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Initial evaluation of the impact of post-combustion capture of carbon dioxide on supercritical pulverised coal power plant part load performance

Hannah Chalmers *, Jon Gibbins

Energy Technology for Sustainable Development Group, Mechanical Engineering Department, Imperial College, Exhibition Road, London SW7 2AZ, United Kingdom

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Abstract

Pulverised coal-fired plants often play an important role in electricity grids as mid-merit plants that can operate flexibly in response to changes in supply and demand. As a consequence, these plants are required to operate over a wide output range. This paper presents an initial evaluation of some potential impacts of adding post-combustion CO_2 capture on the part load performance of pulverised coal-fired plants. Preliminary results for ideal cases analysed using a simple high-level model indicate that post-combustion CO_2 capture could increase the options available to power plant operators. In particular, solvent storage could allow higher effective plant load factors to be achieved to assist with capital recovery while still permitting flexible operation for grid support. A number of areas for more detailed analysis are identified.

Keywords: Post-combustion CO_2 capture; Fossil-fired power plant flexibility; Part load performance

1. Introduction

Successful implementation of carbon capture and storage (CCS) technologies should allow the continued use of fossil fuels in many applications, including power generation, but with significantly reduced carbon dioxide (CO_2) emissions. A range of engineering desk studies (e.g. a series of IEA Greenhouse Gas R&D Programme studies summarised in [1]) have predicted the costs and performance of power plants with CO_2 capture at full load. The published literature does not, however, contain any detailed assessments of the predicted impacts on part load performance of adding CO_2 capture to power plants.

Fossil-fired plants have higher marginal operating costs than nuclear and most renewables, even when they operate within CCS schemes with an associated reduction in any charges for CO_2 emissions. As a result, fossil-fired plants may be mid-merit and so may not run continuously at full load. Instead, their output will vary, partly in response to changes in supply or demand within the grid so that the quality and security of electricity supply is maintained. Understanding part load performance of these plants is important to determine how plant operation can be optimised within their operating environment. A number of other key factors also contribute to characterising the suitability of plant to act as flexible mid-merit plant including technical constraints, such as the ability of plant to start-up, shutdown and ramp output up or down rapidly.

Experience in the UK market suggests that the position of plants in the merit order can change significantly during the plant lifetime. Thus, the suitability of plants to operate as mid-merit should be assessed at the design stage, even if they are initially designed for base-load operation. Also, even at an early stage in a plant's life, appropriate use of

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* Corresponding author. Tel.: +44 (0)7888 801020; fax: +44 (0)20 75941472.
E-mail address: hannah.chalmers@imperial.ac.uk (H. Chalmers).

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various operating options for plants with CO_2 capture might improve the economic returns, compared to simple fixed-output operation. For example, there may be potential to vary capture rates in response to variable electricity and carbon prices. To fully evaluate this facility would require a detailed analysis of possible future electricity and carbon markets as well as the specific technical capabilities of the power plant and capture system, but some preliminary assessments are presented.

This paper reports the results of an initial study on the flexibility of post-combustion CO_2 capture plants with a particular focus on potential impacts on power plant part load performance and operations for a pulverised coal-fired plant. A simple model for plant off-design behaviour is developed and a series of ideal cases are used to consider possible plant performance curves. This model is also used to explore some alternative operating patterns for power plants with post-combustion CO_2 capture. Similar analysis could also be applied to other CO_2 capture technologies. However, it appears that plants with post-combustion CO_2 capture would be most able to take advantage of the variable operating procedures analysed here. Discussion of useful further work suggested by the initial analysis is also included.

It should also be noted that much of this paper will focus on initial modelling of one particular aspect of CO_2 capture plant flexibility and on one type of capture plant. Many other options and potential impacts associated with developing CCS systems using power plants should also be subjected to further study. For example, the use of biomass co-firing at power plants with CO_2 capture allows CO_2 that was removed from the atmosphere by biomass as it grew to be placed into permanent geological storage [2]. It is likely that the level of implementation of these measures will depend on the policy framework, including any value attached to CO_2 reductions and, in the case of co-firing, the availability of renewable fuel. Also, it is important to understand how CO_2 transport and storage operations interact with power plant behaviour. It seems likely that any restrictions on short term operating patterns could be avoided by adopting operating procedures that allowed for some CO_2 buffering in the pipeline transport system, other interim storage or the use of a variable-flow storage site (e.g. disused gas reservoir, saline aquifer). The matching of CO_2 supply to demand and/or an appropriate combination of storage sites should therefore be considered carefully at an early stage of capture project development.

2. Post-combustion capture for power plants

In all CCS schemes, CO_2 is collected from a large point source before it is treated and compressed for transport to safe geological storage. Post-combustion capture systems, as illustrated schematically in Fig. 1, are placed downstream of the combustion and other flue gas treatment processes. For coal-fired plants improved flue gas desulphurisation may be required to minimise the loss of solvent during the CO_2 capture process, but this is not necessary for gas-fired plants since they do not produce significant quantities of sulphur containing compounds in their flue gases.

The CO_2 capture process for post-combustion capture consists of three stages. First, CO_2 is removed from the flue gas by absorption in a packed ‘scrubber’ or absorber

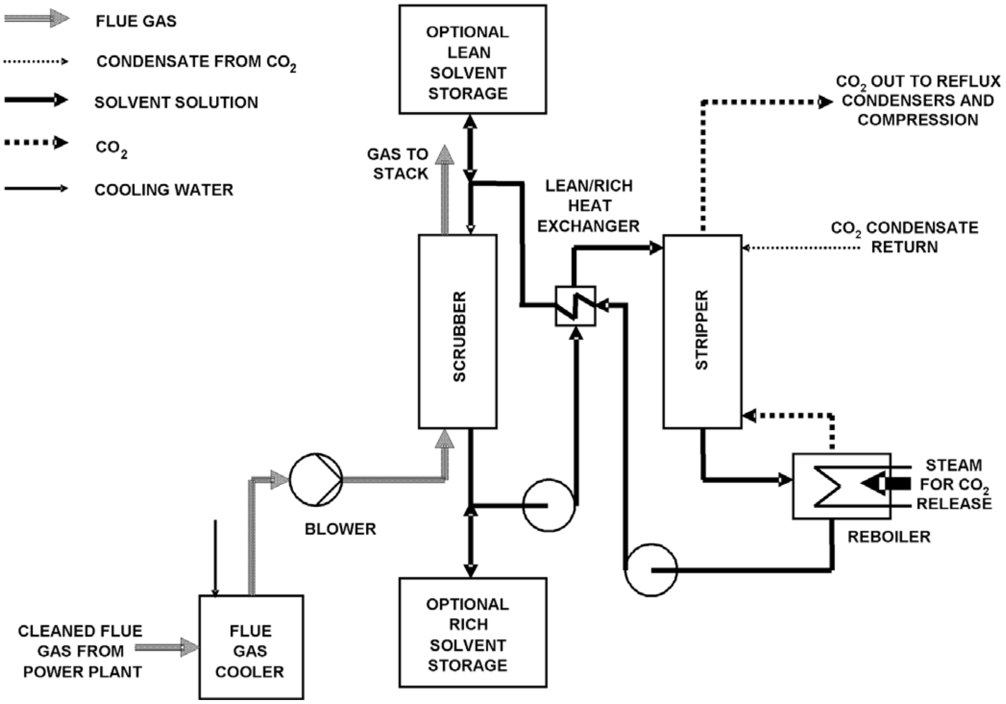

Fig. 1. Schematic diagram of post-combustion capture plant with optional solvent storage tanks.

column (or other gas/liquid contactor). The 'rich' solvent containing CO_2 is then heated in a reboiler and associated stripper column to release the CO_2 which is compressed, typically to 110 bar, for transport to a geological storage site. The regenerated solvent is now 'lean' and can be recycled back to the absorber. Most post-combustion CO_2 capture processes discussed in the literature and considered closest to commercial deployment use amine-based solvents [3]. However, other options are also under consideration, including amino acid-based solvents and ammonia solutions [4].

The most energy-intensive aspects of post-combustion CO_2 capture processes are the supply of heat for solvent regeneration and, to a lesser extent with current solvents, shaft power for CO_2 compression. It is now generally accepted that the most efficient way to reheat rich solvent in the reboiler is using steam taken from the power cycle [5]. As such, this steam is no longer available for electrical power production and an associated decrease in steam cycle efficiency is observed. A range of operating modes might be possible for power plants with post-combustion CO_2 capture, particularly if solvent storage (where CO_2-rich solvent is not regenerated immediately) is available, and these are discussed in later sections of this paper.

In the ideal models which are discussed in this paper it is assumed that, as an initial approximation, simple relationships can be used to represent the CO_2 capture efficiency penalty across all loads. These models are based on a consideration of expected behaviour for key components of the base power plant and CO_2 capture unit. For example, it is expected that the energy penalty associated with abstracting steam from the steam cycle will vary with different loads since the steam mass flow through the low pressure turbine cylinders is altered by diverting steam to the CO_2 capture plant for solvent regeneration with an associated impact on turbine efficiency. Against this, however, is the likelihood that an absorber system operating at part load will have reduced steam consumption per unit of CO_2 captured, due to reduced heat and mass transfer resistances. Other potential changes in plant efficiency at varying loads should also be explored. For example, waste heat rejected in the CO_2 compression process should be used to provide heat where possible within the power cycle (e.g. replacing condensate heating in the steam cycle) [5]. As CO_2 capture plant load is varied the potential for heat transfer between the capture plant and the power cycle could also vary, with associated impacts on power plant efficiency. Thus, one implicit assumption in the ideal analysis presented in this paper is that sufficient low grade heat for condensate heating is available from CO_2 compressor intercooling at all operating loads.

Some other important considerations relate to the sizing of plant to handle variable flows associated with off-design and part load operation. These could include recycle rates adjusted to maintain stable operation in many elements of the CO_2 capture system, including compressor/dryer units and the absorber. The design of the absorber system for post-combustion capture should also be able to accommodate variations in the CO_2 capture process, including day-to-day changes such as changing inlet temperatures depending on ambient conditions. Where possible, appropriate provisions should also be made to allow improvements in CO_2 capture technology (in particular improved solvent formulations) to be utilised as they are developed. It is important to note that any consequential additional output can only be accommodated if the plant has been built to allow these changes in operation. For example, the alternator and turbine must be sized appropriately and, because less 'waste' heat may be rejected from the CO_2 drying and compression system for condensate heating, low pressure turbine tappings may need to be included to allow subsequent installation of conventional condensate heaters.

3. Potential impacts of post-combustion capture on transient performance

Although this paper concentrates on the steady-state part load performance of coal-fired power plants with post-combustion capture, it is also useful to have some understanding of the transient behaviour of plants as they change load. The primary areas of interest are plant start-up, shutdown and load following. In the final case, the fossil-fired power plant output varies to help ensure that supply and demand within an electricity network remain balanced. In all cases, one important concern is whether power plant transient performance will be negatively affected by adding CO_2 capture since this could have an adverse affect on plant economics, particularly for mid-merit plant where the ability to offer flexibility to the grid operator can provide an important revenue stream (e.g. by providing spinning reserve to the network – where a plant operator is paid to operate the plant at part load so that additional capacity can be brought online very quickly by rapidly increasing plant output if there is a sudden increase in demand or reduction in supply from other sources such as wind generation). Identifying potential improvements to plant transient performance is therefore also important since it is possible that these could improve a power plant's economic case.

Further work is required to better understand transient behaviour of power plants with CO_2 capture. However, in general, it is expected that post-combustion capture should not impose constraints on power plant start-up times since excess flue gas can be vented. However, since the steam cycle and CO_2 capture plant are integrated, the power plant output, power cycle efficiency and steam mass flow in some parts of the cycle will be determined, in part, by the volume of steam abstracted for solvent regeneration. Thus, some constraints to power plant start-up could occur depending on the ability of the plant to handle changed steam flows and power production. Also, in electricity markets where there is a cost associated with emitting CO_2, the cost of producing electricity can be significantly increased if CO_2

is not captured, with an associated increase in the cost of CO_2 emissions included in the cost of electricity. A possible need to vent CO_2 during start-up could be an important addition to start-up costs that would alter plant operators' dispatch decisions, although (as discussed below) this may be avoidable with moderate amounts of solvent storage.

For load following operations, one constraint added by CO_2 capture could be the ramp rate of the CO_2 compression system, although a dynamic simulation of compressor and process is required to accurately predict system behaviour and this is beyond the scope of this initial study. If there is some constraint on the ability of plants with CO_2 capture to follow load when compared to the plant without capture resulting from CO_2 compressor characteristics, it may also be possible to change the load for the CO_2 compression train at a different rate to the power plant by careful control of the amine scrubbing plant, particularly if solvent storage is possible. This area of plant operation is not well understood, however, and, as with start-up, the implications for CO_2 emissions and other areas of plant performance during the transient period where power plant and capture plant loads are varying, possibly independently, requires further study. One consequence might be that CO_2 capture rates would be reduced slightly during periods of rapidly increasing load and increased slightly during reducing load. However, there is obviously less scope for numerically large increases in CO_2 capture rates than for decreases.

It is important to realise that it is expected that a number of areas of plant operation will not be fully understood until they are systematically investigated using full plant models or pilot and demonstration plants. For example, appropriate measures will be required to ensure that the steam used for solvent regeneration can provide heat within a relatively narrow band of acceptable temperatures across the plant operating range (i.e. be within a defined pressure range, although extraction pressures at the turbine can decrease slightly due to reduced pressure and temperature drops expected during part load operation of the amine plant) so that sufficient CO_2 will be released from the rich solvent in the reboiler, but the solvent itself will not decompose. While it is expected that steam supply pressures can be appropriately regulated, there is potential for some mismatch to occur when a boiler is operated under sliding pressure conditions to improve power plant ramp rates.

Finally, it should also be noted that adding post-combustion capture may provide options that could improve plant load following characteristics. For example, by varying the volume of steam abstraction for solvent regeneration over very short timescales, output changes due to variations in the steam cycle and possibly CO_2 compressor power will be approximately additive to changes that can be affected by opening the main turbine control valve and drawing down on the stored thermal energy in the boiler at coal-fired power plants [6]. But the rapidly increased higher loads can also be sustained for much longer periods than when only the stored energy in the boiler is available, giving sufficient time to bring additional burners into service.

4. Preliminary quantitative analysis of part load performance

One important step in quantifying the part load performance of power plants is determining plant efficiency and CO_2 emissions across the operating range. Earlier work undertaken by the authors to develop appropriate models to do this is outlined in [7]. In the current study, models for supercritical coal-fired power plant behaviour, including with post-combustion capture added, are refined. A part load performance curve for a pulverised coal-fired power plant with a supercritical steam cycle and no CO_2 capture is developed based on published sources [8,9]. Performance curves for a similar plant with post-combustion CO_2 capture are then estimated using a range of ideal cases that are quantified in this paper using the energy penalties listed in Table 1. Where possible, the performance of plants with CO_2 capture has been matched to a plant which has full load behaviour as reported in a detailed engineering study of post-combustion capture completed for the IEA Greenhouse Gas R&D Programme [3]. Also in line with this study, net plant efficiency is defined as net power out as a proportion of fuel heat input to the boiler.

In these ideal cases, a number of anticipated real impacts of adding CO_2 capture have been ignored although, as outlined in Section 2, the cases chosen are based on the expected behaviour of some key components of the base power plant and CO_2 capture equipment. Also, it has been assumed that the primary fuel is used to provide all heat input to the power cycle for all loads and that the impact of start-up and shutdown costs on plant dispatch decisions can be ignored. As such, the results obtained may not fully represent the behaviour of real plants. However, they do provide indicative preliminary data to allow some possible CO_2 capture plant operating patterns to be compared.

Table 1
Modelling of efficiency penalty for post-combustion capture at pulverised coal-fired power plants

	% Point penalty at full load	Model for multiple CCS units on one site	Model for single CCS unit on one site
Steam for CO_2 separation	5	Constant % across whole operating range	Constant % across whole operating range
Power for CO_2 separation	1	Constant % across whole operating range	Constant % across whole operating range
CO_2 compression	3	Constant % across whole operating range	Constant % from 75% to 100% CO_2 load Constant MW below 75% CO_2 load

To gain some understanding of potential differences between ideal and real plants, it is useful to quantify the sensitivity of modelling results to key assumptions where possible. For example, at one extreme, if power plants can be fitted with multiple capture and compression units which can be adjusted in small steps (a likely situation for a multiple-unit station with multiple CO_2 compressors drawing from a common manifold and possibly also a common low pressure steam supply for the solvent reboilers), as a first approximation it can be assumed that a constant percentage efficiency penalty is applied by the CO_2 separation and compression processes across the plant operating range. This is based on the assumption that, for a given capture process with a particular fuel, the 'energy'[1] penalty per unit of CO_2 captured (and hence per unit of fuel used) is constant and independent of the non-capture efficiency of the power plant to which the CO_2 capture equipment is fitted and that it remains constant for all loads (or that the various effects of part load operation tend to compensate, as discussed above). Thus the energy to capture the CO_2 per unit of fuel can be expressed as a (fixed) percentage of the fuel's heating value, with the same ratio of units as power plant efficiency. The following equation then defines the plant efficiency for a given fuel input:

$$\eta_{CCS} = \eta_{noCCS} - \%\text{penalty} \tag{1}$$

where η_{CCS} is the net plant efficiency for a given fuel input with CCS operating, η_{noCCS} is the net plant efficiency for a given fuel input without CCS operating and %penalty is the percentage points energy penalty for capture at 100% load. Although this is clearly an approximation, it can be justified by considering the behaviour of the capture scheme. For example, a typical CO_2 compressor system is likely to be capable of efficient turndown to approximately 75% of full flow at constant discharge pressure [10]. But if all units at a typical power plant site were fitted with CO_2 capture then a bank of compressors would be required to provide sufficient capacity for the whole plant and, if the compressors have a common suction manifold, then varying numbers of compressors can be used at any particular time. For example, at a power station where four CO_2 compressors were used in this way, the whole CO_2 compression system could have efficient CO_2 compression in the range from about 19% to 100% of full load. For the solvent-based capture process occurring in the scrubber and stripper columns, pump and fan loads might not decrease linearly with gas throughput. However, it seems likely that these effects could be offset by other changes – for example, as noted above, some equipment, such as absorbers and reboilers, is expected to operate more effectively at part load.

Where units cannot necessarily be adjusted in small steps or the use of multiple components cannot be applied to allow overall efficient plant turndown over a wide range (e.g. if CO_2 capture is fitted to a single stand-alone unit) the simple model above cannot be applied. In this case, if stable operation of CO_2 capture plant below the limiting loads is possible, it will only be able to occur with reduced efficiency. For example, stable operation of the CO_2 compression system will require flow recirculation. To give an indication of potential changes in plant performance, an alternative model for efficiency penalty is required. A worst case scenario could be that the power consumption would remain constant below the limiting load – i.e. a constant MW efficiency penalty would be applied. In this case, the plant efficiency with CCS based on heat inputs to the power plant is then given below:

$$\eta_{CCS} = \eta_{noCCS} - [\%\text{penalty}_{load1} \times (\text{heat in}_{load1}/\text{heat in}_{load2})] \tag{2}$$

where η_{CCS} is the net plant efficiency for a given fuel input with CCS operating, η_{noCCS} is the net plant efficiency for a given fuel input without CCS operating, $\%\text{penalty}_{load1}$ is the energy penalty associated with adding capture at the limiting load, load 1 is the limiting load (minimum load at which efficient part load performance occurs) and load 2 is the lower load at which efficiency is being calculated.

Using off-design efficiency curves for plant without capture based on published literature [8,9], efficiency curves for the plant operating range can be plotted. Fig. 2 illustrates some typical curves for the ideal cases defined above.

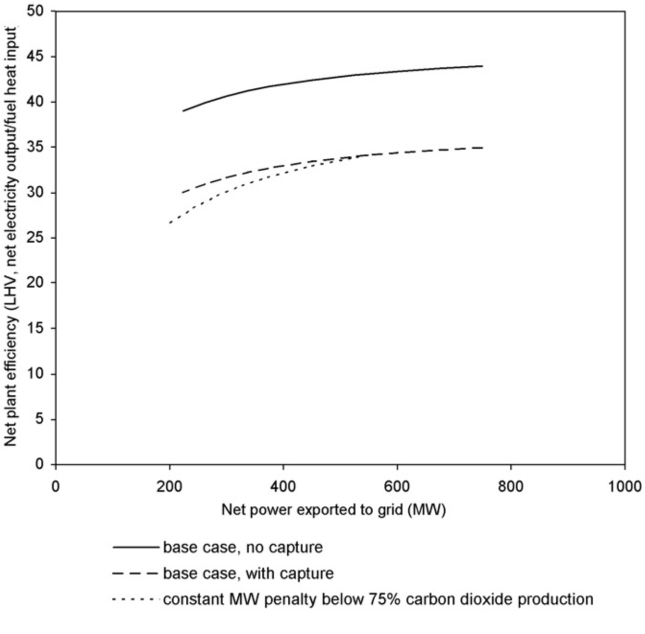

Fig. 2. Part load efficiency curves for supercritical coal-fired plant with post-combustion capture using an amine-based solvent and supercritical coal-fired plant without CO_2 capture.

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[1] The term 'energy' penalty is in common usage although it would be more accurately named the 'electricity' penalty since it represents the 'lost' electricity output due either to direct consumption by capture-related equipment (e.g. compressors, circulating pumps) or to reductions in steam turbine output due to steam abstraction. The heat transfer from the steam in the solvent reboiler is, however, much higher, typically around three times the reduction in electricity output due to steam abstraction (after heat integration is applied).

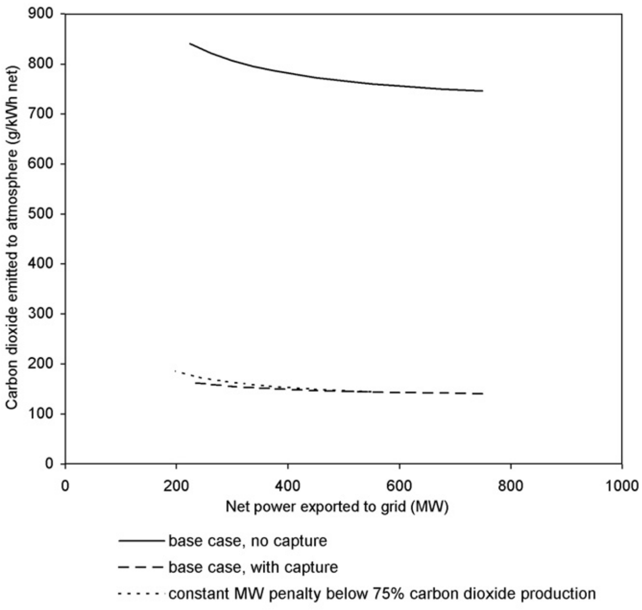

Fig. 3. Part load CO_2 emissions for supercritical coal-fired plant with post-combustion capture using an amine-based solvent and supercritical coal-fired plant without CO_2 capture.

CO_2 emissions profiles for different technologies can also be calculated and these are shown in Fig. 3 based on coal CO_2 emissions of 91 kg CO_2/GJ thermal (LHV basis), in line with assumptions for a world-traded Australian thermal coal used in a recent IEA Greenhouse Gas R&D Programme study on post-combustion capture [3]. The CO_2 capture efficiency is assumed to be 85%, although at real plants it is expected that this would be increased or decreased within limits set by the equipment, ambient conditions, etc., to maximise the net revenue.

5. Outline of potential for avoiding capture energy penalty by venting carbon dioxide

One option for significantly improving the flexibility of fossil-fired power plants with CO_2 capture added is to identify options for changes in operating procedures, in some cases with some associated additional expenditure. For post-combustion capture plants, it is expected that the capture energy penalty can be almost entirely avoided by stopping CO_2 capture and venting the CO_2 in the flue gases. This would avoid the need for steam abstraction and compressor and amine plant ancillary power consumption, assuming that the balance of plant is appropriately sized to handle the increased steam flow in the low pressure steam turbine cylinder and condenser and the additional power available to send out (or alternatively the fuel input could be reduced in line with balance of plant constraints, but this does not make maximum use of most of the capital assets in the plant). For real plants, changes in the power cycle (e.g. steam flow to the low pressure turbine cylinders and the availability of heat from the CO_2 capture plant for condensate heating if a full complement of conventional condensate heaters is not fitted) when CO_2 is vented imply that optimum efficiency may not be obtained in both the capture and non-capture cases, particularly if capital costs are to be minimised. However, this is not quantified for the ideal models reported in this paper. Instead it is assumed that when all CO_2 produced by the power plant is vented, the efficiency of the plant returns to that of a plant without CO_2 capture as defined in Fig. 2.

It is expected that CO_2 venting in some form should be an option for all power plants with post-combustion CO_2 capture without significant additional capital expenditure beyond the extra capacity required directly in the LP turbine, condenser, alternator/switchgear, etc. In some cases, this expenditure may not be additional above the baseline plant specification, depending on the attitude of the power plant purchaser to reliability, availability, maintainability and operability. For cases where additional capital expenditure is required, appropriate long-run economic analysis is required to determine whether this capital expenditure can be justified by expected profits associated with venting CO_2 under appropriate economic conditions (and within the limits imposed by any environmental legislation). Some difficulties associated with completing analysis of this kind are identified and discussed in Section 7.

Defining and checking data for long-run economic analysis should often involve appropriate analysis of short-run costs and revenues. For example, for the ideal models defined in this study, the cost of operating the base case capture plant defined in Figs. 4 and 5 (see Table 2 and the next section for an outline definition of all cases shown

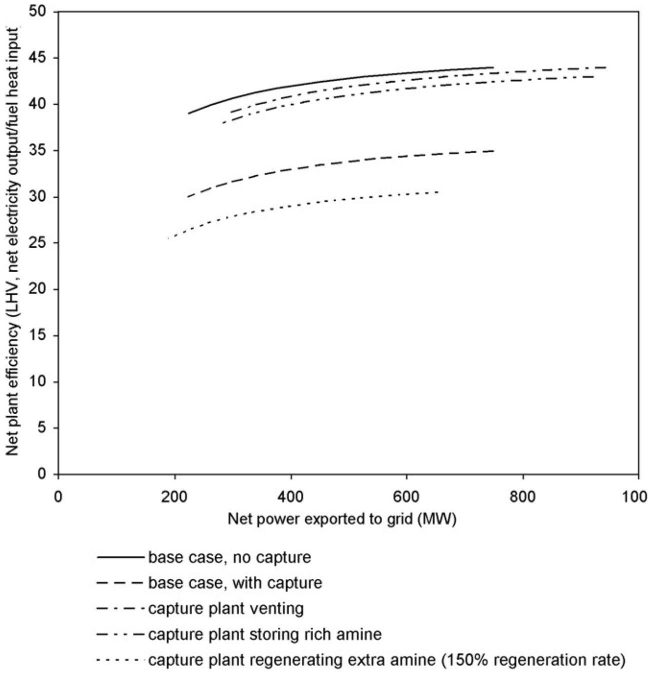

Fig. 4. Part load efficiency curves for options for supercritical coal-fired plant with amine-based post-combustion capture compared to supercritical coal-fired plant without CO_2 capture.

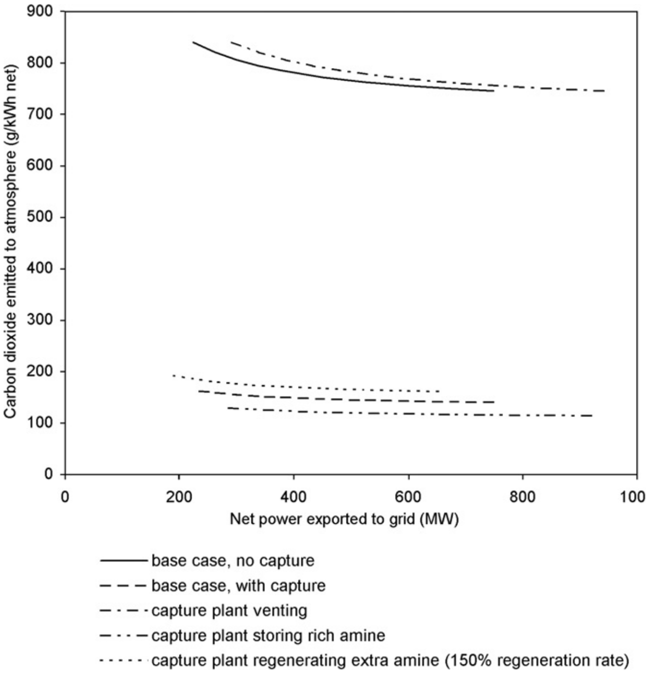

Fig. 5. Part load CO_2 emissions curves for options for supercritical coal-fired plant with amine-based post-combustion capture compared to supercritical coal-fired plant without CO_2 capture.

Table 2
Different options for power plant operation with post-combustion capture

Case	Description
Base case (capture)	85% of CO_2 produced captured using post-combustion process and rich solvent regenerated immediately
Vent all CO_2	As capture base case, but with capture plant not operating. Thus net MW out increased for all loads since no capture energy penalty if balance of plant has appropriate capacity, but also higher CO_2 emission
Store 85% CO_2 as produced	As capture base case, but with capture plant storing rich solvent to be regenerated later. Thus net MW out increased for all %loads, subject to any balance of plant restrictions. There is still a small capture energy penalty (e.g. for absorber tower pressure loss and solvent pumping, taken as 1% of fuel LHV for this analysis), but also low CO_2 emissions
Extra regeneration	As capture base case, but with an additional volume of solvent regeneration (i.e. all CO_2 from current production captured with rich solvent regenerated immediately, but rich solvent flow rate increased by adding solvent from storage tank)

on these figures) at full load of 750 MW for 1 h is around £15,300 plus any cost associated with emitting 105 tCO_2 during those operations. If that plant was to vent CO_2 then the full load would increase to 921 MW with an associated operating cost of around £10,800/h (a reduction compared to operating with CO_2 capture since variable costs associated with CO_2 capture are avoided) and CO_2 emissions of approximately 700 tCO_2/h. Fig. 6 shows the variation in break-even cost where plant operation would switch from full load operations with CO_2 capture running to venting CO_2 at the increased full load available when only these options are available, based on analysis of short-run marginal costs and revenues.

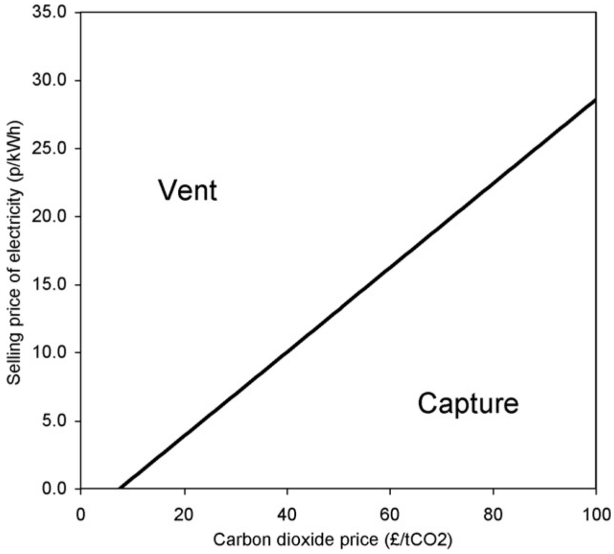

Fig. 6. Decision diagram for choice between operating plant with CO_2 capture or with CO_2 vented assuming maximum fuel input.

Clearly, the relative profitability of these operating options is dependent on both the selling price of electricity and the CO_2 price. When CO_2 prices increase, the break-even point in terms of electricity selling price required for the plant to switch from CO_2 capture to venting is also increased. For low CO_2 prices a negative break-even electricity selling price is reported indicating that when CO_2 prices are low (below ~£7.50/tCO_2) the plant would always vent CO_2 regardless of the electricity selling price, unless other constraints (e.g. environmental law) required the plant to operate with CO_2 capture. This result can be explained by noting that when the CO_2 price is low, a plant venting CO_2 does not experience a significant financial penalty for emitting increased volumes of CO_2 and also that it is significantly cheaper to operate the plant without CO_2 capture if there is no significant financial penalty or other constraint on high CO_2 emissions. In particular, the variable operating and maintenance costs associated with CO_2 capture, storage and transport process are avoided when CO_2 is vented, as are the effects associated with decreased plant efficiency when CO_2 capture is used. The results reported here are generally in agreement with previous work at Imperial College [6] which concluded that CO_2 venting could be an attractive option for coal-fired plants with amine-based CO_2 capture when £/MWh electricity prices are 2–3 times higher than £/tCO_2 prices. Although, a much lower electricity price is required to justify CO_2 venting at low CO_2 prices, for the ideal cases modelled in this paper this 'rule of thumb' is accurate for CO_2 prices of around £20/tCO_2 and above.

As discussed above, some CO_2 venting should be an option available for all plants with post-combustion CO_2 capture. However, for plants to fully exploit potential additional revenue associated with venting CO_2 in certain conditions (e.g. extreme price spikes associated with periods of high demand such as cold snaps during winter), some areas of plant including the low pressure turbine, condenser and generator will require appropriate design to accommodate the large variation in flows associated with venting CO_2 and hence not abstracting steam from the steam cycle. For the base case assumptions chosen for this study (including a CO_2 price of £25/tCO_2 as outlined in the Section 6.2 below) it seems likely that pulverised coal-fired plants fitted with post-combustion CO_2 capture would not routinely vent CO_2 if other coal capacity was available since the marginal cost of electricity is higher than for the coal-fired plants operating with CO_2 capture. This also implies that significant additional capital expenditure to allow the power plant to operate at maximum load when CO_2 is not captured may not be justified. However, if these modifications are partly justified by other considerations (e.g. plant reliability) then venting of CO_2 could be a useful additional operating option. In the case outlined in this paper, when CO_2 is vented the maximum output from the plant is increased by nearly 200 MW. Thus, if electricity prices were high and other additional generation options were limited, the increased revenue associated with this additional capacity could be sufficient to justify venting CO_2 rather than operating with CO_2 capture.

6. Outline of potential for shifting capture energy penalty by storing carbon dioxide

6.1. Technical outline of solvent storage requirements

It is also possible that CO_2 could be captured continuously but that most of the energy penalty associated with CO_2 capture could be incurred at some other time if solvent storage tanks are used between the CO_2 scrubber and stripper columns in the capture plant, as shown in Fig. 1. In this case power plants could then operate for several hours with CO_2 in the flue gas removed in the stripper column as in base case operation but with the energy-intensive solvent regeneration and CO_2 compression processes left until later. The rich solvent containing CO_2 leaves the scrubber as normal and is temporarily stored in solvent storage tanks, avoiding the majority of the energy penalty for the amine capture process, which is incurred as a result of abstracting steam from the steam cycle and compressing CO_2. Some time later, typically when lower electricity selling prices apply so the plant output is less valuable, the rich stored solvent would be regenerated by adding it to the 'normal' solvent stream being produced due to plant operations.

Table 2 summarises some possible operating conditions for a power plant with post-combustion capture, including some operating modes that would be made available by using solvent storage. Again, the quantitative analysis reported here is restricted to ideal cases where a constant percentage energy penalty for CO_2 capture is assumed across the power plant operating range. It is also assumed that for regeneration of stored solvent the energy penalty is increased directly in proportion to the volume of solvent regenerated, again neglecting changes in capture system and power cycle performance associated with changing steam mass flows and other cycle integration effects. Figs. 4 and 5 show off-design efficiency and CO_2 emissions curves for ideal cases of the options listed in Table 2, compared with the single operating curve available for plants without CO_2 capture. For illustrative purposes, the maximum load and operating range for the base case capture and non-capture plants have been assumed to be equal. Different operating possibilities for the plant with CO_2 capture are shown by curves which have an identical range of fuel inputs compared to the base case plant with CO_2 capture but different MW sent out.

The addition of solvent storage tanks, the purchase of more solvent and the likely provision of additional capacity in balance of plant components to allow extra power to be generated and exported would require further capital expenditure. Depending on market conditions this outlay could be justified by an increase in plant revenues associated with improved plant flexibility and an associated ability to offer ancillary services to the electricity network operator and this is discussed further in the next section. For example, solvent storage could provide increased plant capacity (i.e. reserve) at times of high electricity demand. In this case, the day/night price differential for electricity selling price would be important to allow a comparison between the value of additional output generated in periods when solvent was stored and the value of output that would be unavailable when stored solvent is regenerated later.

6.2. Analysis of potential uptake of solvent storage based on short-run marginal costs

A number of analytical methods are available to explore the potential uptake of the additional power plant operating options with post-combustion capture which are discussed above. This section will outline a method which uses short-run marginal cost (SRMC) of electricity, i.e. not long-run marginal cost (LRMC) and levelised costs, to explore expected power plant dispatch options. SRMC includes only those costs which are incurred to run a plant which has already been built – mostly fuel, the cost of obtaining carbon credits for CO_2 emissions and variable operating and maintenance costs, although these are only significant for plants operating with post-combustion capture. In contrast, analysis with LRMC would take into account all plant costs, including paying back initial capital expenditure and fixed operating and maintenance costs. One important plant characteristic which is determined by SRMC, but critical in correctly estimating LRMC, is the load factor which indicates how many operating hours are achieved by the plant in a given time period. Once a plant has been built, the decisions on whether a plant should be run or not (i.e. dispatched) will be determined by analysis of projected short-term costs and revenues. If short-term revenues a larger than short-term costs then the plant will run. If the converse is true then the plant will not run. Clearly, the result of this analysis gives the plant load factor.

One useful approach to provide an initial analysis of power plant operating decisions is to treat SRMC as an indicator of the break-even electricity price at which power plant operators will dispatch the plant. Since, by definition, SRMC does not allow any comparison of capital expenditure to establish different power plants on the grid, it cannot be used for a full analysis of power plant economic performance. However, understanding the power plant dispatch behaviour, which is strongly dependant on SRMC, is a necessary precursor to provide input assumptions required for analysis based on LRMC. As well as identifying a projected load factor, as discussed above, if assumptions for analysis of long-run analysis are underpinned by appropriate short-run analysis then this load factor should also be set in the context of a realistic set of price assumptions (including fuel and carbon) which are expected to lead to that operating pattern. Also, as outlined in following sections, short-run analysis can be used to indicate expected net short-term revenues (i.e. plant earned income which remains to contribute towards paying off capital etc once short-run costs included in the SRMC have been taken into account) for different operating patterns, such as a full cycle of solvent storage with associated solvent regeneration, which must be properly understood for an accurate analysis of plant long-run economic performance to be carried out.

Fig. 7 illustrates the basic SRMC of electricity generation for each of the processes listed in Table 2. It is assumed that all variable operation and maintenance costs associated with the use of amine solvent should be included in the SRMC for solvent storage and that the transport cost is included in the SRMC for plant operation when CO_2 is produced, i.e. the cost of transport for CO_2 captured when solvent is stored is assumed to be included in the SRMC of regenerating that solvent, not in the SRMC for power plant operation with solvent storage. Although a comparison of the SRMC with the electricity selling price is often sufficient to indicate whether a plant should run or not (although in reality with some additional considerations including the impacts of start-up and shutdown fuel costs and impacts on plant component life, etc.) in the case of solvent storage and regeneration, as noted above, it may be more useful to consider the costs associated with a whole cycle including storage and regeneration, since the processes are, by definition, coupled. Although a loss may be made if electricity prices are low when solvent is regenerated (e.g. overnight), this could be offset by additional revenue associated with having the capability to store solvent when electricity prices are much higher (e.g. during the day and, in particular, during any peaks which occur). This additional revenue can, however, unambiguously be assigned to the SRMC cost calculations for running periods when solvent is being regenerated, since it arises solely as a consequence of undertaking that solvent regeneration.

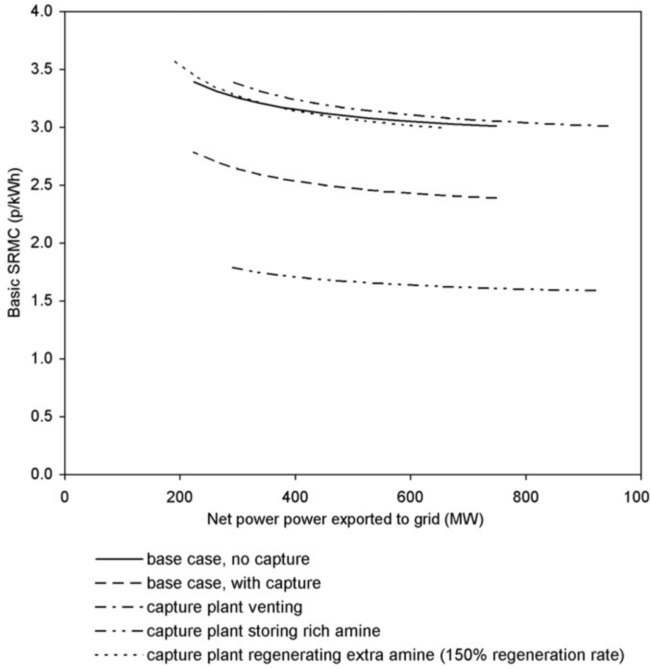

Fig. 7. Basic SRMC for options for supercritical coal-fired plant with amine-based post-combustion capture compared to supercritical coal-fired without CO_2 capture.

The break-even cost for these paired processes of solvent storage and regeneration, can be found and expressed by a number of methods. This study proposes the use of an ‘adjusted SRMC’ for one part of the storage/regeneration cycle which gives the break-even cost for one operation once the profit/loss associated with the other part of the cycle is known (or assumed/calculated from appropriate assumptions for the purposes of further exploratory analysis). For example, revenues gained from an assumed period of solvent storage are taken into account to find selling prices for electricity during periods of additional regeneration that would allow operating costs from the whole solvent/regeneration cycle to be recovered. As with the non-storage cases, this analysis considers only marginal costs, so does not indicate the selling price for electricity that would be required to pay back the additional capital investment required for the construction of solvent storage facilities and for any additional plant modification nor, as an offset, any benefit from an increased load factor in reducing the required selling price per kWh to recover the capital investment in the rest of the plant.

Basic marginal costs for running the plant while storing and regenerating additional solvent, including the same elements as cases without solvent storage, can be calculated as shown in Fig. 7. The profits obtained during periods when solvent is stored can also be calculated, assuming that market conditions to determine profits can be known, or reasonably assumed as part of the analytical process. For a given plant output during additional solvent regeneration, the time required for regeneration of all stored solvent can also be calculated given an assumed rate of additional solvent regeneration. The adjusted SRMC for solvent regeneration is then defined by Eq. (3). Plant operators could also decide to regenerate solvent at a non-constant output power and/or solvent regeneration rate. In such cases, Eq. (3) should be appropriately adapted by summing operational costs and respective energy output under various different conditions:

$$\text{adjusted SRMC}_{\text{regen}} = (\text{opcost}_{\text{regen}} - \text{profit}_{\text{storage}})/(\text{load}_{\text{regen}} \times \text{time}_{\text{regen}}) \qquad (3)$$

where adjusted SRMC is for the period when solvent is regenerated at a given plant output and regeneration rate, $\text{load}_{\text{regen}}$ is the selected output capacity in MW (or kW, etc.) from the plant during the period of solvent regeneration, $\text{time}_{\text{regen}}$ is the time required to allow for regeneration of all stored solvent given a selected $\text{load}_{\text{regen}}$ for the plant regenerating solvent and rate of additional regeneration, $\text{opcost}_{\text{regen}}$ is the basic cost of operation for $\text{time}_{\text{regen}}$ in £ or p given the plant operating conditions (e.g. rate of solvent regeneration) and $\text{profit}_{\text{storage}}$ is the profit obtained during the period while solvent is stored for later regeneration in £ or p (considering the solvent storage operation in isolation for the purposes of analysis).

For the ideal cases shown in Fig. 8, maximum plant output is set to 750 MW for the non-capture plant and the base case plant with CO_2 capture. Coal price is chosen as £1.4/GJ in accordance with the central value in other ongoing work at Imperial [11] and the carbon price is set to an illustrative level of £25/tCO_2 so that the analysis represents a situation where some CCS schemes are expected to be commercially viable as a result of the value associated with avoiding CO_2 emissions. An illustrative cost of £5.5/tCO_2 for CO_2 transport and storage in an offshore aquifer [11] is also included, although it is not yet clear whether this cost would necessarily be included in the cost of electricity for all projects.

Fig. 8 shows the adjusted SRMC for regeneration for various possible plant operating conditions. For the cases with solvent storage, it is assumed that solvent storage occurs with a plant operating at full load of 921 MW. Two electricity prices during solvent storage operations are considered: 3.4 p/kWh (i.e. 1 p/kWh higher than the SRMC of generation for the base case plant with CO_2 capture operating with continuous regeneration of produced CO_2 at full load) and 4.4 p/kWh (i.e. a further 1 p/kWh above the previous case). The times shown are for complete regeneration of stored solvent with continuous operation of the power plant with the given additional regeneration configuration (rate of additional generation and location within power plant operating range – i.e. full load, minimum stable generation or somewhere between these extremes).

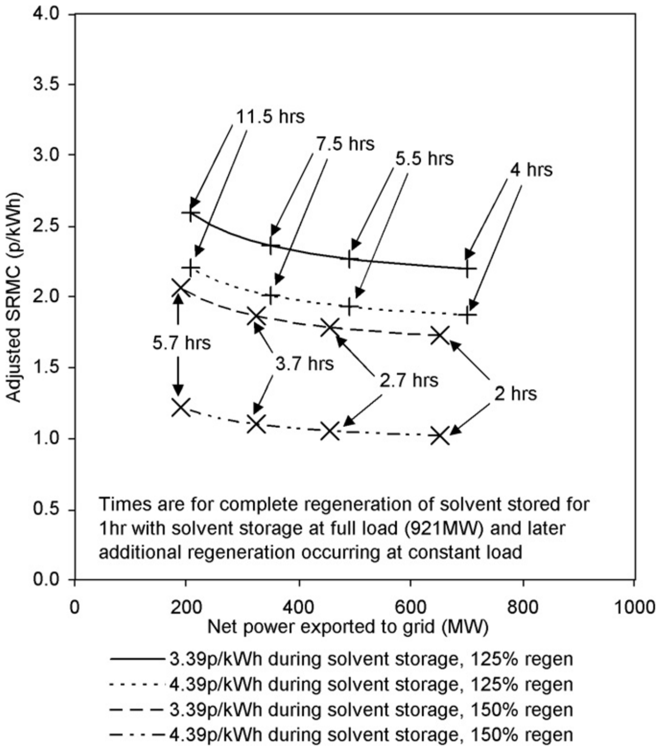

Fig. 8. Adjusted SRMC for two plants with same fuel inputs and different operating patterns for CO_2 capture plant operating with solvent storage.

As outlined above, during periods of additional solvent regeneration plant efficiency will be decreased further than with base case CO_2 capture operations resulting in reduced plant efficiency with an associated increase in fuel use and also a slight increase in CO_2 emissions. Although this results in a higher basic SRMC of electricity generation for the period of additional solvent regeneration than for the base case with CO_2 capture, the adjusted SRMC for electricity generated with additional solvent regeneration, which takes into account profits from the associated period of solvent storage, can still be lower than for plants without solvent storage. Thus, under some conditions, it is expected that solvent storage could be used on a regular basis to improve plant short-run economic performance by storing solvent at times of high demand (allowing the plant to generate additional revenues as a result of the high electricity prices associated with periods of high demand) and then regenerating additional solvent at times of lower demand when electricity prices will also be lower.

6.3. Analysis of potential uptake of solvent storage based on net revenues and short-run profits

Although the adjusted SRMC data reported here is useful since it gives a single parameter to compare different plant operating options on a short-run cost basis and, additionally, requires relatively few assumptions in generating the data used for comparison, it is important to remember that conclusions based on Fig. 8 do not take into account the possibility that plants without solvent storage may not run during off peak periods, when a plant with storage could still be run advantageously to regenerate solvent, since the value associated with solvent storage generates sufficient additional income to offset the otherwise uneconomic low electricity price. As such, further analysis which takes account of this operating decision is required for a more complete understanding of the conditions under which solvent storage could be economically attractive on a short-run basis. It is expected that these considerations could be included within an adjusted SRMC approach. However, this study uses direct calculation and comparison of net revenues for different plant operating patterns to establish which market and plant operating conditions provide environments which provide a net increase in short-run revenue (which is plant income left to cover capital costs and other long-run costs once short-run costs have been taken into account). Although this method requires additional assumptions, which reduce generality of the conclusions reached, it provides clearer results to illustrate the potential profits and losses associated with solvent storage and regeneration operations for the particular examples which are analysed.

Fig. 9a and b plot the additional net short-run revenue associated with solvent storage and regeneration for the conditions used for Fig. 8 and electricity prices during solvent regeneration of 2.39 p/kWh (i.e. the SRMC of generation for the base case plant with CO_2 capture operating with continuous regeneration of produced CO_2 at full load) and 2.89 p/kWh (i.e. 0.5 p/kWh above the previous case). The net increase (or loss) is based on comparison with a case where the same fuel input is used at a CO_2 capture plant without solvent storage. A clear difference in the pattern of results is obtained when the two cases are compared since for the lower electricity price during regeneration the base CO_2 capture plant does not run (or if it did, it would generate no net short-run net revenue since 2.39 p/kWh is the break-even cost for full load operation for this plant in this study), whereas with the higher electricity price it does. In particular, for cases where a 2.39 p/kWh electricity price during solvent regeneration is assumed, net additional revenue reduces at lower loads directly reflecting the increased adjusted SRMC for part load operation, with a constant net revenue obtained from the plant operating without solvent storage since it only generates a net revenue during solvent storage operations (and maximum fuel input is assumed for all solvent storage cases used in this study). When the electricity price is assumed to be 2.89 p/kWh both plants operate during the period when additional solvent is regenerated at the plant operating with solvent storage. Both plants have increased adjusted SRMC at part load and, for the ideal cases considered here, the change in adjusted SRMC seen for both cases is such that a constant change in net short-term revenue across all loads is calculated for each case analysed here. If a similar result

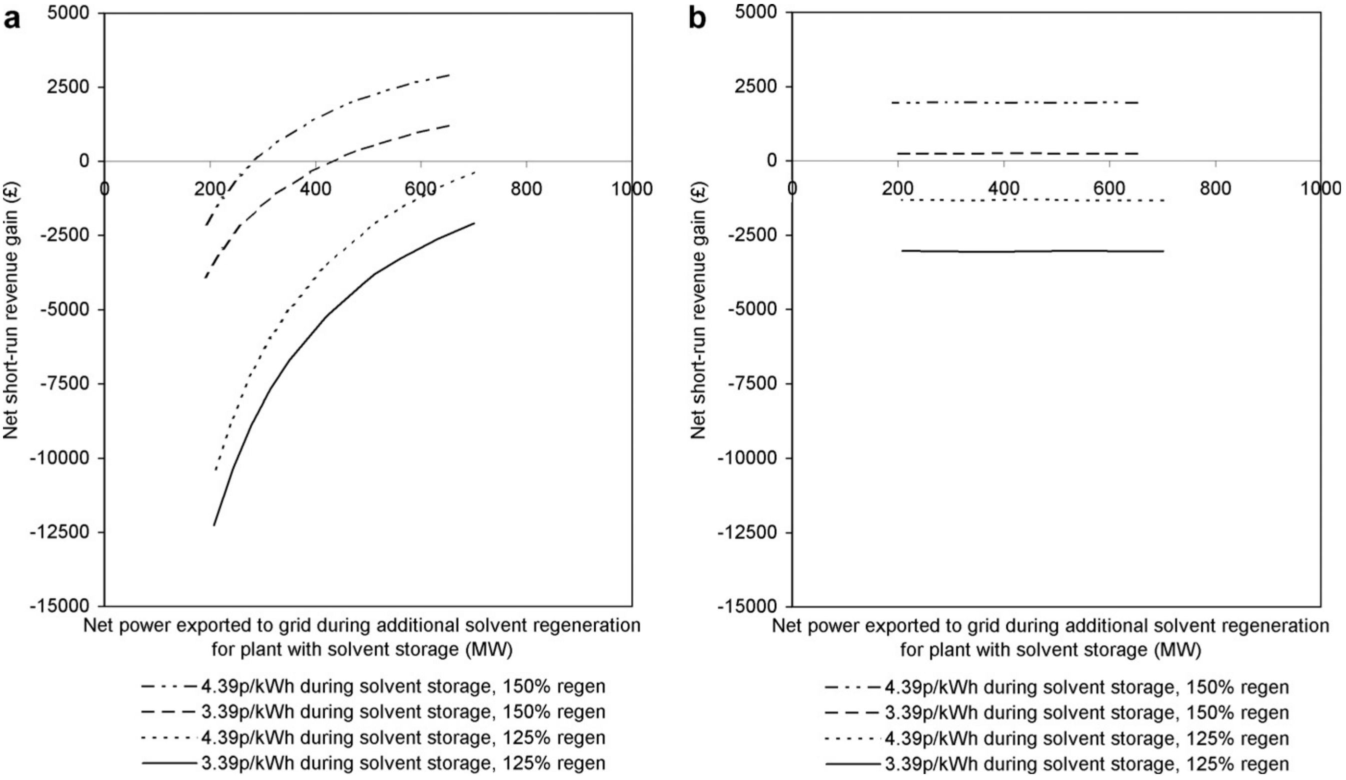

Fig. 9. Gain (or loss) in short-run net revenue associated with solvent storage compared to a base case CO_2 capture plant with the same fuel input (a) for electricity price of 2.39 p/kWh during additional solvent regeneration and (b) for electricity price of 2.89 p/kWh during additional solvent regeneration.

were obtained for 'real' plant models then this could be an important conclusion, which is likely to alter conclusions about which operating modes are considered to be worthwhile for plants operating in a real market. Thus, further consideration with more detailed plant models, which take into account various aspects of real plant behaviour which have not been included in the ideal models presented here is likely to be worthwhile. More generally, the results of the current study discussed here, seem to indicate that optimum plant operating patterns may differ depending on market conditions. Thus, further work including more realistic electricity market assumptions also seems to be worthwhile but is beyond the scope of the present study.

Although the limited range of case studies reported here does not allow many general conclusions to be drawn, one important implication of Fig. 9 is that, for the market conditions used in these examples, plants with solvent storage could provide better economic performance on a short-run basis than plants without the option of solvent storage, depending on the market conditions when CO_2 is stored and regenerated. This supports the conclusion of the previous section using an adjusted SRMC method that, once built, it is expected that coal-fired plants with solvent storage could have higher load factors than plants without solvent storage depending on the conditions in the market within which they operate. As discussed above, power plant load factor is an important consideration in long-run analysis of power plant economic performance because higher load factors indicate that the plant is run more frequently. However, it is important to note that higher load factors must also be associated with reasonable plant income for the electricity generated if they are to be seen as an indicator of improved capital payback times and increased long-run profitability.

Another important result which is true for all cases considered in this study is that short-run revenues are higher for cases with higher rates of stored solvent regeneration. In fact, for all cases where solvent was regenerated by adding 25% to the flow volume of currently produced solvent (i.e. for a 125% solvent regeneration rate), plant short-run revenues were higher for plants operated without solvent storage than for those which used solvent storage. However, net revenues were higher when compared to plants without solvent storage for almost all cases where 50% of the flow volume of currently produced solvent was added from solvent storage tanks (i.e. 150% solvent regeneration rate). Thus, there is a clear trade-off between the capital costs required to allow solvent storage regeneration, with increased capital costs and possibly greater energy penalties (which have not been modelled in the initial study reported here) associated with faster regeneration rates, and the net revenue that can be obtained by storing and regenerating solvent.

Perhaps not surprisingly, higher electricity prices during solvent storage and lower electricity prices during solvent regeneration improved the economic case for solvent storage in all cases. It is also interesting to note that the reduced efficiency associated with additional solvent regeneration effectively reduces the minimum stable generation load for the plant. This could be beneficial in situations where fossil plant has to be kept online as spinning reserve for the grid, but the grid operator would obviously prefer to maximise the proportion of generation from other plants with cheaper marginal costs than fossil-fired plants (but which are usually less controllable or flexible e.g. intermittent renewable sources, nuclear). A plant regenerating solvent would probably also be able to pick up load faster than a conventional pulverised coal plant at reduced load, since the boiler would be operating at relatively high loads already.

7. Changes to plant net revenue and implications for long-run economic viability of solvent storage

A full analysis of project viability requires a detailed consideration of fixed costs, including paying back capital and some operating and maintenance costs. SRMC-based analysis, such as that used above, is useful since the merit order which determines power plant dispatch (i.e. which plants are run to meet demand at any given time) is based largely on SRMC. For example, as discussed above, plants with higher marginal costs of electricity are less likely to run than plants with lower marginal costs with an obvious impact on the assumed load factor in overall plant economic calculations. Also, when load factors assumed in long-run analysis have been based on SRMC-based analysis then it is more likely that consistent models will be built, including costs for fuel and CO_2 emissions which are likely to lead to the defined plant load factors.

It is also important to note that LRMC-based analysis will often require the use of average costs which will be levelised over the operating period in question. However, approaches based on average cost must be carefully designed to ensure that they appropriately characterise the more detailed short-run behaviour they are representing. For example, Fig. 9 identifies a number of cases where running a plant with solvent storage followed by a period of additional regeneration increases power plant short-run net revenue – and this is displayed in the adjusted SRMC developed in Section 6.2. A more common approach for long-run analysis can be to simply average and compare the basic SRMC of different operating patterns. Table 3 shows the breakdown of costs associated with average cost and adjusted SRMC for a case study where a plant is operated with maximum fuel input for 3 h (not necessarily continuously) and two possible operating configurations are considered: 1 h solvent storage followed by 2 h with additional regeneration and a base case where CO_2 is captured and regenerated at a constant rate for assumed electricity selling prices.

In the analysis based on average cost using basic SRMC only shown in Table 3, the conclusion would be that solvent storage should not be used since the average cost for operation without solvent storage is 2.39 p/kWh but this

Table 3
Breakdown of costs for analysis of different power plant operating patterns using different methods for electricity price 3.39 p/kWh during solvent storage and 2.39 p/kWh during solvent regeneration

Quantity	With solvent storage and 150% regeneration	Without solvent storage
MW available for dispatch with maximum fuel input during storage operations	920	750
SRMC during storage operations	1.59 p/kWh	2.39 p/kWh
Net revenue[a] during 1 h storage period[b]	£16,950	£7492
Net plant output during 1 h storage period[b]	920 MWh	750 MWh
MW available for dispatch with maximum fuel input during regeneration operations	652	750
Basic SRMC during regeneration operations	3.00 p/kWh	2.39 p/kWh
Net revenue[a] during 2 h period required for full additional solvent regeneration[b]	−£7894	£0[c]
Net plant output during 2 h period required for full additional solvent regeneration[b]	1304 MWh	1500 MWh
Average SRMC for solvent/regeneration cycle[d]	2.41 p/kWh	2.39 p/kWh
Net profit for solvent/regeneration cycle	£8694	£7492
Adjusted SRMC for regeneration[e]	1.72 p/kWh	1.89 p/kWh

[a] Plant income from electricity sales not required to cover operating costs.

[b] For simplicity, only data for full fuel input and with a single electricity price assumed for each operating period is reported in these illustrations.

[c] Note that this selling price is the short-run break-even point for the plant under the assumptions used in this study. Thus, further analysis taking more costs into account may indicate that this plant would not run during the period when a plant with solvent storage would still be running to regenerate additional solvent. However, this would not change the later conclusions reported here.

[d] Defined as total costs for operation divided by total electricity dispatched.

[e] As defined by Eq. (3) in Section 6.2.

is slightly increased to 2.41 p/kWh with solvent storage. This result is what would be expected given the definition of the ideal models used in this study which assumes a slight efficiency penalty for solvent storage operations. However, the adjusted SRMC, which takes account of increased net revenue during solvent storage operations indicates that solvent storage should increase plant short-run net revenue in this case since the adjusted SRMC for the plant operating with solvent storage is lower than for the plant operating without solvent storage. As such this case is an example of an occasion where long-run analysis using average costs which are not appropriately defined could reach a different conclusion to that reached when results from short-run analysis are taken into account in more detail.

Given the difficulty of basing long-run analysis on detailed short-run considerations of different plant operating patterns with their associated costs and net revenues, an alternative approach could be to use the net revenues calculated based on SRMC and short-run plant income to build up an estimate of an annual payment that would be available for paying off capital and contributing to other fixed costs. If market conditions are assumed or modelled over the period of plant operation to be analysed, then some conclusions could be drawn about likely plant operating patterns. For example, Table 4 shows some possible annual payments associated with the additional revenue gained by using solvent storage/regeneration for full load operation in the cases analysed in Section 6.2, where 250 cycles is the number of cycles which would occur each year for one cycle on each working day (for a 5 day working week and 50 working weeks per year). However, it should be noted that detailed analysis with a more accurate model of real market behaviour is likely to indicate different net revenues on different days as a result of a number of factors including seasonal variation in electricity prices and price spikes associated with specific events such as particularly high demand for particular periods, e.g. a ‘cold snap’ during a UK winter.

Table 4
Possible annual payments for solvent storage cases with 150% additional regeneration rate

Electricity prices for solvent storage and additional regeneration periods (p/kWh)	Additional net revenue associated with 1 h solvent storage (£)	Annual payment for 250 cycles of solvent storage (£)
3.39/2.39	1202	300,600
3.39/2.89	238	59,400
4.39/2.39	2914	728,600
4.39/2.89	1950	487,400

Detailed technical analysis to allow accurate estimation of capital expenditure to allow maximum CO_2 venting and/or solvent storage is beyond the scope of this initial study. It is also important to remember that estimations of capital expenditure generally include a number of significant simplifications which could lead to significant changes in the results reported when compared to ‘real’ behaviour. For example, estimations of capital expenditure for construction are often location-specific and can vary significantly from year-to-year (and even day-to-day) depending on a number of factors including commodity prices and any bottlenecks developing in supply chains. Also, the work presented here has used assumed future electricity prices

– i.e. it has produced results which are accurate with perfect foresight. However, real markets do not have perfect foresight. Instead, power plant operators must make decisions which are accompanied by a significant risk that the future will not be as their analysis predicts. Thus, analytical techniques which take into account risk premiums and the value of having different options (e.g. those which could be available if CO_2 capture is added, particularly if provision is made to allow solvent storage) should be used if a more accurate model of real market behaviour is to be developed.

8. Conclusions

The methodology and some key results of a preliminary modelling exercise undertaken to provide some indication of the part load performance of pulverised coal-fired power plants with post-combustion capture added using ideal test cases have been presented. CCS schemes consist of a number of different integrated elements and it is important that each of these is considered to an appropriate level of detail for a robust analysis to be carried out. The development of the model reported here has highlighted a number of areas where further work to better understand part load performance and behaviour of power plant could be beneficial. For example, the synchronisation of power plant start-up with capture operations has not yet been fully addressed. Also, changes in power cycle efficiency as a result of variable steam flow and heat integration between the power cycle and CO_2 capture plant must be subjected to more detailed analysis, with conclusions checked against operating experience as demonstration plants are built.

Although the majority of this paper has focussed on steady-state part load performance and possible additional operating modes for power plants with CO_2 capture, a number of other aspects of plant behaviour should contribute to a broad assessment of power plant flexibility. For example, this paper outlined some possible impacts of post-combustion CO_2 capture on some important aspects of power plant transient behaviour. In general, it is expected that post-combustion capture will have little or no effect on power plant start-up times. However, if it is necessary to vent CO_2 during start-up procedures then the cost associated with this could alter plant operators' dispatch decisions, particularly if solvent storage is not available. For load following some potential constraints to plant ramp rates can be identified, including the ramp rates of CO_2 compression systems and interactions with CO_2 transport and storage systems. However, there is also potential for plants with post-combustion capture to have improved load following characteristics since it is expected that the volume of steam abstraction for solvent regeneration can be varied rapidly with an associated change in overall plant output.

The results reported for the ideal cases explored in this paper highlight the potential for post-combustion CO_2 capture at power plants to permit a wider range of different operating modes for plant operators. This could have a number of operational implications, including the possibility of providing additional response and reserve services to the grid. In particular, CO_2 venting could be a useful measure to provide additional capacity to the grid on occasions where the price of electricity (in £/MWh) is significantly higher than the cost of CO_2 emissions (in £/tCO_2). Solvent storage could also provide a range of further options and in particular might allow fossil plant with CCS to compete more effectively for base-load operation, with associated higher load factors, even against plants such as nuclear and some renewables that have lower SRMC but less flexibility. This may offset the additional investment that solvent storage would require, although additional analysis of plant revenues and costs is required. Overall, given the importance of mid-merit operation for many fossil-fired plants (and for grid security) these extra options should be considered in the economic assessment of CCS schemes based on post-combustion CO_2 capture at power plants.

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