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Bluewaters Units 3&4

Report on Biomass Co firing and Carbon Capture Ready Plant

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BLUEWATERS UNITS 3&4
REPORT ON BIOMASS CO FIRING AND CARBON CAPTURE READY PLANT

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PROJECT 101012/00166 - BLUEWATERS UNITS 3&4

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1. EXECUTIVE SUMMARY

Griffin is currently undertaking the project development work for Bluewaters Power Station Units 3&4. In order to minimise Green House Gas (GHG) emissions, Griffin is proposing the new plant would be designed to co-fire up to 15% biomass with coal and be 'Carbon Capture Ready' to take advantage of carbon capture and storage when the technology becomes commercially viable. This report covers the identification of technologies and issues related to biomass co-firing, carbon capture readiness, and provisions to be made in the initial plant design and layout.

Biomass co-firing

Biomass co-firing can be broadly classified into direct co-firing and indirect co-firing.

Direct co-firing of biomass and coal occurs in the same boiler where as indirect co-firing occurs in separate boilers.

Direct Co-firing

For pulverised fuel boilers, the following options are available for direct co-firing.

- Pre -mixing of biomass and coal and co-milling
- Stand alone biomass handling and milling system with direct injection of biomass into the boiler

The co-milling system is simple from a blending point of view and avoids dedicated feeding system for biomass. It is more suitable for lower co-firing ratios (up to 5%) and limited mainly due to operational problems in mills attributable to the high percentage of moisture and volatile matter present in biomass.

In the second system (direct injection), a separate milling system and a separate or common fuel conveying system is used. Fuel firing occurs either through a common set of burners for coal and biomass or through dedicated burners for biomass. Depending on the type of biomass, direct injection has the advantage that it eliminates co- milling problems despite its complexity (from a control and interface perspective) and high capital cost. Although the direct injection method has been showing encouraging results and has the potential to co-fire up to 15%, there is limited experience with direct injection.

Indirect Co-firing

In indirect co-firing, a dedicated direct fired biomass boiler or pre gasifier is used. Compared to the direct co-firing options, a dedicated biomass boiler provides a few advantages such as non contamination of coal ash, increased flexibility with regard to selection of biomass boiler technology, capacity, and operation. However, the capital costs and space requirements are high for a dedicated biomass co-firing facility in comparison with the direct co-firing option.

Technology Development and Issues

The bulk of the biomass co-firing experience comes from retrofit applications. The co-firing of biomass and coal has been commercially applied in a small scale but large scale co-firing (> 10%) is still being trialled in many plants. Drax power station in the UK for example is building potentially the largest biomass co-firing plant at their existing 4000 MW facility to produce 10% of its output from biomass co-firing.

Enstedvaerket power plant at Abenraa in Denmark has a separate biomass boiler with an output of 40 MWe, approx 6% of the main plant capacity of 660 MWe. However, a stand alone biomass boiler for co-firing option is not very common and industry experience and references are limited.

It is understood that in trials at Australian power stations, direct co-firing ratio of even up to 5% was not successfully tested.

With the available information, biomass co-firing up to 15% may be feasible but requires further investigations with boiler suppliers.

Carbon Capture

Two methods of CO_2 capture applicable for Bluewaters 3&4 are post combustion capture and oxygen combustion.

Post combustion CO_2 capture uses amine based scrubbing technology. It is based on chemical absorption to capture CO_2 from the flue gas. The concentrated stream of CO_2 is then cleaned and pressurised for transport and long term storage.

In Oxygen fuel combustion, air for the combustion of coal will be replaced with oxygen. A portion of the flue gas is recirculated into the furnace to control the flame temperature and to increase the concentration of CO_2 in the flue gas. CO_2 is separated from the non recirculated flue gas, further compressed and dispatched for long term storage.

Carbon Capture Ready Plant

The intent of designing a plant that is “Carbon Capture Ready” is to make design provisions and space allocations to allow retrofitting of the equipment to capture the carbon in the future. The plant has to cater to the future regulations and future technology. Building a plant capable of retrofitting either of the technologies will be complex. To a certain degree the impacts could be minimised by suitable design and layout provisions such as space for future equipment and systems, design flexibility, space provision for upgrading the balance of plant equipment etc described in the subsequent sections of the report.

There is a great deal of uncertainty as to what design provisions are required and could be made today for a ‘carbon capture ready plant’ since development of the technology is still in its preliminary phases. Building a plant intended to be carbon capture ready without knowing which of the applicable capture technologies would be used in future makes the design and layout provisions more complex and uncertain. More over, the capture technology that becomes commercially viable may have undergone changes/improvements from the currently known information. This could potentially render the provisions made today inappropriate and/or inadequate. Decisions would have to rely on the information available on the present technology.

WorleyParsons is of the opinion that more investigations and detailed discussions with technology providers and boiler and turbine vendors are required before a firm decision can be made on building Carbon Capture Ready plants.

2. INTRODUCTION

Griffin Energy (Griffin) is currently in the advanced stages of construction of Bluewaters Units 1&2 comprising two pulverised coal fired units of 208 MW (net) near Collie, about 220 km southwest of Perth. In order to meet the growing demand for electricity in the region, Griffin is now undertaking the project development work for Units 3&4 to add two more units of 208 MW (net) each. The new units (Bluewaters Units 3&4) will be installed adjacent to the existing units.

As part of the environmental approval process, Griffin has prepared a draft project scoping document and Public Environmental Review Document (PER) for the Environmental Protection Authority (EPA), Western Australia. To reduce Green House Gas (GHG) emissions, Griffin is proposing Bluewaters units 3&4 would be designed to co-fire biomass with coal and be ‘Carbon Capture Ready’ when the technology becomes commercially viable in Western Australia.

Griffin, through their environmental consultant Strategen has approached WorleyParsons to prepare a brief report on the technical feasibility of utilising up to 15% Biomass co-firing and to discuss issues related to carbon capture readiness.

3. SCOPE

The scope of this report is divided into issues related to biomass co-firing and those related to carbon capture readiness as follows:

3.1 Biomass Co-firing

- Review options available for biomass co-firing such as direct co-firing and indirect co-firing
- Discuss Co-firing technology development status and issues

3.2 Carbon Capture

- Identification of carbon capture technologies
- Discuss provisions to be made in the initial plant design and layout for future implementation of carbon capture technology

3.3 Exclusions

The following are excluded from the scope of the report.

- Detailed investigations
- Capital and O&M cost estimates
- Biomass fuel availability
- Plant layouts and general arrangement drawings
- Designs and calculations
- Detailed identification of risks and risk analysis
- Alternative technologies for boilers such as fluidised bed combustion, super critical cycles etc.
- GHG reduction measures for Bluewaters 1&2
- CO_2 transport and storage.

This report has been prepared based on a qualitative approach and does not intend to provide any data or absolute values with regard to its scope due to the short time that was available to produce this report. WorleyParsons has not had any discussions with vendors in the preparation of this report and strongly recommends Griffin to enter into discussions with potential boiler and turbine manufacturers and technology providers as early as possible to take their feedback into consideration.

3.4 Terms of reference

- WorleyParsons proposal dated 11 August 2008
- Subsequent email correspondences between WorleyParsons and Griffin dated 12 August 2008
- Comments from Griffin on the initial report as conveyed during the meeting held on 17 September 2008

4. BIOMASS CO-FIRING

Biomass can be defined as fuel derived from plant or animal matter such as wood wastes, forest residues, agricultural remains etc. Biomass is considered to be carbon neutral if grown in a sustainable manner. This means there is no net increase in CO_2 levels due to biomass firing and provides utilities an option to replace a portion of coal which would reduce the GHG emissions.

A number of research and testing programmes have been undertaken by various institutes and utilities world wide with regard to co-firing biomass with coal. Much of this has been done on existing plants for retrofit application. Bluewaters 3&4, perhaps, has the advantage of specifying co-firing requirements in the design stage which could lessen the complexity and issues normally present with retrofit applications.

This report discusses the options available for biomass co-firing and the technical issues associated with co-firing biomass. WorleyParsons understands that Griffin has done its own research on biomass availability and hence topics on the availability and cost of biomass are beyond the scope of this report. This report also does not cover the economic aspect of biomass co-firing. At present WorleyParsons has no information on the type of biomass intended to be used in Bluewaters 3&4 and due to the limited time available, this report does not cover the potential issues in co-firing with various types of biomass. The type of biomass will have an influence on handling, storage and conveying, co-firing ratio and boiler performance.

Biomass co-firing can be broadly classified into direct co-firing and indirect co-firing.

4.1 Direct Co-firing

Biomass and coal are fired in the same boiler in direct co-firing. For pulverised fuel boilers, the following options are available for direct co-firing.

4.1.1 Pre –mixing of biomass and coal and co-milling

Pre mixing is generally done upstream of bunkers & coal feeders. The system is simple from a blending point of view and does not require separate feeding system for biomass. Blending can be accomplished off site before delivery of fuels to the plant or on site. Off site blending is not very common and depends on the type of biomass and fuel supply contracts. Onsite blending can be done on the belt conveyors feeding the bunkers. The co-milled fuel is conveyed to the boiler through common pipeline and burners. This arrangement is more suitable for lower co-firing ratio and limited mainly by milling issues due to the fibrous nature of biomass, high percentage of moisture and volatile matter present in biomass. Test results have shown that this option is more suitable for co-firing ratios up to 5%. Designing co-milling systems for a new plant could address some of the issues with co-milling operations but may not be feasible for higher co-firing ratio due to the reasons mentioned above.

4.1.2 Stand alone biomass handling and milling system with direct injection of biomass

Direct injection co-firing will have a dedicated biomass handling and milling system. Direct injection can be achieved by using common burners or through dedicated biomass burners. When dedicated biomass burners are used, design changes are required to the draft plant, needs careful consideration on mill system and furnace performance, needs to address issues related to interface and controls. For new plants, these issues could be addressed at the design stage and may find the dedicated biomass burner option attractive despite its relatively high cost and complexity.

The other option is the injection of pre milled biomass into the pulverised coal firing system. This can be done either into the coal pipe work downstream of mills or near the coal burners. Introduction of biomass into the coal pipes near the burners would have the shortest length of mixed fuel pipes and will be less influenced by mill events. However, this arrangement adds congestion in the layout due to the extra space needed for additional biomass pipes.

Depending on the type of biomass, the direct injection method has the advantage that it avoids co-milling problems, less influenced by variation in coal properties, independent of mill load limitation and flow variation issues in coal mills. However, the direct injection option is more complex from a control and interface perspective and is capital intensive.

Although the direct injection method has been showing encouraging results and has the potential to co-fire up to 15%, there is limited experience with direct injection. Selection of any particular option needs to be based on the properties of biomass, co-firing ratios, effect on boiler performance, especially at higher co-firing ratios and recommendations from boiler manufacturers.

4.2 Indirect Co-firing

In indirect co-firing, biomass and coal are burned in separate boilers. A dedicated direct fired biomass boiler or pre gasifier could be used in this option. Steam from the biomass boiler and main plant would be fed to the plant steam turbine. Steam side and feed water side interfacing would be required for this option. Capital cost of this option is higher compared to direct co-firing options but provides a few advantages. Ash from coal and biomass can be handled separately and coal ash is not contaminated by biomass ash. This eliminates the potential issue of fouling and corrosion of main boiler components due to alkaline biomass ash. In addition, there is increased flexibility with regard to selection of biomass boiler technology, capacity and type of biomass and is not limited by direct co-firing issues. There would be flexibility in operation as problems with the biomass unit would not affect the main plant and vice versa. As already mentioned above, the capital costs and space requirements are high for a dedicated biomass co-firing facility.

4.3 Technology development and issues

Biomass co-firing with coal has been tested in many pulverised coal plants world wide. To a greater extent the technology has been commercially applied in a small scale. Some of the constraints in higher co-firing ratios have been to deal with the technical concerns with regards to boiler performance, fouling and corrosion issues, limitations in space for storage and handling of biomass and availability of biomass. Large scale co-firing (> 10%) is still being trialled in many plants. Drax power station in the UK for example is building potentially the largest biomass co-firing plant at their existing 4000 MW facility. The facility will have a dedicated system for biomass handling and milling and will use direct injection method. When built, this plant would produce 10% of its output from biomass co-firing.

Enstedvaerket power plant at Abenraa in Denmark has a separate biomass boiler with an output of 40 MWe approx 6% of the main plant capacity of 660 MWe. The main driver behind a separate biomass boiler was due to the corrosive characteristics of biomass fuel and to prevent contamination of coal ash. However, a stand alone biomass boiler for co-firing option is not very common and industry experience and references are limited.

It is understood that in trials at Australian power stations, co-firing ratio of even up to 5% was not successfully tested. Some of the potential issues with biomass co-firing are:

- During trial runs in the existing pulverised coal installations in Australia, it was found that co-milling biomass in quantities up to 5% in pulverising mills created operational problems which caused mills to be shut down.
- Co-firing ratio up to 15% (energy basis) has not been commercially proven in pulverised coal boilers.
- Variation in the type of biomass and its properties may pose operational issues in future. Similarly, the ability to co-fire successfully with variation in coal property may also be an issue.
- Design flexibility is required for boilers to operate with and without biomass under MCR conditions. As the co-firing ratio increases, there would be more issues with ash deposition and fouling of boiler surfaces. Co-firing at higher ratio may require better quality biomass fuel.
- Direct co-firing may render ash unsuitable for marketing and use in cement industry and other potential applications.
- Depending on the type of biomass, biomass storage and handling system may generate additional dust and be subject to biological activity.

With the available information, biomass co-firing up to 15% may be feasible but requires further investigations with boiler suppliers.

4.4 Layout and Environmental consideration

As discussed in the preceding sections, it appears dedicated biomass handling and storage systems with direct injection into the boiler would be the preferred choice for Bluewaters 3&4. Therefore, adequate layout provision needs to be made for biomass reception, unloading, storage and handling. Layout and handling system requirement would also depend on the type of biomass and co-firing ratio.

If a standalone biomass boiler option is considered, more space would be required.

Although burning biomass still produces CO_2, it is a carbon neutral fuel. It is expected that there will be no net increase in CO_2 emissions due to biomass co-firing. On a net basis, CO_2 emissions would be reduced (due to reduced coal consumption) by more or less at the same percentage level of co-firing.

Biomass is a low or zero sulphur fuel. Therefore, SO_x levels are expected to reduce equivalent to the percentage co-firing ratio used.

Biomass has generally low fuel bound nitrogen which would reduce NO_x produced from fuel bound nitrogen. However, predicting thermal NO_x is more complex and it may be assumed that overall NO_x levels would remain more or less at the same level although chances are towards achieving lower emission levels.

Biomass has very low ash content. Co-firing should cause reduced ash generation and particulate levels corresponding to the quantity of coal being displaced and the ash content in coal. However, biomass may have more chlorine and potassium than coal and can cause fouling and corrosion problems.

To enable co-firing of biomass for Bluewaters units 3 & 4, the site layout will need to be reviewed in detail and with input from plant suppliers to ensure the is adequate provisions for:

- Fuel storage and handling
- Operation and maintenance.

5. CARBON CAPTURE

5.1 Overview of Technology

Two methods of CO_2 capture applicable for Bluewaters 3&4 are post combustion capture and oxygen combustion. Both technologies capture the CO_2 from the boiler flue gas. Oxygen combustion also includes the requirement to change from using air in the combustion process to using oxygen.

5.1.1 Post Combustion

Typically, the CO_2 concentration in flue gases is of the order of 12-15%. The post combustion capture technology commonly uses chemical absorption to capture the weak stream of CO_2 from the flue gas. The process scrubs the flue gas using amine based solvents. Amine solution absorbs CO_2 when cold and releases CO_2 when heated. This technology consumes significant amount of thermal energy for regeneration of solvents which is typically proposed to use low pressure steam from the plant. The concentrated stream of CO_2 is then cleaned and pressurised for transport and long term storage. The main equipment for post combustion capture of CO_2 is an absorber, a stripper tower and associated pumps, ducts and piping. The process is estimated to have approximately 95% efficiency.

Another post combustion capture method being developed by Alstom is the chilled ammonia process. Alstom has undertaken extensive R&D work for the commercialisation of this technology. The process uses ammoniated solution and has key systems such as flue gas cooling, absorption and high pressure regeneration. The energy requirements are believed to be significantly less for the chilled ammonia process than that for the amine scrubbing process.

5.1.2 Oxygen Combustion

In oxygen combustion, coal burns in oxygen rather than in combustion air. An air separation unit (ASU) would separate oxygen from air before combustion and releases nitrogen and other inert gases to atmosphere. Since pure oxygen is used for combustion, the flame temperature is high and needs to be controlled to avoid possible operational issues with the boiler. For this purpose, a portion of the flue gas is taken from downstream of the particulate removal equipment and recirculated into the furnace. Recirculation also helps heat transfer surfaces to be in the design limits and increase concentration of CO_2 in the flue gas which makes it easy to capture. The non recirculated flue gas is compressed, cooled and condensed to separate CO_2. The separated CO_2 is further compressed and dispatched for long term storage.

5.2 Carbon Capture Ready

Post combustion and oxygen combustion carbon capture technologies are still under development and have not been successfully commercialised. A number of pilot projects and research projects are being undertaken worldwide to establish the viability of these technologies. With the increasing awareness and concerns over GHG emissions, conditions could be imposed on new utilities to be 'carbon capture ready'. This fundamentally means the plant should be able to retrofit carbon capture equipment at some point in time in future when the CO_2 capture technology is proven and when suitable transport system and repository for the captured CO_2 is available.

The following sections would briefly discuss the provisions to be made in the design for a unit to be carbon capture ready.

5.2.1 Provisions in Design and Layout

To be carbon capture ready the plant has to cater to the future regulations and future technology, and be capable of having the carbon capture equipment retrofitted economically. As mentioned in the preceding sections, there are two applicable technologies for Bluewaters 3&4 viz. post combustion capture and oxygen firing method. Building a plant capable of retrofitting either of the technologies will be more complex than if a single technology were to be available.

The following design and layout provisions could be made for a plant which would be built 'carbon capture ready'. These provisions could be viewed more of as investment decisions rather than specific designs.

Post Combustion Process

Compared with the oxygen combustion process, retrofitting post combustion CO_2 capture with amine scrubbing will require less modification of the plant. Some of the design and layout provisions that could be explored for post combustion capture are discussed below:

1. Amine scrubbing requires low pressure steam for solvent regeneration process. One of the sources for this steam is extraction from the cross over piping between LP and IP sections of the turbine. Research shows that this reduces the plant output and efficiency by approximately 20-30%.

However, the following design provisions could be made

   a. Efforts should be taken to maximise the boiler efficiency applicable to the selected technology.

   b. Flexibility for future modification to steam turbine configuration to avoid complete rebuilding of LP sections of the turbine. If the turbine vendors do not encourage this, a complete replacement of the LP turbine could be the option.

   c. Space provision for a stand alone cogeneration plant could be explored. The cogen plant would provide the necessary LP steam for the amine process (instead of extracting steam from the LP turbine) besides generating saleable electricity.

2. Current research shows the amine process requires lower levels of SO_2 in the flue gas than is generally required under environmental regulations, since higher levels of SO_2 hampers the performance of the capture system. An upgrade of the Flue Gas Desulphurisation (FGD)

plant may be required so space provision for future upgradation should be incorporated in the current design.

3. The amine plant would be located between the FGD plant and the stack. Therefore, space provisions have to be made for future installation of the scrubbers and towers.
4. Space provision to be made in the layout to upgrade/upsize the electrical auxiliaries to meet the additional power requirements for the amine process and CO_2 compression. This means space for additional transformers and switchgears etc.
5. Space provision in the layout for future pipe racks and cable ducts.
6. Adequate design provisions in the flue gas equipment and stack for the variation in flue gas quantity. A separate stack for unit 3&4 could also be considered when the carbon capture equipment is retrofitted.
7. Space provision in the control room for expansion of the control system.

Oxygen Combustion

The oxygen combustion process will require modifications to the flue gas ducting and to the combustion process since the combustion air is replaced with oxygen. The following design provisions should be considered to allow retrofitting of oxygen combustion:

1. To maintain the same output, adequate design provisions are to be made in the combustor and heat transfer surfaces to switch over from air combustion to oxygen combustion.
2. Unlike the amine process, there is no need to reduce the SO_2 levels for oxygen combustion. However, design provisions are to be made in the FGD for handling a more concentrated stream of SO_2 and CO_2 rich flue gas. It is not clear at this stage if there are specific sulphur level requirements / limits in the storage /injection well process.
3. Provision for integrating with the ASU with defined tie in points. Further integration possibilities could be explored for the integration of the steam turbine with the air compressor of the ASU.
4. Space provision in the layout for flue gas recirculation duct. Extra space should be allocated for recirculation fans.
5. Space provision to be made in the layout to upgrade/upsize the electrical auxiliaries and distribution to meet the additional power requirement for ASU, fans and CO_2 compressors. This requirement is expected to be quite significant and adequate space provisions should be allowed for additional transformers, switch rooms etc.
6. Space provision in the layout for future pipe racks and cable ducts.

7. Adequate design provisions in the flue gas equipment and stack for the variation in flue gas quantity. A separate stack for unit 3&4 could also be considered when the carbon capture equipment is retrofitted.

8. Space provision in the control room for expansion of the control system.

From the layout shown in the scoping document, it appears that space is available in the vicinity of the power station complex. It is reasonable to expect that space provision for retrofit, potentially reduces the time for retrofit. However, detailed investigations are required to ascertain the space requirements for carbon capture and the suitability of the presently proposed layout to be carbon capture ready.

5.2.2 Environmental Considerations

A plant fitted with CO_2 capture equipment is expected to have the following impact on emissions

- Amine process requires very low SO_2 levels. The FGD equipment may need to be upgraded to achieve this so the emission level of SO_2 would reduce for the same output. For Oxygen combustion technology, no appreciable changes are expected in the SO_2 levels, except that the concentration of SO_2 in the flue gas would go up.
- CO2 emissions could reduce by 95% to near zero emission depending on the technology used.
- There is no significant change expected in the particulate emissions except increased concentration levels in the flue gas. This is especially true for oxygen combustion due to the reduced flue gas quantity.

5.2.3 Risks and Issues

There is a great deal of uncertainty as to what design provisions are required and could be made today for a 'carbon capture ready plant' since development of the technology is still in its preliminary phases. Building a plant intended to be carbon capture ready without knowing which of the applicable capture technologies would be used in future makes the design and layout provisions more complex and uncertain. More over, the capture technology that becomes commercially viable may have undergone changes/improvements from the currently known information. This could potentially render the provisions made today inappropriate and/or inadequate. Current decisions would have to rely on the information available on the present technology.

- Future CO_2 capture regulations could affect the current provisions.
- Variation in quality of coal could affect the adequacy of current provisions.
- Currently the auxiliary power requirements are quite high especially for the absorber blowers, ASU and CO_2 compressors. Efficiency is further reduced for the post combustion capture process because a portion of LP steam would be unavailable for power generation due to its use in solvent regeneration for the amine process.

- A common stack for units would add complexity to the layout for retrofit.

WorleyParsons is of the opinion that more investigations and detailed discussions with technology providers and boiler and turbine vendors are required before a firm decision can be made on building Carbon Capture Ready plants. It is expected that, for Bluewaters 3&4, post combustion capture technology would be more suited (compared with oxygen combustion technology) from a CCR point of view because it involves minimum modifications to boiler and auxiliaries.

6. BASIS AND ASSUMPTIONS

This report has been prepared on the following basis and assumptions.

- WorleyParsons has not done any detailed investigations with regard to the options discussed in this report and relies on publicly available information and in house data. More detailed investigations on 'Biomass co-firing' and 'Carbon Capture Ready plant' options to ascertain the viability of these options are required. Building a carbon capture ready plant needs careful examination and detailed in depth investigations before a decision can be made whether 'Carbon Capture Ready' is a feasible option.
- Issues related to the type of biomass, biomass quality and potential availability have not been considered and such issues could change the design provision needed and increase the risks. This report does not cover the systems required for biomass reception, handling and storage on and off site.
- This report did not include capital cost and operation cost implications, electricity pricing issues, and legislative requirements with respect to any of the options.
- No discussions were held with vendors or technology providers due to the limited time that was available.

7. REFERENCES

- *Paper on 'Advanced biomass co-firing technologies for coal fired boilers' by W R Livingston, Doosan Babcock Technology and Engineering*
- *'Biomass co-firing in coal fired boilers' a publication by the U.S department of energy*
- *'Experience of indirect co-firing of biomass and coal' –publication by IEA clean coal centre - UK*
- *'How ready is "capture ready" – preparing the UK power sector for carbon capture and storage'- a report by the Scottish centre for carbon storage*
- *'Capture Ready Coal Plants-Options, Technologies and Economics'- paper by the Massachusetts Institute of Technology USA*