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CARBON CAPTURE AND STORAGE – IMPLICATIONS FOR CCGT DEVELOPMENT

By

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Carbon Capture and Storage – Implications for CCGT development

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Synopsis

This paper describes the various methods of Carbon Capture and Storage (CCS) applicable to Gas Turbines (GT) and CCGT plant, focusing on the three most advanced technologies: post-combustion chemical capture of CO_2 from GT exhaust; gasification of coal with pre-combustion CO_2 capture followed by combustion of low carbon fuel in a GT; and oxyfuel technology, or combustion of gas with oxygen rather than air. The current status of each technology is described and possible future developments are considered.

The technical issues involved in both CCS equipped new-build thermal plant and retrofit of CCS to existing and future thermal plant are described, including both space requirements and design implications. The meaning of Carbon Capture Ready is discussed and the impacts of the new EU and UK consenting regime for thermal plant are presented.

The impact of the different types of CCS on operation of CCGT and SCGT is discussed.

The cost of power generation from thermal plant fitted with CCS is presented in comparison with other power generation options.

The paper also includes a discussion of possible developments in the future CCS industry, including transportation and storage networks.

1. Introduction

There are many carbon capture technologies currently in development. The three technologies closest to commercialisation which are applicable to gas turbines are post-combustion chemical capture of CO_2 from Combined Cycle Gas Turbine (CCGT) exhaust; gasification of coal with pre-combustion CO_2 capture followed by combustion of low carbon fuel in a CCGT; and oxyfuel technology, or combustion of gas with oxygen rather than air.

2. Post-combustion capture

For post combustion capture of CO_2, the flue gas is cooled and blown into an absorber, in which a chemical solvent that absorbs CO_2 is sprayed into the flue gas. The cleaned flue gas may then be reheated before being released into the atmosphere. The CO2-loaded solvent is reheated in a stripper to release the CO_2. Electricity is required by the process, mainly for blowing the flue gas through the absorber unit, and preparing the CO_2 for transport. Heat is required for releasing the CO_2 from the solvent, and cooling is required for the flue gas, the solvent and the captured CO_2.

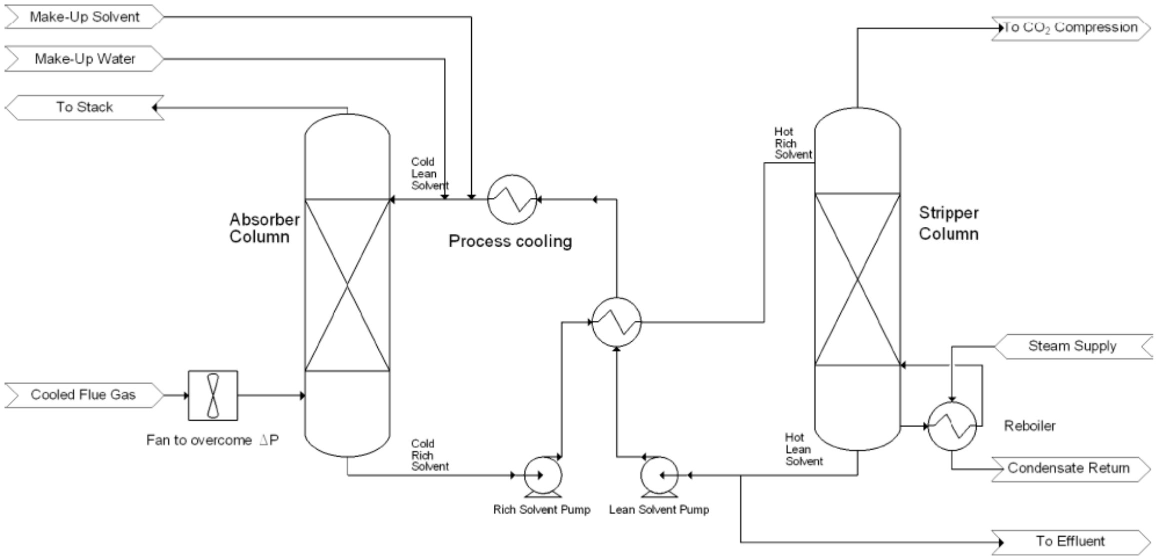

Figure 1: Carbon Capture Process

The most advanced solvents used for post combustion carbon capture are amines, which require the temperature of the flue gas and solvent to be reduced to between 35ºC and 50ºC. Companies offering amine solutions include MHI, Aker, Fluor, HTC Purenergy, ABB Lummus and Cansolv. There are a number of “advanced” or “second generation” amine solvents under development, and other chemical solvents such as ammonia and amino acids are also being offered. Alstom are developing a chilled ammonia process, which requires chilling of the flue gas and solvent to less than 5ºC. Powerspan also offer an ammonia process and Siemens are developing an amino-acid process, both of which will operate at similar temperatures to amine processes. Amine processes are currently more advanced than other chemical solvents. The technical issues relating to post-combustion capture described in this paper largely apply to amine post-combustion capture.

Many engineers think of post-combustion as an easy option, an “add-on,” with the CCGT plant operating as normal, and a capture plant tacked on at the end. In fact there can be varying levels of integration of post-combustion capture and CCGT plant. It is possible to build a capture plant that uses electricity from the grid, steam from a stand-alone boiler and a separate cooling system, but this is far from the most efficient method of operation. More efficient would be to use steam extracted from the steam cycle for heating, and offset the cooling required by the related reduction in condenser cooling. It should also be remembered that dedicated boilers would result in production of more CO_2, which must also be captured.

There are three possibilities for when carbon capture will be applied to CCGT plant. The first is a newbuild CCGT with capture applied from day one, in which case the cycle would most likely be optimised for operation with capture, but would retain the possibility of operation without capture. For post combustion capture this would mean that the steam cycle would be optimised for operation in Combined Heat and Power mode, delivering a large amount of process steam to the capture plant. The capture and power plant would likely share a cooling system and other auxiliary services.

The second possibility is retrofit of capture to a CCGT that was not originally designed as a Carbon Capture Ready (CCR) plant. For post combustion, all of the steam cycle components must be checked to ensure that they can cope with the large steam extraction. The most likely place to extract the steam would be the cold reheat, as the turbine will not have an extraction port. It may not be feasible to convert the steam turbine to deliver the required amount of steam to the capture plant. In this case dedicated boilers would be required to produce the steam required, which is less efficient than using Low Pressure (LP) steam from the steam cycle. These would use more fuel, requiring a larger capture plant. Even if using LP steam is possible, if the plant includes an air cooled condenser, the capture plant cooling system cannot take advantage of the reduction in condenser cooling load.

The third possibility, which is the one that concerns the majority of CCGT designers, owners and operators at present, is a CCGT plant that is built CCR, which will later be retrofitted with carbon capture. The technical issues described in this paper largely apply to retrofit of carbon capture to a CCR gas plant.

A large amount of space is required for the capture, compression or liquefaction and cooling equipment for post combustion capture. There are a number of studies in the public domain relating to the space required for this equipment, including one focusing particularly on CCGT.[1]

If the plant is not integrated, the flue gas exiting the CCGT could be as low as 80°C. With integration, the condensate returning from the capture plant will increase the feedwater temperature, so that the flue gas exit temperature could be as high as 120°C. For Simple Cycle Gas Turbine (SCGT), the turbine exit temperature will be higher still – up to 630°C. Whatever the configuration, the flue gas must be cooled before entry to the absorber. A heat exchanger transferring heat from the flue gas entering the capture process to the cleaned gas exiting the capture process will fulfil most of the cooling requirement, but an additional cooling stage is required, most likely a direct contact water cooler.

The capture process depends on the difference in temperature between the absorber and stripper – the solvent can hold more CO_2 at lower temperatures than at higher temperatures, so the bigger the difference, the more it can capture. For amine solvent, the temperature in the stripper is limited to about 120°C, as above this temperature the solvent can be damaged. Typically the flue gas and solvent are cooled to as low a temperature as is feasible before entering the absorber, as the absorption reaction itself is exothermic. Cooling the flue gas to 35°C could capture more than 90% of the CO_2 in the flue gas. Cooling to 50°C will capture less than 90%. The amount of CO_2 that can be captured is therefore limited by the cooling medium temperature and type of cooling available: once through, recirculating or air cooling.

A large quantity of steam at 120-160°C is required for the stripper, and there is also an intermittent requirement for a small quantity of steam at up to 7 bar for the reclaiming process (cleaning of solvent). This steam can be produced in a dedicated boiler, but it is more efficient to take it from the steam cycle. The steam requirement is about 35%-45% of the steam at the point of extraction, which will have a significant impact on the steam cycle.

To demonstrate that a plant is CCR with the intention of using LP steam from the steam cycle, it must be ensured during design that the steam cycle could cope with this extraction of steam, although as the power plant will initially operate without CCS it will be designed to maximise efficiency in the non-CCS mode. Therefore the CCR preparations should interfere with the steam turbine as little as possible. Assuming a triple pressure reheat cycle, there are three possible sources of steam:

a) Cross-over i.e. Intermediate Pressure (IP) turbine exit / LP turbine induction
b) Extraction port on the IP turbine or LP turbine
c) Cold reheat i.e. High Pressure turbine exit

CCS steam requirements and the type of CCS plant chosen is likely to change between design of the CCR power plant and retrofit of CCS, so an extraction port on the turbine is unlikely to provide steam at the optimum temperature and pressure for the final CCS design. Putting an extraction port on both the cold reheat and crossover would maximise the possibilities for steam pressure and temperature when time comes to retrofit, thereby maximising the possible solvent types and processes, while minimising the impact on the turbine before retrofit.

In addition to reducing steam flow in the turbine, other impacts on the cycle of removing the steam include changes to the low temperature economiser, dearator and reheater. The temperature of the water at the exit of the economiser before entry to dearator will be increased. Unless the dearator pressure is allowed to rise, the dearator may require a partial bypass to prevent venting. This will increase the cooling requirement. Lower steam through the reheater tends to overheating and excessive steam temperatures and so should be considered in the design of the reheater. More capacity is also required in the desuperheater. These impacts should be considered during the design of the steam cycle. These components may need to be replaced during retrofit, if they are not designed with these future requirements in mind.

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[1] Retrofit of CO2 Capture to Natural Gas Combined Cycle Power Plants, IEA Greenhouse Gas R&D Programme, January 2005

For once through cooling systems, the reduction in cooling for the condenser could be used to partially offset the cooling requirements for the capture plant. This will not be possible for an air cooled condenser. For air cooled CCGT plant, additional cooling towers or air coolers will require significant extra land, in addition to of the land for the capture equipment itself. Installing dry cooling towers for the condenser rather than an air cooled condenser would allow the cooling system to share the cooling load of the capture plant and CCGT.

The higher exhaust temperature, lack of steam in the cycle and smaller size of SCGT are disincentives to application of post-combustion capture to SCGT, compared to CCGT.

There are numerous pilot plants in operation using amines for CO_2 capture from flue gases of various types. The largest post-combustion capture project on natural gas is underway in Norway, where Aker have won the EPC contract for a 100,000 tpa plant at the European CO_2 Technology Centre in Mongstad. This is due to be completed in 2011, and will clean flue gas from both a CCGT and a refinery. Full scale capture on a 400 – 500 MW CCGT would be circa 1 Mtpa, 10 times larger than the Mongstad plant.

Modelling implies that the reduction in CCGT plant efficiency due to steam, power and cooling requirements of current Best Available Technology (BAT) post combustion capture is from 57% to 49%. These figures are for an 850MW CCGT plant, with steam extracted from the cold reheat, flue gas cooling using a gas/gas exchanger which reheats the cleaned flue gas, and the capture plant cooling requirement met partly by the reduction in condenser cooling. Many other opportunities for improvement exist, including improved solvents and improvements in auxiliary processes such as solvent cleaning. Chilled ammonia is claimed to have much higher efficiency than amine capture, but it is not yet at commercial scale. A 20MWe pilot plant in West Virginia has recently begun operating using Alstom's chilled ammonia process, but results are not yet available.

Interstage cooling in the absorber and interstage heating in the stripper will improve the efficiency of the cycle. Integration of heating/cooling processes e.g. heating of feedwater through cooling of captured CO_2 also offer the possibility of improving the efficiency of the overall cycle. One promising possibility for CCGT plant is the use of additional duct firing to raise more steam. This improves the capture process efficiency by reducing oxygen content and increasing CO_2 content in the flue gas. It also raises additional steam, meaning there is less of an impact on the LP turbine. As with dedicated boilers however, this does require capture of the additional CO_2 produced, resulting in a larger capture plant.

3. Pre-combustion capture

If a mixture of fuel and CO_2 is in a gaseous state, the CO_2 can be captured before combustion. Because of its higher carbon content, carbon capture is likely to be applied to coal plant sooner than gas plant. Integrated Gasification Combined Cycle (IGCC) plants have been operating since the 1980s, but have been less economically viable than standard coal plant so have not been widely used. Indications are that IGCC with pre-combustion CO_2 capture will be similar in price to pulverised coal plant with post-combustion capture. The advent of CCS therefore represents a large potential market for gas turbines within IGCC plant. It is likely that these plants will be constructed as newbuild IGCC with carbon capture sooner than carbon capture will be retrofitted to gas plant.

In an IGCC plant, coal is gasified and undergoes a shift reaction with steam, resulting in a hydrogen fuel with significant quantities of steam and CO_2. The CO_2 can then be captured prior to burning the hydrogen in a CCGT.

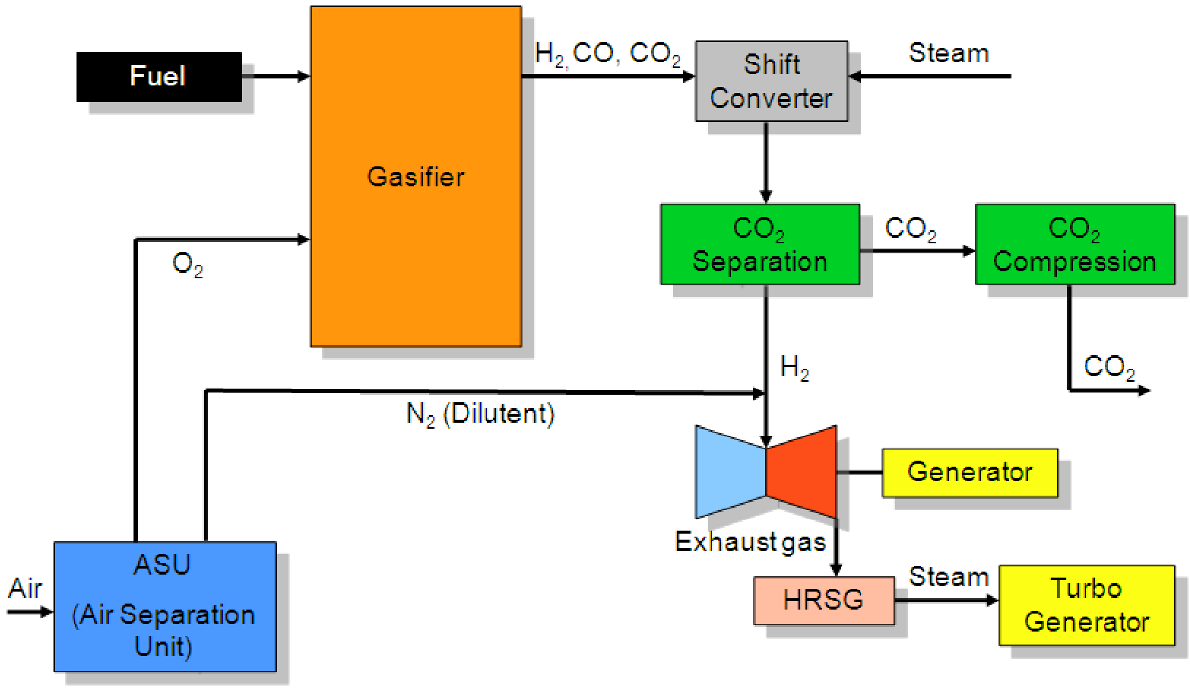

Figure 2: IGCC plant with pre-combustion capture

Gasification is a mature and well understood chemical process for conversion of pulverised coal and oxygen to syngas, a mixture of CO and H_2, with some CO_2. Steam is reacted with this syngas in a shift reaction process to convert the remaining CO to CO_2, producing a mixture overwhelmingly composed of hydrogen and carbon dioxide. The CO_2 can then be captured before the hydrogen is combusted in a CCGT. The gasifier can be air blown or oxygen blown. Either nitrogen, water or steam can be used to dilute the hydrogen in the GT.

The capture plant itself is similar to a post-combustion plant in operation. However, physical solvents such as poly-glycols or methanols are preferable to chemical solvents such as amine, due to the higher percentage of CO_2 in the gas stream being cleaned. Physical solvents are more efficient than chemical solvents at capturing CO_2, requiring less steam per tonne of CO_2 captured.

It is also possible to reform natural gas to produce hydrogen and pre-combustion capture could be applied to this fuel. It is possible that CCGT plant could be retrofitted with natural gas reforming and pre-combustion capture. Natural gas reforming is similar to coal reforming. Instead of gasification, natural gas is either partially oxydised or reformed with very high temperature steam to produce syngas. A shift reaction with lower temperature steam can then be used to convert this syngas to hydrogen and CO_2 in a similar manner to coal-derived syngas. Due to the lower CO_2 percentage in reformed natural gas, chemical rather than physical solvents would be required to capture the CO_2 from the natural gas derived hydrogen.

It is also possible to burn the hydrogen in SCGT. The high exhaust temperature is not a barrier to the capture process, however as with post-combustion capture, steam would have to be produced. For both pre-and post combustion, the start up time for the process would be an issue for peaking plant.

There are a number of opportunities for optimisation and integration of the IGCC cycle with the CCS plant. It is unlikely that the capture process itself will improve significantly, as physical capture of CCS is already a mature technology, widely used in the oil and gas industry. Technology providers are capable of building a full scale IGCC or natural gas reforming plant with pre-combustion capture now, so it is available at commercial scale. A number of large projects have been proposed, however none have yet been completed. One currently planned natural gas reforming and precombustion capture project is the 1.7 Mtpa Hydrogen Power Abu Dhabi plant.[2]

[2] http://www.hydrogenenergy.com

Due to the higher carbon emissions of coal compared to gas, it is likely that IGCC with pre-combustion capture will become economically viable before conversion of natural gas to hydrogen with pre-combustion capture. For a newbuild IGCC plant with pre-combustion capture, the gas turbine must be capable of burning H_2 and withstanding higher temperatures than standard GT. To avoid excessive temperatures, either the fuel must be saturated with water vapour before entry or steam injection into the GT is required. The GT must therefore be capable of withstanding higher CO_2 and H_2O proportions than standard GTs. Gas turbines are currently available which have the capability to burn fuel from a pre-combustion capture plant. For example GE offer turbines which have experience operating at high fractions of H_2, CO_2 and H_2O[3]. If steam rather than nitrogen is used to reduce the combustion temperature, the steam proportion means that dry low NOx burners are not required.

It is possible to build a gas plant ready for pre-combustion capture from either coal or gas reforming, but due to the availability of natural gas at the site, and the smaller area requirements, it is more likely that retrofit would be to natural gas reforming. There are quite significant differences in the operation of the GT with pre-combustion compared to conventional gas plant. In the absence of repowering, it is unlikely that a non-CCR gas turbine could be converted to operation with hydrogen.

As with post-combustion, the major retrofit issue is of space for the new equipment. Space is required for a methane reformer and pre-combustion capture plant, or for coal storage, a coal gasifier, shift reactor, and pre-combustion capture plant.

GT owner-operators seem to be ignoring the possibility of pre-combustion CCR, instead focusing on post-combustion. On tight sites, pre-combustion may offer a major advantage, which is that the hydrogen could be produced at a location distant from the power plant, and transported to the power plant. This means that the majority of the CCR area could be at a different location to the power plant. This is not an easy option, as to demonstrate that the plant is CCR, not only the space but also the hydrogen transport route must be shown to be available and must be kept available for the foreseeable future to maintain CCR status. It is likely that this will only be possible for very short transport routes. The increased costs associated with transportation and the reduced opportunities for integration will reduce the economic viability. It is important to remember that the plant must be shown to be economically viable to get consent. However for plants on very tight sites, with access to transport routes to larger available and suitable sites, this remains a promising but largely unexplored option.

The existing CCGT would need to be converted to burn the resulting hydrogen-rich fuel. In order to avoid replacing the GT entirely, a GT capable of withstanding the required conditions should be installed in the CCR gas plant. The fuel supply piping would need to be replaced during retrofit as the fuel flow rate will be higher. The exhaust temperature of the GT will be lower, resulting in a lower steam temperature, which can cause lower quality steam in the LP section of the ST.

One option for integration of the cycle is to bleed some of the compressed air from the air compression section of the GT to the gasifier. This would also tend to counteract the effects of the increased fuel flow rate. This would require significant changes to the fuel injection and combustion section of the GT.

4. Oxyfuel

Oxyfuel combustion refers to burning a fuel with pure oxygen instead of air. Assuming the fuel is a hydrocarbon, the combustion products are overwhelmingly composed of water vapour and carbon dioxide, with little or no nitrogen. This greatly simplifies the separation process, requiring only cooling to separate the water from the CO_2. In order to prevent extreme temperatures, some of the flue gas must be recycled to the combustion chamber. It is possible to vary the quantity of oxygen at the inlet, for example allowing greater than 21% oxygen in the combustion chamber. The production of oxygen is a major energy requirement of the cycle. Oxyfuel is the term usually used for this technology. The term oxycoal has been trademarked for a particular oxyfired coal cycle, but the term oxygas is more commonly used in the welding and metal cutting industry so is not widely used for oxyfuel technology.

Currently the two largest combustion CCS projects in the world are coal oxyfuel demonstrations. Vattenfall's Schwarze Pumpe plant in Germany is a 30MWth coal fired plant, producing process steam

[3] GE marketing presentation to PB, September 2008

for use in a nearby factory. Alstom has designed the boiler and recirculation duct, BOC Linde the liquefaction plant and road transport. At present permitting difficulties and public opposition mean that the project is not injecting the captured CO_2 into a storage site, but rather emitting it to atmosphere. Doosan Babcock are testing an oxyfuel coal burner with a 40MWth capacity, but the CO_2 captured at atmospheric pressure is simply diluted and emitted. Gas fired oxyfuel technology is at a much smaller scale.

In addition to oxygen firing of CCGT plant, a number of less conventional natural gas oxyfired cycles have been proposed. It is likely that these cycles would all be newbuild; it is unlikely that CCGT would be retrofitted to unconventional power cycles.

For oxyfiring of conventional CCGT plant, the flue gases from the plant, composed of mainly CO_2 and H_2O with little or no nitrogen, will be cooled and compressed, most likely in a number of stages. Water will be removed after each stage of cooling, resulting in a stream overwhelmingly composed of CO_2. Most of the gas will be recirculated to the CCGT. Oxygen will be produced from air in an Air Separation Unit (ASU) and delivered to the CCGT for combustion. There are two possibilities for where in the cycle the recirculated flue gases could be extracted. The first is after the Heat Recovery Steam Generator (HRSG), in which case the gases would be at close to atmospheric pressure and would contain both CO_2 and H_2O. It is likely that this gas would be recirculated to the inlet of the air compressor section of the GT. It would therefore make sense to recirculate the flue gas after the initial cooling stage rather than immediately after the HRSG.

The second possibility is extraction from some point during the carbon drying and compression process, in which case the recirculated gas could be almost pure CO_2 and could be at a high pressure. In this case it would be reasonable to recirculate the high pressure CO_2 directly to the combustion section of the GT. To reduce the power requirements for the ASU it would also make sense to divert the compressed air from the GT compressor section to the ASU. These two options are shown below.

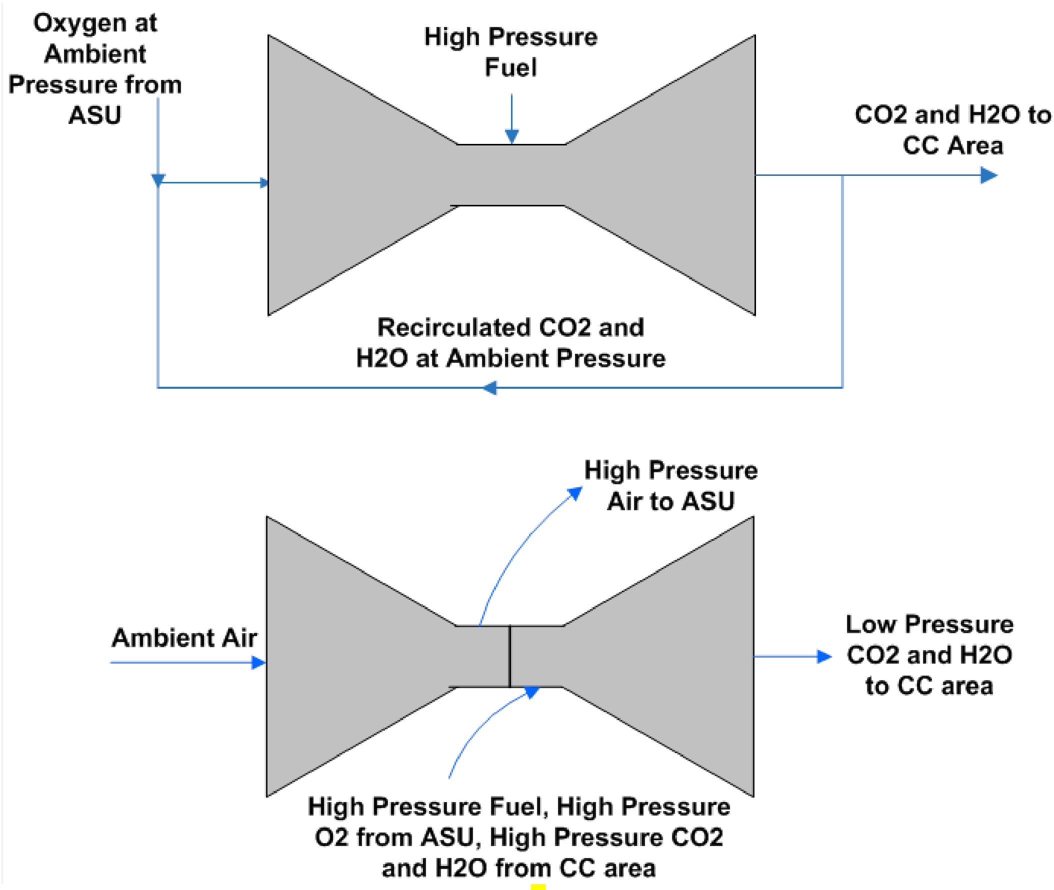

Figure 3: Options for recirculation of flue gas in an oxyfired GT

As with precombustion capture, it is likely that the most efficient method of integration of the cycle would be diversion of compressed air from the GT, and return of a high pressure gas stream to the combustion section. Unlike precombustion, all of the compressed air must be extracted, so that the combustion and expansion sections of the turbine are isolated from the compression section during oxyfuel operation. Oxyfuel plant will most likely use air combustion during startup, to reduce the requirement for a large amount of oxygen storage. Therefore a valve or valves would be required to allow the switch to oxyfuel after startup, isolating the compression section, diverting the compressed air to the ASU and allowing the high pressure recirculated flue gas and oxygen into the combustion section of the turbine. This would be a major undertaking for a retrofit, and is more likely for a newbuild oxyfuel CCGT.

For retrofit of oxyfuel to CCGT, it would be preferable to minimise changes to the CCGT, so it is more likely that the flue gas would be recirculated to the inlet of the compression section of the GT. Operation on an inlet stream as similar to ambient air as possible would be preferable. This could be achieved by recirculating the flue gas at low temperature and pressure and mixing it with oxygen before inlet to the GT.

Oxyfuel could be applied to both CCGT and SCGT. Unlike precombustion and postcombustion capture, oxyfuel does not require steam, so may be more suited to SCGT. The ability to start up using air firing and switch to oxyfiring allows for the operational flexibility required of peaking plant.

To design a plant as oxyfuel ready, the major issue is again one of space for the additional equipment. Space is required within the power plant for the recirculation duct to the inlet of the GT. The inlet section of the GT will most likely need to be replaced or altered during retrofit, even for a CCR plant.

5. CO_2 Transport and storage

Once the CO_2 has been captured, it must be prepared for transportation, transported, and injected into a suitable geological formation such as a depleted oil or gas well or a saline aquifer. In the UK storage will be offshore in the near future. The most likely methods of transportation are as high pressure gas or supercritical fluid in a pipeline, or as liquid in ship, road or rail tankers. For pipeline transport the CO_2 must be dried and compressed to the required pressure. This has a large power requirement. For liquefaction the CO_2 is compressed to around 7 bar, dried and cooled to around –50°C. To be carbon capture ready, space for these processes must also be allowed for in the carbon capture area. The choice of capture method does not affect the transportation method. Under current consenting conditions, to demonstrate carbon capture readiness, it must be assumed during the economic assessment that only the CO_2 from the plant being consented is to be transported. However in the medium term “hubs” or “clusters” are likely, with a number of plants feeding into a single transport route and storage site. In the long term it is likely that there will be a network of CO_2 pipelines, into which individual projects can deliver their CO_2.

6. Consenting requirements

The EU Directive on the Geological Storage of Carbon Dioxide (the "Directive") requires an amendment to Directive 2001/80/EC, commonly known as the Large Combustion Plants Directive such that Member States are to ensure that all newly consented combustion plants with an electrical capacity of 300MW or more have assessed whether:

- Suitable storage sites are available
- Transport facilities are technically and economically feasible; and
- It is technically and economically feasible to retrofit for CO_2 capture.

An assessment of whether these conditions are met is then to be submitted to the relevant competent authority, which in the UK is the Department of Energy and Climate Change (DECC). The competent authority shall then decide if these conditions are met on the basis of the assessment and other available information. If the conditions are met, the competent authority must ensure that suitable space on the installation site for the equipment necessary to capture and compress CO_2 is set aside. This requirement to include suitable space is commonly referred to as Carbon Capture Readiness.

In the UK the new consenting regime is stricter than the EU regime. All new thermal plant with a capacity of 300MW or more must be CCR. If retrofitting CO_2 capture to the plant is not economically feasible, the plant will not be consented. As part of a Section 36 application, it is now necessary to submit a CCR feasibility study, demonstrating that it is technically and economically feasible to retrofit CCS to the plant. As part of the CCR study the developer is required to:

- Demonstrate that they have sufficient space on or near the site to accommodate carbon capture equipment in the future;
- Undertake an assessment into the technical and economic feasibility of retrofitting carbon capture technology;
- Propose a suitable area of deep geological storage offshore for the storage of captured CO_2;
- Undertake an assessment into the technical and economic feasibility of transporting the captured CO_2 to their proposed storage area, including a suggested route corridor; and,
- If necessary, apply for and obtain Hazardous Substance Consent (HSC) when applying for Section 36 Consent.

If granted Section 36 Consent, developers will be required to:

- Retain the additional space on or near the site for the carbon capture equipment;
- Retain their ability to build on that site in the future (if their application included plans for some space needed for the capture and compression of CO_2 to be off site); and
- Submit Status Reports to the Secretary of State for DECC on the effective maintenance of the plant's carbon capture readiness.

The first Status Report will be required within 3 months of the date on which a consented station first begins to supply electricity to the grid (thus avoiding any burden which could be placed on the operator with an unimplemented consent). Further Status Reports will be required every two years thereafter until the plant moves towards retrofitting carbon capture and storage equipment.

At present it does not seem that hazardous substances consent will be required for a CCR power plant. Amines are not classified as requiring hazardous substances consent. A CO_2 pipeline or storage for compressed CO_2 would be hazardous, but as with gas pipelines, the CO_2 pipeline is not part of the site, and would be covered by the pipeline safety regulations, rather than the COMAH regulations.

When applying for consent for a CCR power plant, it is necessary to demonstrate that it is possible to retrofit without requiring hazardous substances consent. When time comes to retrofit CCS, the capture plant must be consented separately from the power plant. At this time, depending on the type of CO_2 capture and any storage of CO_2 onsite, it may be necessary to apply for hazardous substances consent for the capture plant.

7. The meaning of Carbon Capture Ready (CCR)

Prior to the new consenting regime, CCR requirements were simply to leave a space for future carbon capture equipment: if an additional 40% of the land area of the plant were set aside for CCS the plant was deemed to be CCR. This is no longer the case. Now, to be classified as CCR, an indicative layout must be submitted to the authority, including placement of major items of plant, demonstrating that enough land has been set aside. In order to size these items of plant a technical assessment must be undertaken. The developer is not required to use these layouts when the time comes to retrofit.

It is also necessary to demonstrate that where necessary space has been left within the new power plant. The following is a non-exhaustive list of areas where space must be left within the power plant to demonstrate that the plant is CCR. Each plant is obviously different and the final design of the plant must take these issues into account.

<u>All</u>

- Carbon Capture (CC) area: Space for new plant and equipment to be installed during retrofit, i.e. carbon capture plant, compression or liquefaction equipment, fuel treatment plant, air separation plant etc. This must be supported by a technical assessment of what is required for retrofit and an indicative layout demonstrating that the space will be sufficient.
- Space for additional cooling water intake, cooling towers or air coolers.
- Space for electrical substation for delivery of electricity to CC area (depending on site layout)

<u>Post-combustion</u>

- CC area: Space for flue gas heat exchanger, additional flue gas cooler, chemical solvent carbon capture plant and associated equipment and compression or liquefaction plant
- Space for flue gas ducting to/from the stack and the CC area
- Steam production: either
    - Space for fuel delivery (e.g. gas pipeline) to the CC area, or
    - Space to install ports or blanked off ports for offtake of steam from the IP/LP crossover and/or cold reheat and space for the associated steam/water ducting and/or pipes to and from the steam cycle and the CC area

Pre-combustion

- (If IGCC) CC area: Space for coal storage, gasifier, reformer and physical solvent carbon capture plant and associated equipment, and compression or liquefaction plant
- (If gas reforming) CC area: Space for gas reforming equipment, chemical solvent carbon capture plant and associated equipment, and compression or liquefaction plant
- (If fuel treatment distant from power plant) Space for transport of fuel from CC area to power plant
- Space for increased size of fuel supply piping to GT, and space to enable retrofit of associated injectors
- GT must be designed to withstand conditions after retrofit

Oxyfuel

- CC area: space for ASU and associated equipment, space for flue gas cooling, water separation and compression or liquefaction equipment, space for flue gas recirculation ducting and fan
- Space for flue gas ducting from the HRSG exit to CC area
- Space for recirculated gas ducting to inlet of GT
- Space for ducting of oxygen from CC area to GT intake (unless mixed with recirculated gas in CC area)

All other major plant and equipment could be constructed within the CC area. Obviously the temptation for power plant developers is to do as little work as possible in the short term, particularly as many developers are sceptical that CCS will be applied within the lifetime of plant being consented now. However, if and when the time to retrofit CCS does arrive, having the benefit of space within the power plant for items such as control and instrumentation cabling from the control room to the CC area could greatly reduce cost of retrofit. Areas where leaving additional space now could greatly simplify retrofit in the future include the following:

All

- Space for additional water treatment equipment
- Space for tie-ins to the cooling system
- Space for control and instrumentation cable routing to control room
- Space for additional compressed air equipment and cooling water/demineralised water pumps
- Space to transport large modules to CC area to reduce on-site construction requirements

Post-combustion

- Even if a dedicated boiler is planned, leaving space or blanked off steam ports on the cold reheat and/or IP/LP crossover would allow for the possibility of the more efficient option of using LP steam. Conversely, even if use of steam from the steam cycle is planned, allowing for space for fuel lines to the CC area would allow for a dedicated boiler.
- Space to retrofit HRSG with additional duct firing to increase steam production

Pre-combustion

- Space to retrofit HRSG with larger superheater modules to counteract the lower exhaust gas temperature
- A blanked off bleed system in the GT to allow for offtake of some compressed air, and space for associated ducting to CC area.
- Space to allow replacement or significant alteration of the combustion section of the GT

Oxyfuel

- A blanked off bleed system in the GT to allow for offtake of some compressed air, and space for associated ducting to CC area
- Space to allow replacement or significant alteration of the combustion section of the GT
- Space for ducting of all compressed air to CC area, and ducting of high pressure CO_2 and oxygen to combustion section of GT

If space for all necessary auxiliary equipment is not left within the power plant, each piece of equipment must be provided within the CC area upon retrofit. This requires a larger CC area and dedicated plant to be installed during retrofit. This would be wasteful of both space and resources. It is obviously easier to increase the capacity of an existing water treatment plant for example than to build an additional water treatment plant, which would be necessary if the space for additional capacity is not left within the initial CCGT water treatment plant.

8. Cost of Carbon Capture

Parsons Brinckerhoff has modelled the cost of power generation, including capital and operating costs over the lifetime of the plant. The provisional costs shown in Figure 4 were produced in March 2009 and were for current capital costs, with operating costs extrapolated across the lifetime of the plant. The cost model is currently being finalised and updated, and an in-depth report will be issued in early 2010.

The costs of IGCC with pre-combustion capture and standard coal and CCGT plant with post combustion capture were included in this analysis.

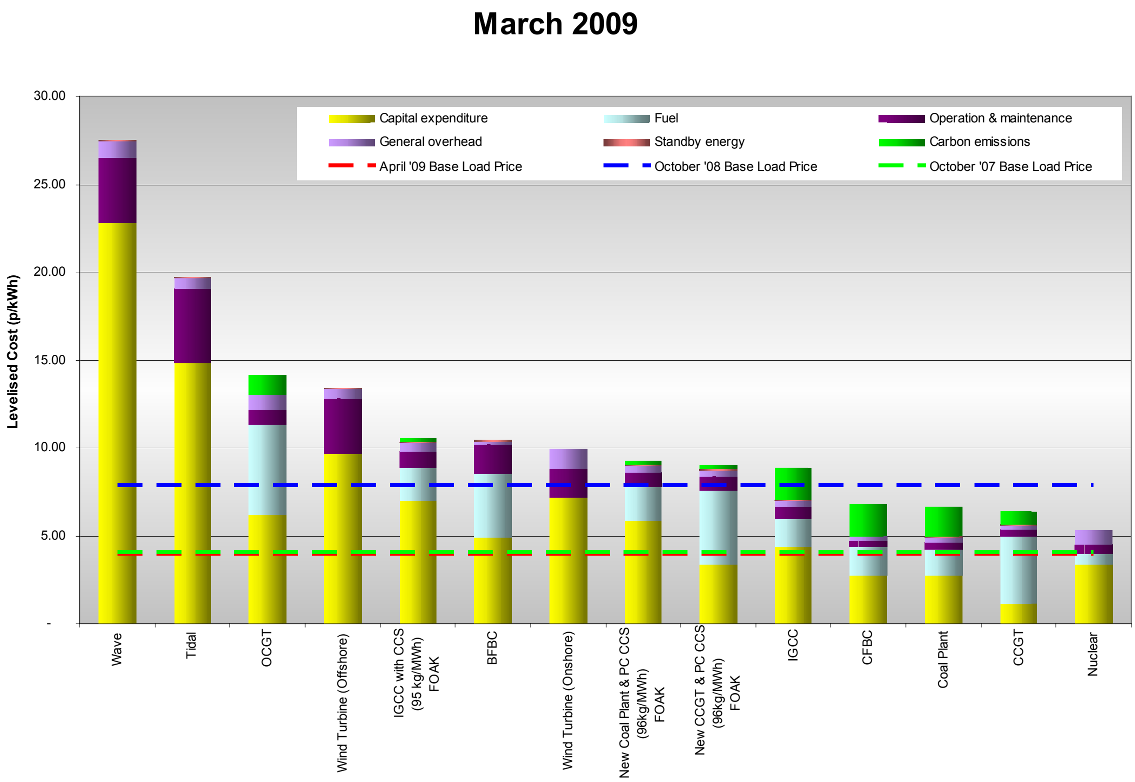

Figure 4: Provisional cost of power generation[4]

As shown in Figure 4, the cost of power generation from coal and gas plant with post combustion capture is lower than the cost of wind generation. IGCC with pre combustion capture is more expensive than onshore wind generation, but is cheaper than offshore wind generation.

It is clear from these numbers that in order to compete with conventional thermal plant the carbon price must increase significantly, and the cost of CCS must reduce. Both of these are likely in the future, but in the short term some form of assistance is required to enable carbon capture to be

[4]Parsons Brinckerhoff cost modelling

implemented. Due to coal's higher carbon content, this support is being provided for coal plant, through the DECC CCS competition and other mechanisms, but less support is available at present for application of CCS to gas plant.

Summary

Four options for use of GT within power plant with CCS have been described: post combustion capture of CO_2 from CCGT, IGCC with pre combustion carbon capture, natural gas reforming with pre combustion carbon capture and oxyfiring of natural gas in a GT. The requirements for demonstration of Carbon Capture Ready status for each of these options were described, along with a list of optional changes to the design of a standard gas plant, which would greatly simplify and reduce the cost of retrofit of carbon capture to CCGT plant.