another important aspect for future work is the understanding of the possible benefits associated with smoothing, with interim solvent storage, variations in CO₂ flow exiting the boundaries of CCS power plants.

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Appendix A.

Table A1
Operation characteristics and assumptions for the power plants models.

Power plant operational characteristics						
	CIO case			AIO case		
Heat input (LHV basis) [MWth]	1273			1273		
Net full load plant efficiency [%LHV]	45.8			45.8		
CO ₂ emissions [g/kWh _{net}]	680			680		
Gross output [MW]	625			625		
Auxiliary power consumption [MW]	42			42		
Net output [MW]	583			583		
Steam parameters (base load)						
Streams	Pressure [bar]	Temperature [°C]	Flow [kg/s]	Pressure [bar]	Temperature [°C]	Flow [kg/s]
Main steam (HP turbine inlet)	299.0	603.0	462.7	299.0	603.0	462.7
Cold reheat (HP turbine exhaust)	64.8	359.6	385.7	64.9	359.7	385.9
Hot reheat (IP turbine inlet)	62.8	623.3	385.7	62.9	623.1	385.9
Final feed water	324.2	309.6	462.7	324.2	310.3	462.7
IP/LP cross over	4.0	228.3	336.2	7.7	304.2	336.7
Other assumptions						
Boiler feed water pumps	70% efficiency 99.6% drive efficiency					
Condensate pumps	70% efficiency 99.6% drive efficiency					
Feed water heaters	4 × LP heaters + 3 × HP heaters					
Feed water tank and deaerator	Deaerator at 10 bar					
Flue gas temperature [°C]	126 °C at air heater exit					
Furnace exit excess air	0.17					
Cooling water temperature [°C]	15 °C					
Condenser pressure [mbar]	45 mbar					
Minimum load	40% MCR without secondary fuel support					
Steam cycle operation	Sliding pressure & fixed pressure			Sliding pressure		
Design coal	Bituminous coal					
Environmental measures	State-of-the-art DeNO _x , ESP, FGD, 5% unburnt carbon based on design coal.					
Power plant auxiliaries ³						
Primary & secondary air fan consumption	1.6% of gross power output					
Heat rejection auxiliaries	0.8% of cooling duty					
Air pollution control units consumption	0.4% of gross power output					
Coal characteristics						
Ultimate analysis [% mass of]						
Ash	8.4					
Carbon	66.8					
Hydrogen	3.78					
Nitrogen	1.1					
Chlorine	0.27					
Sulfur	1.71					
Oxygen	7.78					
H ₂ O	10					
Total	99.84					
Net heat value (LHV) [MJ/kg]	26.114					
Excess air [%]	16					

^a Estimates from [EBTF \(2011\)](#).

Appendix B. Supplementary data

Supplementary data associated with this article can be found, in the online version, at [doi:10.1016/j.ijggc.2016.01.027](https://doi.org/10.1016/j.ijggc.2016.01.027).

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