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Initial Evaluation of Carbon Capture Plant Flexibility

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Abstract
Fossil fuel generating capacity is currently run at variable load in many power systems to achieve instantaneous demand/supply matching and provide reserve capacity. This paper discusses changes to the flexibility of fossil-fired power stations as a result of adding carbon capture and suggests that these changes could be analysed effectively using a grid simulation technique to identify changes to the cost of secure and reliable electricity generation. The modelling presented here focuses on describing and analysing various modes of operation for post-combustion capture plants. Other capture technologies may also alter plant flexibility and some specific examples are highlighted.

Keywords: plant flexibility, (post-combustion) capture, economic analysis

Introduction

Interconnected electricity systems, often referred to as ‘grids’, connect power generators to electricity users through a transmission system. Grids ideally use the characteristics of technologies operating in them to provide the lowest possible cost of generation while maintaining response and reserve capacity to ensure quantity and quality of supply. Especially for systems with limited or no hydroelectric generation capacity, fossil-fired power plants often play an important role since they can usually be operated flexibly to balance changing demand and provide back-up capacity for intermittent renewable generation and unplanned plant outages. As policy-makers call for increased penetration of intermittent generation in many countries, options for electricity storage are also becoming increasingly important to ensure power quality while minimising constraints on the output of renewable generation available to the grid [1]. This paper presents an approach to plant modelling applied to fossil-fired plant with post combustion capture using amine scrubbing, including the potential use of amine storage to provide an additional form of electricity storage. A series of test cases have been considered, leading to a preliminary economic analysis of plant flexibility. Also, plant models could be combined with grid simulation techniques to develop an overall analysis of the implications of adding carbon capture to fossil-fired power plant.

Post-Combustion Capture Plant using Amine Scrubbing

Capture of carbon dioxide (CO_2) at a fossil-fired power plant by applying post combustion capture using amine scrubbing is a reasonably well developed concept. Although further detailed development and demonstration is required a number of engineering studies have now been completed (e.g. [2]). Figure 1 shows a typical plant layout, with the addition of amine storage tanks to provide further operating options for plant operators. Flue gas from the power plant enters the scrubber where CO_2 is absorbed from the flue gas by an amine-based solvent. The ‘rich’ amine solvent is transferred from the scrubber to the stripper where CO_2 is released by heating with steam abstracted from the power station steam cycle. Finally, the released CO_2 is compressed and transported to safe storage and the ‘lean’ solvent is reused. Most studies concentrate on a single, full load, design case where CO_2 is continually captured with set capture plant efficiency. However, post combustion capture plants could offer a variety of different operating modes to plant

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operators. For example, the volume of steam used for CO_2 release could be varied very quickly, with an associated change in plant net electricity output (and CO_2 capture level), since some or all of the steam normally used for regenerating CO_2 could also remain in the power plant to generate additional electricity if turbines and generators are appropriately sized. It is also technically possible to operate the power plant without CO_2 capture at all for extended periods. Although this would attract carbon emission penalty payments, it could be a valuable facility for providing additional capacity under extreme conditions. If solvent storage tanks are added, an increased electricity output could be obtained for a number of hours without releasing CO_2 to the atmosphere since CO_2 could still be removed from the flue gas in the stripper, but with the energy-intensive CO_2 release process left until later [3].

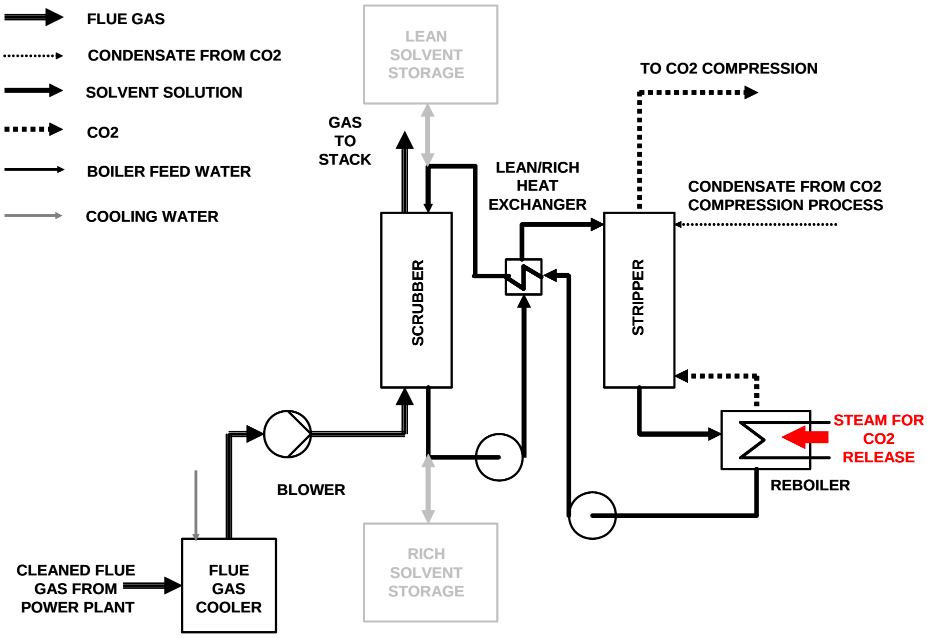

Figure 1 Flow Diagram for Post Combustion Capture using Amine Scrubbing

Initial Modelling of Power Plant with Carbon Capture

To evaluate the potential worth of the plant operating modes such as these it is important to develop a robust plant model. Where power plants operate within electricity markets, a key output is the short run marginal cost of electricity (MCoE), which is the additional cost incurred by the power plant utility by running a plant within its portfolio (i.e. given that it has already been built). In general, MCoE is dominated by fuel cost and, for areas where a CO_2 trading scheme is in operation, a payment for the CO_2 emitted by the plant. For fossil-fired plant operating with post-combustion capture the cost of consumables for amine scrubbing must also be added. In addition, the cost of transport and storage of CO_2 should also be added for some schemes depending on operating and contractual arrangements. The key assumptions applied follow [2] where possible and are given in Table 1. Figure 2 shows input and output parameters for the initial models developed for a coal-fired plant with a supercritical steam cycle and a natural gas-fired combined cycle (NGCC) plant.

It can be assumed that, for a given capture process, the energy 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 capture equipment is fitted. 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 units as power plant efficiency. The efficiency of a power plant fitted with a particular design of capture equipment is always the original plant efficiency less a fixed number of percentage points. Thus a supercritical steam power plant with 44% LHV efficiency might have its efficiency reduced to 35% LHV when an amine post combustion plant is fitted. A sub-critical steam plant with 38% LHV

efficiency would be reduced to 29% LHV efficiency with the same CO_2 capture equipment. Note that the fractional reduction in plant output is not constant, being 20.5% of the output in the first case and 23.7% in the second.

Table 1 Baseline assumptions for Plant Model

Description	**Assumption/Basis**
Plant efficiency curve (no capture) for supercritical coal	Calculations based on [4] and [5]
Plant efficiency curve (no capture) for NGCC	Based on [6]
Plant efficiencies at 100% load (based on LHV)	Supercritical coal: 44% (no capture) and 35% (with capture) NGCC: 55.5% (no capture) and 48.5% (with capture)
Carbon capture plant efficiency	85% of CO_2 produced is captured
CO_2 produced from fuel	Coal: 91kg CO_2/GJ burned and Gas: 58.5kgCO_2/GJ burned (both estimated based on PH4/33 base case)
Fuel price	Coal: $1.5/GJ and Gas: $3/GJ
Carbon price	0 or 20 €/t CO_2 emitted
Illustrative transport/storage price	$10/t CO_2 captured
Cost of variable O&M	Negligible (normal assumption in the literature)
Cost of consumables (for amine scrubbing)	~$3.5/t CO_2 (calculated based on PH4/33)
Currency Conversions	£=€1.4, £=$1.75 and £=100p
Additional lifetime costs associated with turndown	Ignored*

*Note that according to [7] *"[one] component of cost of providing response is associated with increased maintenance and cost of governing equipment. An agreed figure for this cost is £4.5/MW/h and has been used routinely for compensating generators for holding response services."* Where this payment is provided by the network operator to power plant utilities, it seems reasonable to ignore these additional lifetime costs in calculating MCoE associated with operating plant turned down (i.e. below maximum load and, thus, not at design conditions). However, an appropriate approach to considering these costs should be considered, including consideration of similar costs for the capture plant components (including amine scrubbing system and compressors etc).

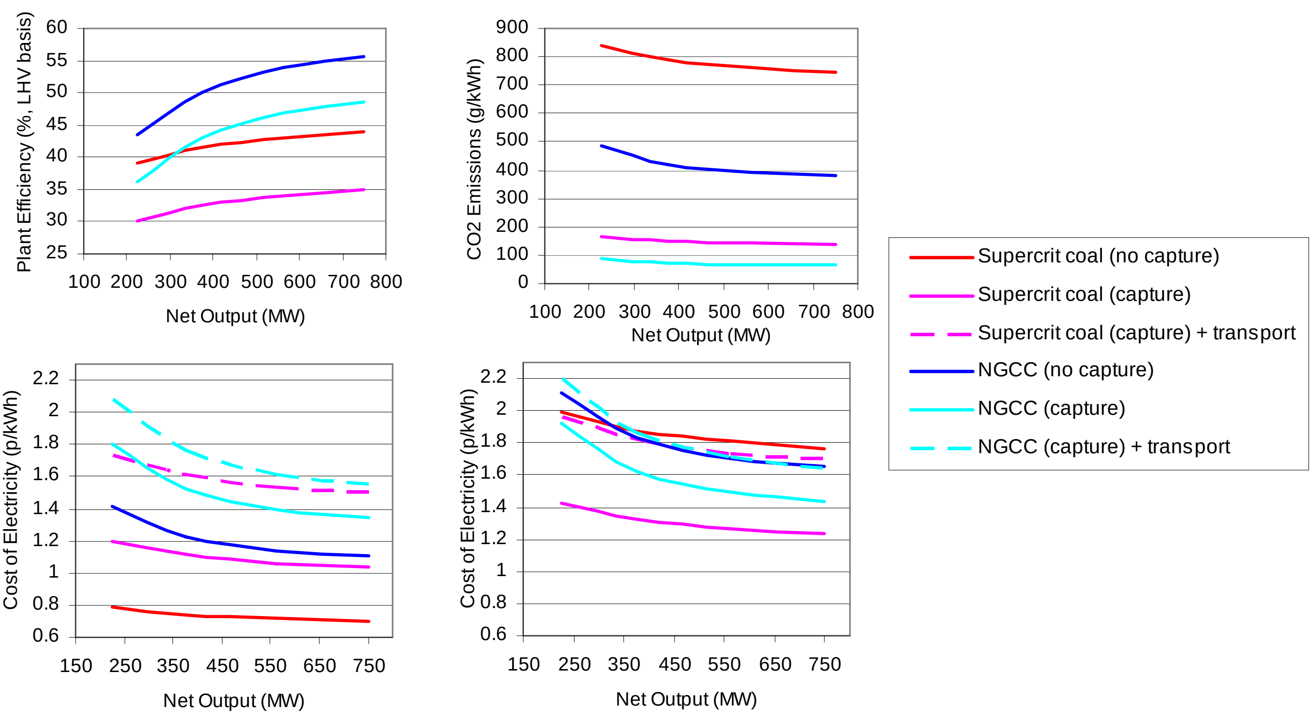

Figure 2 Model Inputs and Outputs for Base Cases (MCoE without carbon payment (left) and with carbon payment (right))

For this initial study it has been assumed that the energy penalty in terms of percentage point reduction in plant efficiency remains constant for all loads. In reality, the number of units of energy required to capture CO_2 might change at part load and there are a number of competing effects to consider. For example, pump and fan loads might not decrease linearly with gas throughput. However, it seems likely that some equipment, such as absorbers, will operate more effectively at part load. Also, the steam abstracted from the steam cycle would have produced less electricity had it remained in the steam cycle. Assuming constant CO_2 compressor efficiency relies on the use of multiple units so that a bank of compressors is available. All compressors in use at any given time would then run at or close to full load. There may also be operational difficulties associated with operating various areas of the plant at low loads. Similarly, it seems likely that this should not present problems at sites where all units are fitted with capture since operations could be arranged so that units which are operational have sufficient throughput to ensure stable operation.

Use of Plant Model to Investigate Plant Flexibility

Various different operational modes may be available to plant operating with post-combustion capture as a result of potential changes to operation of the amine scrubbing system. An initial study considering four cases, as defined in Table 2, has been carried out to gain some quantitative understanding of the associated plant economic performance. These cases do not cover every option but they should give a useful initial understanding of changes to fossil-fired plant characteristics, including MCoE, for a range of potential operating scenarios. Also, CO_2 venting and rich solvent storage both provide useful ancillary services to the network operator since additional power could be delivered to the grid very quickly and for a sustained period of time (or, if necessary, additional power could be absorbed if stored solvent is being regenerated, e.g. to take advantage of higher-than-expected levels of wind generation). Often plant operators will be able to gain additional value from offering such additional services, although this is not quantified here.

Table 2 Baseline assumptions for Plant Model

Case	**Description**
Base Case (no capture)	As above – 750MW plant, maximum net output
Base Case (capture)	As above – 750MW plant, maximum net output with 85% of CO_2 produced captured 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, but also high CO_2 emission.
Store 85% CO_2 as produced	As capture base case, but with capture plant storing rich solvent to be regenerated later (see next case for an example). Thus net MW out increased for all %loads although there is still a small capture energy penalty, but also low CO_2 emission.
Double regeneration	As capture base case, but with double volume of solvent regeneration (e.g. all CO_2 from current production captured with rich solvent regenerated immediately, but rich solvent flow rate doubled by adding solvent from storage tank).

The increased MCoE associated with additional regeneration (as shown in Figure 3) is counteracted by additional net output to generate more profit at other times. The case of double regeneration is given as one example for regeneration of stored rich solvent, but it is likely that a range of operating scenarios for plants with solvent storage could be developed that might provide a better economic case. An appropriate metric to assess the profitability of different cases should be developed. Also, when additional solvent is regenerated, the minimum stable generation of the plant is effectively reduced. This could be useful at times of low demand since more intermittent generation could be included on the grid without compromising security or quality of supply.

Figure 3 reports the MCoE for two test cases (NGCC with no carbon payment and supercritical coal with a €20/tCO_2 emitted carbon payment). MCoE results vary considerably depending on the assumptions used so reasonable sensitively analysis is crucial.

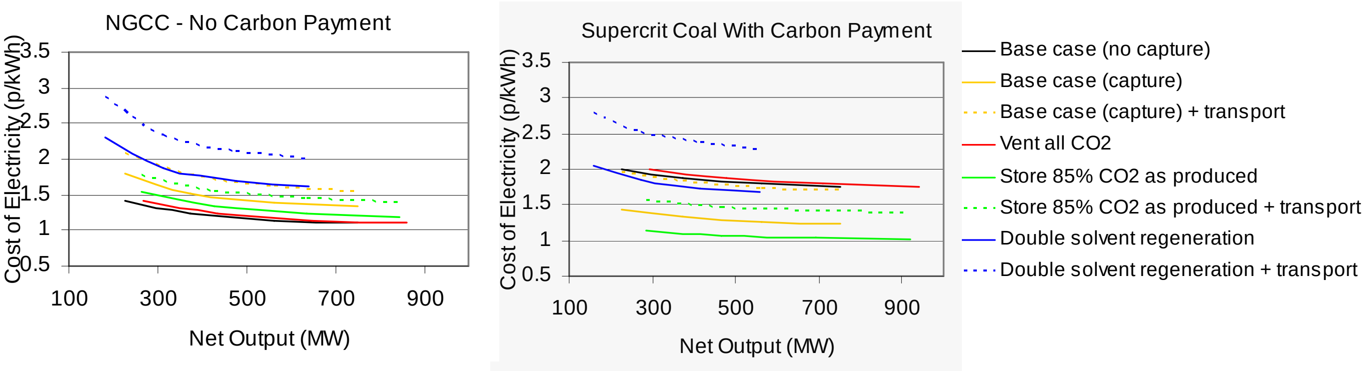

Figure 3 Cost of Electricity for NGCC with no carbon payment (left) and Supercritical Coal with €20/tCO_2 emitted payment (right)

Other Flexible Options for Various Capture Plant

Detailed plant models for pre-combustion (and other) capture technologies have not yet been developed. It seems likely that they will exhibit less flexibility than post-combustion capture plant due to differing operating characteristics for these processes. For example, according to [8] over half of the energy penalty associated with IGCC-based pre-combustion capture is associated with the shift reaction and related impacts which are integral to the plant operation and so cannot be avoided. However, another key characteristic of pre-combustion capture plants is that the shift reaction produces hydrogen which is used for electricity generation and so might also be connected to a local hydrogen network. This would allow for more flexible operation since the plant could supply the network at times of low electricity demand and, potentially, receive hydrogen from that network to make up any shortage in hydrogen supply from on-site production facilities.

It is also worth noting some potential benefits that could be associated with exploiting the potential for switching some fuel supply at a pulverised coal-fired power plant to biomass, including at plants where carbon capture is operated. Since the typical efficiencies of biomass-only and coal-fired plant are approximately 35% and 45% respectively (based on LHV using best current technology) co-fired biomass can provide up to an additional 30% output per unit of biomass input compared to biomass-only plant. Also, plants that co-combust biomass with coal can be much more flexible in accommodating any variations in supply by changing the volume of coal combusted, thus helping to stabilise biomass prices, independent of gluts or shortages in supply. Finally, it is also interesting to note that when carbon capture is combined with biomass combustion there should be a net reduction of CO_2 from the atmosphere since biomass removed CO_2 from the atmosphere as it grows and most of this CO_2 will not return to the atmosphere if carbon capture is used when it is burned.

Further Analysis of Provision of Reserve by Carbon Capture Plant

One of the key distinguishing features of the electricity system is that the balance between demand and supply must be maintained at all times. Demand is not currently controllable in most grids, so this balancing must be achieved using the generation system. Any changes in demand must be met by almost instantaneous changes in generation. Also, balancing unpredicted changes in demand and generation availabilities requires various forms of generation reserve, covering time frames from seconds to hours and days. Reserve capacity in the time scale from a few minutes to several hours, is generally provided by part-loaded synchronised plant, such as fossil-fired power stations.

Figure 2 shows that these thermal units operate less efficiently when part-loaded and consequently MCoE and CO_2 emissions increase. This paper has suggested several options for carbon capture plant to provide additional benefits to the system. For example, switching off CO_2 capture or using amine storage allows increased plant output within a reasonable timescale to provide this standing reserve requirement. Although venting of CO_2 would increase CO_2 emissions, the relatively low frequency of events requiring the use of available reserve capacity suggests that the provision of standing reserve by carbon capture plant that reduces the amount of synchronized reserve provided by part loaded plant, could bring additional cost savings and overall reductions in CO_2 emissions. As discussed previously, using amine storage should also provide various ancillary services to the grid. Quantification of these benefits, which will become increasingly important as more intermittent renewables are introduced, to understand the economic performance of fossil-fired power plants where carbon capture is added is an important area for further work. Accurate analysis will require an understanding of grid operation which cannot be assessed using traditional steady-state economic analysis. Thus, comprehensive grid simulation studies should be conducted to evaluate economic and CO_2 performance of the provision of reserve by carbon capture plants allowing improved capture plant optimisation at the design stage.

Conclusion

This paper describes a plant modelling technique that has been applied to provide an initial analysis of plant flexibility options for post-combustion plant using amine scrubbing. This model should provide a useful basis for further work to consider particular operating patterns to provide maximum value to the electricity grid (both technically and economically) as well as improving individual plant economics. In particular, it is suggested that this model could be used within a grid simulation to provide a whole system analysis which identifies optimum system performance while ensuring that security and quality of supply are not compromised. Other technologies could also provide flexible operation at fossil-fired plants and some options have been highlighted.

Acknowledgements

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