Potential for Synergy Between Renewables and Carbon Capture and Storage

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Abstract

In recent years, increasing concerns have been raised about global emissions of carbon dioxide which could lead to dangerous climate change. A significant proportion of these emissions have been generated by the burning of fossil fuels for electrical power generation and various methods have been proposed to reduce them. In many countries increased use of renewable energy, often including intermittent sources such as wind, has been strongly encouraged by policy makers. However, it is clear that they still require development and support. In addition, carbon capture and storage (CCS) technologies have now been identified as potentially feasible options to significantly reduce carbon dioxide emissions at fossil-fired power stations. This paper explores the potential for synergy between these families of technologies. In particular, it discusses the roles of different plant in the generation mix and suggests that the use of flexible plant, such as fossil-fired plants, could be key in allowing successful use of significant penetrations of intermittent technologies. It suggests various modes of flexible operation that could be possible for fossil-fired plant with carbon capture and presents an initial model to quantify the performance of capture plants. Suitable methods for further analysis are discussed. It is also important to realise that some renewable technologies are not intermittent and a portfolio of technologies must be developed. Thus, potential synergies and conflicts with these technologies should also be identified and the particular example of biomass co-firing at pulverised coal-fired plant is given.

1. Introduction

Throughout the world, industrialised countries have interconnected electricity systems, often known as grids, which connect a range of power generators to electricity users through a transmission system. All grids exploit the inherent strengths of the various technologies operating in them to provide the lowest possible cost of generation whilst ensuring response and reserve capacity are available to maintain the quantity and quality of supply. Fossil-fired power plants often play an important role in these systems since they are inherently flexible so can be used to balance changing demand and provide back-up capacity for intermittent renewable generation.

Increasing concern over the impact of carbon dioxide (CO_2) emissions on the atmosphere is leading to significant changes in the technology mix used for electricity generation. For example, many policy makers are providing encouragement for various forms of generation using renewable energy sources and it has been suggested that carbon capture and storage (CCS) technology could be applied to fossil fuel-fired generation leading to significantly reduced emissions. The characteristics of capture plants that could be implemented at power stations as part of CCS schemes could be important in shaping the electricity generation mix in the short to medium term since the availability of flexible fossil-fired plants is likely to be important to provide the grid conditions necessary for maximum penetration of intermittent renewable sources currently under development. In addition, other synergies and conflicts between the portfolio of renewable technologies and various capture plant options should be considered.

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This paper discusses preliminary work to establish important technical and economic issues related to the flexibility offered by fossil-fired power stations and some potential changes as a result of adding carbon capture. Understanding the technical characteristics of power plant with capture is crucial in determining what roles such plants could play on the grid, allowing potential synergies and conflicts between capture plants and renewables to be identified. In particular, the potential for flexible fossil-fired power plants to support increased penetration of electricity generation using intermittent renewable sources in the short to medium term is examined and likely changes to fossil-fired plant flexibility resulting from the use of carbon capture are outlined. It is also important to note that a portfolio of renewable options are under development and these other technologies should not be ignored in considering the impacts of carbon capture plants. For example, there are specific opportunities to use carbon capture with biomass combustion for power generation, particularly at plants where biomass is co-fired with pulverised coal. Initial modelling to underpin economic analysis of the various options for flexible operation of fossil-fired plant has been conducted and the availability of various economic modelling methods to use this information in a wider analysis is discussed.

2. Electricity Grids

Before discussing synergies between different electricity generating technologies, it is first important to explore the environment within which they operate. This paper will focus on synergies between renewables and carbon capture plant in an open electricity market. Thus, the following section will provide a brief review of typical roles for thermal plant, such as those that could operate with carbon capture, in an interconnected grid and some particular issues associated with the addition of renewable energy sources, focussing on intermittent sources. An introduction to electricity storage and demand side response in this context is also provided.

2.1 Typical Plant Roles for Thermal Plant

The detailed operation and behaviour of real electricity markets is complex and will not be discussed in detail here. However, an overview of the underlying principles of a perfect market is useful. Electricity networks should operate on the principle of a merit order which is well established in the literature (e.g. [1]). According to this principle, the decision to determine which plant will operate will be based on the short run marginal cost (SRMC) of generation. The SRMC contains only those costs which will be incurred in addition to fixed costs if a plant is actually used to generate electricity. Therefore, it does not include capital costs or fixed operation and maintenance (O&M) costs. Plants with the lowest SRMC should operate in preference to those with higher costs and this defines a merit order with the lowest cost plants highest in that order. The selling price of electricity should be set by the marginal generator, that is the most expensive plant that is required so that the demand can be fully met.

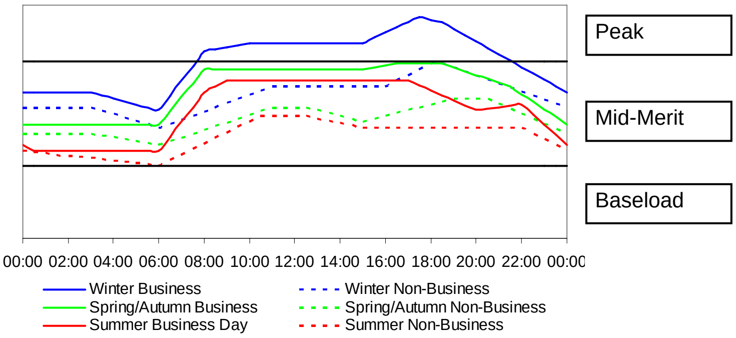

Figure 1 Typical Operating Profiles for an Electricity Grid[2]

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[2] Demand profiles based on [2] and peak assumed to be >80% of peak load based on operating data in [3]

Figure 1 shows typical operating profiles for different categories of day and classifies the capacity used to meet demand as baseload, mid-merit and peak. The highest merit plants should operate as baseload and would be expected to run whenever they are available. By definition, these plants will have low fuel and variable O&M costs. In general, there will be a trade-off between this low SRMC and the capital cost of the plant. Nuclear power plants are typical examples of baseload plants and are rarely seen operating as mid-merit or peak plant. Most renewable sources will also have low SRMC in terms of fuel and variable O&M costs so would be expected to be relatively high in the merit order. However, there is some debate over whether they can be considered to be a reliable contributor to baseload generation (see Section 2.2).

The majority of power plants are mid-merit and their operating patterns vary according to a number of factors including the cost of fuel, in particular the difference in cost between different fuels, and the demand pattern. Mid-merit plants tend to be fossil-fired plant that have higher variable costs and lower capital costs than baseload plants. They will also provide the network with a number of ancillary services that ensure the security and quality of supply. These are discussed in the literature (e.g. [3]) and include provision of response and reserve capacity to ensure that generation matches varying demand. This flexibility is also required to accommodate any changes in supply, for example as a result of planned or unplanned outages.

Low merit, peak plant are used infrequently so require low capital expenditure to be a viable economic option. In general, they will have high SRMC leading to high electricity costs to meet demand at times when they are required. They will also tend to be highly flexible and, hence, able to provide a rapid response in the event of unforeseen circumstances requiring rapid provision of additional generating capacity. Typical examples are open cycle gas turbine plant, oil-fired plant and hydro pumped storage. It should also be noted that most networks will contain more generating capacity than is required to meet the maximum expected load. This provision accounts for the possibility that some plants may be unavailable to meet demand when required and is important to ensure security of supply. However, it also implies that some plants must be maintained in working order, requiring appropriate expenditure, although they will not be used frequently, if at all.

2.2 Renewable Intermittency, Capacity Credit and Curtailment

The previous section focussed on thermal plant operating in an interconnected grid. However, in many countries increasing volumes of renewable capacity are being introduced and much of this is intermittent generation that cannot be expected to be available at all times. Although there is the possibility of unplanned outages for other conventional plant, the introduction of significant capacity which is likely to be unavailable much more frequently can be challenging for network operators and the implications are a cause of significant discussion in the literature.

Often discussions of renewable intermittency focus on establishing a capacity factor which is designed to quantify how much conventional generation is replaced by the introduction of a certain capacity of renewable generation. The various arguments in the literature will not be revisited here, but two recent reviews which may be useful for the interested reader are [4] and [5].

For the purposes of this paper, one key conclusion is that the capacity credit associated with intermittent generation is variable and depends on a number of factors including the generating technologies chosen, their geographic distribution and the level of penetration of intermittent sources. For example, [6] suggests that the “feasible penetration level” for wind could vary from 4 to 50% and identifies a variety of factors that determine this. For the purposes of this study, one that is particularly relevant is the generation mix. A greater proportion of generation can come from intermittent sources, which are difficult to control, if flexible plant are operating alongside them, thus providing the network operator with options to maintain security and quality of supply. Denmark is often used as an example for successful introduction for high penetrations of wind into the energy mix and also shows the importance of this network flexibility since it makes significant use of Norwegian hydro to ensure supply matches demand [2]. It is also important to realise that where sufficient flexible generation is not available grid operators will not normally allow intermittent sources to provide electricity to the grid even if they seem to provide a lower SRMC than the current marginal generator.

2.3 Electricity Storage and Hydrogen Economy

Although the provision of flexible plant to ensure reliable matching of supply and demand is one option to support increased penetration of intermittent renewable generation, it is not the only option. Electricity storage could also have an important contribution to make in smoothing out intermittent output and allowing renewable electricity to be used even if it is not required for use at the time when it is generated. For example, when excess electricity is generated, a storage scheme can be charged with energy that would otherwise be wasted. The scheme can then discharge this energy at a time when demand is higher or the availability of intermittent resources is reduced. Analysis of the value of storage schemes in various applications can be found in the literature for various cases (e.g. [7], [8]).

A detailed description of storage technologies and their optimum uses is beyond the scope of this paper. However, [9], [10] and [11] provide useful reviews for the interested reader. For the purposes of this paper it is important to note that storage technologies can operate on different timescales. Some operate on short timescales (e.g. minutes and sometimes second) to improve grid control providing services including stabilisation and smoothing, whereas others operate over longer timescales helping to balance load and generation for example by levelling load. Section 3.2 will introduce possible storage options related to carbon capture technologies that could be considered alongside the longer timescale technologies discussed here. This increased range of options may be important since it seems that the options currently available to operate storage synergistically with renewables are limited. For example, [12] suggests that *"compressed air energy storage (CAES) and pumped hydro are the only storage technologies that offer sufficiently low storage-specific capital costs suitable for use in conjunction with large wind farms."*

It is also interesting to note the potential introduction of hydrogen as an energy vector forming the basis for a hydrogen economy. This could have wide-ranging implications across most, if not all, energy sectors but one potential implication would be further options for using renewable energy, thus providing another use for renewable energy possibly including storage schemes. [13] provides an overview of relevant technology concentrating on potential for hydrogen production from methane, possibly combined with CCS, and wind, but also identifying a range of other options.

2.4 Demand Side Measures

Finally, although this paper will concentrate on discussing electricity generation, it is also important to remember that demand need not be entirely inflexible. An alternative to altering generation to match supply and demand is to change demand. For example, in February 2006 the US Department of Energy issued a detailed report discussing various mechanisms that can be used to encourage or control demand response to changes in electricity generation [14].

In general, demand response can be split into two categories. Price-demand response encourages customers to use less electricity when prices are high by using pricing methods that accurately represent the value and cost of electricity. This should reduce the peak required generating capacity. Incentive-based demand response could be viewed as a stronger mechanism and involves direct payment of users by the system operator to reduce load if there are grid reliability problems or high prices. Thus, in some ways, it is very similar to the ancillary services provided by mid-merit generating plant.

3. Carbon Capture and Storage in the Energy Mix

Having summarised some key characteristics of the generation mix, the role of different carbon capture technologies within the mix can be identified and discussed. This section introduces the key carbon capture technologies available for near-term implementation, highlighting their likely operating characteristics. In particular, different modes of plant flexibility are discussed and resulting potential synergies with renewable electricity generation are identified.

3.1 Key Technologies

Although carbon capture and storage has only recently begun to receive significant attention from policy makers as a useful technology to be considered in the electricity generating mix, scientists and engineers have been developing schemes for some time. A recent special report by the Intergovernmental Panel on Climate Change [15] provides a useful introduction to the wide range of technologies that are at various stages of development, although it should be noted that the field is developing rapidly so it is likely that certain elements will have developed significantly since its publication, including cost estimates. Figure 2 provides a schematic representation of the capture processes that are likely to be dominant for some time.

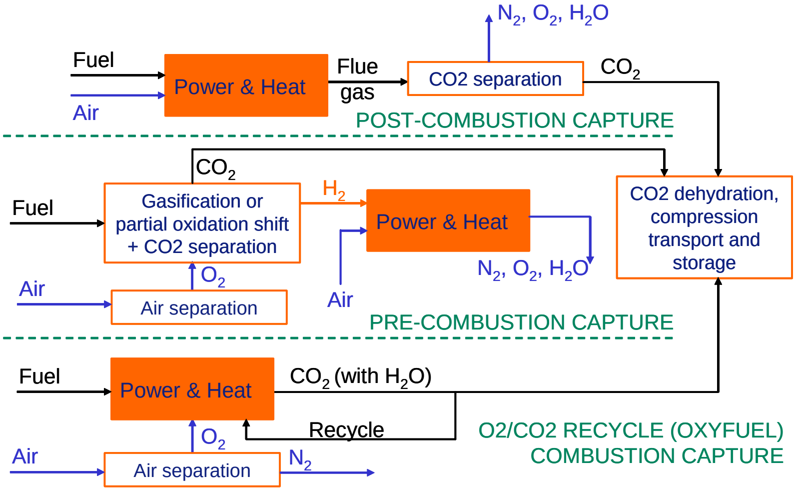

Figure 2 Schematic Diagrams of Carbon Capture Processes[3]

Unlike pre-combustion and oxyfuel capture, carbon capture using post-combustion capture does not require any fundamental changes to the combustion process. Thus, a power plant with post-combustion capture can be viewed as a slight modification to a ‘normal’ fossil-fired plant, for example, using pulverised coal or natural gas combined cycle (NGCC). Following combustion the flue (waste) gas, which contains CO_2, is transferred to the capture plant and, for coal-fired plants treated to remove sulphur compounds using an appropriate flue gas desulphurisation technique. Typically, ~85% of the CO_2 in the flue gas is then removed from the flue gas by absorption into a solvent in a chemical cleaning process. Finally, the flue gas is vented to atmosphere and the CO_2 is removed from the solvent by heating, compressed and dried for transport to safe geological storage. The second stage of the capture process (known as solvent regeneration) and, to a lesser extent CO_2 compression, is energy intensive so has an associated energy penalty leading to reduced power plant efficiency.

At pre-combustion capture plant, the combustion process is altered and fossil fuel input is converted to hydrogen and CO_2 rather than being burned directly in air. This chemical process requires oxygen which must be separated from air in an energy intensive process which leads to a reduction in plant efficiency. The produced CO_2 stream is then treated appropriately to allow CO_2 to be transported for safe storage with the hydrogen burned in a combined cycle plant to produce electricity.

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[3] After [16]

Oxyfuel plants are a natural progression from post-combustion capture plants, but include a fundamental change in combustion with fuel burned in oxygen rather than air. Again, an energy intensive air separation plant will be required to produce oxygen with an associated efficiency penalty. Oxyfuel combustion is significantly more complex than combustion in air applied at power plants using post combustion capture and requires some of the waste gas from the combustion process to be recycled to reduce temperatures so that they are acceptable to meet material constraints. However, the waste gas stream will contain a significantly higher proportion of CO_2 than is possible with air combustion and this avoids the need for a solvent based separation process before compression and drying for transport to safe storage.

Although the carbon capture methods shown in Figure 2 clearly adopt different approaches, they all have the basic aim of altering the processes at a fossil-fired power plant so that CO_2 is produced in a separate stream that can be transported to safe storage. Pre-combustion and post-combustion technology is now ready for full scale demonstration and implementation (e.g. [17], [18]) although, as with all new technology, there is still some work required to establish fully commercial applications. Oxyfuel is slightly less well developed so will not be discussed in detail in this paper.

It is also important to note that carbon capture can be retrofitted to some, but not all, existing power plants depending on a range of factors including the availability of sufficient space to add the additional equipment required for carbon capture and access to an appropriate storage site. This also suggests that it is important that the design studies for new-build plants should consider the possibility of adding capture at a later stage since, although carbon capture technology is not sufficiently developed to be applied to all fossil-fired plants now, it seems likely that it could be applied well before the end of the 40-year lifetime of an average plant. This could provide an important contribution to reducing global CO_2 emissions and can lead to the building of 'capture-ready' plants. A more detailed discussion using the example of gasification for pre-combustion capture is given in [19].

3.2 Impact of CCS on Fossil-Fired Plant Roles and Flexibility

Fossil-fired plant can fulfil a number of different roles within electricity markets. Clearly the addition of carbon capture to these plants will have some effect on their performance and it is important to understand what these impacts are. This allows synergies or conflicts with renewable energy use to be identified. Some changes to fossil-fired plant behaviour with capture added seem likely to apply to all cases, whereas others are only relevant to specific technologies.

Adding carbon capture to fossil-fired power plant is probably the only method that will allow continued use of large volumes of fossil fuels for electricity generation in a world where CO_2 emissions are capped in reaction to concerns about dangerous climate change. Thus, at the most basic level, carbon capture radically alter the potential composition of the energy mix, simply by allowing continued provision of flexible electricity generation using fossil fuels. Although fossil-fired plants are not likely to undercut nuclear power plants in terms of SRMC it should be noted that it is technically possible for them to run continuously to provide a flexible baseload. This could allow an increased penetration of intermittent renewable resources even during times of low demand.

It also seems likely that adding capture to power plant could provide utilities and the network operator with an alternative provision for meeting peak power requirements. Since carbon capture requires energy intensive processes that reduce plant efficiency and, hence, plant capacity. However, at times of high demand it should be technically possible to stop carbon capture and CO_2 compression for transport. Although, this would result in a large emission of CO_2 to atmosphere it would also increase plant capacity due to an improvement in plant efficiency. As discussed above, different capture processes have energy penalties associated with different parts of the generation process so the recoverable output varies between plants. For example, at a post-combustion capture plant it is expected that almost all of the energy penalty associated with capture could be avoided leading to a potential increase in output of over 25% for a post-combustion plant at a coal-fired power station using a supercritical steam cycle. This is significantly higher than the ~10% change that might be expected at a coal gasification plant with pre-combustion capture since the shift reaction and oxygen production from air separation are integral aspects of the electricity generation process.

It may also be possible to provide further improvements in fossil-fired plant flexibility with post combustion capture if storage tanks are provided within the capture plant, as shown in Figure 3, to allow solvent storage leading to some flexibility in determining when the energy penalty for the capture process is applied to the power plant output.

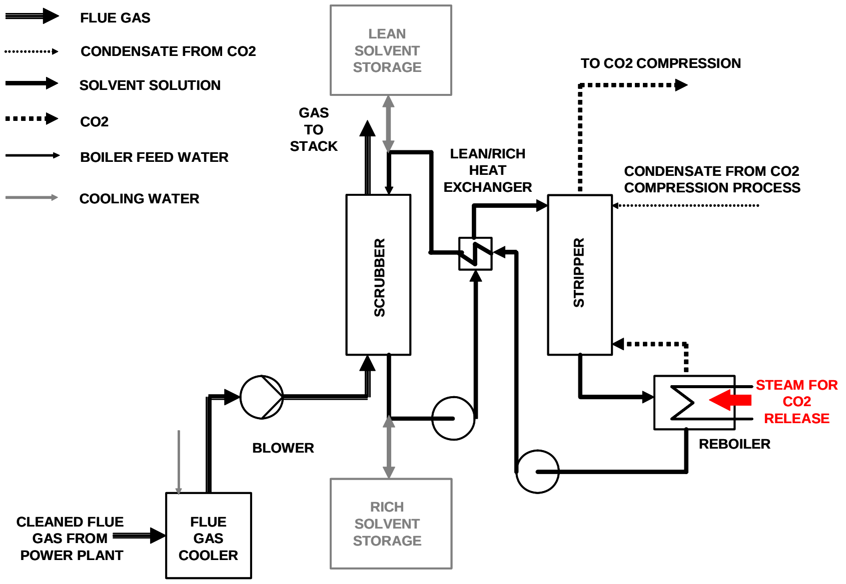

Figure 3 Schematic Diagram of Post Combustion Capture Process

The post combustion capture processes is split into two phases. In the scrubber, CO_2 is transferred from the flue gas to the solvent in a process which will lead to a small energy penalty leading to a drop in power plant efficiency of no more than 1-2% points. In the second phase, steam that could otherwise be used for electricity generation is diverted from the power plant to the capture plant to release CO_2 from the solvent. CO_2 is then compressed and dried before transport to safe storage. The energy penalty associated with this second phase is much more significant, and can be as much as a 5% point drop associated with solvent regeneration and a further 3% point drop for compression [20]. However, when solvent storage tanks are added, the second phase can be delayed thus allowing plant output to increase to approximately the same value as for the case of venting to CO_2 to the atmosphere described above but without an associated increase in plant CO_2 emissions.

The length of time that this additional output could be maintained for would depend on the capacity of the storage tanks, although if the storage tanks became full then the plant could then switch to venting CO_2. In fact, it seems likely that solvent storage could serve different roles depending on the position of the plant within the merit order. For baseload plant, storage tanks could be provided to allow solvent storage throughout the peak day period allowing the plant to gain maximum benefit from high electricity price. The storage tanks could then be emptied overnight when lower loads (and hence lower electricity prices) were on the system. This would lead to a corresponding increase in the energy penalty associated with the capture plant and hence output available for sale. However, this might be beneficial for renewable generation since this would effectively reduce the minimum output required for the plant to operate stably. Hence, the capture plant would act like a storage scheme that was charging overnight and there would be additional capacity available for intermittent renewable generation without compromising system security.

For mid-merit plant, it is likely that solvent storage could allow improved provision of ancillary services since the output from the plant could be varied more rapidly in this case than with other load following techniques. Steam that is used for solvent regeneration in the capture plant could also be used to generate additional electricity if it were not abstracted from the steam cycle. Thus, power plant output can be varied as rapidly as the valve controlling steam flow can be operated (assuming that no uncontrollable transients are associated with the process). It should also be noted that as well as providing a potentially large swing in output power, this changed output could be available for a relatively long period of time, allowing the mismatch between generation and demand to be resolved by some other method before CO_2 venting became necessary. Provision of this kind of response is likely to be very important for successful implementation of large penetrations of intermittent renewables until a wide portfolio of other reliable technologies with complimentary characteristics becomes available.

Finally, although plants with pre-combustion capture are unlikely to provide improve ancillary services using the methods discussed above, they could play an important role in the development of the hydrogen economy [21]. Although, it has been assumed that the production of hydrogen must be coupled to electricity generation, this need not be true if the plant participates in a local hydrogen network. In this case, hydrogen produced by other plants (or generated at other times and stored on site) could be used to generate electricity but with a significantly reduced energy penalty. At times of low demand, any hydrogen produced that was not required for electricity generation could be exported into the local network for other use in other applications (or stored for later use in periods of higher demand). This option is not explored further in this paper but, if it proved to be technically feasible, could be subjected to a comparable analysis.

4. Initial Model of Carbon Capture Plant

The qualitative discussion in the previous sections is important to develop a reasonable understanding of the potential synergies between renewables and carbon capture plants. However, in order to fully understand their potential for implementation, a robust quantitative description is required as a basis for further analysis. This section presents a preliminary model describing carbon capture plant, using post-combustion capture as an example. Early results from the model are reported and the validity of the simplifying assumptions used is discussed and areas for further work are identified.

4.1 Model Description and Results

A power plant with CO_2 capture produces less electricity per unit of fuel than the corresponding power plant without capture. It can be assumed that, for a given capture process, the energy required per unit of CO_2captured, 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 so is similar to a power plant efficiency. Thus, 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 related to that capture process. For example, the supercritical steam power plant modelled here has a 44% LHV efficiency without capture which might have its efficiency reduced to 35% LHV when an amine post combustion plant is fitted [20]. 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.

When power plants operate at part load, their efficiency is reduced due to a range of well-established factors including the reduced efficiency of turbines generating electricity when operating off-design. However, given that capture plant efficiency can be considered to be independent of non-capture power plant efficiency it can be assumed that energy penalty for capture at part load remains constant in terms of %LHV efficiency points at all loads. For part load operation this is a simplifying approximation since it is possible that the energy required per unit of CO_2 captured might change. For example, additional energy per unit CO_2 might be required since pump and fan loads might not reduce linearly with reduced gas throughput and the electricity used for these systems will come from the power plant, which will be operating less efficiently at part load. However, it is also possible that less energy per unit CO_2 will be required at part load since amine solvents might be more effective as they should have more time to reach maximum CO_2 concentration in the scrubbing unit. In addition, lower temperature drops should occur in the heat exchangers involved in the scrubbing process and the electrical output that would have been obtained from the steam used for solvent regeneration is reduced since the turbine will be operating less efficiently. Ultimately, experience operating units at part load is required to fully understand how these conflicting processes interact to determine the energy requirement for the capture process at various loads.

The plant models outlined here are designed to report the SRMC of generation for power plant and, where possible, use data for capture plant that were developed as part of a detailed engineering study undertaken by the IEA Greenhouse Gas R&D Programme [20] are used to form the baseline assumptions given in Table 1.

Table 1 Baseline assumptions for Plant Model

Description	**Assumption/Basis**
Plant efficiency curve (no capture) for supercrit coal	Calculations based on [22] and [23]
Plant efficiency curve (no capture) for NGCC	Based on [24]
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 €/tCO_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 [2] "[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 short run marginal cost of generation associated with operating plant turned down (i.e. below maximum load and, thus, not at design conditions). However, an appropriate approach to considering costs such as these should be considered as further work, including consideration of similar costs for the capture plant components (including amine scrubbing system and compressors etc).

The assumption that the CO_2 compression energy penalty in terms of energy required per unit of CO_2 is only valid for plants where there are multiple units on one site with capture fitted. Although this should be the usual case for carbon capture implementation for a whole plant, it may not be true for any initial demonstration projects applied to one unit at a particular site. Although the efficiency of an individual compressor will reduce at part load, it is expected that a number of banks of compressors will be required to handle plant CO_2 emissions. Thus, compressors could be brought on and off as appropriate so that each individual compressor was operating at or near its design point.

Calculated plant efficiencies, CO_2 emissions and SRMC are plotted for the supercritical coal-fired plant and NGCC plant outlined in Table 1 are plotted in Figure 4. SRMC cost is given with and without an indicative payment for transport and storage. It should be noted that potential transport and storage costs could vary between different schemes [15] and it is also likely that different CCS schemes may take different approaches to apportioning these costs. Cases with no payment for CO_2 and a €20/t CO_2 payment which is of the order of magnitude currently experienced by power plants operating in the EU Emissions Trading Scheme [25] are considered.

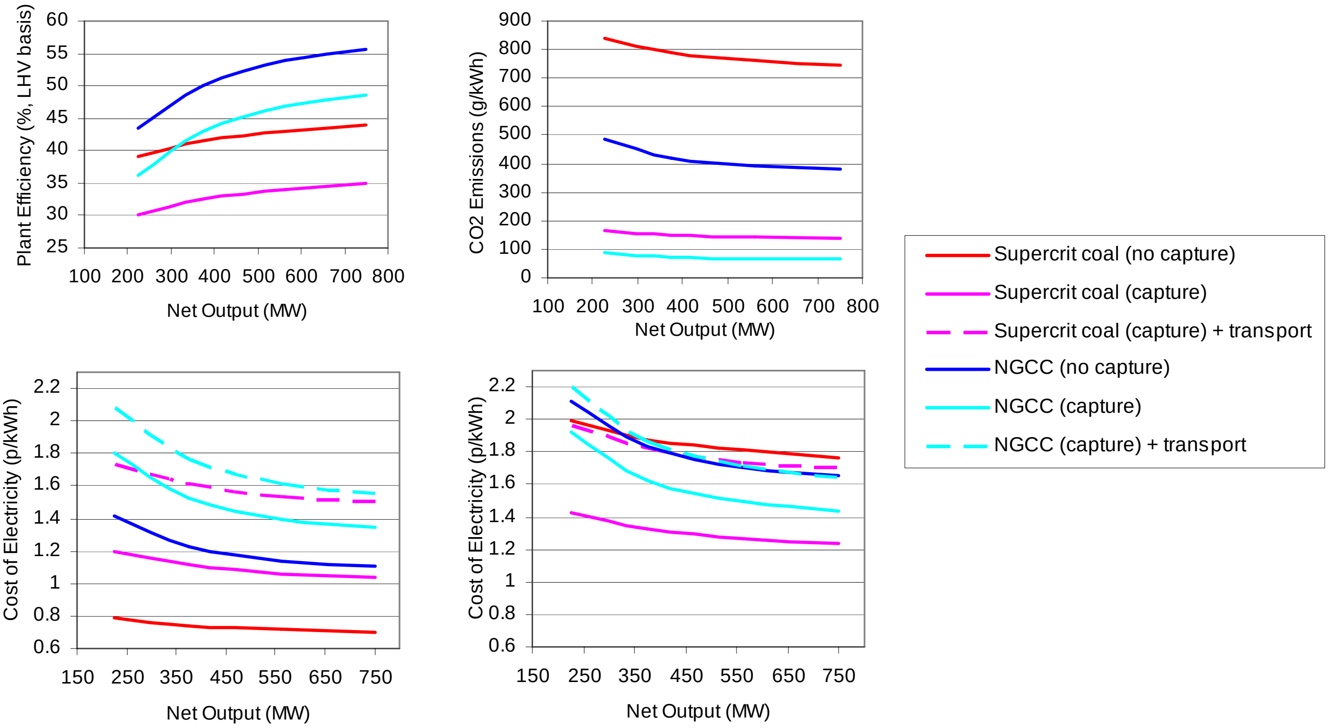

Figure 4 Model Inputs and Outputs for Base Cases

This technique has been applied to various cases, outlined in Table 2, which are designed to simulate the different options suggested in Section 3.2 with results shown in Figure 5. Although these cases do not describe all the available options they should give an initial quantitative understanding of the options discussed. For example, in the case of venting it should be possible to vent only some CO_2 in cases providing some control over the additional output provided by the plant and this may allow CO_2 venting to provide a load following ancillary service. Also, various storage scenarios should be considered requiring a variety of different configurations for additional regeneration of stored solvent.

Table 2 Summary of Various Test Cases

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).

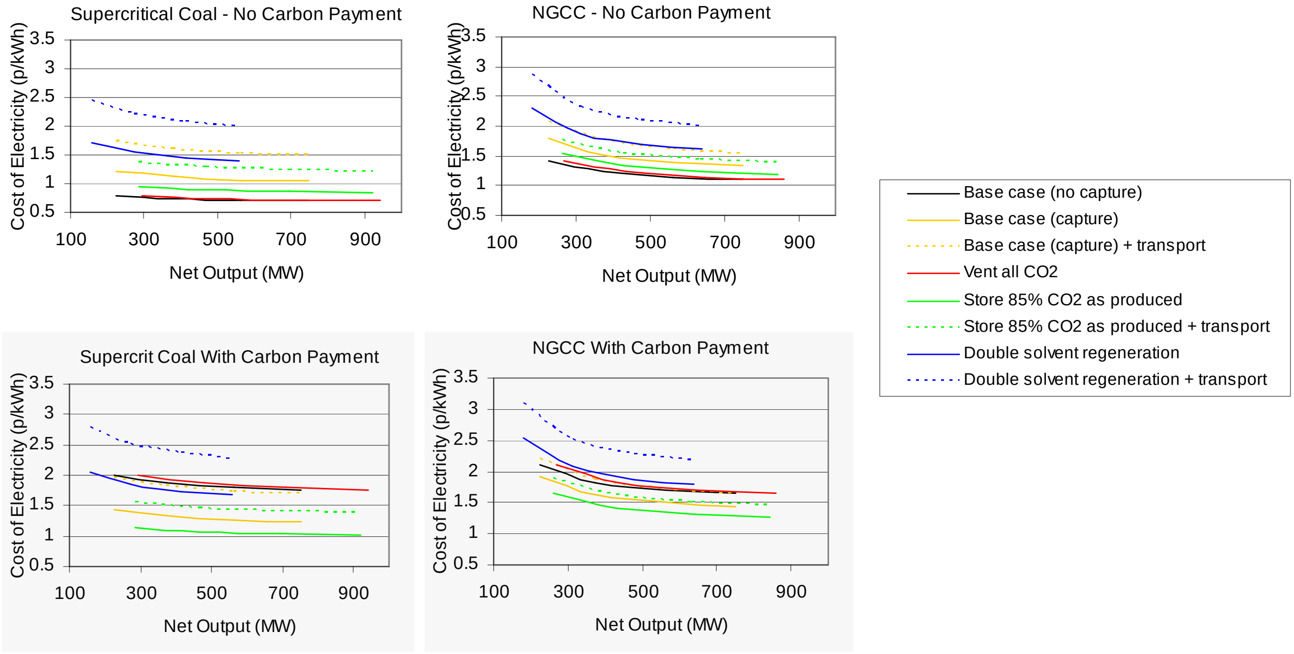

Figure 5 Results for Various Test Cases

4.2 Accuracy of Assumptions and Areas for Further Work

Clearly, the work outlined here is an early model that should be further developed and checked to ensure the robustness of results to be used for further analysis. As well as checking assumptions of capture behaviour and related energy penalty as experience is gained with demonstration plants, it is important to consider likely development in carbon capture technologies themselves. For example, [26] provides an evaluation of potential cost reductions from improved amine-based CO_2 capture systems and [27] explores the use of ammonia compared to amine-based solvents showing that it might have a lower energy penalty. It is also important to consider potential interactions between the capture plant and the associated transport and storage schemes that might restrict which modes of operation can be used since CO_2 output from the plant.

Also, particularly given the sensitivity of the results obtained to carbon price, it is important that appropriate sensitivity analysis for other variables is also considered. This could include quantification of relevant ranges for fuel price and an attempt to quantify possible changes to the energy penalty associated with the capture process. The inclusion of additional lifetime costs associated with running plants at part load should also be considered and it should also be useful to apply this technique to other options, including pre-combustion capture plant and sub-critical coal plant.

5. Economic Assessment of Carbon Capture Options

A detailed economic assessment comparing the various options for carbon capture plant operation suggested above to other options has yet to be carried out. However, some typical techniques for assessment have been reviewed to identify their likely strengths and weaknesses to provide a suitable analysis. In particular, it is important that the assessment methods and criteria chosen are able to effectively analyse the flexible aspects of potential plant operation and also that the different characteristics of various different carbon capture technologies are recognised and treated appropriately.

Various economic modelling techniques are applied to electricity market analysis. They tend to be appropriate to analyse different problems as a result of their own particular characteristics. In general, methods can be classified as macroeconomic, which tend to consider behaviour of particular sectors of the economy rather than particular technologies, and microeconomic models which are based on technology-specific information. The literature also includes a number of papers that attempt to draw together the strengths of both top-down and bottom-up modelling using various methods, including equilibrium models. Clearly, econometric models would not provide a suitable framework to analyse potential synergies between renewables and CCS discussed within this paper since they are not designed to accommodate particular details of specific technologies or their interactions. Thus, it is important to focus on applications of other modelling techniques to identify appropriate methods for assessing the ideas developed in this paper.

In the UK, much of the economic analysis carried out as a basis of determining energy policy in recent years has been based on the MARKAL model ([28], [29]). MARKAL models are based on user-defined technology databases and typically aim to identify the least cost mix of energy use across the economy. However, they are not able to consider technology interactions within the electricity generation mix at the level discussed in this paper. Although appropriate parameters can be added to take account of the generation mix allowed so that security of supply is not compromised, it seems unlikely that the genuine minimum cost of generation can be determined by MARKAL modelling alone since it is not able to consider the characteristics of technologies, and their interactions, in sufficient detail to optimise the plants used or other measures taken.

A small selection of other papers which aim to analyse the use of carbon capture within the electricity mix can be found in the literature (e.g. [30]-[32]). Although these studies provide useful insights, none of these seem to consider the range of power plant performance across different operating loads or provide a suitable framework to understand the detailed interactions between the different technologies operating in the electricity market. Some studies also fail to differentiate effectively between different carbon capture technologies which may also give misleading results.

Thus, it seems that a different analytical framework is required to allow a systematic study of the potential synergies between renewables and carbon capture that have been introduced in this paper. One possibility might be to use a dynamic model of the grid applying the principles of the merit order, alongside appropriate constraints to maintain security and quality of supply [33]. Another possibility might be the application of real options theory. In this case, plant flexibility could be viewed as an option and the analysis would be focussed on identifying the best investments.

Of course, as well as identifying an appropriate analytical technique it is also important to identify relevant parameters that can be interpreted to provide a useful result. It seems likely that analysis should identify costs and value at both plant and system level. At a plant level it is possible that certain system parameters might determine the viability and worth of particular schemes. For example, carbon price and ratio of peak to overnight electricity price are likely to be critical factors in determining whether the capital expenditure required for amine storage could be justified. At a system level, the aim of analysis may be to identify scenarios with the lowest possible cost of electricity generation (i.e. cheapest marginal generator) but while ensuring that security and quality of supply constraints are met.

It is also important to understand which assumptions are made to underpin analysis. For example, this paper has reported SRMC for various options since this is the basis for the merit order that determines plant dispatch. However, it has not included an evaluation of lifecycle costs that may be altered as a result of running plants away from their optimum design point. Also, investment decisions should be based on the expected profit of a project over its lifetime so this would include other considerations such as capital expenditure and fixed O&M costs. In addition, appropriate risk analysis would be required. It is also important to note that determining optimal configurations for analysing options is not trivial. For example, [7] suggests that a full analysis of energy storage schemes requires consideration of *"power to energy relationships of a given storage technology and the corresponding unit marginal cost"*. In the case of amine storage, this could be further complicated since different operating procedures could be applied at the same plant at various points in its lifecycle.

6. Biomass Co-firing and Other Potential Synergies Between CCS and Renewables

This paper has focussed on intermittent renewable generation and synergies with flexible fossil-fired plant using carbon capture to support increased penetration. Of course, not all renewable sources are intermittent and the development of a portfolio of technologies is vital for long term development of electricity networks and markets. Thus, it is also important to consider potential synergies or conflicts in other areas of renewables development.

One particular example is biomass co-firing at pulverised coal-fired power plant. The introduction of carbon capture at coal-fired plant could significantly extend the scope for this activity which would not be possible if coal-fired power plant were not in the electricity mix. In co-firing plants, biomass can be mixed with coal in the current milling system or injected directly into the boiler using a separate system. Co-milling is a lower capital expenditure option, but greater proportions of biomass can be used with direct injection. Although there are a number of operational issues that need to be carefully considered it seems that none of these is insurmountable [34]. Many power plant operating companies view biomass co-firing as a commercially viable implementation of renewable energy, but are sceptical about biomass-only plant [35] and co-firing is now common at pulverised coal plants in some countries. For example, in the UK in 2003/4 there was 158MW installed biomass-only plant and 516MW available from co-fired stations [36]. Thus, biomass co-firing plants provide a valuable opportunity to use biomass for electricity generation that would not otherwise occur. If schemes are properly managed then they can also be useful to develop the infrastructure that is also required for further development of biomass-only plant [37].

Biomass combustion is important since it is a predictable and controllable form of renewable energy as long as appropriate crops can be grown. When biomass grows, it removes CO_2 from the atmosphere. If this is then released during combustion for electricity generation then the whole process is considered to be approximately carbon neutral since the CO_2 removed from the atmosphere will be released. However, if biomass is burned at a plant with carbon capture then there should be a net removal of CO_2 from the atmosphere which might provide a useful mechanism for offsetting emissions from other CO_2 generating activities where emissions cannot be reduced so easily.

As well as considering biomass co-firing as an opportunity to develop biomass-only plants, it is important to note its value as an electricity generating technology in its own right. A typical stand-alone biomass plant would have a capacity of no more than 50MW whereas coal-fired units will often have an output of no less than 500MW. Thus, use of biomass fuel as a small proportion of generation at a co-firing coal plant can use a similar volume of fuel as a stand-alone plant. Also, the efficiency of coal-fired plants is significantly higher than stand-alone biomass plants (approximately 45% and 35% respectively with best available technology), so co-fired biomass could provide up to an additional 30% electricity output per unit of biomass input compared to biomass burned at a biomass-only plant. It can be argued that this represents a significantly improved use of the fuel since it should imply increased CO_2 emissions reductions at reduced cost.

Finally, it is also important to note that plants which co-fire biomass with coal can be much more flexible in accommodating any variations in biomass supply (e.g. due to seasonal variation in availability of crops) than their biomass only counterparts since changes in supply can be balanced by changes to the volume of coal burned. This could lead to an increase in the volume of biomass that can be used for electricity generation since biomass-only plants are likely to be sized so that they could be fully operational at maximum capacity throughout the year, thus reducing their ability to accommodate such changes in availability of biomass. Also, biomass suppliers could be assured more consistent prices for their products, independent of gluts or shortages.

7. Conclusion

As a result of increasing concern over the impacts of CO_2 emissions on the global environment and the potential for dangerous climate, various changes to the technologies used for electrical power generation have started to occur in some countries. In particular, some policy makers have provided significant support for the introduction of renewable energy sources for electricity generation and the potential use of carbon capture and storage at fossil-fired power plants to significantly reduce CO_2 emissions is being seriously considered. This paper discusses the potential for synergy between these two families of technologies highlighting the flexibility of fossil-fired power plants with capture and the importance of the availability of plants with such flexible behaviour in allowing maximum penetration of intermittent renewable sources. An initial model to allow analysis of various options is outlined and the potential application of various analytical techniques to develop an appropriate wider analysis of particular carbon capture characteristics and synergies or conflicts is discussed. It is also important to realise that a portfolio of renewable energy sources should be developed for electricity generation and thus potential synergies and conflicts between carbon capture and these other options should also be considered. In this paper, the particular example of co-firing of biomass at pulverised coal plants is considered.

Acknowledgements

This work is being undertaken within the UK Carbon Capture and Storage Consortium (www.ukccsc.co.uk), funded by the UK TSEC programme, and DTI Cleaner Coal Project 407.

The authors also gratefully acknowledge discussions with various colleagues at Imperial College that have helped to develop their understanding of potential methods for economic assessment of carbon capture flexibility.

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