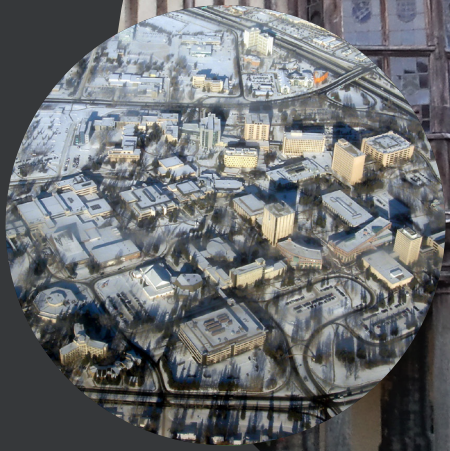
Evaluating technology options to mitigate greenhouse gas emissions



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Review compiled and designed by Becky Kemp

Cover Images

- The famous Mathematical Bridge, connecting the older and the newer half of Queens' College (2014-06)
- The President's Lodge at Cloister Court (the oldest buildings on the river, ca. 1460) (2014-06)
- Tokyo's Imperial Palace (2014-07)
- Bird's eye view of the University of Calgary (2014-10)
- Central Street Bridge in Calgary (2014-10)

Contents

Background

The IEA Greenhouse Gas R&D Programme (IEAGHG) hold a primary remit to act as an informed source of impartial information on greenhouse gas mitigation options, and this is achieved by the instigation and management of research studies and technological evaluations, and the establishment and maintenance of a growing series of international research networks. The reports from these studies and networks form the core of information available to IEAGHG members on an ongoing basis.

Each technical study will include a short overview prepared by the respective IEAGHG staff member responsible for the management of the study, and each network report incorporates a short executive summary, briefly summising the topics discussed at the meeting, and any significant conclusions or developments.

This book follows up on the success of the second Overview Book produced at the end of 2013. It draws together the overviews and executive summaries written by IEAGHG over the course of 2014, segregating the overviews into their respective category, as directed in the contents, in order to allow IEAGHG members and other readers to quickly identify the reports by subject area, or area of interest at a glance.

This book also serves as a quick reference guide for IEAGHG staff and members to quickly and efficiently pick out previous reports that may be useful or relevant to current activities and studies.

EVALUATION OF RECLAIMER SLUDGE DISPOSAL FROM POST-COMBUSTION CO_2 CAPTURE (2014-02)

Introduction

Post combustion CO_2 capture using aqueous amine based solvents is considered to be the most widely used technology in large scale CCS demonstration projects. An important environmental issue with respect to post-combustion capture is the generation of considerable amounts of degraded amine waste that has to be mitigated or disposed of properly. Amine based solvents for CO_2 absorption can degrade due to the presence of gaseous species present in the flue gas such as CO_2, SO_x, NO_x, O_2, halogenated compounds and other impurities. Degradation products formed by amine based solvents can include heat stable salts (HSS), non-volatile organic compounds and suspended solids. Figure 1 shows the different mechanisms of amine based solvent loss.

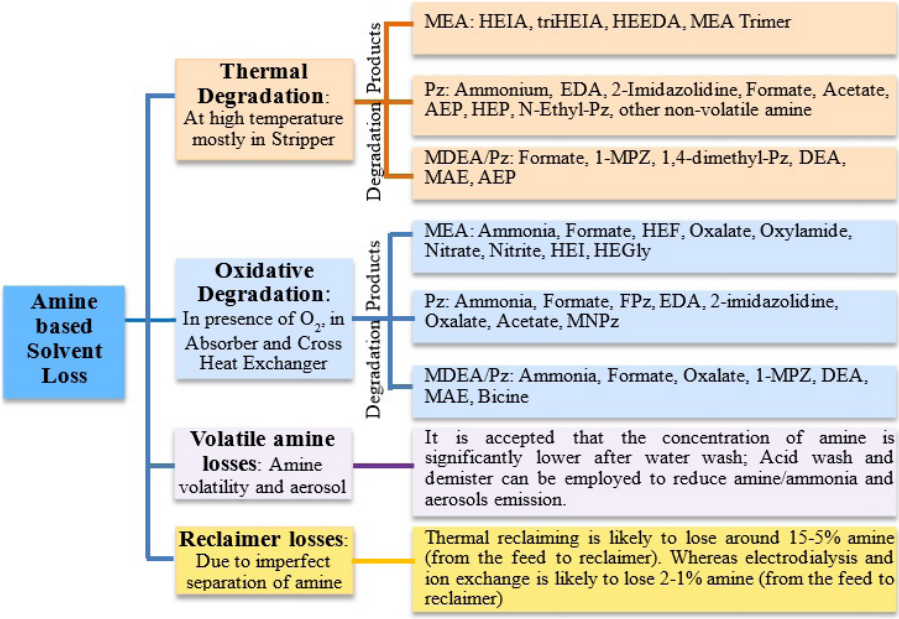

Figure 1, Amine based solvent loss by different mechanism and their degradation products. *MEA (Monoethanolamine), MDEA (Methylenediethanolamine), Pz (Piperazine), HEIA (Hydroxyethylimidazolidone), triHEIA (Cyclic urea of the trimer), HEEDA (Hydroxyethylethylenediamine), EDA (Ethylenediamine), AEP (N-aminoethyl-PZ), HEP (N-hydroxyethyl-PZ), 1-MPZ (1-methyl-PZ), DEA (Diethanolamine), MAE (N-methyl-aminoethanol), AEP (Aminoethylpiperazine), HEF (Hydroxyethyl formamide), HEI (Hydroxyethylimdazole), HEGly (N-(2-hydroxyethyl)-glycine), FPz (N-Formyl-PZ), MNPz (N-nitroso-piperazine).*

Another degradation compound nitrosamine will be formed by the absorption of NO_2 as a nitrite. This nitrite can react with secondary amine e.g. Pz and form carcinogenic nitrosamines e.g. MNPz. MnPz is thermally unstable and will decompose rapidly at stripper conditions. Other containments present in the flue gas such as mercury, selenium, arsenic and other metals will be also present in the amine based solvent.

Effect of degradation products on amine based solvent properties

Degradation products such as heat stable salts and larger polymers formed from solvent degradation are typically stable and non-volatile. These degradation products will accumulate in the circulating amine solvent at a constant rate. The following list shows the effects of these products on solvent properties:

- Increase of non-alkaline impurities such as formamide and amine sulphate increases the viscosity of the solvent. An increase in viscosity affects the heat transfer coefficient in the cross exchanger, diffusion coefficient, affecting mass transfer, which will result in an increased energy requirement of the process.
- The accumulation of amine degradation products, which will have different properties than the amine solvent, will degrade the kinetics of CO_2 absorption, heat of CO_2 absorption, and the operating CO_2 absorption capacity in most of the solvent cases.
- Based on lab-scale experiments and pilot plant tests, a clean amine based solvent is rarely seen to be foaming, but it is possible that foaming is probably a consequence of the presence of impurities.
- It is considered that corrosion is increased by degradation products which may serve as chelating agents and by dissolved salts that increase ionic conductivity. However, corrosion is also expected to increase oxidative degradation due to the accumulation of the dissolved metal catalysts.

Therefore, solvent reclaiming is necessary for the efficient operation of the process. In this study degradation of some of the conventional solvents for the CO_2 absorption process such as MEA, MDEA/Pz and Pz are evaluated for both coal and natural gas power plants. Different reclaiming technologies such as; thermal reclaiming, ion exchange and electrodialysis were evaluated based on different amine based solvents and economics. Furthermore different reclaimer waste disposal options such as: landfilling, cofiring in a

boiler, using in a cement kiln and waste water treatment were also evaluated.

Study Approach

In this study different solvent reclaiming technologies were evaluated for two reference power plants: Supercritical Pulverised Coal (SCPC) and Natural Gas Combined Cycle (NGCC) at their respective gross power outputs (900 and 810 MWe, respectively). A low sulphur Australian coal was used for SCPC case. A selective catalytic removal (SCR) unit is assumed upstream of the CO_2 capture unit for both the coal and natural gas power plants. In addition a wet flue gas desulfurization (FGD) unit and a sodium hydroxide polishing unit, is located upstream of the CO_2 capture unit in the coal-fired power plant thus reducing the SOx concentration to 10 ppmv or less .

Regarding the CO_2 capture process; first the flue gas is passed through a blower in order to increase the pressure to 110.3 kPa and a direct contact cooler to lower the temperature to 40°C. The cooled flue gas is sent to the absorber where CO_2 is absorbed at 40°C. The CO_2 lean amine solution from the stripper is cooled and sent to the top of the absorber, and the rich solution exits the bottom of the absorber. The treated flue gas exits from the top of the absorber and is sent to the stack. The CO_2 rich solution exchanges heat with hot CO_2 lean solution in a cross heat exchanger. This preheated CO_2 rich solution flows to the stripper where CO_2 desorbs from the solution. A steam-heated reboiler provides heat to the stripper column for CO_2 desorption and sensible heating of the liquid. The hot lean solution exits from the bottom of the stripper and is cooled through cross exchange with the rich solution. Warm stripper overhead gas flows to a condenser where the vapour is cooled and water is condensed. The remaining CO_2 vapour flows to a multi-stage compression train. It was assumed that the CO_2 exiting the capture plant was delivered at pipeline pressure of 11.0MPa and 30°C for all cases.

The amine based solvents investigated in this study were 7Mole Monoethanolamine (MEA), 8Mole Piperazine (Pz) and 7Mole/2Mole Methyldiethanolamine (MDEA)/Pz. The required amine circulation rates were estimated from the optimized lean and rich solvent loadings for each of the six capture reference cases at 90% CO_2 capture rate. The CO_2 concentration in the flue gas was assumed to be 11.78 volume %, and 4.09 volume % for coal-fired and natural gas-fired power plants respectively. At their respective

electric power outputs and flue gas rates, assuming 90% CO_2 removal, this equates to CO_2 removal rates of 810 tonne/hr and 365 tonne/hr for the coal-fired power and natural gas-fired power plants respectively.

For the solvent reclaiming, a slipstream of lean amine is taken from the lean amine stream downstream of the regenerator and lean amine pump (and upstream of the cross-exchanger) and continuously fed to the reclaiming unit. The material balances assumes a 0.1% slipstream ratio of solvent feed to the reclaimer compared to total circulation rate of amine within the capture process; this slipstream ratio is less than the 0.5% to 3% slipstream suggested by reclaiming vendors and given in literature, but this 0.1% slipstream was taken due to the requirement to keep solvent losses at acceptable levels. An overview of all 3 reclaiming technologies investigated in this study is presented in Table 1.

Parameters	Thermal Reclaiming	Ion Exchange	Electrodialysis
Process conditions	Atmospheric pressure, 149°C; For MDEA, 6.6-13.3kPa, 177°C	Atmospheric pressure, 40°C	Atmospheric pressure, 40°C
Amine recovery	85-95%	99%	96-98%
Heat Stable Salt removal	100%	90%	91.5%
Metal/Non-ionic product removal	100%	0%	0%
Waste characteristics	Semi solid	95% water	95% water
Equipment required	Gas-fired heater, cross exchanger, inlet separator, vapor scrubber, overhead accumulator, vacuum pump, reflux condenser, cooler and carbon filter	Neutralization and filtration (one micron pre-filter) required upstream of package ion exchange unit	Filtration, Feed pump, Membrane unit

Table 1, An overview of different reclaiming technologies

In a Thermal reclaiming process, the process is a kettele type reboiler with a packed column. The amine fed to the reboiler and the liquid level is maintained several inches above the tube bundles. The amine and water are vaporized in the kettele and sent through a packed stripping column. The vapours (water, amine and CO_2) exit the top of the column to be condensed

and sent to the lean solvent stream at the suction of the amine pump. The heavier boiling point and non-volatile impurities (heat stable salts, solids and dissolved metals) as well as a small fraction of amine based solvent and remining liquid is coming out as a thick sludge at the bottom of reclaimer and is periodically removed by a vaccum pump to a storage vessel or truck for transportation.

In Ion exchange solvent reclaiming process, the lean amine slipstream is fed into the cation exchange resin packed bed where the undesirebale cations bind to the resin and are removed from the amine stream. Then the amine is sent to the anion exchange resin bed where anion impurities are removed. The anion and cation resins are periodically regenerated by adding sulfuric acid and sodium hydroxide to the beds respecively. During this regeneration large amount of low concentration brine is produced, typically having 5% salt solution, NaOH and H_2SO_4.

Elecrodialysis solvent reclaiming process has a series of ion-selective membranes and electrodes. The amine stream is sent where cation moves towards negatively charged cathode and anion moves towards positively charged anode. A negatively charged cation exchange membrane between the anode and the waste stream prevent the anions from moving away from anode resulting in a concentrated anion waste stream. A positively charged anion exchange membrane is placed similarly between the second waste stream and the cathode to prevent the cations from moving further towards the cathode resulting in a cation waste stream.

Cost Estimation of Different Reclaiming Technologies

Different solvent reclaiming technologies were evaluated on the basis of their captial and operation costs. For the capital cost evaluation it was assumed that the concentration of heat stable salts (HSS) in the amine solution to the reclaimer is approximately 3 wt%. This figure was based on the information gathered from different literature sources which suggests that this is the approximate value of reported concentrations when amine solutions were subjected to batch reclaiming. When considering the turndown, the commercial reclaiming vendors have suggested having multiple units in parallel that can run at constant flow rates. Therefore, four parallel reclaiming units were assumed for each of the three reclaiming technologies in this study.

Figure 2 represents the coal and natural gas cases capital costs required for different reclaiming technologies for different reference solvents. It can be noticed that the costs of thermal and electrodialysis reclaiming are similar to each other for all solvents. Whereas the ion exchange reclaiming process is found to have a higher cost when compared to the other two reclaiming technologies. This is due to the higher purchased equipment cost which is manily due to the presence of six adsorption beds (two for adsorption, two for regenration and two for standby). As well the capital cost was influenced by the selection of stainless steel material for the adsorption bed and initial cost of cation and anion resins.

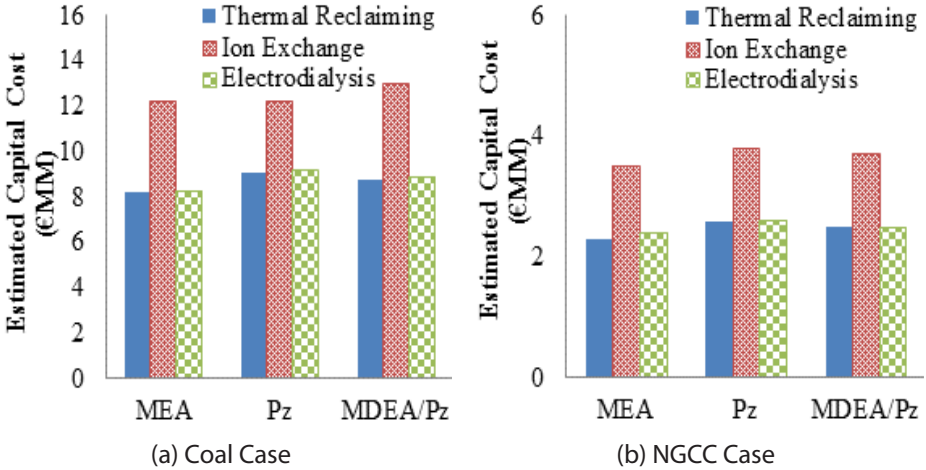

Figure 2, Estimated capital cost of different reclaiming technologies

The operational cost for different reclaiming technologies depends on the maintinance and labor cost, electricity cost, solvent loss, consumables (soldium hydroxide for HSS neutralization, sulfuric acid, sodium hydroxide for ion exchange bed regeneration, demineralzied water) and for ion exchange and electrodilaysis replacement of resin and membranes respectively. Figure 3 shows the coal and natural gas case estimated annual operating costs fo the different reference solvents.

The solvent cost has an impact on the operational cost and solvents such as Pz ($5/kg) and MDEA/Pz ($2.42/kg) have higher operational costs compared to MEA ($1.91/kg). Moreover the formation of heat stable salts is found to be

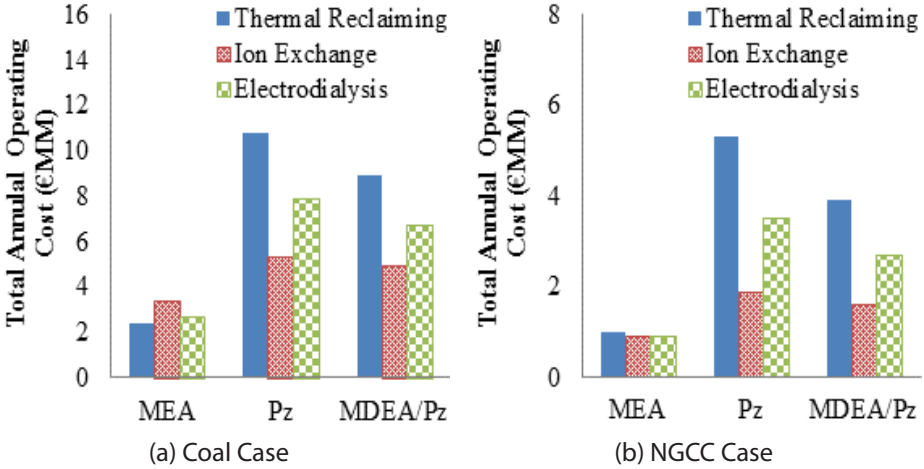

Figure 3, Estimated annual operating cost of different reclaiming technologies based on continous 0.1% slipstream ratio of solvent fed to the reclaimer

significantly lower for Pz and MDEA/Pz solvents when compared to that of MEA. On the basis of 5% solvent loss in the thermal reclaiming process for all reference solvents, Pz and MDEA/Pz, results in a higher operating cost for the coal and NGCC cases. The cost of solvent loss was noticed to be higher in electrodialysis process when compared to that of ion exchange process for coal and NGCC case.

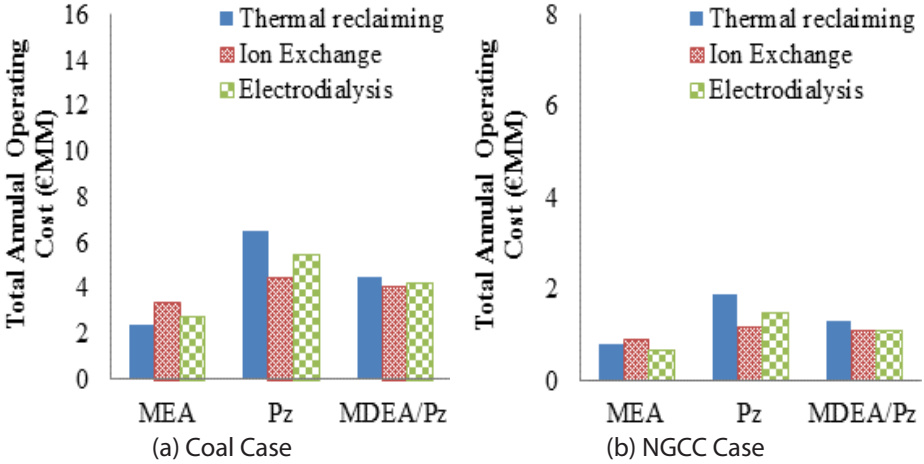

Figure 4,Estimated annual operating cost of different reclaiming technologies based on continuous <1.5 wt% heat stable salt concentration in the feed to the reclaimer

When considering the energy requirement for different reclaiming processes, thermal reclaiming was found to be the highest followed by ion exchange and electrodialysis. Hence from these results it is clear that it is important to adjust the reclaimer feed on the basis of heat stable salt formation for different solvents in order to reduce the solvent loss. Therefore, another evaluation was also performed in this study in which the <1.5wt% heat stable salt concentration was kept in the reclaimer feed.

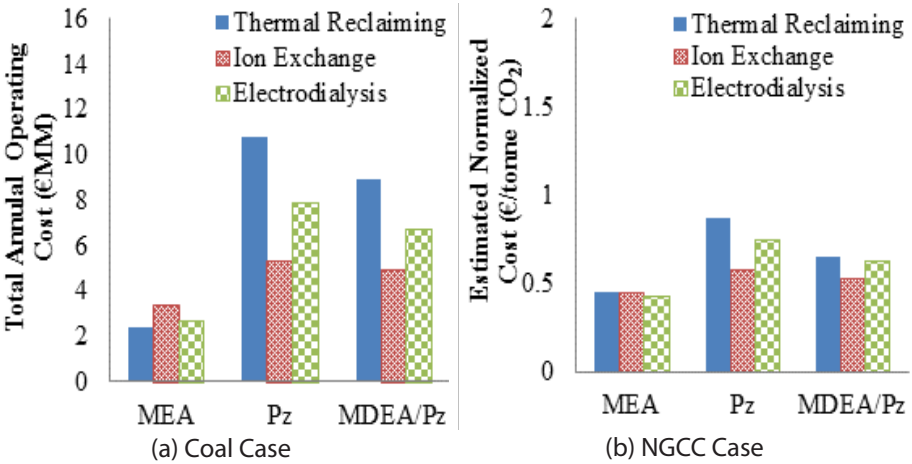

Figure 5, estimated normalized cost for different reclaiming technologies based on continous <1.5 wt% heat stable salt concentration in the feed to the reclaimer

Figure 4 shows that the annual operating cost is found to be lower when compared to the results shown in Figure 3, especially for the thermal reclaiming process where 5wt% solvent entering the reclaimer is assumed to be lost. The operational cost for ion exchange and electrodialysis is found to be lower with a constant heat stable salt concentration (<1.5wt%) feed to the reclaimer.

When considering the reclaiming cost on the basis of electricity requirement for the reclaimer it will account for 0.6 to 1.3% and 0.3 to 0.4% of total electricity demand from the CO_2 capture process for coal and NGCC cases respectively. Figure 5 shows the normalised cost '€/tonne CO_2 captured' for the coal and NGCC cases. It can be noticed that the reclaimer cost is found to be in range of 0.84 - 1.64 €/tonne CO_2 and 0.61 - 1.27 €/tonne CO_2 for coal and NGCC respectively.

Sensitivity analysis

In order to identify the effect of changes in process parameters such as increasing stripper temperature and changes in impurities concentration entering the CO_2 capture process, a sensitivity analysis for MEA and MDEA thermal reclaiming for coal case gives the following insights:

- Increasing CO_2 regeneration temperature from 120 to 150°C for MDEA case increases the higher molecular weight polymer degradation product formation, resulting in an increase in the operational cost.
- The NO_x concentration change was found to be the parameter that is affecting most the normalised cost €/tone CO_2, for both MEA and MDEA solvents. This is because the NOx concentration is directly related to HSS formation as NOx react with amine to from HSS.
- The concentration of O_2 affects the oxidative degradation; hence by increasing O_2 to 10% in flue gas increases the cost of solvent reclaiming for both MEA and MDEA.
- Corrosion metals are an important parameter affecting degradation; hence when considering zero concentration of corrosion metals in the solvent, the reclaiming cost is lowered for both MEA and MDEA.

Reclaimer Sludge Characterization

The wastes generated from three evaluated reference solvents MEA, Pz and MDEA/Pz for different reclaiming technologies were characterized according to the current regulatory structures in the US and EU. This characterization was performed by evaluating the characteristics of the CO_2 capture solvent, the metals content and the nitrosamine content. Characteristics of the other minor constituents (e.g., HEIA, HEEDA, etc.) were not considered in this evaluation. The characterization was based upon the waste composition as determined by the model in the study; no real reclaimer waste was analysed for this purpose. In practice, the generated wastes need to undergo analytical testing to definitively characterize it as hazardous or non-hazardous.

US regulations

- Thermal reclaimer wastes from coal-fired power plants may have mercury concentrations that exceed regulated limits. However, the model assumptions in this study took a conservative approach and may have

overestimated mercury content in the waste. Furthermore, use of flue gas mercury controls should be capable of reducing mercury concentration in waste to levels below regulated limits.

- The reclaimer waste generated from MDEA thermal reclaiming process for the coal case shows that the waste is non-hazardous (and thus not corrosive) unless the metal concentration exceeds the toxicity characteristic leaching procedure threshold.
- Waste streams from ion exchange and electrodialysis reclaiming process were assumed to be non-corrosive due to their high (95%) water concentration and non-corrosive pH.

Reclaimer Waste	Waste Category	EU Waste Regulation
MEA, Pz & MDEA/Pz Thermal reclaiming Coal and NGCC w/o & w additional water	Irritant	If MEA, MDEA & Pz concentration is >10%
MEA, Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Harmful	If MEA, MDEA & Pz concentration is >25%
MEA Thermal reclaiming Coal w/o water addition; Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Toxic	If MEA, MDEA & Pz concentration is >5%
MEA, Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Corrosive	If MEA and Pz concentration is > 5%
Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Carcinogenic	Pz and MDEA/Pz will produce nitrosamine which will be >0.1%
Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Sensitizing	Pz is categorized as sensitizing (R42/43)
MEA, Pz & MDEA/Pz Thermal reclaiming Coal and NGCC	Ecotoxic	Can be Ecotoxic due to presence of metal

Table 2, Overview of reclaimer waste categorization based on EU regulations 2000/523/EC

[1] Sensitizing - A waste is considered sensitizing if it is a substance or preparation which, if it is inhaled, ingested or if it penetrates the skin, is capable of the following: Eliciting a reaction of hypersensitivity; and Such that on further exposure to the substance or preparation, characteristic adverse effects are produced.

EU regulations:

Table 2 represents the categorization of the reclaimer waste generated by different solvents (MEA, PZ & MDEA/Pz) for different reclaiming technologies on the basis of EU regulations. It can be noticed that mainly thermal reclaiming waste from coal and NGCC case for all reference solvents falls into the category of Irritant, Harmful, Toxic, Carcinogenic, Corrosive, Ecotoxic. Whereas coal and NGCC case thermal reclaimer waste from Pz and MDEA/Pz is categorised as a sensitizer. This is because Pz is a categorized as sensitizer (R42/43) and no minimum concentration of sensitizer[1] was given to be characterized as hazardous. Hence, ion exchange and electrodialysis wastes from PZ and MDEA/PZ maybe categorized as sensitizing wastes.

For the MEA reclaimer waste to be characterized as carcinogenic there was no indication found in the safety data sheet for MEA of carcinogenicity. Substances are classified as carcinogenic when greater than 0.1%. Safety data sheet for PZ indicates no reports of carcinogenicity; however, thermal reclaimer wastes from PZ and MDEA/PZ processes will contain nitrosamines which are suspected carcinogens. Modelling work in the study predicted that these nitrosamines will be present in the thermal reclaimer wastes stream at a concentration above the threshold value of 0.1%.

Ion exchange and electrodialysis reclaimer waste which will contain up to 95% water were found to be not in the hazardous category. However, due to the categorization of Pz as sensitizing material these wastes may be hazardous when categorized as sensitizing wastes.

Disposal Options for Reclaimer Waste

The reclaimer waste generated from a post combustion capture process should be disposed of sustainably. Therefore, on the basis of waste categorization (non-hazardous and hazardous) the feasibility of reclaimer waste disposal options such as landfill, water incineration, cement kiln, cofiring in boiler, co-firing in NGCC HRSG, using as selective non-catalytic reduction (SNCR) reagent and power plant waste water treatment, were evaluated (see Figure 6).

The following are some important information to consider for different reclaimer waste disposal options.

- Non-hazardous and Hazardous landfill will require the complete analytical

data of the waste. The waste shall be in the solid form or solidified enough so that it does not threaten cap integrity. The thermal reclaiming waste from NGCC and coal fired power plants can be landfilled in the US but it does not meet the criteria to be landfill in the EU.

- Regarding the option of disposal in a cement kiln, the thermal reclaimer waste from MDEA/PZ coal case could provide up to 15% of the thermal input to the rotary kiln, while the coal-fired MEA reclaimer waste could only be used in very low quantities.
- The introduction of reclaimer waste especially with higher metal concentrations, sulphate or NaOH, would require an adjustment of the raw material to prevent influencing the resulting cement properties such as setting behaviour and strength development.

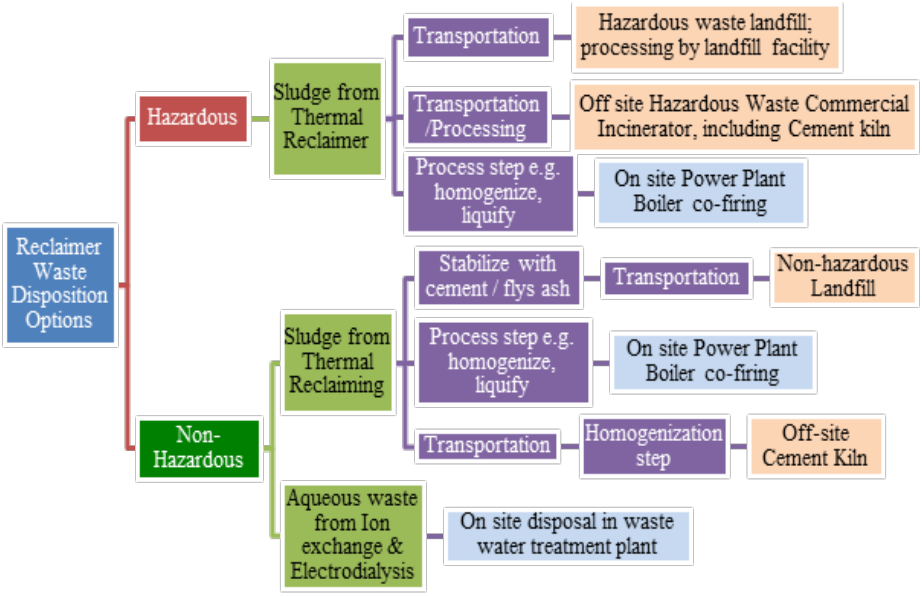

Figure 6, Disposition options for hazardous and non-hazardous reclaimer waste

- The addition of the amine sludge to a cement kiln would require additional testing to show that the kiln emissions would still comply with the applicable emission limits while using the sludge as fuel.
- When considering disposing of the reclaimer sludge in power plant

boiler, the heating value is an important factor to be considered. The undiluted thermal reclaimer waste shows heating values equivalent to typical US and EU lignite coals, while the heating value of the diluted sludge is somewhat below the heating value for German lignite.

- Based on US regulation if the reclaimer waste is not classified as a legitimate fuel and it is non-hazardous, then a utility boiler co-firing the waste would be subject to Commercial and Industrial Solid Waste Incinerator regulation (CISWI), whereas when thermal reclaimer waste is considered a hazardous waste, then a boiler firing this material would be regulated as a hazardous waste combustor under 40 CFR 261.
- In EU co-firing any amount of reclaimer waste in the boiler furnace triggers the Waste Incinerator Directive (WID); and there is no minimum threshold. For hazardous wastes containing greater than 1% halogenated organic substances, the requirement is 2 seconds retention time at a temperature of 1100°C; for all other wastes the WID require to have at least a 2 seconds residence time at 850°C in the boiler.
- When co-firing in the boiler, there will be a slight increase in SO_2 and NO_x concentration in the flue gas, which can be accommodated by flue gas desulfurization (FGD) and SNCR. Metal concentrations could increase as a result of reclaimer waste co-firing. Therefore, different emission control strategies shall be evaluated to determine the impact of the disposal of reclaimer waste.
- Reclaimer waste can also be used as a reagent in SNCR. This would require some additional consideration to be taken into account such as corrosion, which can occur due to the impurities present in reclaimer waste. The consistency of reclaimer waste concentration is very important for optimum performance, as well as the NO_x concentration can also be increased.
- The reclaimer waste generated from ion exchange and electrodialysis are more suitable to be treated in waste water treatment plant at power plant. It would require additional units to a typical power plant wastewater treatment facility, such as an advanced oxidation system and bioreactor, in order to treat the amine present in the reclaimer waste.
- A plant-specific analysis would be required to determine if existing wastewater treatment facilities could handle the additional volume from

the reclaimer waste. In the US, there are neither regulatory limits nor proposed regulatory limits specific to wastewater generated from CO_2 control technologies.

Expert Reviewers' Comments

In general most of the reviewers have found this study very comprehensive and an excellent resource for the industry and regulators summarising the latest information related to the environmental characterisation of major reclaimer waste pollutants. Reviewers suggested to include the model used to estimate the formation of degradation products, this has been taken into account and details of the model will be provided in the appendix. Reviewers have suggested including more information on the nitrosamine formation and counter measures to remove them. Information on nitrosamine formation from NO_2 and an estimated nitrosamine mass flow rate in reclaimer waste is included along with information on destruction of nitrosamine. One of the reviewers has emphasised that besides demonstration projects for post combustion capture processes it is also required to develop environmental standards and procedures for the post combustion capture plants.

Conclusions

This study gives an insight into the reclaimer waste generated by the conventional amine based solvents used for CO_2 post combustion capture processes, as well as characterizing the reclaimer waste based on US and EU regulation and identifying the most suitable reclaimer waste disposal options. It was noticed that for the solvents studied: monoethanolamine (MEA), piperazine (PZ), and methyldiethanolamine/piperazine (MDEA/PZ), oxidative degradation contributes more to the solvent loss than thermal degradation or volatile losses. In the NGCC cases higher formate concentration was found due to greater oxidation, but lower overall contaminant accumulation which is due to the lower concentration of SOx and NOx entering in the flue gas. For coal based power plants, thermal reclaiming may be the preferred option as it is the most robust solvent reclaiming method that will remove a majority of all types of degradation products and impurities from the amine solvent such as heat stable salts, high molecular weight polymeric products and transition metals. Whereas for natural gas based power plants ion exchange and electrodialysis solvent reclaiming process is more preferred as these

technologies are most effective when extremely high incursion rates of heat stable salts are present.

Regarding to the reclaimer waste characterization, based on US regulation the coal-fired thermal reclaimer waste is likely to be classified as hazardous due to the presence of metals (from coal cases such as cadmium, lead, chromium, arsenic), whereas thermal reclaimer wastes from NGCC power plants do not contain metals and will not be classified as hazardous. In the EU the thermal reclaimer wastes from both the coal-fired and NGCC power plants would likely to be considered hazardous. The waste streams from the ion exchange and electrodialysis waste contain up to 95% water. In the US regulations these wastes will not be classified as hazardous, whereas in the EU due to Pz classified as sensitizing, the reclaimer waste from ion exchange and electrodialysis process for PZ and MDEA/PZ solvent may be classified as hazardous. Various reclaimer waste disposal options were investigated by looking into waste landfilling, combustion in a waste incinerator, firing in a cement kiln, firing at the power plant and handing in the waste water treatment plant. Thermal reclaimer waste has the potential to provide heating value (MDEA/Pz ~15% of total fuel heating value); hence this waste may be suitable for disposal in a cement kiln or co-firing in a power plant boiler. There will be regulation which will be required to be considered when disposing of reclaimer waste in a cement kiln or co-firing into the boiler at power plant. Moreover the impacts on emissions will also be looked into. Ion exchange and electrodialysis reclaimer waste is diluted waste hence, is most suitable to be disposed of in waste water treatment plant, which will require additional equipment to a standard power plant waste water treatment plant. Overall, it is considered that reclaimer wastes generated by different type of amine based CO_2 solvent can be disposed of sustainably.

Recommendations to Executive Committee

Based on the outcome from this study IEAGHG would like to highlight that the next step in the area of amine based solvent reclaimer waste will be to evaluate reclaimer waste from real pilot plants and based on that data identifying the most suitable disposal option. This type of work is however not part of IEAGHG main activities. Hence, IEAGHG would like to give recommendations to the researchers and engineers active in this area on some important areas for future work. During upset conditions the impurities in the solvent will be

affected; hence solvent reclaiming should be evaluated under process upset conditions to identify the cost of reclaiming specifically for ion exchange and electrodialysis. There will be some nitrosamine present in the reclaimer waste; hence further work is required to reduce the nitrosamine in the reclaimer waste. This can be achieved by NO_2 and SO_2 polishing as well as by UV treatment for complete destruction of nitrosamine. Corrosion should be minimized in thermal reclaiming process by implementing cathodic protection.

It is important to develop technologies for the selective removal of impurities in order to remove transition metals together with heat stable salts. This can be achieved by implementing a combination of solvent reclaiming technology such as thermal reclaiming (for non-ionic compounds) in combination with ion exchange (for heat stable salts). IEAGHG would like to recommend that the characterization of reclaimer waste from a real plant is very important in order to determine the procedure for waste handling and identify the most suitable waste disposal options. This will also allow the plant operators to set up standards, procedures and communication required for environmental agencies.

CO_2 CAPTURE AT COAL-BASED POWER AND HYDROGEN PLANTS (2014-03)

Key Messages

- This study provides an up-to-date assessment of the performance and costs of coal-based power and hydrogen plants with and without CO_2 capture.
- The thermal efficiencies of power plants with CCS based on pulverised coal firing with oxy-combustion or post combustion capture, and IGCC with pre-combustion capture are all around 35% (LHV basis), which is around 9 percentage points lower than a reference pulverised coal plant without capture.
- The levelised cost of electricity is about 92 €/MWh for plants with oxy-combustion or post combustion capture and 115 €/MWh for IGCC plants with pre-combustion capture. This is about 75-125% higher than the reference pulverised coal plant without CCS.
- Costs of CO_2 emission avoidance compared to the reference plant are 60-100 €/t.
- The rate of CO_2 capture in oxy-combustion and IGCC plants could be increased from 90% to 98%, while reducing the cost per tonne of CO_2 emissions avoided by 3%.
- Net CO_2 emissions of a plant with post combustion capture could be reduced to zero by co-firing 10% biomass (on a carbon basis), without increasing the cost per tonne of CO_2 avoided, depending on the price of biomass.
- The raw water requirements of the pulverised coal power plants with CCS could be reduced to near zero by using seawater or air cooling. For the ambient conditions considered in this study this would have little impact on the efficiency (<1 percentage point) and capital cost (<2%).
- The efficiency of producing hydrogen by coal gasification with CCS would be 58% LHV basis (65% HHV basis) and the levelised cost of production would be 16.1 €/GJ LHV basis (13.6 €/GJ HHV basis).

Background to the Study

In recent years, IEAGHG has undertaken a series of studies on the performance and costs of plants incorporating the three leading CO_2 capture technologies: post combustion, oxy-combustion and pre-combustion capture. In the time since those studies were undertaken there have been significant technological advances and substantial increases in estimated plant costs. IEAGHG therefore decided to undertake a wholly new study on costs of capture at coal based plants producing the two leading low-carbon energy carriers, namely electricity and hydrogen. This study provides a baseline for possible future studies on plants in other countries, plants using other capture processes and capture in industries other than power and hydrogen generation. The study was carried out for IEAGHG by Foster Wheeler.

It should be noted that the focus of this study is to provide an up-to-date technical and economical assessment of coal-fired power and hydrogen plants with CCS. The study does not aim to provide a definitive comparison of different technologies or technology suppliers because such comparisons are strongly influenced by specific local constraints and by market factors, which can be subject to rapid changes.

Scope of Work

Study cases

The study assesses the design, performance and costs of the following coal based power generation plants.

- Supercritical pulverised coal power plant without CO_2 capture (reference plant)
- Supercritical pulverised coal power plant with post combustion capture based on CANSOLV solvent scrubbing
- Supercritical pulverised coal power plant using oxy-combustion
- IGCC plant based on GE slurry feed, oxygen blown gasification and pre-combustion capture using Selexol solvent scrubbing
- IGCC plant based on Shell dry feed, oxygen blown gasification and pre-combustion capture using Selexol solvent scrubbing
- IGCC plant based on MHI dry feed, air blown gasification and pre-

combustion capture using Selexol solvent scrubbing

The study also assesses the following hydrogen production plants, all based on GE oxygen blown gasification and Selexol solvent scrubbing:

- Plant with high net electricity co-production, including two 130MWe E class gas turbines
- Plant with intermediate net electricity co-production, including two 77MWe F class gas turbines
- Plant with low electricity co-production, including a PSA off-gas fired boiler.

All of these baseline plants have 90% CO_2 capture. This is expected to be adequate for early CCS plants but some overall energy system models have shown that in the longer term, when national and global emission limits will be tighter, the emissions of the residual non-captured CO_2 may be a significant constraint on the amount CCS, particularly coal-based CCS, that can be accommodated in the overall energy system. If CCS plants emit significant amounts of CO_2 it will be necessary to apply even tighter emission controls to other areas of human activity, such as transport and agriculture, which could involve very high greenhouse gas abatement costs. This study assessed the technical feasibility and costs of achieving a higher level of CO_2 capture (around 98%) in oxy-combustion and IGCC plants. In the oxy-combustion case this was achieved by passing the vent gas from CO_2 purification through a membrane separation unit. For gasification based plants an additional MDEA solvent scrubbing stage was added after the Selexol scrubber.

An alternative way of achieving near-zero net emissions of CO_2 would be to co-fire some biomass, assuming that biomass that is produced in a sustainable way has near-zero net emissions of CO_2. Biomass could be used in post, pre and oxy-combustion capture plants. This study assesses a plant with 90% post combustion capture and sufficient co-firing of woody biomass to achieve zero net emissions.

Another possible constraint on the large scale application of CCS in some places may be water availability. To complement the base case plants which use natural draught cooling towers, sensitivity cases based on once-through sea water cooling and dry air cooling were assessed.

In addition to the sensitivities to percentage CO_2 avoidance and the type of cooling system, the study also assessed the sensitivities to various economic parameters, including the coal price, capacity factor, discount rate, plant life, CO_2 transport and storage cost and CO_2 emissions cost.

Technical and economic basis

The technical and economic basis for the study is described in detail in the main study report. The main base case assumptions are:

- Greenfield site, Netherlands coastal location
- 9C ambient temperature
- Natural draught cooling towers
- Eastern Australian internationally traded bituminous coal (0.86% sulphur a.r., 25.87 MJ/kg LHV)
- Coal price: €2.5/GJ LHV basis (equivalent to €2.39/GJ HHV basis)
- 2Q 2013 costs
- Discount rate: 8% (constant money values)
- Operating life: 25 years
- Construction time: Pulverised coal plants - 3 years, Gasification plants – 4 years
- Capacity factor: Pulverised coal plants – 90%, Gasification plants – 85%
- CO_2 transport and storage cost: €10/t stored

The pulverised coal plant without capture is based on a single boiler, a net output of around 1000MWe and state-of-the-art steam conditions (27MPa, 600/620C) as used in new large coal fired power plants in Europe and Japan. The pulverised coal plants with post combustion and oxy-combustion capture have the same coal feed rate but lower net power outputs of 820-840 MWe due to the energy consumption for capture. The coal feed rate of the IGCC plants is determined by the fuel feed rate of the two gas turbines, which are state of the art 50Hz F-class turbines suitable for high hydrogen content gas. The net power outputs of the IGCC plants are in the range of 800-880MWe, i.e. similar to the pulverised coal plants with capture.

Cost definitions

Capital cost

The cost estimates were derived in general accordance with the White Paper

"Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants", produced collaboratively by authors from IEAGHG, EPRI, USDOE/NETL, Carnegie Mellon University, IEA, the Global CCS Institute and Vattenfall[1].

The capital cost is presented as the Total Plant Cost (TPC) and the Total Capital Requirement (TCR).

TPC is defined as the installed cost of the plant, including project contingency. In the report TPC is broken down into:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency

TCR is defined as the sum of:

- Total plant cost (TPC)
- Interest during construction
- Owner's costs
- Spare parts cost
- Working capital
- Start-up costs

For each of the cases the TPC has been determined through a combination of licensor/vendor quotes, the use of Foster Wheeler's in-house database and the development of conceptual estimating models, based on the specific characteristics, materials and design conditions of each item of equipment in the plant. The other components of the TCR have been estimated mainly as percentages of other cost estimates in the plant. The overall estimate accuracy is in the range of +35/-15%.

Levelised cost of electricity

Levelised Cost of Electricity (LCOE) is widely recognised as a convenient tool for comparing the unit costs of different technologies over their economic lifetime. LCOE is defined as the price of electricity which enables the present

[1] Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants, IEAGHG Technical Review 2013/TR2, March 2013.

value from all sales of electricity over the economic lifetime of the plant to equal the present value of all costs of building, maintaining and operating the plant over its lifetime. LCOE in this study was calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from lower capacity factors in the first two years of operation.

The Levelised Cost of Hydrogen (LCOH) is calculated in the same way except that it is necessary to take into account the revenue from the sale of electricity co-product. It was assumed that the value of the electricity co-product is the cost of production in the IGCC plant that uses the same gasification and CO_2 capture technology as the hydrogen production plants, i.e. the GE gasification plant. If the lowest cost CCS power generation technology had been used to value the electricity output, the LCOH would have been higher.

Cost of CO_2 avoidance

Costs of CO_2 avoidance were calculated by comparing the CO_2 emissions per kWh and the levelised costs of electricity of plants with capture and a reference plant without capture.

$$CO_2 \text{ avoidance cost (CAC)} = \frac{LCOE_{ccs} - LCOE_{Reference}}{CO_2 \text{ Emission}_{Reference} - CO_2 \text{ Emission}_{ccs}}$$

Where:
CAC is expressed in Euro per tonne of CO_2
LCOE is expressed in Euro per MWh
CO_2 emission is expressed in tonnes of CO_2 per MWh

A pulverised coal plant without capture was used as the reference plant in all cases because the current power plant market indicates that this would in most cases be the preferred technology for coal fired plants without capture. The energy efficiency penalty for capture and the cost of CO_2 avoidance would be different if an alternative reference plant was used, for example an IGCC or a gas fired plant without capture.

Findings of the Study

Power generation plants

Plant performance

A summary of the performance of the baseline power plants with and without capture is given in Table 1.

	Net Power Output	CO_2 Captured	CO_2 Emissions	Efficiency		Efficiency Penalty for Capture (LHV)
				HHV	LHV	
	MW	kg/MWh	kg/MWh	%	%	% Points
Pulverised Coal						
No Capture (Reference Plant)	1030	-	746	42.2	44.1	
Post Combustion Capture	822	840	93	33.6	35.2	8.9
Oxy-Combustion	833	823	92	34.1	35.7	8.4
IGCC						
Shell, Oxygen-Blown	804	837	93	33.9	35.5	8.6
GE, Oxygen-Blown	874	844	94	33.3	34.9	9.2
MHI, Air-Blown	863	842	104	33.2	34.8	9.3

Table 1, Power plant performance summary, pulverised coal plants

The efficiencies and CO_2 emissions of the plants with capture are all broadly similar, the difference between the highest and lowest efficiency is less than 1 percentage point. Future technology improvements, such as development of improved solvents, air separation units and gas turbines, could change the relative efficiencies of the processes. For example, Cansolv reported that they have undertaken pilot plant tests with an improved solvent which is expected to achieve a 20% reduction in steam consumption compared to the

figures they provided for use in this study and there would also be other cost improvements. They hope to commercialise this solvent in the near future.

The efficiency penalties for oxy-combustion and post combustion capture are towards the bottom of the range in published data[2], demonstrating the improvements in capture technologies and thermal integration. Most published studies compare the efficiencies of IGCC plants with capture against IGCC plants without capture, so the efficiency penalties in those studies are not comparable to those shown in table 1. However, the average efficiency of IGCCs with capture in this study is similar that of published studies[2].

CO_2 capture almost eliminates SO_x emissions and also reduces NO_x emissions, except for the post combustion capture case which has specific emissions about 25% higher than the reference plant, due to the lower thermal efficiency.

Capital cost

The capital costs of the plants are summarised in Table 2 and breakdowns of the total plant costs are given in Figures 1 and 2.

	Total Plant Cost (TPC)	Total Capital Requirement (TCR)	TPC increase compared to the reference plant
	€/kW	€/kW	%
Pulverised coal plants			
No capture (reference plant)	1447	1887	
Post combustion capture	2771	3600	91
Oxy-combustion	2761	3583	91
IGCC plants			
Shell oxygen-blown	3157	4350	118
GE oxygen-blown	3074	4238	112
MHI air-blown	3046	4200	110

Table 2, Capital costs of electricity generation plants

[2] Cost and performance of carbon dioxide capture from power generation. M. Finkenrath, IEA, 2011.

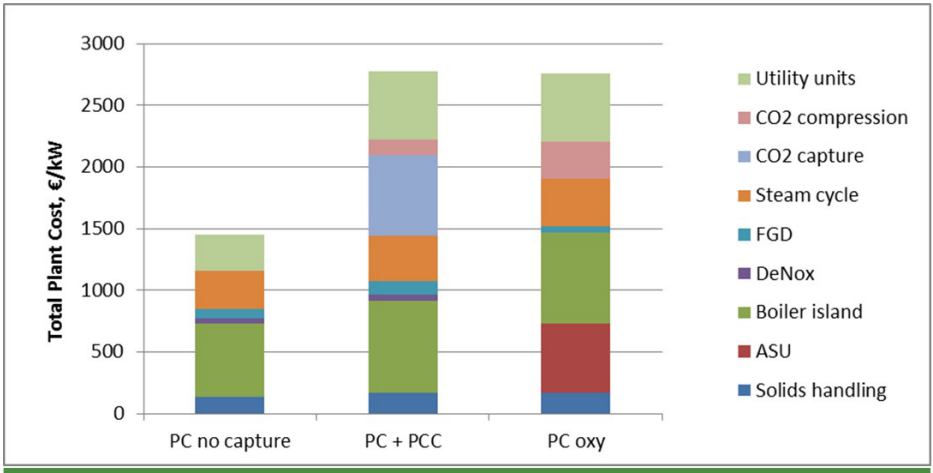

Figure 1, Specific Total Plant Cost of pulverised coal plants

Including capture increases the specific cost per kWe of the pulverised coal cases by 91% compared to the pulverised coal reference plant. This cost increase is partly due to the cost of additional plant required for capture and partly due to the reduced net power output per unit of thermal capacity, e.g. boiler size. There is no significant difference between the specific capital costs of the post combustion capture (PCC) and oxy-combustion plants. The main cost of additional plant for oxy-combustion is the cost of the Air Separation Unit (ASU). The cost of the 'CO_2 compression' unit is higher in the oxy-combustion plant than in the post combustion plant because the volume of gas to be compressed is greater, due to the presence of impurities, and due to the cost of the CO_2 Processing Unit (CPU) which removes the impurities. The CPU is included in the 'CO_2 compression' unit cost in Figure 1, although it could also be considered to be a type of 'CO_2 capture' unit.

The specific capital costs of the three IGCC plants with capture are similar and they are 110-118% higher than the cost of the pulverised coal reference plant, The MHI air blown gasifier plant has higher costs for gasification, syngas treating and acid gas removal (AGR), which is to be expected due to the higher volume of the fuel gas but it avoids the cost of a large ASU[3].

[3] Note, the MHI gasifier plant includes a small ASU which provides nitrogen for coal feeding but the vendor included this in the cost of the gasification unit

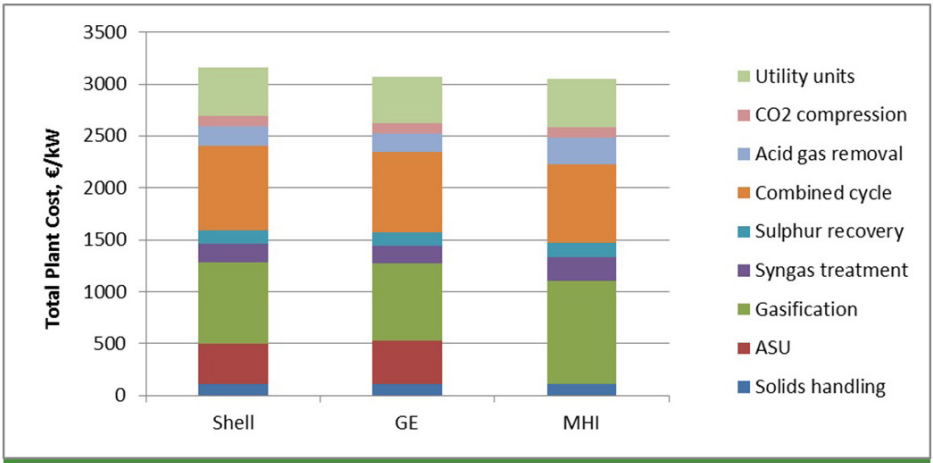

Figure 2, Specific Total Plant Cost of IGCC plants

Levelised costs of electricity and CO_2 avoidance cost

Levelised costs of electricity (LCOE) and CO_2 avoidance cost (CAC) are shown in Table 3 and Figure 3. The costs of the IGCC plants are higher than pulverised coal combustion plants, mainly because of higher capital costs and fixed operating and maintenance (O+M) costs, particularly maintenance costs.

	Levelised Cost of Electricity		CO_2 Avoidance Cost
	€/MWh	% increase compared to the reference plant	€/tonne
Pulverised coal plants			
No capture (reference plant)	52.0		
Post combustion capture	94.7	82	65.4
Oxy-combustion	91.6	76	60.8
IGCC plants			
Shell oxygen-blown	116.5	124	98.9
GE oxygen-blown	114.4	120	95.8
MHI air-blown	114.5	120	97.4

Table 3, Levelised cost of electricity and CO_2 avoidance cost

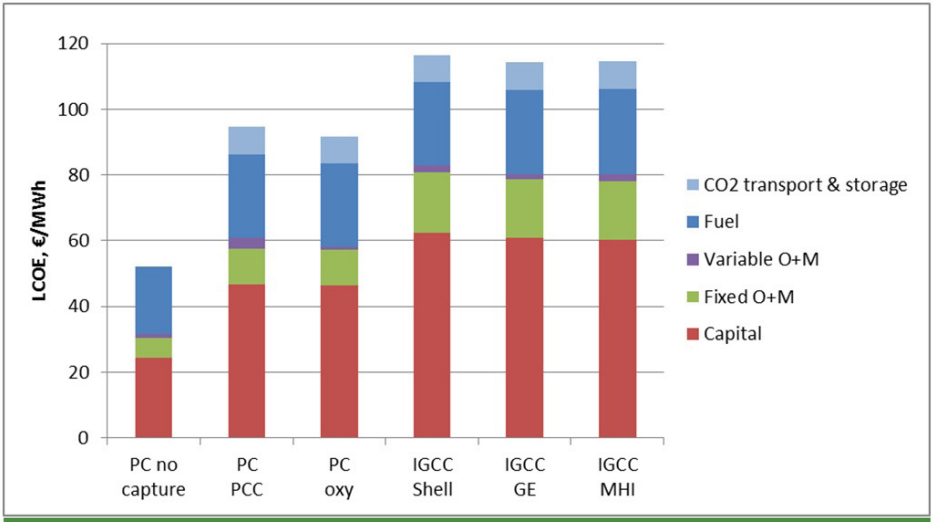

Figure 3, Levelised Costs of Electricity

Hydrogen plants

A summary of the performance of the baseline hydrogen plants with capture is given in Table 4. The plants co-produce electricity, to satisfy the plants' own consumption and they also provide some net output, as described earlier. The 'Net efficiency to hydrogen' in Table 4 is calculated by assuming that the net power output displaces electricity generated by a GE gasification IGCC plant with CO_2 capture. It should be noted that while the efficiencies of coal fired power plants are higher on an LHV basis than on an HHV basis, hydrogen plants have a higher efficiency on an HHV basis.

	Hydrogen output	Net power output	Efficiency to hydrogen	Efficiency to net power	Net efficiency to hydrogen	
			LHV	LHV	HHV	LHV
	MW	MW	%	%	%	%
High electricity	659	448	26.3	17.8	60.9	53.8
Medium electricity	969	289	38.6	11.5	65.3	57.7
Low electricity	1390	37	55.4	1.5	65.5	57.9

Table 4, Hydrogen plant performance summary

Capital costs of the hydrogen production plants are shown in Table 5 and the levelised costs of hydrogen (LCOH) are given in Table 6. For the calculation of LCOH, the electricity co-product is valued at 114.4 €/MWh, i.e. the production cost of the corresponding IGCC case (GE gasifier). Similarly, the capital cost associated with electricity production in the IGCC plant is subtracted from the capital cost of the co-production plants to give the specific capital cost of hydrogen production.

	Total Plant Cost (TPC)	Total Plant Cost (TPC)	Total Capital Requirement (TCR)
	M€	€/kWH net	€/kWH net
High electricity co-production	2461	1646	2272
Medium electricity co-production	2390	1549	2137
Low electricity co-production	2101	1430	1974

Table 5, Capital costs of hydrogen plants

	Levelised Cost of Hydrogen (LCOH), €/GJ	
	HHV basis	HHLHV basis
High electricity co-production	15.4	18.2
Medium electricity co-production	14.4	17.0
Low electricity co-production	13.6	16.1

Table 6, Levelised cost of hydrogen

The highest net efficiency to hydrogen and the lowest cost of hydrogen production are achieved by the plant with the lowest amount of electricity co-production, which is based on feeding the PSA off-gas to an on-site boiler.

Plant design sensitivity cases

Near-zero emission plants

The performance and costs of the plants with near-zero emissions are summarised in Table 7, which also shows the change in costs compared to plants with 90% capture. Increasing the percentage CO_2 abatement reduces the efficiency and increases the capital cost and LCOE. The largest increase in LCOE is for the biomass co-firing case and the lowest is for the oxy-combustion

case. The CO_2 abatement costs per tonne are lower for the near-zero emission cases than for the 90% capture cases. In the case of oxy-combustion this is because capturing CO_2 from the vent gas from the CO_2 purification unit is relatively simple and low cost. In the case of IGCC, the reasons for the cost reduction are more complex. The cost of CO_2 abatement comprises the cost of cost of capture (shift conversion, CO_2 separation etc.) and the higher cost of the core IGCC process without capture compared to a pulverised coal plant without capture. Although the cost of capturing each extra tonne of CO_2 in an IGCC may be higher in the near-zero emissions case than in the 90% capture case, the extra costs for the core IGCC units compared to a pulverised coal plant remain the same. This cost is spread over a greater number of tonnes of CO_2 captured, resulting in a lower specific cost.

	Efficiency		TPC		LCOE		CAC	
	%	% pt. change	€/kW	€/kW change	€/ MWh	€/MWh change	€/t	€/t change
PCC+biomass (100% abatement)	34.6	-0.6	2887	+115	100.5	+5.8	65.1	-0.3
Oxy-combustion (97.6% capture)	35.3	-0.4	2823	+62	94.2	+2.6	58.3	-2.5
IGCC (98.6% capture)	34.1	-0.8	3203	+128	119.2	+4.8	92.5	-3.3

Table 7, Near-zero emission plants

It should be noted that biomass could also be used in oxy-combustion and IGCC plants and greater proportions of biomass could be used, thereby achieving 'negative emissions'. However, availability of biomass fuel may be limited due to competition with other land uses such as food production and natural habitats. Also, biomass may have a higher value for abatement of CO_2 emissions in other sectors where other low-CO_2 options are more limited, such as production of biofuels for transport. This study has shown that even if biomass availability is a constraint, it would be possible to build CCS plants with near-zero emissions, if required, without increasing the specific cost of CO_2 abatement.

A near-zero emission variant of the hydrogen plant with low electricity co-production was also assessed. The net efficiency to hydrogen (LHV basis) was 0.9% points lower than the 90% capture case and the TPC was 4.4% higher.

Cooling system sensitivity

The net raw water requirements of the power plants with CCS are 22-28% higher than that of the reference plant without capture. However, alternative cooling systems can be used to reduce the net water requirement of power plants with CCS to near zero in the case of oxy-combustion and post combustion capture and by around 70% in the case of IGCC. For the ambient conditions considered in this study, using once-though seawater cooling instead of natural draught cooling towers increases the thermal efficiency of plants with CCS by 0.5-0.7 percentage points and using air cooling reduces the efficiencies by 0.2-0.7 percentage points. This is mainly due to the effects on the turbine condenser pressure. Both of these cooling systems reduce the total plant cost by 1.5%. However, at higher ambient temperatures air cooling is expected to have a more negative impact.

Economic sensitivities

The costs of CCS depend on economic parameters which will vary over time and between different plant locations. It is important therefore to consider the sensitivity of costs to variations in parameters. The sensitivity to the coal price, economic discount rate, plant life, cost of CO_2 transport and storage, operating capacity factor and the cost penalty for non-captured CO_2 emissions were assessed. Sensitivities were assessed for all of the main study cases and the results for each parameter are presented in graphical format in the main report. As an example, sensitivities for the pulverised coal plant with post combustion capture are shown in Figure 4. The results would be similar for the oxy-combustion plant.

Coal price can vary over a wide range due to local coal availability and mining costs and market variability. Varying the coal price by ±1.5 €/GJ from the base case of 2.5 €/GJ changes the LCOE by ±15.5 €/MWh.

The operating capacity factor of the plant may be lower than the 90% base case assumption in this study, either because of poor reliability and availability of the plant or because of electricity system constraints, i.e. other power

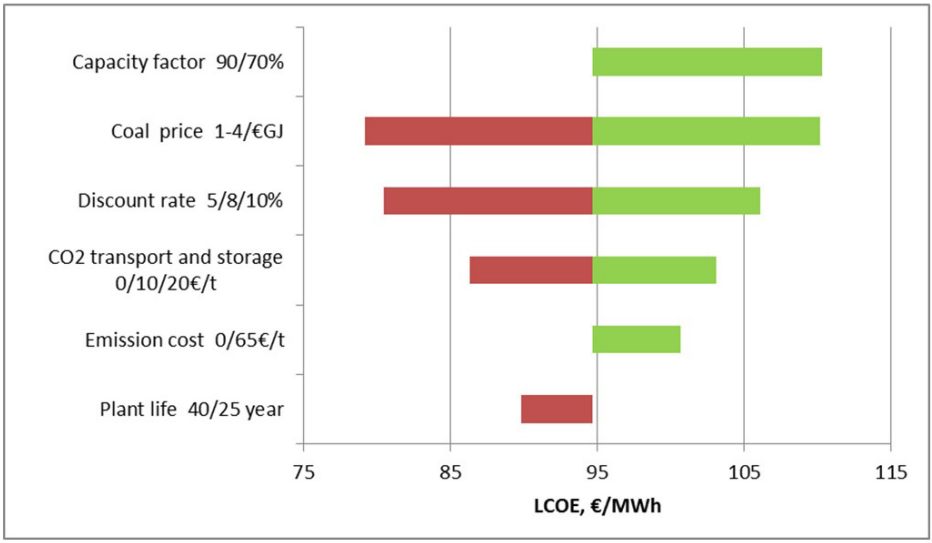

Figure 4, Sensitivities of Levelised Cost of Electricity (plant with post combustion capture)

generators with lower marginal operating costs being operated in preference to CCS plants at times of low power demand. Reducing the capacity factor can have a substantial effect of the LCOE. Figure 4 shows that reducing the capacity factor from 90% to 70% would increase the LCOE by 15.6 €/MWh. If the plant operates at a low capacity factor because of electricity system constraints the impacts on plant profitability and rate of return may be much less significant because the times when the plants are forced to not operate would by definition be times of low electricity prices. However, this is difficult to assess because electricity prices depend on the costs of the other generating plants in the overall electricity system.

Costs of CO_2 transport and storage are expected to vary considerably between different sites. At sites where CO_2 can be sold, for example for enhanced oil recovery, the net cost may be zero or even negative. If the CO_2 has to be transported a long distance in a relatively small pipeline for offshore storage the cost would be substantially greater than the 10 €/t base case scenario in this study. Sensitivities to costs in the range of zero to 20 €/t of CO_2 stored are shown in Figure 4 but the range of costs may be higher in some circumstances.

The main economic evaluation in this study does not include a cost for emitting non-captured CO_2 to the atmosphere. Including a cost that is equal to the cost of CO_2 abatement by CCS in this plant, i.e. 65 €/t CO_2, would increase the LCOE by 6 €/MWh.

The LCOE is relatively insensitive to increasing the plant life from 25 to 40 years, because of the effects of economic discounting. The sensitivities of CO_2 avoidance cost (CAC) to variations in the economic parameters are shown in Figure 5.

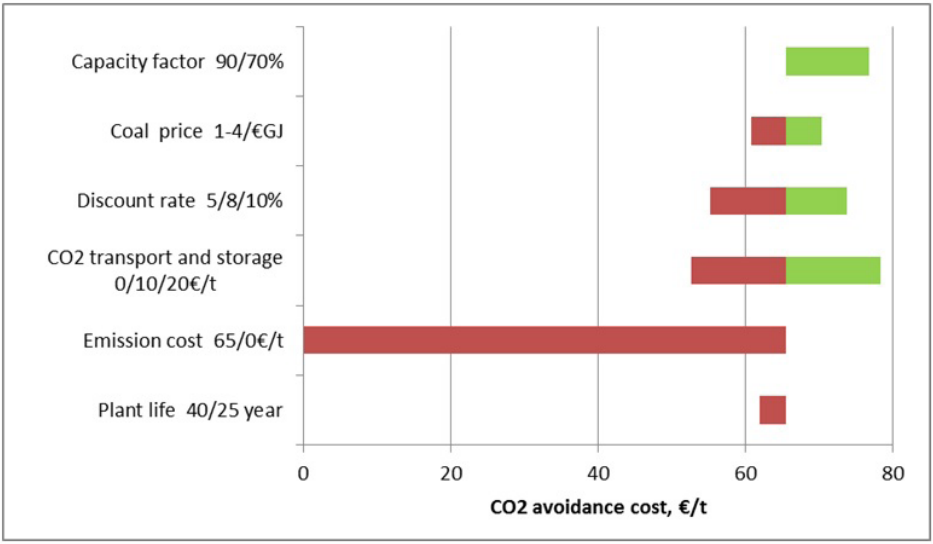

Figure 5, Sensitivities of CO_2 avoidance cost (plant with post combustion capture)

It can be seen that variations in the CO_2 emission cost, which has relatively little impact on the LCOE of the plant with capture, has by far the largest impact on the CO_2 avoidance cost, because it has a large impact on the LCOE of the reference plant. Conversely, the coal price, which has a relatively large impact on the LCOE of the plant with capture has a relatively small impact on the avoidance cost, because it has impacts on both plants, the only difference being due to the lower efficiency of the plant with capture. Apart from the emissions cost, the parameter which has the greatest impact on the avoidance cost, for the ranges considered in this study, is the CO_2 transport and storage cost, which obviously only affects the costs of the plant with

capture.

Plot areas

Preliminary plot plans were produced for the baseline plants with and without capture. The area of the reference plant without capture is 20ha. The inclusion of CO_2 capture increases the area to 26ha for the boiler-based cases and 29ha for the IGCC cases.

Expert Review Comments

Comments on the draft report were received from reviewers at six organisations in the power industry, CCS project development and research. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard. The contractor provided IEAGHG with responses to all of the comments and made appropriate modifications to the report.

The main critical comment was by a reviewer who said that if different gasifier designs had been selected for the IGCC and hydrogen cases, the results would have been more favourable. The choice of gasifiers for this study depended on the availability of licensors to support the study at the time it was carried out and the technology variants they wanted to offer. The CO_2 purity specification was also questioned but CO_2 purity is still a subject for debate. IEAGHG is currently undertaking a study to assess the effects of impurities on CO_2 transportation.

Conclusions

- The thermal efficiencies of power plants with CCS based on pulverised coal combustion with post combustion capture, oxy-combustion and IGCC with pre-combustion capture are 34.8 - 35.7% LHV basis, which is around 9 percentage points lower than a reference pulverised coal plant without capture.
- The levelised cost of base load electricity generation is about 92 €/MWh for boiler-based plants with oxy-combustion or post combustion capture and 115 €/MWh for IGCC plants with pre-combustion capture. This is about 75-125% higher than the reference pulverised coal plant without CCS.

- Costs of CO_2 emission avoidance compared to the reference plant are 60-65 €/t for boiler based plants with CCS and 95-100 €/t for IGCC plants.
- Increasing the rate of CO_2 capture to 98% in oxy-combustion and IGCC plants would increase the cost of electricity by 3-5% but reduce the cost per tonne of CO_2 emissions avoided by 3%.
- Co-firing biomass can be used to reduce net CO_2 emissions of plants with CCS to zero, assuming biomass is regarded as a 'zero net CO_2' fuel. In a plant with post combustion capture this increases the cost of electricity by 6% and has no impact on the cost of CO_2 avoidance, but the cost depends strongly on the cost of biomass, which depends on its availability.
- The net efficiency of producing hydrogen by coal gasification with CCS is 57.8% on an LHV basis (65.5% HHV basis) and the levelised cost of hydrogen is 16.1 €/GJ LHV basis (13.6 €/GJ HHV).
- Alternative cooling systems could be used to reduce the water requirements of pulverised coal power plants with CCS to close to zero and reduce the requirement for IGCC with CCS by around 70%. For the ambient conditions of this study, using sea-water cooling instead of cooling towers increases the thermal efficiency by a maximum of 0.7 percentage points and using air cooling reduces the efficiency by a maximum of 0.7 percentage points. Both cooling systems reduce the capital cost by 1.5%. It is expected that air cooling would have more negative impacts at higher ambient temperatures.

Recommendations

- The performance and costs of plants with without CCS will depend on local conditions, such as ambient conditions, fuel analyses and costs, and plant construction and operating costs. This study which is based on a site in the Netherlands could be extended to assess plants at other sites world-wide, particularly in developing countries which are expected in future to account for a large proportion of the global stock of coal fired power plants.
- Various new capture technologies are currently being developed, offering the prospect of lower energy consumptions and costs. When sufficient information becomes available further studies should be undertaken to assess such processes on a consistent basis to this study.

- This study assesses the relative costs of producing electricity and hydrogen with CCS, on a consistent basis. This information could be used as an input to further studies to assess the optimum low carbon energy carriers for different energy consuming sectors.

EVALUATION AND ANALYSIS OF THE PERFORMANCE OF DEHYDRATION UNITS FOR CO_2 CAPTURE (2014-04)

Key Messages

- A number of suitable technologies for CO_2 dehydration exist. This study focusses on a comparison of molecular sieve and triethylene glycol (TEG) systems.
- Consideration of multiple dehydration technologies in series can be beneficial, e.g. a more basic technique can offload the main dehydration unit resulting in cost reduction.
- It is possible to protect dehydration systems that are sensitive towards certain impurities against degradation by using guard beds or additional upstream treatment.
- The minimum CAPEX and OPEX for both molecular sieve and TEG systems depend mainly on operating pressure and type of regeneration.
- In case of high inerts, the CAPEX will increase for both molecular sieve and TEG systems.
- Presence of NO_x, SO_x and H_2S leads to a 7% higher CAPEX but no significant difference in OPEX for molecular sieve systems. Currently, it is not possible to evaluate the effect of impurities on the costs of TEG systems.
- Due to lack of vendor support, the information on costs and operation is somewhat preliminary, fragmentary and uncertain. Re-engagement of vendors will be a priority for future projects and studies.

Background to the Study

The dehydration step is a small part within the full CO_2 capture and storage chain yet this unit plays an important role in maintaining the integrity of the system. In the past, this step usually appeared as a black box process, with little information available on its detailed design. However, the conventional drying technologies face a number of challenges that need consideration before full-scale deployment. These include, for example, the effect of impurities in the captured CO_2 stream on the dehydration process.

IEAGHG commissioned AMEC to carry out this study in order to examine the

characteristics of the various drying processes and their integration into the CCS system.

Scope of Work

The scope of work for this study comprises four main elements:

1. Evaluation and characterisation of processes for the dehydration of captured CO_2
2. Preparation of guidance on the selection of processes to match the various requirements for water dryness of CO_2
3. Evaluation of methods for monitoring and management of water dryness
4. Analysis of future drying technology developments

AMEC used information available from the different capture processes to produce a set of dehydration feed gas compositions. Base case data represent the minimum and normal impurity levels. Water content of saturated gas depends on the temperature and pressure of the gas stream. Several test cases consider higher levels of impurities and inerts.

This study investigates three different moisture levels: 550 ppmv (typically used in pipeline systems that experience relatively high ambient temperatures), 50 ppmv and < 10 ppmv (typically required where downstream processing involves low temperature or cryogenic conditions).

AMEC considered two different CO_2 flow rates: 2 million te/year (typical amount of CO_2 captured from a 1 GWe gas-fired power plant with at least 85% capture rate), and 4.5 million te/year (typical mass flow for a 1 GWe coal-fired power plant with at least 85% capture rate).

The contractor asked the vendors to provide economic and technical data, including the maximum rate achievable for a single dehydration train.

Findings of the Study

Background issues

Due to the lack of vendor engagement, many of the conclusions presented are of a preliminary nature. This is why re-engagement of the package vendors is important for future activities.

Dehydration media vendors assisted with estimates of the number of beds and bed size. They were also able to help with information on the effects of impurities on the molecular sieve adsorbent and the role of side reactions. Important background issues relevant to the full CCS chain are the following:

- The presence of inerts and impurities can lead to significant changes in the CO_2 physical properties. In addition, impurities can affect the desiccant and lead to higher rates of corrosion. These changes need further understanding and quantification.
- The adequate modelling of physical properties of CO_2 containing inerts and impurities requires new or modified equations of state.
- Water ice, hydrates or liquid CO_2 can form, when cooling wet CO_2 gas below certain limits of pressure and temperature. Figure 1 shows the crossover region of hydrate, water ice and liquid CO_2 formation for selected temperature and pressure conditions.
- There is a wide range in dry CO_2 moisture specifications used for pipelines in the literature. These specifications influence the selection of the appropriate dehydration technique.

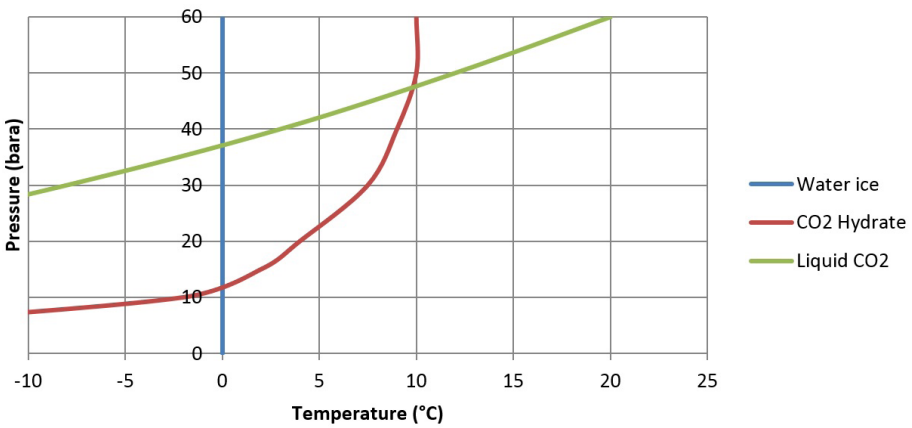

Figure 1, Combined hydrate/water ice/liquid CO_2 plot

In the case of solid desiccant systems, the following approaches are helpful for dealing with impurities:

- Additional amounts of desiccant can cater for the effects of impurities
- Use of an acid resistant desiccant, which can better withstand the impurities
- Applying guard beds (e.g. activated alumina or silica gel that can tolerate acidic impurities)

In the case of liquid desiccants, impurities can form solids, cause foaming or react with the desiccant to build corrosive products. The below mentioned measurements can assist with addressing these issues:

- In-line filtration
- High-efficiency column internals
- Anti-foam
- Degradation/corrosion inhibitors

It is important to know and consider the specific impurities and their normal and maximum concentrations during design. Sometimes the levels of impurities are not acceptable, because of either their damaging effects or the increase in necessary dehydration media volume. In this case, removal of the impurities in a separate upstream process is an option.

Some of the dehydration techniques do not achieve low moisture levels, however they are straightforward, low cost processes, often required in a process anyway (such as compressor inter-stage cooling and knockout). This could offload the main dehydration unit, resulting in smaller, less costly dehydration systems.

Most of the liquid and solid desiccant systems investigated in this study are applicable for use with gaseous CO_2. The different processes and desiccants can achieve orders of magnitude different product moisture contents. Basic liquid desiccant systems can achieve 150 ppmv; enhanced liquid desiccant systems 30 ppmv. Solid desiccant systems can reach lower levels. Activated alumina and silica gel can get down to < 10 ppmv while molecular sieves can achieve 0.1 ppmv.

Technologies

The CO_2 streams produced by the various combustion and capture processes are of different quality, containing different types and concentrations of inerts and impurities. The list below explains the differences between the various CO_2 capture processes, which are relevant to dehydration:

- Post combustion capture delivers a water-saturated CO_2 rich gas from the stripper condenser at pressures just above atmospheric.
- Pre-combustion capture provides multi-stream CO_2 gases from the AGR unit at low pressure and medium pressure conditions.
    - The Rectisol process delivers dry CO_2 gas at < 1 ppmv moisture containing small levels of methanol. The gas does not require further drying and the methanol content will usually not condense out in the subsequent compression and/or cooling process.
    - The Selexol solution contains water, so the process supplies a water-saturated CO_2 gas. Selexol has a low vapour pressure so there is minimal contamination of the dry CO_2 stream. UOP advise that lower water levels of around 500 – 1000 ppmv are achievable, but only at pressures in excess of 10 barg with a purity of less than 98%.
- CO_2 rich gas from oxyfuel combustion will have a wide variation of composition and pressure dependent on the technology selected for the CO_2 processing unit (CPU). The gas entering the dehydration unit is water-saturated and contains inerts and other trace amounts of acidic components – mostly the residual NO_x from the selected NO_x-SO_x removal process upstream.

For post-combustion and pre-combustion capture, a variety of different dehydration pressures is possible. This depends on the available supply pressure and compressor interstage conditions. Oxyfuel cases span a range of pressures from 5 to 30 bara, dependent on the supply pressure and downstream processing requirements.

Information from both package vendors and media vendors centred around two basic process mediums: TEG and molecular sieves. Because of this, the study focusses on a discussion of these two media.

Selection of acid resistant molecular sieves (type 3A or 4A) is favourable for CO_2 streams with high levels of impurities (typically NO_x, SO_x and H_2S). The quantity of desiccant required is a function of the selected adsorption time, the number of beds in parallel and any margin added due to the presence of impurities. Low-pressure operation will require larger diameter beds and larger bed volumes to cater for the higher volume of gas and the increase in moisture content.

Media life of both molecular sieve and TEG varies between 2 and 4 years, typical are 3 years.

The maximum train size appears to vary considerably. For molecular sieve cases with feed gas at 30 bara and 30°C the range (from different vendors) varied between 300 and 600 te/hr. The limitations depend on several factors including the maximum vessel diameter, the capital cost of the vessel, the maximum number of beds of a certain size in parallel, the adsorption time of each bed and the regeneration rate. It is desirable to keep the bed size small to avoid the requirement for large volumes of desiccant and associated vessels. At a certain point, it is more practical to split the feed across an additional number of trains. Bed adsorption times of less than 6 hours are generally unattractive.

Preliminary estimates show that a TEG regeneration unit can handle the moisture of up to 3,500 te/hr of CO_2 rich gas, although this quantity would perhaps require multiple contactors.

Future expansion of capacity is possible for both molecular sieve and TEG systems if the original design allows for additional beds.

Costs

Data presented in this section is a combination of data received from different vendors (as part of this study), data from previous AMEC projects and AMEC modelling and cost estimation. The figures show the cost numbers as uninstalled equipment costs and in the form of cost indicators. A cost indicator of "1" represents the baseline. In general, the capital costs of dehydration equipment are a minor part of the overall costs for a CCS plant.
There is a wide spread in molecular sieve capital cost data from different vendors for a fixed operating pressure. Figure 2 plots the cost indicator

against CO_2 flow rate and shows the maximum and minimum cost lines. The differences are due to several factors:

- The regeneration techniques proposed by different vendors. Atmospheric pressure regeneration with air will be less costly. The amount of equipment required is significantly lower than for a high-pressure regeneration using CO_2. The volume of CO_2 gas passing through the online bed is also lower, so smaller bed size results.
- Use of the CO_2 compression facility to provide the driving force for the regeneration gas results in less equipment for the dehydration package but larger compression and cooling equipment and higher compression costs.
- The materials of construction proposed.
- The number and size of the individual adsorption beds proposed.
- The number of parallel dehydration trains proposed.

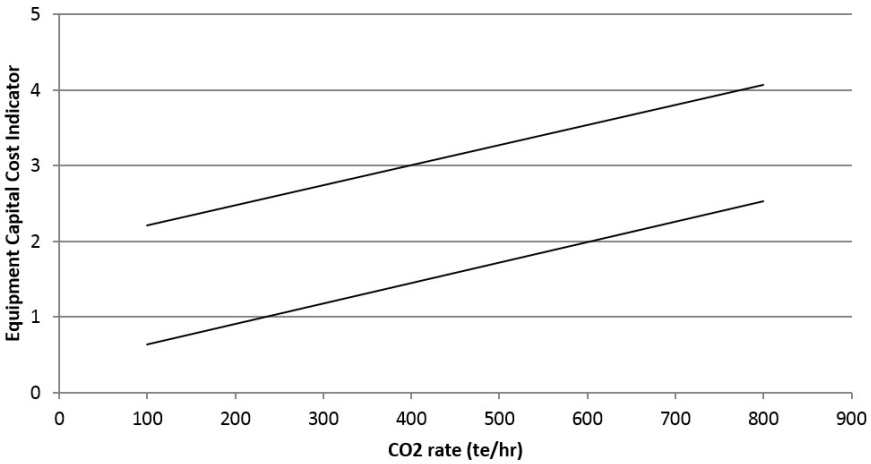

Figure 2, CAPEX indicator for molecular sieve

Operating pressure has an effect on the equipment capital costs of molecular sieve systems. Limited available data indicates that equipment capital cost passes through a minimum. Figure 3 illustrates the qualitative relationship between the capital cost and the operating pressure for a molecular sieve system with a minimum at 25 – 30 bara. The actual location of the minimum

is application specific and depends on:

- The same reasons that cause differences in capital cost (see above).
- The equipment design pressure (whether it is set to be 10% above the maximum operating pressure or designed for compressor settle out pressure on compressor trip).
- The type of regeneration and the extent of regeneration equipment.

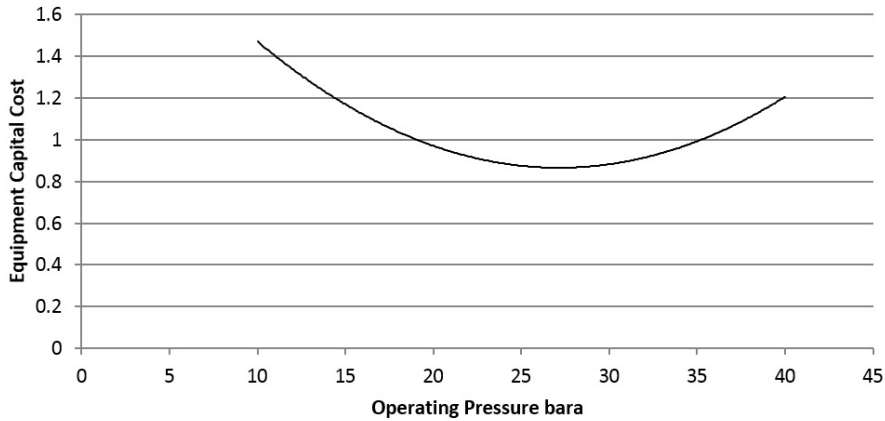

Figure 3, CAPEX indicator for molecular sieve as function of operating pressure

There is no difference between the capital costs of the molecular sieve equipment for target moistures of 550 ppmv, 50 ppmv and < 10 ppmv. Media suppliers and package vendors all advised that it is normal to design for the removal of water from the gas stream to achieve < 1 ppmv, irrespective of the target moisture required. However, at lower target moisture, the cycle time of each bed becomes shorter.

Data on liquid desiccants, i.e. TEG, is lacking. The available data is for water-saturated raw gas at 30 bara and 30°C. The raw gas stream is relatively pure containing > 99% CO_2 with low levels of impurities. Target product moisture is 50 ppmv; the TEG process includes the use of stripping gas to increase the TEG concentration. Figure 4 shows the equipment capital cost indicator as a function of CO_2 flow rate. The line represents a maximum cost line.

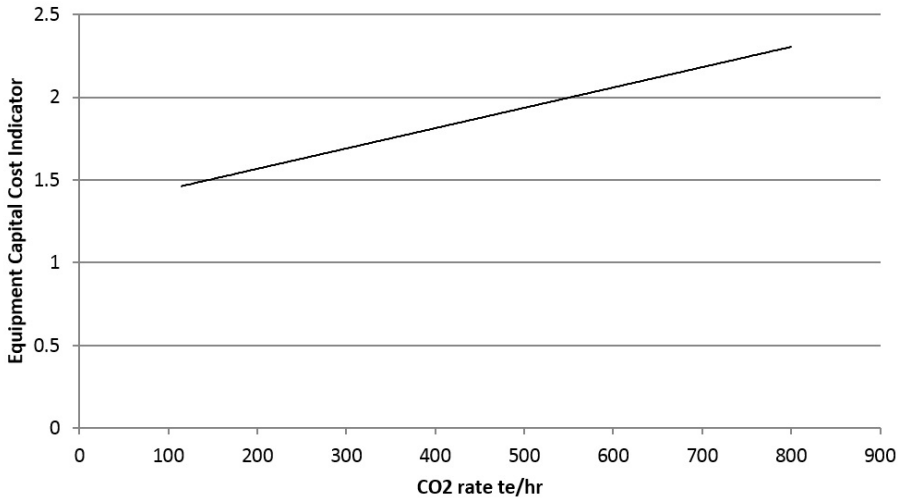

Figure 4, CAPEX indicator for TEG

Higher levels of target product moisture (i.e. greater than 150 ppmv) will require only basic equipment; the stripper is not necessary. The cost for such a system will therefore be lower.

In case of high impurities:

- Increased oxygen levels have no effect on the molecular sieve equipment cost. However, oxygen can degrade TEG. It is not possible to evaluate the effect on TEG equipment capital cost because acceptable limits are unknown.
- The case with 100 ppmv NO_x, 100 ppmv SO_2 and 100 ppmv H_2S results in:
    - The use of an acid-resistant molecular sieve with an increase in media volume of ~ 5% and an increase in media cost of ~ 15%. Molecular sieve equipment capital cost will be ~ 7% higher.
    - Again, it is not possible to determine the effects on TEG equipment capital cost.

A clear recommendation is to discuss impurity issues with the vendor at an early stage, as an upstream removal might be advantageous or essential.

In case of high inerts content the cost of the equipment is higher per tonne of CO_2 present than for a low inerts gas. The reasons for this are:

- The increased volume of raw gas requires a larger diameter TEG contactor or larger diameter solid desiccant bed.
- The gas carries a higher amount of water. This extra amount of water needs removal. The circulation rate of TEG will therefore increase and the equipment in the TEG circulation loop will be larger. Similar, solid desiccant systems require larger media volumes to remove the increased amount of water.

Figure 5 presents the results of the operating cost estimation for the following cases:

- Molecular sieve at 265 te/hr – Options from two different vendors, one using low pressure regeneration with atmospheric air (minimum case) and another using CO_2 at pressure for regeneration (maximum case). Vendors advised to use a lifetime of 3 years for the molecular sieve.
- TEG at 265 te/hr – Only a single vendor has provided data. Lifetime of TEG desiccant can vary between 3 – 10 years, depending on the extent of impurities present. This study assumed a value of 3 years.

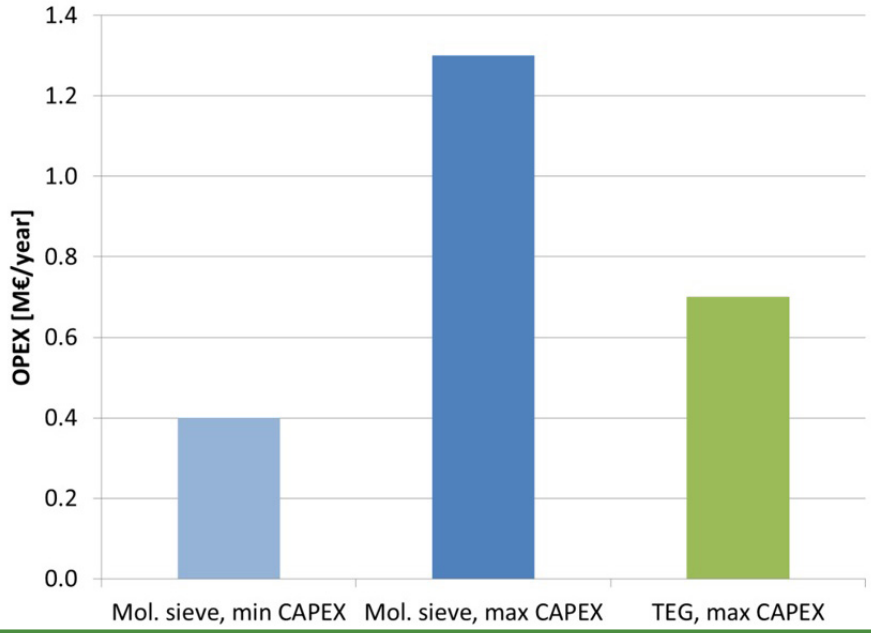

Figure 5, OPEX estimates for different dehydration systems

Comparing data from the same vendor indicates that the TEG system annual operating cost is significantly lower than that for the molecular sieve package. However, the more basic molecular sieve package, from a different vendor, but for the same raw gas conditions, indicates that the annual operating costs can be significantly lower than those for a TEG system. Figure 6 shows estimated minimum operating costs for molecular sieve packages as a function of CO_2 flow rate.

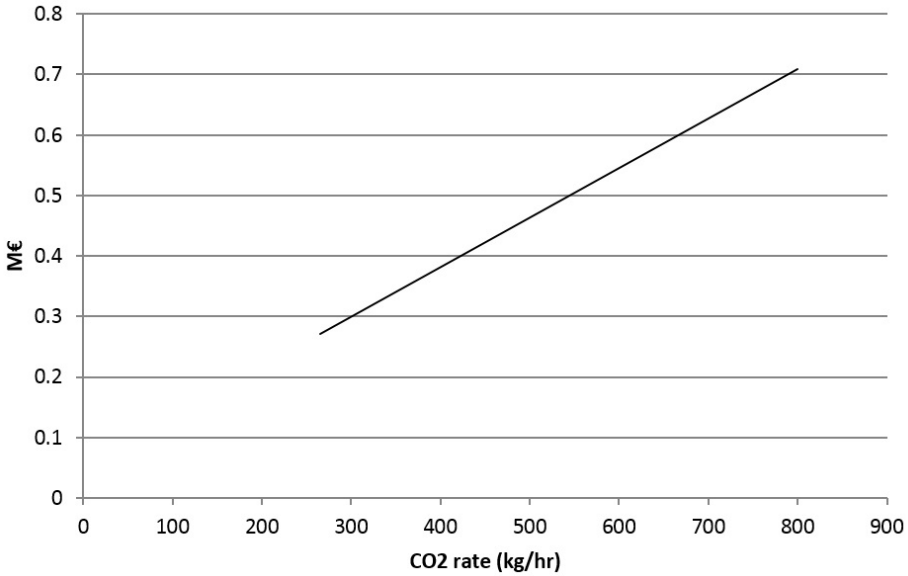

Figure 6, OPEX for molecular sieve as function of CO_2 flow rate

The limited information available from vendors suggests that operating pressure has an effect on operating costs; the regeneration power consumption will pass through a minimum. The actual minimum pressure will vary for individual applications.

The vendor data also indicates that the effect of impurities on molecular sieve operating cost is insignificant. The increased bed volume results in higher capital cost, which impacts onto maintenance costs, taxes and insurance. Desiccant cost increases as well, but regeneration power consumption will be lower.

Selection

It is usually appropriate to consider combinations of different dehydration techniques to achieve the required target moisture content. Figure 7 illustrates the relative applicability ranges of the various dehydration technologies.

Under most circumstances, it is invariably cheaper to offload the final dehydration system by use of more basic techniques, if their application is feasible. In case of water-saturated, low-pressure gas it is beneficial to use the compression/cooling equipment (which is mandatory to reach the export conditions) to raise the pressure, knockout the condensed water and reduce the gas equilibrium moisture content as part of the normal compression process. This has the following effects:

- Minimisation of the moisture that enters the final dehydration package.
- Reduction of the actual volume of raw gas in the final dehydration plant, which results in smaller equipment.

The presence of certain impurities can physically damage molecular sieve desiccants. Installation of a short section of guard bed (containing silica gel or activated alumina) immediately above the molecular sieve bed can help avoiding deterioration. However, the guard bed will have a design life and once aging starts it will no longer offer protection to the molecular sieve.

Using multiple dehydration techniques in series is possible. For example, compression/cooling, followed by a TEG system, followed by molecular sieve polishing. The benefits of such systems depend on the individual process requirements. They can provide a higher level of product moisture integrity in the event of a malfunction. The extent of capital cost penalty is process specific.

In the event that a second molecular sieve dehydration train is necessary to process the gas, installing a TEG system upstream can offload the molecular sieve system. Smaller adsorber bed volumes and/or increased bed adsorption time will result.

For each specific application, a cost-benefit analysis is essential to determine the most cost effective option.

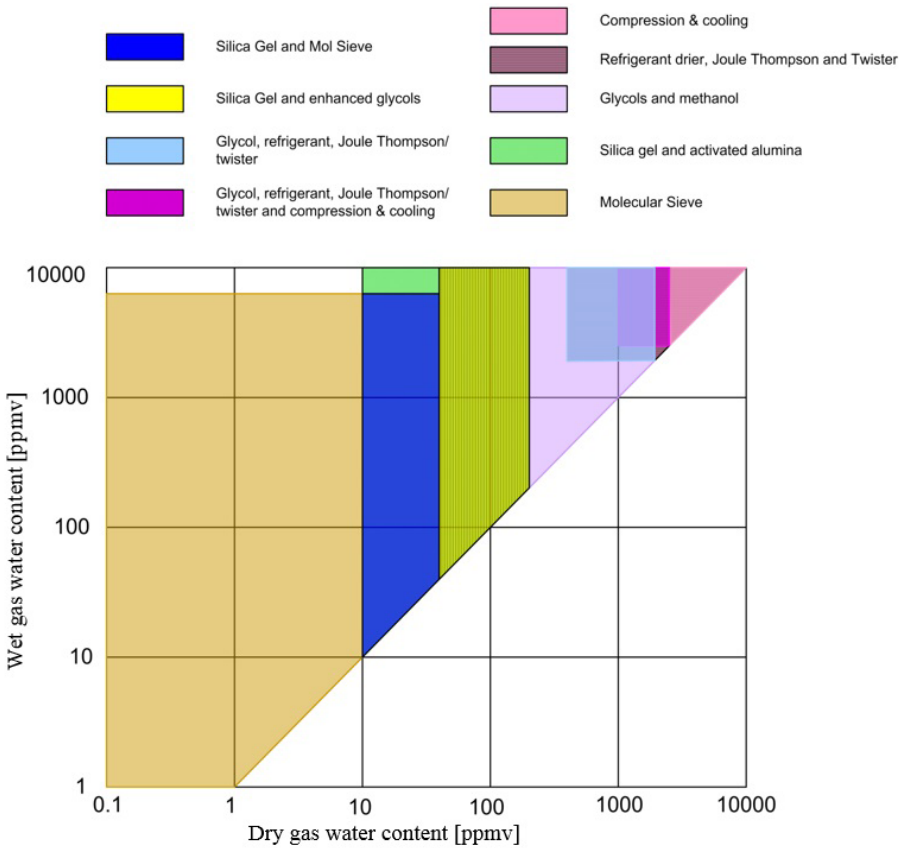

Figure 7, Ranges of applicability of different dehydration technologies

The pressure for CO_2 dehydration depends on many considerations, including:

- Hydrate formation conditions
- Liquid CO_2 formation conditions
- Water solubility in CO_2
- Compressor interstage conditions
- Interstage cooling temperatures
- Minimum temperatures experienced at the point of dehydration and downstream
- CO_2 export pressure

- CO_2 supply pressure
- Downstream processing requirements (e.g. liquefaction or cryogenic processes)
- CAPEX/OPEX of dehydration equipment

Operation and monitoring

Monitoring of the drier performance ensures that water breakthrough does not occur. It is important to use a continuous monitoring system, because manual sampling and analysis will not be sufficient. The presence of CO_2 itself and the potential contaminants limit the number of available analysis techniques.

Many companies, which provide industrial moisture measuring instrumentation, declined to assist in this study. Participating vendors proposed a range of different physico-chemical measuring principles:

- Laser absorption spectroscopy
- Phosphorous pentoxide (P2O5) coated cell
- Quartz crystal cell
- Silicon sensor

As with the desiccants, impurities play an important role, so it is necessary to discuss the issue with the vendors to select the most appropriate technique and device.

The sampling system can significantly influence the overall performance and recovery time from upset conditions. Sampling usually involves pressure let-down and the related Joule Thomson chilling can result in condensation of any of the components present. Because this can affect both the analyser and the analysis result, vendors recommend sample heating systems. A reasonable response time is essential to ensure quick detection of off-spec product and remedial actions. To avoid damage or prolonged erroneous readings under upset conditions, the design of the sensor needs to consider these conditions.

Maintenance frequency depends on the gas quality. In the event that a contamination incident occurs, cleaning of the sensor and associated lines will be necessary. Particulates are a particular issue for some types of device, such

as the phosphorous pentoxide device, because they can block the capillary. Another issue are reactions at the cell surface that may cause contamination of the cell or formation of water and result in erroneous readings.

A number of two moisture analysis points is usually the minimum. If a fault develops at one location, then the second location will act as a backup. The analysis points are in different locations in the plant (one immediately after dehydration and another further downstream).

Operators should develop plans regarding what to do if off-spec gas has reached downstream equipment. The actual course of action depends on the extent of the moisture excursion and the conditions prevalent in the equipment at that time.

Further work

Several areas need additional work to enable a full and adequate consideration of dehydration processes and issues. This study identified the following key areas for further investigation:

- The effects of inerts and impurities on physical properties of CO_2, as both can cause significant changes in the phase envelop and saturated water content of CO_2.
- Modification of the related physical properties estimation methods and models.
- Clarification and quantification of the hydrate formation issue. One reference suggests limiting the water content to < 60% of saturation to avoid hydrate formation, but other references argue that the maximum amount of hydrates will be too small to cause operational problems in CCS applications.
- Re-engagement of vendors. Their opinions on CCS as a market have changed because of the cancellation of most major CCS projects and the DECC and NER300 competitions.
- Research on membranes for dehydration of supercritical CO_2.
- Development of acid resistant solid desiccants that can better deal with impurities. Vendors are currently working on this sensitive area of research, but are not willing to discuss it yet.

Expert Review Comments

Six reviewers from industry and governmental organisations submitted comments. In general, most reviewers felt that the report provides a good background on CO_2 dehydration options and the issues surrounding its application to CCS. The majority of the reviewers understood that the lack of vendor support affected the quality and quantity of information in the report. Comments included the request for more information in certain sections, especially on costs and detailed system design. Where possible, AMEC added clarification and technical detail, improved figures and carried out own estimations, e.g. providing a heat and mass balance for a TEG system.

Conclusions

The purpose of this study was to examine the characteristics of the various dehydration processes and their integration into CCS systems.

A number of suitable technologies for CO_2 dehydration already exist. Vendors quoted molecular sieve and TEG systems as the most likely technologies for implementation. However, due to lack of vendor support, the cost and operating information presented in this report is preliminary, fragmentary and associated with uncertainties.

Design and operation of dehydration units come along with several challenges. This study identified that it is usually beneficial in terms of economics to consider a series of dehydration techniques in order to offload the main system. Besides, application of guard beds and upstream treatment can offer protection for sensitive desiccants.

The minimum CAPEX and OPEX for both molecular sieve and TEG systems depend mainly on operating pressure and type of regeneration. For a fixed operating pressure, there is a wide spread in CAPEX data quoted by the vendors. In case of high inerts, the CAPEX will increase for both molecular sieve and TEG systems. Presence of impurities, such as NO_x, SO_x and H_2S, leads to a 7% higher CAPEX but no difference in OPEX for molecular sieve systems. At this time, it is not possible to evaluate the effect of impurities on the costs of TEG systems.

Areas requiring further work are, for example, the effect of inerts and impurities on the physical properties of the CO_2 stream. Some vendors

indicated that interest in CCS projects might be limited in the near future, so it seems that re-engagement of the vendors will be a priority for any future projects and studies.

Recommendations

IEAGHG should track the research and project activities in this area. Maybe it will be possible to continue and expand on the existing study later, when vendors are willing to provide more involvement and information. In the meantime, it would be a good idea to engage the approached vendors in IEAGHG activities and networks related to CO_2 capture and transport.

TECHNO ECONOMIC EVALUATION OF DIFFERENT POST COMBUSTION CO_2 CAPTURE PROCESS FLOW SHEET MODIFICATIONS (2014-08)

Introduction

Post combustion CO_2 capture technology is one of the potential technologies which will most likely to be applied at large scale CO_2 capture facilities in power plants. One of the main concerns for the solvent based CO_2 post combustion capture (PCC) technology for power plant is the relatively large energy penalty. The energy required to regenerate the solvent and run the PCC process in a coal fired power plant is currently considered to be equivalent to a reduction in the thermal efficiency of about 20% (from roughly 44 -35% LHV) when around 90% CO_2 is captured[1]. A reduction in energy penalty for solvent based CO_2 post combustion capture process can be achieved by improving solvent properties, better integration with power plant as well as by improving process design.

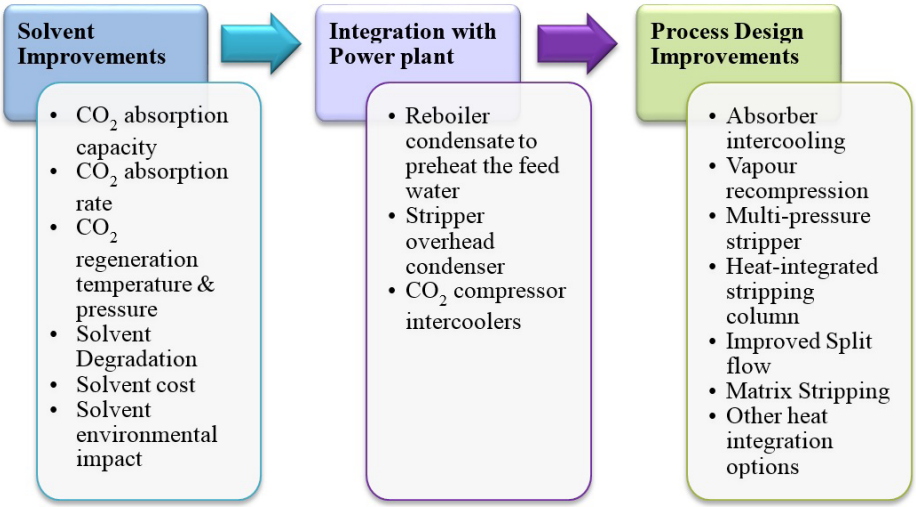

Figure 1, Improvements for amine based solvent CO_2 post combustion capture process

[1] Adams D., Davison J. 2007, Capturing CO_2, IEAGHG report.

Regarding to the improvement in process design, different process flow sheet modifications have been reported in literature and patents for chemical solvent based CO_2 absorption processes[2]. These process modifications reduce the energy penalty imposed by the CO_2 post combustion capture plant. The proposed process flow sheet modifications are multi-component column, inter-stage temperature control, heat integrated stripping column, split flow process, vapour recompression, matrix stripping and various heat integration options[2]. Comparison of these reported modifications was difficult as these were evaluated based on different solvent properties and process conditions. Also there are some process modifications more suitable for particular solvent than the others. In order to identify the suitable process modification for full scale PCC application it was necessary to evaluate further in detail these modifications on the same process condition for their energy savings, additional unit required and additional cost.

Therefore, there was a requirement to evaluate these process modifications on similar solvent and process conditions with a state of the art rate-based CO_2 absorption model. IEAGHG has commissioned this study to evaluate the feasibility of these different amine-based CO_2 post combustion capture process modifications for coal and natural gas based power plants.

Scope of the study

Following are the scope of this study:

- Technical evaluation of different process modifications shall be performed and issues related to operational, energy efficiency, process complexity and process control shall be identified.
- Economic evaluation of these process modification options shall be performed in order to find the trade-off between increased capital and lower operational cost.
- Identify major technical challenges and gaps for different process modification options.

[2] A. Cousinsa, L.T. Wardhaugh, P.H.M. Feron, 2011, A survey of process flow sheet modifications for energy efficient CO_2 capture from flue gases using chemical absorption, International Journal of Greenhouse Gas Control, 5, 605–619.

Study Approach

In this study Super Critical Pulverised Coal (SCPC) fired power plant of 900MW gross power, with a net efficiency of 45.2% (LHV) without CO_2 capture and Natural Gas Combined Cycle (NGCC) power plant of 883MW gross power, with a net efficiency of 58.2% (LHV) without CO_2 capture are evaluated. The most suitable simulation tools for steady-state simulations were chosen; Ebsilon®Professional for the overall power plant and the CO_2 compression and Aspen Plus® for the CO_2 capture process. The CO_2 capture plant for SCPC and NGCC consists of two greenfield CO_2 capture trains. Moreover, current state of process improvement such as generic improved amine based solvent 'Solvent 2020', absorber intercooling and operating stripper at higher pressure (5Bar) was considered in this study. Solvent 2020 was an artificial solvent which has the same CO_2 absorption mechanisms as amines (carbamate and bicarbonate formation). The properties like density, viscosity and heat capacity were assumed to be similar to those of a solution with 7mol MDEA (Methyldiethanolamine) and 2mol PZ (Piperazine) per kg H_2O. Thus, the corresponding ASPEN Plus® property model was used for the simulations. The reaction kinetics of 'Solvent2020' were enhanced compared to 7MDEA/2PZ, which results in chemical reactions that are not kinetically hindered. This was the main property improvement compared to other solvents for 'Solvent 2020'. 'Solvent 2020' was assumed to be thermally stable up to approximately 150°C, which was the same temperature as for PZ. Thus, thermal degradation was not expected to occur when operated at temperatures below this limit. Oxidative degradation was assumed to be negligible. In addition, 'Solvent 2020' was also assumed to be not corrosive in the chosen operating range.

Figure 2 shows the impact of these CO_2 capture process improvements on the efficiency penalty for SCPC power plant. It can be noticed that the largest reduction on power plant efficiency penalty (from 9.8% to 7.52%) was achieved by using an improved solvent named 'Solvent 2020' when compared to conventional solvent 30wt% Monoethanolamine (MEA).

This reduction was due to the lower specific reboiler duty and cooling water requirement by using an improved solvent, 'Solvent 2020'. Further improvement was implemented by operating the stripper at a higher pressure of 5 bar, which shows that despite having a higher specific heat

duty, the penalty imposed by compression duty was reduced which leads to lower efficiency penalty of 7.45%.

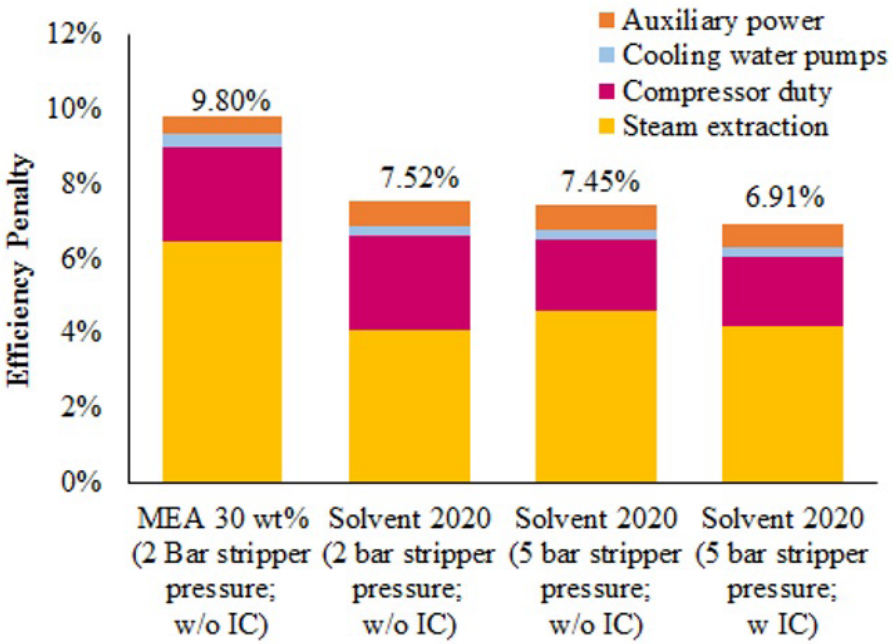

Figure 2, Effect of different improvements on SCPC CO_2 capture base case plant efficiency. [IC: Intercooling]

It can be noticed from Figure 2 that further process design improvement by implementing intercooling in the absorber, reduces the efficiency penalty to 6.91%. This was due to the increased solvent CO_2 absorption capacity, which resulted in a lower solvent circulation rate, leading to a lower steam extraction requirement.

In the NGCC CO_2 capture base case, the CO_2 concentration in the flue gas was significantly lower. Therefore, in order to minimize the energy requirement of the CO_2 capture plant, flue gas recirculation (FGR) was considered which leads to a CO_2 concentration of 9.1vol% in the flue gas. Similar effect of improved solvent and improved process design was noticed for NGCC CO_2 capture base case (see Figure 3). It can be noticed that the improvements considered in this study reduce the NGCC efficiency penalty from 7.86% to 5.93%.

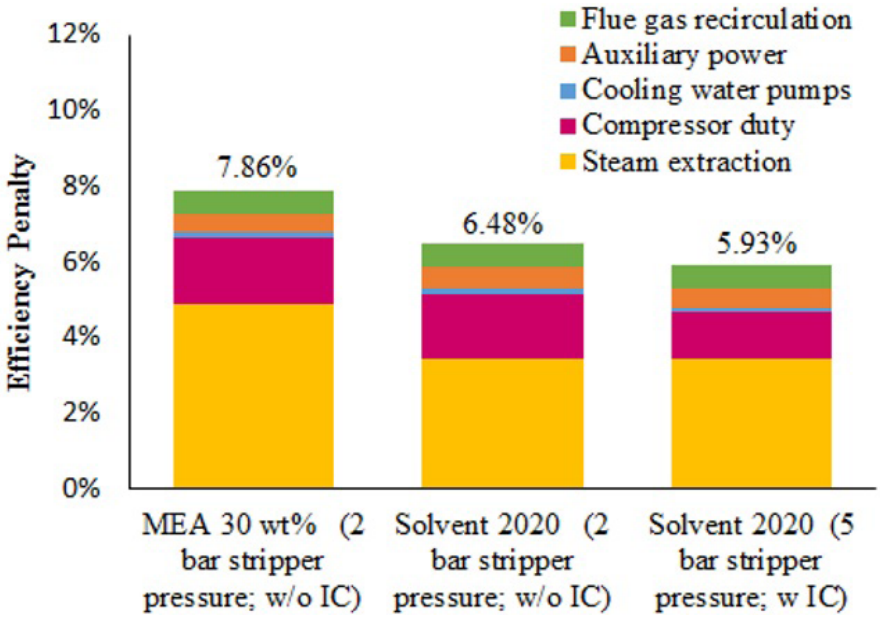

Figure 3, Effect of different improvements on NGCC CO_2 capture base case (with FGR) plant efficiency. [IC: Intercooling]

Effect of waste heat integration

For the SCPC CO_2 capture base case, basic heat integration with the power plant by returning reboiler condensate to the preheating route for the feed water was considered. Also advanced waste heat integration was performed by using heat available from the CO_2 compressor intercooler and stripper overhead condenser.

SCPC Power Plant	Base case with IC; w/o HI	Base case with IC; with HI
Steam extraction	4.16%	4.21%
Compressor duty	1.90%	2.06%
Cooling water pumps	0.23%	0.21%
Auxiliary power	0.62%	0.60%
Heat Integration	-	-0.97%
Overall efficiency penalty	6.91%	6.11%

Note: IC: Intercooling, HI: Waste Heat Integration

Table 1, Effect of waste heat integration on efficiency penalty for SCPC CO_2 capture base case.

Table 1 show that by implementing the above mentioned waste heat integration in the SCPC CO_2 capture base case, a reduction of 0.97% in efficiency penalty, resulting in a total efficiency penalty of 6.11% was achieved. In the NGCC case, basic integration was considered by injecting reboiler condensate into the superheated steam (spray attemperation) to reduce the temperature and prevent hot spots in the reboiler. The remaining reboiler condensate was partially returned to the water steam cycle upstream of the economiser of the heat recovery steam generator to increase the temperature to 60°C and thus prevent condensation of vapour in the flue gas. The rest of the condensate was returned downstream of the economiser. A more complex waste heat integration was not considered for the NGCC case as there was no available heat sink.

Therefore, the CO_2 base cases considered for SCPC and NGCC power plants in this study were taken at the current stage of process improvements and an improved amine based CO_2 solvent, representative of a future solvent, with generically improved CO_2 absorption properties probably available in the coming years.

Findings of the Study

Impact on efficiency penalty

Various process modifications were evaluated for SCPC and NGCC cases. This was based on energetic evaluation of the overall process, by looking at energy required/saved by steam extraction, compressor duty, cooling water pumps, auxiliary power and heat integration. Based on this, the overall efficiency penalty was estimated for each evaluated process modification (see Table 2). The overhead condenser SCPC case was found to have the lowest efficiency penalty, due to the reduction in steam extraction penalty. The heat integrated stripper+ OHC heat integration process modification was found to have the next lowest efficiency penalty. In the NGCC case the overhead condenser heat integration and the heat integrated stripper + OHC heat integration cases were found to have the lowest efficiency penalties. This was due to the reduced steam extraction, resulting in the lowest specific heat duty.

Different Process Modifications	SCPC case in %-points	NGCC case in %-points
Base case	6.11	5.93
Vapour recompression	6.09	5.86
Multi-pressure Stripper	6.25	5.86
Heat-integrated stripping column	6.18	5.92
Improved split flow process	5.99	5.46
Matric stripping	6.41	6.04
Overhead condenser heat integration	5.84	5.28
Reboiler condensate heat integration	-	5.83
Vapour recompression + split flow	5.99	5.46
Heat-integrated stripper + OHC heat integration	5.88	5.34

Table 2, Overall efficiency penalty for various process modifications

Moreover, it was also noticed that the combination of vapour recompression with split flow process modification was found to be having a slightly lower efficiency penalty when compared to that of the vapour recompression process modifications.

It can be noticed from these results that the matrix stripping process modification was found to be having a higher efficiency penalty than the base case for the SCPC and NGCC cases. This was due to the increased compressor duty by 0.41% points in the SCPC case compared to the base case, as well as the positive effect of advanced heat integration was reduced, since the temperature level, as well as available waste heat in the overhead condenser was reduced. In the SCPC case the multi-pressure stripping process modification was also found to be having a higher efficiency penalty. It showed that whereas the steam extraction penalty was reduced by 0.24%, the auxiliary power of the CO_2 capture plant was increased by 0.28% points. Also, the positive effect of heat integration was reduced by 0.10% points, since the temperature level of usable waste heat as well as the amount of heat was reduced.

Overall it can be noticed that different process modifications for SCPC and NGCC only bring slight improvements in the efficiency penalty.

Impact on required process equipment

Different process modifications will require additional equipment which will affect the capital investment cost of the unit. Figure 4 (a & b) shows the impact on percentage change in the purchased equipment cost (PEC) for different process modifications for SCPC and NGCC cases.

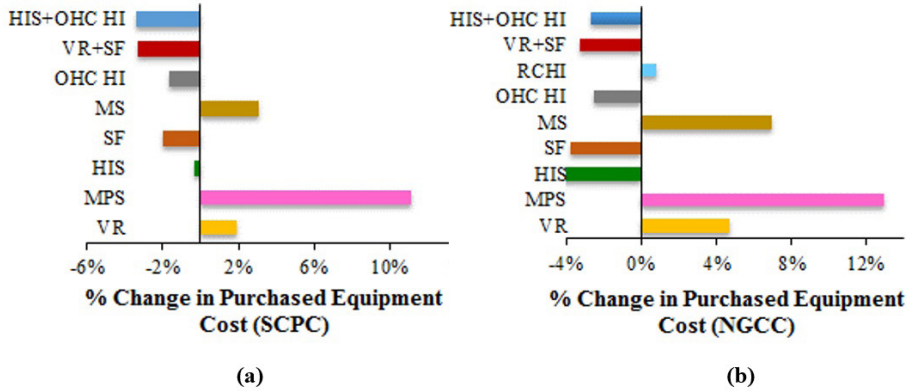

Figure 4, Percentage change in purchased equipment cost for different process modifications compared to the base case. [VR: vapour recompression, MPS: multi-pressure stripper, HIS: heat integrated stripper, SF: split flow, MS: matrix stripping, OHC HI: overhead condenser heat integration, RCHI: reboiler condensate heat integration]

In this study some process modifications were found to be reducing the PEC when compared to that of the base case. Such as for SCPC case vapour recompression + split flow (VR+SF) and heat-integrated stripping column + overhead condenser heat integration (HIS +OHC HI) process modification were found to be lowering PEC when compared to that of SCPC base case. For VR+SF SCPC case the higher cost of an additional flash tank and flash vapour compressor was outweighed by the lower cost of different equipment such as rich solution pump, rich/lean heat exchanger, desorber overhead condenser, condensate return tank, reboiler, reclaimer, reboiler condensate pump and motor and filters required due to improved split flow process. Similarly for SCPC HIS+OHC HI case the additional heat exchanger and stripper heater cost will require smaller rich/lean heat exchanger (RLHX) as well as OHC HI also require smaller dimension for following equipment such as RLHX, desorber overhead condenser, reboiler and reclaimer.

For NGCC, the heat-integrated stripping column (HIS) case was found to have

the most reduced PEC when compared to that of the NGCC base case. As in HIS case the RLHX was smaller in dimension and the rest of the equipment require smaller dimensions leading to lower PEC.

On the other hand, multi-pressure stripper (MPS) process modification showed the highest increase in PEC for SCPC (11%) and NGCC (13%) compared to the respective base cases, as this process modification requires additional two desorber columns and two centrifugal compressors to increase the pressure. For MPS, the SCPC case centrifugal compressors account for 7.4% of the total capture plant PEC and the desorber column accounts for 7.8% of the total capture plant PEC. Whereas for NGCC, the MPS case centrifugal compressors account for 9.8% of the total capture plant PEC and the desorber column accounts for 6.1% of the total capture plant PEC. The second highest increase in the PEC was found for the matrix stripping (MS) process modification; 3% for SCPC and 7% for NGCC when compared to the respective base cases. This was due to the required additional two desorber columns as well as additional two reboilers, reclaimer, overhead condenser and condensate return tank. Another widely evaluated process modification was vapour recompression, which was also found to be increasing the PEC for SCPC (2%) and NGCC (5%) cases when compared to the respective base cases. This was due to the requirement of an additional flash tank and flash vapour compressor.

Impact on Cost of electricity and CO_2 avoidance cost

An economic evaluation of various process flow sheet modifications was performed, based on the additional capital costs of the CO_2 capture plant and the changes in plant performance. The capital cost was estimated based on the major equipment items multiplied by factors to account for the related costs for instrumentation and controls, piping, electrical equipment, etc. The economic indicators which were calculated were the Cost of Electricity (CoE) in €/MWh and the cost of CO_2 avoidance in €/tCO_2 compared to a reference plant without CO_2 capture, using the same fuel. The results are summarised in Table 3. The process modifications such as improved split flow process, OHC heat integration, vapour recompression + split flow and heat integrated stripper + OHC heat integration shows the reduced CoE and lower CO_2 avoidance cost for both SCPC and NGCC case. This was due to the lower operational cost of these process modifications and in some cases also a better net efficiency which lead to lower CoE and CO_2 avoidance cost.

Different Process Modification	SCPC	SCPC	SCPC	NGCC	NGCC	NGCC
	CoE	relative change of CoE	Cco_2 avoided	CoE	relative change of CoE	Cco_2 avoided
	€/M Wh	%	€/tCO_2	€/M Wh	%	€/tCO_2
Base case, SCPC w/o CO_2 Capture (CoE Ref)	42.22	-	-	-	-	-
Base case, NGCC w/o CO_2 Capture (CoE Ref)	-	-	-	59.5	-	-
Base case, SCPC wCO_2 Capture	68.29	61.7%	38.32	-	-	-
Base case, NGCC wCO_2 Capture	-	-	-	76.82	29.1%	54.76
Vapour recompression	68.43	62.1%	38.54	76.99	29.4%	55.27
Multi-pressure stripper	69.53	64.7%	40.17	77.46	30.2%	56.76
Heat-integrated stripping column	68.39	62.0%	38.48	76.51	28.6%	53.77
Improved split flow process	67.87	60.7%	37.69	75.92	27.6%	51.85
Matrix stripping	68.95	63.3%	39.33	77.39	30.1%	56.57
OHC heat integration	67.65	60.2%	37.35	75.73	27.3%	51.21
Reboler condensate integration	-	-	-	76.73	29.0%	54.46
Vapour recompression + split flow	67.78	60.5%	37.57	75.95	27.6%	51.94
Heat-integrated stripper + OHC heat integration	67.71	60.4%	37.45	75.8	27.4%	51.46

Note: Relative change of CoE was based on the % change when compared to CoEref.

Table 3, Cost of electricity (CoE) and CO_2 avoidance cost for various process modifications.

It can be noticed that multi-pressure stripper and matrix stripper cases showed the highest increase in the cost of electricity and CO_2 avoidance cost. In the multi-pressure stripper case the increased capital cost and increased operation cost show that this modification was the most expensive among the other modification studied for both SCPC and NGCC cases. Similarly the matrix stripping modification was also found to be expensive.

Sensitivity analysis

Various aspects of the process modifications were evaluated:

- An increase in CO_2 capture percentage from 90% to 95% was expected to increase the heat duty requirement. Beside that the solvent mass flow rate and lean loading need to be manipulated due to the effect on rich loading.
- Increasing the size of power plant above 900MWe does not impose any limitation for the studied process modifications because additional trains of equipment can be built in parallel.
- The impact of solvent properties on process modification was mainly on the reboiler temperature, as it was limited by solvent degradation at higher stripper temperature and pressure. Therefore, process modifications such as vapour recompression, multi-pressure stripper, heat-integrated stripping column can show more positive improvement.
- During part load conditions the capture plant efficiency reduces and it was expected that vapour recompression and multi-pressure stripping will show higher loss in efficiency during part load. This was due to the reduction in fans' efficiency in part load operation.
- The requirement for process control rises with more complex process flow sheet modification. Matrix stripping was found to be the most complex and other modifications showed slight increases in the complexity.
- When considering retrofitting, issues like space, available utilities and IP/LP crossover pressure are of major importance. The multi-pressure stripper was found to be the most suitable for retrofit, as it shows the lowest temperature level in the reboiler.
- Retrofitting a CO_2 capture unit in a natural gas combined cycle (NGCC) power plant, the main issue will be the installation of flue gas recirculation to increase CO_2 concentration in the flue gas.

Expert Reviewers' Comments

In this study a generic improved solvent 'Solvent 2020' was considered. Some of the reviewers asked to explicitly show the improvements made by using this improved solvent on the power plant efficiency. Therefore, a further simulation was performed for a conventional solvent 30wt% MEA and at

lower stripper pressure of 2bar. To compare the effect of generic improved solvent 'Solvent 2020', further simulation was performed at a lower stripper pressure of 2bar. Hence, such an evaluation makes it clear on the impact of different improvements in amine based solvent CO_2 absorption process. It was suggested by reviewers that the results from this study are very solvent specific. The focus of this study was to evaluate different process modifications based on the current state of improvements in process design, and by using a generic improved solvent. Hence, for a different solvent, the evaluation for each process modifications should be performed.

Conclusions

This study evaluated different post combustion capture process modifications for SCPC and NGCC power plant. The study also evaluated the current state of process design improvements such as absorber intercooling, operation at higher stripper pressure and an advanced level of waste heat integration for the SCPC case. In order to identify the effect of future improvements in the solvent; a generic improved amine based solvent 'Solvent 2020 was considered. Regarding to the different process modifications, matrix stripping was found to be having the highest efficiency penalty due to the increased energy requirement by compressors. Also the cost of electricity and cost of CO_2 avoided for this modification was found to be higher compared to other process modifications. Multi-pressure stripper was also found to be higher in power plant efficiency penalty as well as higher cost of electricity and cost of CO_2 avoided for SCPC and NGCC case. Other process modifications such as OHC heat integration, vapour recompression + split flow and heat integrated stripper + OHC heat integration show lower efficiency penalties, reduced cost of electricity and lower CO_2 avoidance cost when compared to for both SCPC and NGCC base cases. Hence, the evaluation shows that the major improvement in the efficiency penalty was already achieved by using an improved solvent for SCPC and NGCC case. Further process modifications only bring small change in the efficiency penalty.

Regarding to the other issues such as process control, multi-pressure stripping was the most complex, hence, will require a more complex process control system. When retrofitting these process modifications, multi pressure was found to be the more suitable for SCPC case. Whereas for NGCC case the flue gas recirculation was the main issue when considering retrofitting CO_2

capture process.

Recommendations

This study has evaluated different process modifications and identified some potential process modifications for further evaluation. Further evaluating these identified potential process modifications for different potential solvents will provide very useful insights. Moreover, detailed analysis based on the different power plant load conditions, retrofitting, and process control could be performed. IEAGHG would also like to recommend the industry and researchers to evaluate these identified potential process modifications in a real pilot plant tests.

This study has identified that the improvements made in the solvent for CO_2 absorption characteristics was one of the important areas for improving CO_2 capture process efficiency. Hence, an improved solvent has to be tested in pilot plants and it was necessary to develop an exact property model of the solvent which describes the solvent with the effects of all process modifications. Also it was important to have improved solvent with a lower degradation and corrosion.

COMPARING DIFFERENT APPROACHES TO MANAGING CO_2 STORAGE RESOURCES IN MATURE CCS FUTURES (2014-01)

Key Messages

- There are many potential competing users of the surface and subsurface in both onshore and offshore environments
- There are various different approaches to storage management, all of which are highly dependent on the jurisdiction involved
- Most jurisdictions currently work under a 'first-come, first-served' approach
- Management of storage on a first-come, first-served basis is likely to be sustainable in the short to medium term
- Pressure increases do not always result in detrimental effects, but pressure responses in open storage sites should be the focus of a detailed assessment in all cases
- The operator and regulator must understand the consequences of a pressure increase over an area much larger than the extent of the CO_2 plume itself
- The main benefit of a first-come, first-served approach is that the operator has the final decision on where to develop CO_2 storage
- The first-come, first-served approach should work for multiple-stacked sites
- Potential disadvantages of the first-come, first-served approach include possible reduced storage capacities, difficulties for monitoring and a lack of regional storage optimisation with stranded sources.

Background to the Study

Current regulations concerned with carbon dioxide capture and storage (CCS) mean that the licensing of CO_2 storage sites is likely to be undertaken to follow a first-come, first-served basis. Applications for licences (for individual projects) are submitted to regulators and the basis of the regulators' assessment will be primarily to consider if the site is fit for purpose as a storage site for CO_2. This assessment will be subject to certain region-specific exclusions, designed to protect the interests of pre-existing users of the

subsurface, ground surface and seabed.

Storage sites for CO_2 will be selected by the operators on a 'most economically advantageous' basis, to meet the needs of individual clusters of CCS projects. A recent (2013) IEAGHG study, 'Interaction of CO_2 storage with subsurface resources', highlighted that sedimentary basins have multiple potential uses – hence there is potential for CO_2 storage projects to conflict with other subsurface and surface users (see figure 1, overleaf, for a conceptual view of spatial and subsurface interactions which may limit storage site selection). This report showed that increased pore fluid pressure in any reservoir formation (resulting from the injection of CO_2) may reduce storage capacity and increase costs in adjacent sites, which could potentially reduce the efficient use of the storage resource. Therefore a more strategic approach would be required when dealing with sedimentary basins to ensure such formations realise their full resource potential. This raises important questions, including:

- How can CO_2 storage capacity be fully utilised in the presence of potentially competing uses of the subsurface and overlying ground surface or seabed?
- How should storage boundaries be defined in potentially pressure-interacting projects?
- How should potentially interacting resources e.g. CO_2 storage, hydrocarbon exploration and production and natural gas storage be developed most economically in the light of national or jurisdictional policies?
- Factors which may influence the optimisation of a basin include cost, minimising risk, access to a range of uses of the basin, ground surface and seabed, and the value of the resource. Such factors would be considered within the framework of government energy policies. It may also be necessary to look at other, perhaps less tangible potential future uses of the basin.

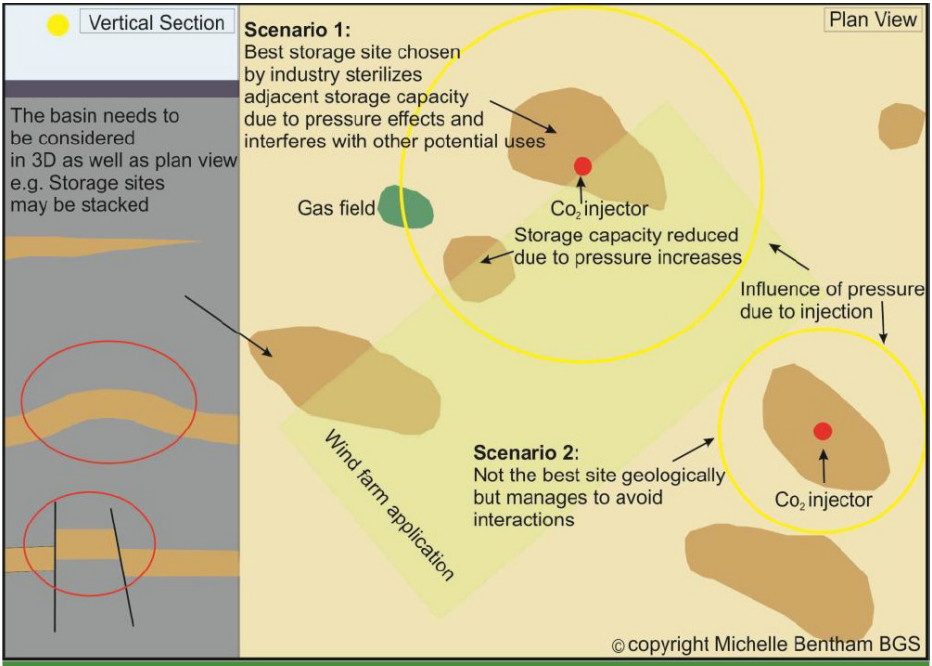

Figure 1, Conceptual view of spatial and subsurface interactions which might limit storage site selection, using a hypothetical example of gas fields and 2 storage site scenarios in the UK Southern North Sea

Scope of Work

This report develops scenarios for CO_2 storage development in the Southern North Sea Basin to compare first-come, first-served and managed approaches to CO_2 storage site licensing. The report describes the benefits and consequences of these broad strategies for the pore space owner and the operator, and considers current approached to managing offshore and onshore storage resources (in a range of jurisdictions).

A workshop was held in the early stages of the report process, which helped to evaluate approaches to the management of pore space in different jurisdictions. The following general issues were discussed at the workshop and are looked at further in the report:

- The availability of storage capacity
- Other uses and users of the pore space
- Priorities on different uses in different jurisdictions

- Potential routes to wider storage deployment
- Technical regulatory challenges for storage in areas of multiple stacked storage opportunities
- Risks that may arise from site interactions
- Examples of pore space conflict resolution
- Strategic initiatives for storage deployment.

The report details potential subsurface interactions, UK policy for CO_2 storage development (including a UK Southern North Sea case study), potential interactions between two case studies in the Southern North Sea, CO_2 storage permitting in the Netherlands, CO_2 storage in Australia, the role of CO_2 enhanced oil recovery (EOR) in Texas, USA and managing the pore space in Alberta, Canada.

Findings of the Study

Pressure as a result of CO_2 injection

Subsurface interactions may occur when a storage project operates within a geological formation and such interactions are well-documented. The most significant potential interactions are likely to be the pressure effects of CO_2 injection and the associated brine displacement. This reservoir pressure increase is a prime risk to other resources (including other storage sites) which are in pressure communication. Figure 2 shows a simulation of the relationship between CO_2 plume extent and the extent of the pressure rise from this injection.

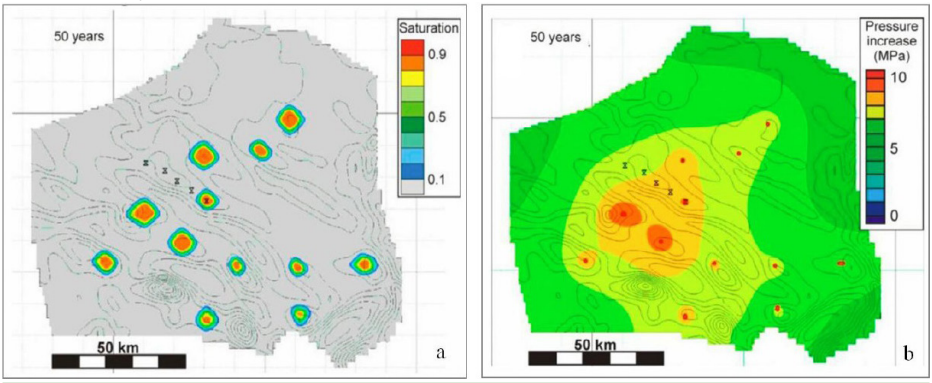

Figure 2, A TOUGH2 simulation showing the relationship between CO_2 plume extent and pressure rise, over a 50 year period.

UK Policy and Regulation for Storage Development

The UK has several strategies and policies to reduce greenhouse gas emissions, including a legally binding target to reduce emissions by at least 80% below base year levels by 2050. The 2012 CCS Roadmap notes that; the UK has extensive storage capacity in the North Sea and clusters of power stations/industrial plants – which could share knowledge and infrastructure to develop CO_2 storage. The Department for Energy and Climate Change (DECC) has recognised the potential for CCS clusters to develop across several regions and their storage strategy identifies the challenge of future storage deployment, included the scale of possible future storage needed. The storage roadmap sets out specific activities that the UK government will focus on in these efforts and other activities (by organisations like the Crown Estate and the Storage Cost Reduction Task Force) will support such efforts. The UK government have undertaken several significant activities for storage research and demonstration (R&D) including a commercialisation competition and a coordinated research, development and innovation programme.

The UK Southern North Sea has a vast amount of storage potential, including in gas fields (the majority of which occur within the Rotliegend Leman Sandstone formation) and saline aquifers (including the Bunter Sandstone, thought to have the best potential for aquifer storage, with good pressure communication across the reservoir).

UK Southern North Sea Case Study

The report undertakes a UK-specific case study to illustrate the range of potential users/ conflicts which could be anticipated as more storage sites are developed. The main classes of potential CO_2 storage sites used are saline water-bearing domes in the Bunter Sandstone formation; gas fields in the Bunter Sandstone; gas fields in the Leman Sandstone; and gas fields in carboniferous limestones. Potential users or conflicts identified include hydrocarbon operations, gas storage and other CCS sites (all subsurface users), and wind farms, dredging areas, pipelines, other operators, environmental protection areas and shipping routes (surface users). Scenarios were developed (first-come, first-served (FCFS) and managed storage resource) to run from 2020 to 2050, to illustrate the interactions that may occur as a result

of CO_2 injection.

Two potential storage sites were chosen to undergo the scenario simulations, with assumptions made that all storage capacity could be used and no pressure management wells are used. No cost assessment was carried out, so differences will arise due to varying site characterisation and commissioning costs. Even in areas with large potential storage resources, surface and subsurface interactions may arise – and early projects will benefit from being able to choose the best sites for a minimal chance of interactions, and the likelihood of interactions will increase as the number of storage sites increase. The managed storage resource scenario demonstrates that CCS could face competition from other nearby CCS projects, wind farms, gas storage sites and hydrocarbon production operations; however it is likely that the development of both options could occur as demand for storage capacity increases, for reasons explained in the report. For example, offshore wind farms could present a physical barrier to accessing any potential storage sites in terms of laying down infrastructure and monitoring above a site, including the safety zones that may be imposed around turbines.

Underground Storage Permitting for CO_2 in the Netherlands

The implementation of CCS in the Netherlands is being driven not only by climate change concerns, but also by potential economic benefits of being a front-runner in this technology. There are many R&D efforts underway in the Netherlands, and the national government works along an organisational model of a privately run CCS market (where the initiative for ction comes from the emitting operators themselves) and the government's role is one of a supervisor. It is interesting to note that the 'Inpassingsplan' (July 2008) under the Spatial Planning Act gives the Dutch government the right to adapt spatial planning by district/local governments in the circumstance of projects of national importance. At present, this country is in the start-up phase of large-scale demonstration projects, aiming to store around 1 MT per year. The Dutch subsurface contains numerous gas fields and the policy of government is aimed at the use of depleted gas fields as CO_2 storage facilities. Figures 3 and 4, below, show the theoretical storage capacity in the Netherlands.

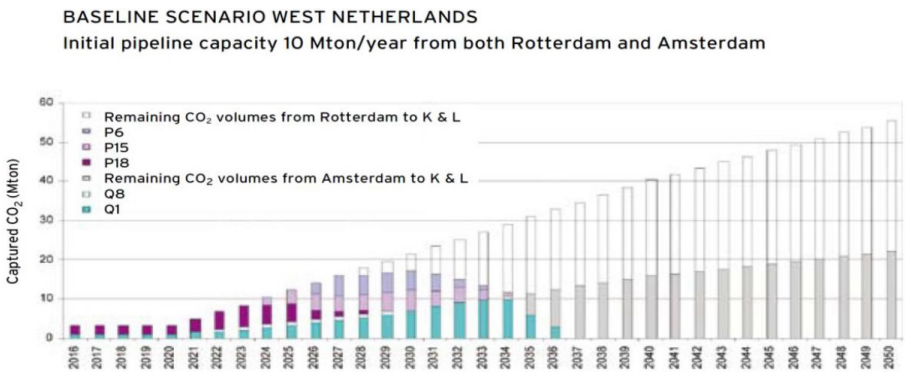

Figure 3, Available theoretical offshore CO_2 storage capacity based on expected end of field

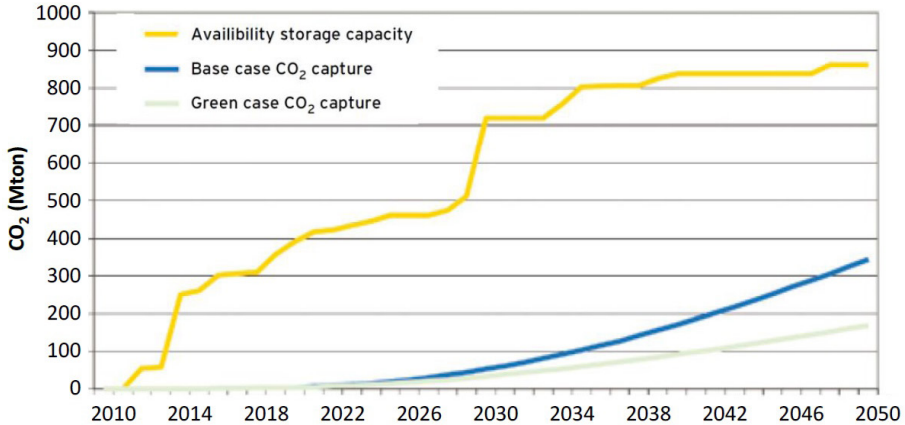

Figure 4, Development of cumulative theoretical onshore storage capacity in northern Netherlands versus the base case scenario and the green scenario for CO_2

There is the potential for competition within the surface and subsurface in the Netherlands, identified in the report. Using existing infrastructure is much more favourable than drilling new wells, but additional issues at the surface may arise, including land use conflicts, potential ground movements and induced seismicity. Public acceptance is likely the biggest barrier to CO_2 storage in the Netherlands and for this reason, at this stage it is only being considered offshore. In the subsurface, most competition between users would arise in an onshore environment, where the storage of CO_2 may prevent gas fields from being used for other storage (e.g. potential UGS sites), but UGS only puts a temporary claim on the rights. Other potential

competition may arise from nearby geothermal producer and injector pairs, or salt production activities from layers directly above the storage reservoir. A key potential offshore conflict includes the issue of connectivity and pressure communication with adjacent fields under development or production.

Australia

In Australia, different jurisdictions follow different approaches to the design of CCS regulatory frameworks. The majority of Australia's storage potential is located offshore (with the most potential residing in North West Western Australia), but 'areas assessed to have greatest storage potential are not well-aligned with key electricity demand/load centres'. There is a limited scope for CO_2 storage in depleted oil and gas fields, as the majority remain in production (and will do for many years) and high recovery rates mean there is little potential for CO_2-EOR.

When discussing potential users and conflicts, it must be noted (as in all locations) that this will be highly site-specific. Offshore conflicts in Australia could include issues with other users, such as fisheries, shipping routes, infrastructure etc., but the greatest potential conflict is with the petroleum industry itself, who is concerned about compromising production. Onshore conflicts may arise from similar users as offshore, but one must consider additional uses such as agriculture. The subsurface issues raise the most concern. Groundwater impacts (an important community-wide issue) are a huge potential conflict, as are the usage conflicts with coal bead methane (CBM) operations – there is a strong coincidence between the CBM resource and potential CO_2 storage sites.

The Australian government have adapted a range of onshore and offshore specific policy and regulatory responses to address storage management. Offshore CO_2 storage is primarily governed by provisions of the government's 'Offshore Petroleum & Greenhouse Gas Storage Act 2006' and its associated regulations. This Act provides for clear security of title for CO_2 operators and also clarifies long term liability issues. The government has also developed detailed guidelines to help CO_2 titleholders and there are clear legislative distinctions between the petroleum industry requirements and those for other users. It is interesting to note that the approach only considers that the projected stored plume must be contained within the injection

licence title, but does not consider the potential extent of the pressure front. State governments are active in working to facilitate the onshore storage of CO_2; Victoria, Queensland and South Australia have all enacted legislation. New South Wales and Western Australia have legislation currently under consideration. The regulatory and policy regimes adopted by state governments have addressed the issues of overlapping tenure and competing/conflicting use in detail.

The Role of CO_2 EOR in Texas, USA

The 'management of CO_2 storage and EOR in the same footprint is generally beneficial to both processes', perhaps why a large amount of recent work has looked further into CO_2-EOR. Pressure elevation (see figure 5, below, for a diagram of increased pressure when closely spaced injector and producer wells are used to 'force seep' the residual oil) is a benefit to a connected EOR reservoir (but a risk factor for CO_2 storage), and EOR may assist in the management of pressure in the storage area. Another benefit is that in EOR-rich areas, there will be a wealth of data which could be used in site characterisation and pre-existing infrastructure, which could be used by other projects.

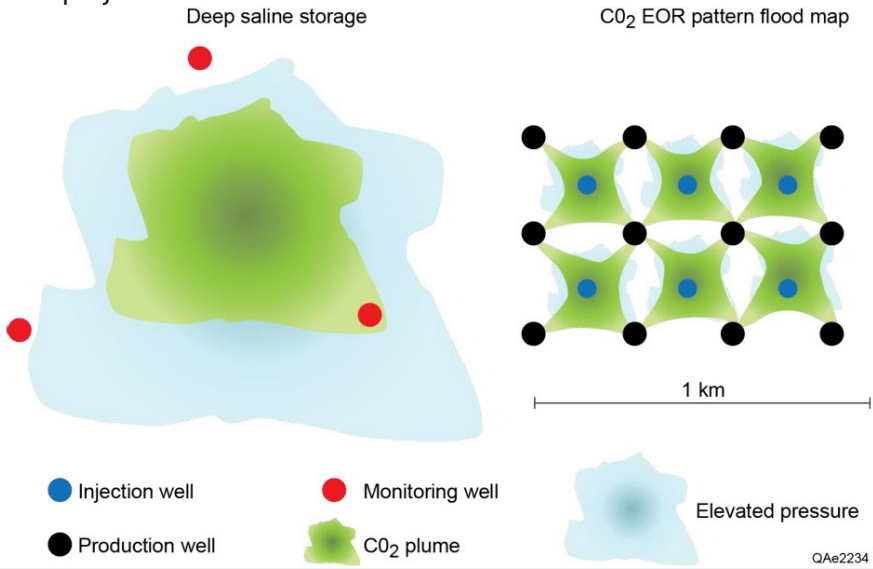

Figure 5, Sketch comparing the area of the CO_2 plume and significantly elevated pressure at deep saline injection with an EOR flood, showing the role on injection and production well patterns in managing and monitoring the flood

CO_2-EOR has a fairly high success rate, but despite the strong technical background with this technology, it is often not economically viable (i.e. the availability of CO_2, capital to construct a delivery pipeline, available financing etc.) and there is competition with other technologies, although there is uncertainty about the extent to which the sale of CO_2 could offset capture costs (the sale of CO_2 could lower this barrier for CCS projects). Other limits of CO_2-EOR may be the nature of recycle; greenhouse gas emissions generated by compression and pressure lifting; well integrity; oil production; and size of the EOR market.

It was recognised that in most cases, the majority of storage capacity is stacked, overlapping and sometimes dynamically connected. There is great potential for CO_2-EOR in such vertically stacked, multiple systems (stacked depleted oil and gas fields and deep saline aquifers) and in such systems, monitoring programmes could be integrated. However, projects undertaking this must be mindful of different risks/uncertainties needed to be considered for the different processes taking place. Potential issues with the joint use of EOR and CO_2 storage could be that there may be documentation and investment in retention, subsurface trespass issues for EOR; and managing conflicts between the EOR and CO_2 storage technologies and processes.

Managing the Pore Space in Alberta, Canada

Alberta's 2008 Climate Change Strategy recognised CCS as a key mitigation technology to address greenhouse gas emissions and in 2009, the Carbon Capture and Storage Act was created to encourage the development of CCS projects in the province.

There are various activities and legislations to enable CCS and the storage of CO_2. The Alberta government assumed long-term liability (a significant uncertainty for CCS) for a storage site once a closure certificate has been issued, thus improving the ability for operators to plan/execute and ensuring the protection of the public. Steps have already been taken by the government to manage the positive and negative interactions between CCS and hydrocarbon resources – it is explicitly mandated in legislation that 'CCS projects will not interfere with or negatively impact oil and gas projects in the province'. The 'pore space tenure' process is the primary process to ensure that CCS development will not negatively impact the hydrocarbon industry

in any way. Where there is high demand for pore space tenure in an area where pore space tenure has already been allocated, the government has to introduce policy and regulations to incentivise operators to allow access to their pore space for the storage of CO_2. There are currently no regulations for this but portions of some Acts allow for the transfer of tenure and for Alberta, it is clear that 'market considerations should be a primary driver behind third part access to sequestration tenure and CO_2 injection'. The Albertan energy regulator has a well-developed process for evaluating and managing subsurface resource interaction, another process to encourage development in CCS.

Expert Review Comments

The study was sent out for a peer review, and detailed comments were received from five expert reviewers in total. The reviewers were overall, very impressed with this study, and many felt that this report will be a valuable resource for operators, regulators and academics.

A few general comments on grammar were received and acted upon throughout the study, and suggestions to rephrase some sentences at various points throughout the report were taken into account, to minimise the chance of misunderstanding of the text by the reader. Specifics and further detail was added to various explanations of terms to ensure proper explanation of certain technological aspects, and further site-specific information has been added where requested and necessary. Several updated references and an updated figure were added as per the request of one reviewer.

Some suggestions were made to add information on the economics of the management scenarios, but this was considered out of scope for the study and therefore no action was taken. It was suggested that more detail and analysis should be added to the various case studies – unfortunately due to time constraints this wasn't able to be done, but is potentially a path for future research.

The final report reflects the comments of IEAGHG and the expert reviewers. The contractors have provided a detailed tabulated summary of the comments received and their actions taken to address these comments, which can be made available to interested parties.

Conclusions & Recommendations

There are many potential competing users of the surface and subsurface in onshore and offshore environments, and this study has demonstrated the potential for interactions between the possibly multiple pore space users.

There are various different approaches to storage management, which are highly dependent on the jurisdiction involved. All jurisdictions looked at in this report manage their pore space on a first-come, first-served (FCFS) basis, in which operators will be able to identify their preferred CO_2 storage site. The operators' decision on the preferred site will be based on their specific geological, technical and financial criteria.

Management of storage on this FCFS basis is likely to be sustainable in the short to medium term – especially in areas with abundant storage potential. There will, however, be competition for the pore space in all regions; an issue likely to become more pronounced as CCS develops and matures. In some jurisdictions there is already a determined hierarchy of uses or constraints but it must be noted that in some countries onshore storage is not considered due to public acceptance issues. Because of this, planning frameworks have already been developed to some extent in many countries considering the deployment of CCS.

Scale and impacts of subsurface interactions during CO_2 storage

The main interaction that must be evaluated is the area, amount, rate and maximum reservoir pressure the storage formation will experience. The consequences of the increase in pressure with injection will vary site to site, depending on the characteristics of the area, the areas past history and other uses in the area – specifically the types of use and proximity to these uses. Pressure increases do not always result in detrimental effects, but pressure responses in open storage sites should be the focus of a detailed assessment in every potential CO_2 storage case.

The scale and impact of a pressure rise will be site-specific. Although many simulations of CO_2 injection into saline aquifers show a pressure response will occur through the connected pore volume, these simulations are often simplified representations of various factors (such as the local geology) and therefore aren't always accurate.

The maximum pressures are experienced around injection wells and this dissipates (with distance) toward the formation boundaries of the connected pore volume. Permeability baffles will limit the amount and extent of the pressure footprint. Simulations suggest that after injection, pressures often dissipate quickly, hence the highest pressures will be observed during injection operations. A number of pressure management strategies are available and may be required to optimise the storage efficiency of a site (whilst maintaining pressures below a defined threshold).

Approaches to strategic management of the storage resource

It is crucial for the operator and regulator to understand the consequences of a pressure increase over an area much larger than the extent of the CO_2 plume itself. It makes sense that an overview of the region (including future uses of the subsurface) is the responsibility of the relevant authority. The operator should be responsible for simulating the extent of the pressure footprint and the regulator for assessing the validity of this modelling.

Pressure increases resulting from CO_2 injection/storage are likely to become an issue when there are multiple CO_2 storage sites within a connected geological formation, injecting at the same time. The combined pressure response will limit the total capacity of the sites. This will decrease the injectivity and increase the need for pressure relief in the formation.

The main benefit of a FCFS approach is that the operator has the final decision on where to develop CO_2 storage, and the approach should work for multiple-stacked sites. Potential drawbacks of this approach include possible reduced storage capacities (in adjacent future storage sites), difficulties for monitoring and a lack of regional storage optimisation. In addition, the FCFS methodology may not lead to a pathway of overall least cost development for storage. To avoid or reduce potential negative interactions, some strategy management is likely to be necessary in most regions.

This study by BGS, on behalf of IEAGHG and GCCSI, looked into scenarios for storage development; the development of clusters; knowledge requirements; defining lease areas; and resolving conflicts.

Knowledge, experience and research gaps

Developing strategic plans for efficient storage use

Consequences of a rise in pressure within a CO_2 storage formation will be very site-specific. In the past, such recognised consequences have been specifically focussed on the geomechanical responses in the reservoir. However, the impacts of pressure increase in non-reservoir rocks should be looked into further. This would help to address the issue of the degree of communication between reservoir rocks in stacked systems.

This report demonstrates that a strategic managed approach to a large formation or regional area may be desirable in certain scenarios of future CO_2 storage. The costs and benefits of such approaches have not yet been established, so studies that evaluate methods to optimise infrastructure for exploration will become increasingly important.

To understand the potential consequences of multiple storage scenarios occurring at the same time, a regional storage characterisation is recommended. These clusters of storage sites could be developed where regions have multiple, connected storage options. However, a current knowledge gap is the amount of pre-competitive characterisation needed to help develop policy for leasing. Along with this, a detailed techno-economic evaluation of storage clusters would also be required. The UK case study detailed in the report demonstrates that targeting fewer but larger, more geographically dispersed storage sites could meet future requirements as an alternative to clusters. Such large sites could provide sufficient storage capacity for multiple capture plants and in the USA, private pore space ownership may inhibit the development of clusters (if a lack of strategic policy occurs).

A potential option to mitigate many of the possible interactions is the 'active reduction of pressure through production of water'. Many studies have looked into this but not evaluated the different approaches to pressure management onshore/offshore, or how pressure could be managed in regions of multiple, sequential CO_2 injection. The optimisation of CO_2 injection and timing (to maximise storage capacity and reduce costs) is required, especially in deep saline aquifers.

Issues of competition (for example in the Netherlands) show that consistent planning is required to ensure an optimal/sustainable use of subsurface space and resources. Australia has competitive legislation on the storage of CO_2 in offshore sites. A key short term objective in all jurisdictions in Australia is to realise early demonstration projects. The government of Alberta has established ownership of the subsurface space/resources and the ability to issue rights to the pore space to potential CCS projects. The government of Alberta's Regulatory Framework Assessment has identified several gaps relating to the management of pore space and this report provides recommendations to address these gaps.

A key challenge in all regions is to ensure regulators from different jurisdictions work together. A range of issues that would benefit from further regulatory guidance have been identified, including as examples: experience in the application of the SROSAI ('significant risk of a significant adverse impact') test in Australia, including development of guidance notes to inform on the use of these tests; the development of a guidance on what constitutes 'good CO_2 storage practice'; and better understanding of the interactions that may occur in the subsurface with CO_2 injection and storage.

EOR as a step towards wider CCS

CO_2- EOR as part of a storage programme can be considered as 'one response to a GHG-driven need to lower barriers to capture'. A review of the benefits/difficulties experienced by current CO_2-EOR projects with other operations can be used to provide information on how future CO_2 storage projects may interact with other uses. The potential for using CO_2-EOR as a method of geological storage is high, and has been demonstrated by early deployments in the USA.

EOR sites have favourable attributes toward the long-term storage of CO_2, including known top seals, well-quantified injectivity and storage potential. Such favourable aspects were identified within the report, including the high quality of storage, good site characterisation and dense monitoring potential, a positive economic signal (from additional oil production), well-known regulatory and liability aspects, and well-known public acceptance (in many areas). Limits to the potential use of EOR as storage include that the whole system response is perhaps weak in terms of emissions and the

energy consumption required by EOR operations reduces storage efficiency. In addition to this, there are numerous well penetrations in EOR areas which could potentially lead to lowered storage effectiveness (but this is an area identified as needing further research). The impact of different types of well failure mechanisms were looked at and such types include acute, high volume, short duration events; the migration of CO_2 into unintended areas, which could occur quickly or over a long period; and low-rate leakage through flawed well construction.

Uncertainties arise with EOR for CO_2 storage for various reasons, one major issue being economics – there are unknown cost curves (of CO_2 and future oil) and uncertainty with capital markets. Other uncertainties with CO_2-EOR include the regulatory environments and public acceptance. Uncertainty is elevated for potentially 'unconventional EOR', so in offshore reservoirs, residual oil zones, fractured reservoirs and gravity-stable floods.

Adjustments are required when using CO_2 for EOR (as opposed to water or other substances); the 'hydrogeologically-connected reservoir must be unitized and operated together'. Any interference between EOR and injection operations could be problematic in that increased pressure is beneficial for the enhanced recovery of oil, but injection operations benefit from decreased pressure. CO_2-EOR for the storage of CO_2 is an interesting and attainable strategy, but would need much legal and regulatory management.

CO_2 STORAGE EFFICIENCY IN DEEP SALINE FORMATIONS: A COMPARISON OF VOLUMETRIC AND DYNAMIC STORAGE RESOURCE ESTIMATION METHOD (2014-09)

Key Messages

- CO_2 storage efficiency starts low, rises quickly, and then levels off in an asymptotic trend to a maximum in much the same way as oil recovery changes in an oil field through time. There is a distinct contrast between an open system, represented by the Minnelusa Formation, and a closed system represented by the Qingshankou and Yaojia Formations. In the Minnelusa Formation it would take 500 years to reach over 50% of the estimated storage capacity whereas this level of capacity could be reached in approximately 50 years in the Qingshankou and Yaojia Formations.
- Care needs to be applied to dynamic storage estimates. The dynamic efficiency method shows that the open aquifer cumulative injection capacity in 50 years is not significantly larger than the closed aquifer one. Consequently, there is a risk that storage capacities could be over-estimated if dynamic conditions are not applied and the properties of 'open' and 'closed' formations are not taken into account.
- Results from this study clearly show that storage capacity estimates are strongly time-dependent. However, it is important to recognise that a key objective of this study was to determine the maximum storage resource without an arbitrary limited time restriction.
- Additional optimisation operations can be implemented to1) increase the rate at which storage efficiency increases or 2) increase the maximum storage efficiency.
- The dynamic results become roughly equivalent to the volumetric efficiency values after about 500 years. Volumetric efficiency values could be used if enough time were given for CO_2 to be injected.
- The biggest single factor that increases storage capacity is extraction of formation saline. There are much bigger differences (P10 – P90) in the modelled capacity of an Open system compared with a Closed system.
- Between 15% to 33% of the injected CO_2 could end up in solution in the

first 50 years of injection, and this percentage could further increase by up to 16% to 41% after 2,000 years.

Background to the study

The goal of this study was to compare the volumetric and dynamic CO_2 storage resource estimation methodologies used to evaluate the storage potential of deep saline formations (DSFs). This comparison was carried out to investigate the applicability and validity of using volumetric methods, which typically require less data and time to apply, to estimate the CO_2 storage resource potential of a given saline formation or saline system. The project has showed how different variables including saline extraction (pressure management), geological uncertainty, boundary conditions and trapping mechanisms affect storage capacity. Dynamic modelling also revealed how CO_2 storage capacity changes over time.

The project goals were accomplished by applying both volumetric and dynamic CO_2 storage resource estimation methodologies to the open-system upper Minnelusa Formation in the Powder River Basin, of the United States, and a closed-system comprising the Qingshankou and Yaojia Formations in the Songliao Basin, of north-east China. These two saline systems were selected because they are representative examples of an open and a closed system. The upper Minnelusa Formation consists of aeolian sand dunes cemented and interspersed with carbonates which act as a single flow unit. The Qingshankou and Yaojia Formations consist of deltaic–fluvial deposits, with good storage properties, separated by lacustrine muds with low storage potential. These formations are representative of a linked stacked storage system and were modeled as one system. Both study areas are in intermontane basins; however, the Qingshankou and Yaojia system does not have areas of discharge and recharge while the Minnelusa does. This results in the Minnelusa Formation acting more as an open system, while the Qingshankou and Yaojia system is expected to behave in more of a closed or semiclosed manner. This contrast adds a further dimension and provides a better comparison between the volumetric and dynamic approaches. The volumetric methodology and open-system storage efficiency terms are described in the U.S. Department of Energy (DOE) Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy National Energy Technology Laboratory, 2010, Carbon sequestration atlas of the

United States and Canada [3rd ed.]) and the closed-system efficiency terms are described by Zhou and others (Zhou, Q., Birkholzer, J.T., Tsang, C.-F., and Rutqvist, J., 2008, A method for quick assessment of CO_2 storage capacity in closed and semiclosed saline formations: International Journal of Greenhouse Gas Control, v. 2, no. 4, p. 626–639). Both these terms were used to estimate the effective CO_2 storage resource potential and efficiency in both the upper Minnelusa and Qingshankou–Yaojia systems.

Model development

The dynamic CO_2 storage resource potential and efficiency values were determined through the use of injection simulation. In both the volumetric and dynamic approaches, a geocellular model was constructed of the entire storage formation and the overlying sealing formations. In both the volumetric and dynamic approaches, the same geological model was used so that the assessments could be made on a consistent basis. For each system, the effective open-system and closed-system storage efficiency terms were calculated so they could be compared to the storage efficiency as determined using the dynamic approach.

Storage efficiency is defined as the estimated storage capacity, determined by dynamic modelling, expressed as a percentage of the theoretical storage resource. The theoretical storage resource represents the absolute total pore volume within a rock formation. In this study the theoretical resource limit only considers the formation properties that make it amenable to CO_2 storage, e.g., good porosity and permeability. The starting point for both approaches was the construction of a geocellular model. Background data was compiled on the selected formations from each basin. Data was retrieved from existing structure contour maps, isopach maps, facies maps, geophysical wellbore logs, core analysis data and general geological interpretation. Petrophysical analysis was then used to determine porosity and permeability properties which could be used to develop facies models that could then be used to determine CO_2 storage potential. The final step is to scale up the facies models within the formation across the entire basin. The procedure is summarised in Figure 1.

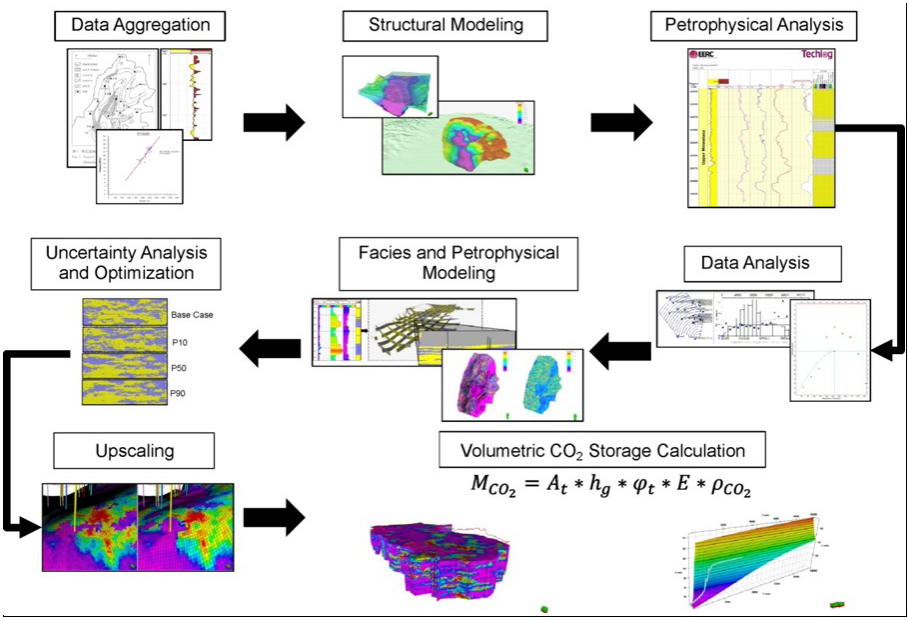

Figure 1, Workflow for the construction of geocellular models to calculate the effective storage resource potential.

Uncertainty analysis and reservoir optimization was also applied to the base line for the models. The high case for each example was a 90th percentile (P90) condition and contains more of the primary storage facies and more pore volume, while the low case was a 10th percentile (P10) condition which has less primary storage facies and less total pore volume. The mid case is represented by a 50th percentile (P50) and is similar to the base case condition. A further refinement was applied in this case by applying boundary conditions which determined the extent of suitable reservoir conditions determined by porosity and permeability thresholds (<5 mD in the Qingshakou–Yaojia system and <1 mD in the Minnelusa Formation). The geocellular model was comprised of interconnected cells which consisted of storage facies above these predetermined thresholds. The procedure is outlined in Figure 2.

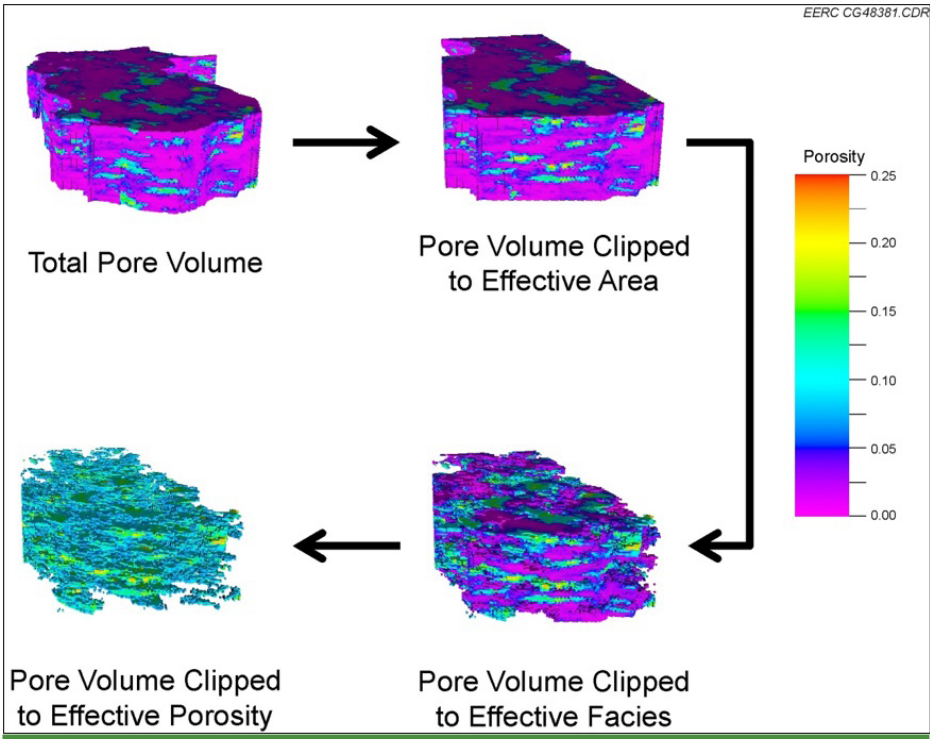

Figure 2, Sequential reduction in total pore volume to the effective pore volume in the upper Minnelusa Formation (the model is shown in Simbox (i.e., all of the cells have the same size and the thickness)

The study also explored how boundary conditions might affect storage capacity. The dynamic models were run for both the upper Minnelusa and Qingshankou–Yaojia systems with modifications to the peripheral cells in the geocellular model to simulate "open" and "closed" conditions". The "actual" boundary conditions were defined by constructing the geocellular model to cover the entire formational extent, including areas too shallow to inject CO_2; areas of discharge, recharge, and outcrops; and all of the overlying sealing formations to the surface. The overlying seals were assigned realistic porosity, permeability, and relative permeability values based on these formation types found in the literature. Constant pressure boundaries were then assigned to the surface, as well as recharge, discharge, and outcrop areas. The lateral edges of the formations were assigned no-flow boundaries. The inclusion of these additional areas outside of those typically considered

for injection in the model made it possible to assess whether the systems are open, closed, or semiclosed. The "open" boundary conditions were defined by taking the same model conditions described in the actual boundary conditions and adding infinite acting boundary conditions to all lateral edges of the formation—including those terminating deep in the subsurface and those that would otherwise be closed because of sealing faults or other features. "Closed" boundaries were assigned the same conditions as the actual boundary conditions except for reducing the permeability to the overlying formations by a factor of 100. If the permeability in the overlying seals is already in the nanodarcy range, the results will not look significantly different than the actual boundary conditions scenario, with both acting as closed systems.

Model simulation results

The results of the model simulations for both systems are presented in Figure 3 which clearly shows a distinct contrast between the two systems. In the case of the upper Minnelusa Formation the results show a divergence of between an efficiency of 18% for an "open case" and 7.2% for a "closed" case after 2,000 years. In addition, the permeability of the overlying seals in the actual and open boundary conditions cases increased the storage efficiency in the actual and open scenarios by 53% and 147%, respectively, illustrating the important role that the formation seals can play in influencing storage efficiency, even in open systems. By contrast, changing the boundary conditions of the Qingshankou–Yaojia cases did little to affect the resulting storage efficiency after 50 and 2,000 years. After 50 years of injection, the Qingshankou–Yaojia system's boundary condition cases had effective storage efficiencies ranging from 0.34% to 0.37%. After 2,000 years, these had increased but still did not vary significantly, with a resulting range of 0.62% to 0.67%. This is probably due to the very low permeability at the lateral edges and overlying seals in the actual boundary condition.

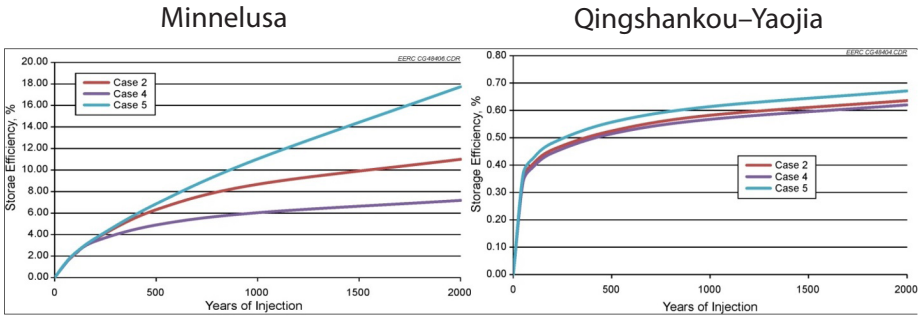

Figure 3, The Dynamic effective CO_2 storage efficiency over time for the actual, open, and closed boundary conditions cases in the Minnelusa and Qingshankou–Yaojia systems

A total of twelve simulation cases were run for both the upper Minnelusa and Qingshankou–Yaojia models to investigate the effects of trapping mechanisms, geologic uncertainty, boundary conditions, well configuration, and injection and extraction strategies. In each simulation run, the entire formation extent and overlying formations were included within the models in order to better understand the pressure buildup effects. Initially, injection was simulated for 50 years, and then the maximum dynamic storage was estimated by running a few cases with continuous injection for up to two thousand years until the maximum storage potential was reached. Based on the results of these simulations, the upper Minnelusa Formation behaved as an open system with dynamic CO_2 storage efficiency ranging between 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2,000 years of continuous injection in cases without water extraction (see Table 1).

	Low	High
Volumetric Efficiency – Closed System	0.54%	0.54%
Volumetric Efficiency – Open System	2.9%	11%
Dynamic Efficiency – 50 years' Injection	0.55%	1.7%
Dynamic Efficiency – 200 years' Injection	1.9%	4.3%
Dynamic Efficiency – 500 years' Injection	2.5%	7.9%
Dynamic Efficiency – 2000 years' Injection	3.4%	18%

Table 1, Minnelusa System Effective CO_2 Storage Efficiency

Time (years)	Case 2* - Mt	%	Case 6** - Mt	%	Case 12*** - Mt	%
0						
50	1,672	11%	742	7%	2,263	12%
100	2,928	20%	1,504	14%	3,698	20%
200	4,830	33%	2,838	26%	5,826	32%
500	8,491	57%	5,830	54%	10,558	58%
1,000	11,662	79%	8,417	77%	14,363	79%
2,000	14,786	100%	10,867	100%	18,168	100%

* Case 2 P50 Actual Boundary Conditions (Base case)
** Case 6 P50 half the number of vertical injectors

*** Case 12 P50 Double the number of vertical injectors

Table 2, Minnelusa Formation – Estimate storage capacities with time

In the case of the Qingshankou–Yaojia system, the dynamic approach resulted in the storage efficiency ranging between 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72% after 2,000 years of continuous injection in cases without water extraction (see Table 3). These results are in very close agreement with the calculated closed system efficiency values and indicate that the system is closed or semiclosed. This approach supports the use of a volumetric estimate for similar systems, as long as a closed-system storage efficiency is applied.

	Low	High
Volumetric Efficiency – Closed System	0.21%	0.21%
Volumetric Efficiency – Open System	1.3%	10%
Dynamic Efficiency – 50 years' Injection	0.28%	0.40%
Dynamic Efficiency – 200 years' Injection	0.39%	0.52%
Dynamic Efficiency – 500 years' Injection	0.45%	0.60%
Dynamic Efficiency – 2000 years' Injection	0.62%	0.72%

Table 3, Qingshankou–Yaojia System Effective CO_2 Storage Efficiency

In contrast to the Minnelusa Formation the Qingshankou–Yaojia system would attain over 50% of its potential storage capacity within 50 years but the rate of storage would decline significantly after about 300 years (see Table 4 and Figure 3). The difference between these two modelled formations is attributed to the contrast in depositional environments and associated variation in facies within each formation.

Time (years)	Case 2* - Mt	%	Case 6** - Mt	%	Case 12*** - Mt	%
0						
50	3,066	55%	2,448	52%	3,312	58%
100	3,547	64%	3,010	64%	3,772	66%
200	4,005	72%	3,459	73%	4,220	74%
500	4,605	83%	3,936	84%	4,803	84%
1,000	5,107	92%	4,305	91%	5,266	92%
2,000	5,578	100%	4,711	100%	5,713	100%

* Case 2 P50 Actual Boundary Conditions (Base case)
** Case 6 P50 half the number of vertical injectors
*** Case 12 P50 Double the number of vertical injectors

Table 4, Qingshankou-Yaojia Formations - Estimate storage capacities with time

The volumetric methodology was applied to the two systems, using both the open-system and closed-system efficiencies. This resulted in open-system effective CO_2 storage efficiency in the upper Minnelusa Formation from 2.9% to 11% and the closed-system effective CO_2 storage efficiency of 0.54%. In the Qingshankou–Yaojia system, the open-system efficiency was 1.3% to 10%, and the closed-system efficiency was 0.21%. This wide range in effective storage efficiency values is due to the large amount of uncertainty in both the geological properties and the flow properties of the system.

This study also investigated the effects of geological uncertainty, boundary conditions, the number and types of wells used, and water extraction techniques on the effective CO_2 storage efficiency. In both the open-system upper Minnelusa and closed-system Qingshankou–Yaojia system, the use of water extraction had the largest effect on CO_2 storage potential, increasing the storage efficiency by as much as 475% in the Qingshankou–Yaojia system

and by approximately 100% in the upper Minnelusa Formation after 50 years of operation. The extraction rate and therefore the estimated level of increased storage efficiency compared with a volumetric base case depends not only on the numbers of injection and extraction wells but also if they are horizontal or vertical.

The study did not specifically examine the cost-effectiveness of different wells but it did compare the technical merits of well orientation. The study compared the effects on capacity assuming different combinations of vertical and horizontal injectors and extraction wells. The study included a comparison of an equal number of vertical and horizontal wells, and a volumetric capacity assuming a P50 condition, for both the Minnelusa and the Qingshankou-Yaojia formations. In the Minnelusa, there is 2% change from Case 2 (base case after 50 years). In the Qingshankou-Yaojia, there was a 3% change from the base case. If this is accurate, the horizontal wells provide no significant benefit over the vertical wells from a capacity standpoint, and they are certainly more expensive. In North America, horizontal wells may be 2-3 times more expensive per well then a vertical well. In the study the horizontals did not provide that much benefit even after 2,000 years, although they might have contributed 20% more capacity. On a site specific case, the use of horizontal wells may be a good option, however it will depend on a number of site specific variables.

Other factors including geological uncertainty and boundary conditions as well as the number and type of wells, did not play as significant a role in increasing the storage efficiency, as local pressure buildup and the concomitant reduction in the rate of injection in the upper Minnelusa Formation. Modelling results showed that regional pressure buildup was by far the biggest limiting factor in the Qingshankou–Yaojia system.

In open-system cases such as the Minnelusa Formation (see Figure 3), the dynamic CO_2 storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO_2 storage resource potential over very long periods of time in the order of several hundred or thousands of years. This is very similar to resource industries, namely, mining and the oil and gas industries, where if CO_2 is treated in an equivalent manner to a resource its maximum storage potential can only be fully realised by using advanced technology, notwithstanding time, economics, regulatory, and

other considerations. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO_2 storage efficiency of a formation will probably take hundreds of wells spaced throughout a formation's area, and it could take decades or possibly thousands of years of injection to fully realise the effective CO_2 storage resource potential.

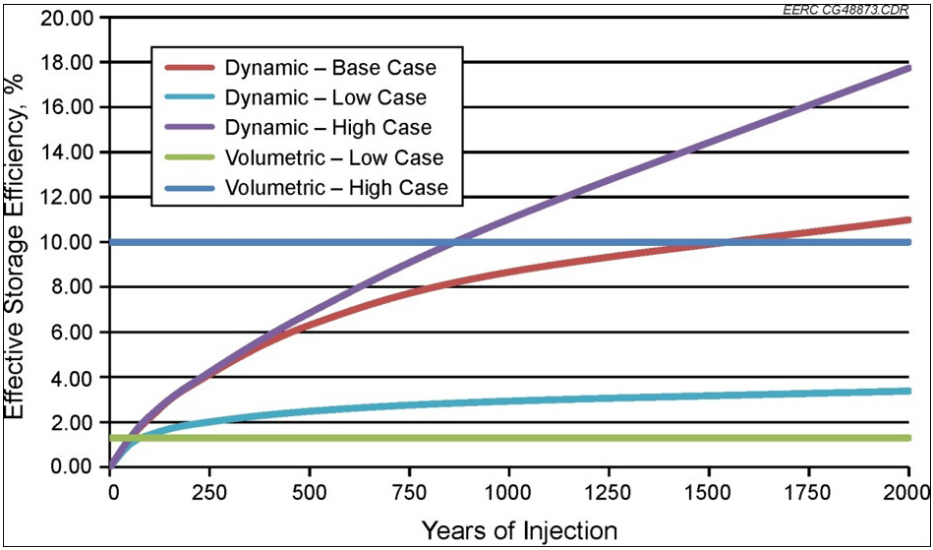

Figure 3, The dynamic CO_2 storage efficiency of open systems is very time-dependent and slowly reaches an asymptote over time which approaches the volumetric effective CO_2 storage efficiency, as shown here with the open-system Minnelusa Formation

Trapping mechanisms are likely to play different roles in storing CO_2 in a formation throughout the life of the storage project. In this study, the main concern was how these trapping mechanisms affect the effective CO_2 storage efficiency. Residual trapping occurs in a two part process, firstly CO_2 displaces the formation fluid and later, generally after the injection stops, the formation fluid (usually brine) imbibes back in and traps a portion of the CO_2 in the pore spaces. Solubility trapping occurs throughout the injection stage and then continues post injection. CO_2 solubility is a function of temperature,

pressure, salinity, and the rate of mixing between the CO_2 and undersaturated formation water.

A series of simulations were run to determine the relative effects of physical, hydrodynamic, residual gas, and solubility trapping on the effective CO_2 storage efficiency of each formation. Over time, the trapping mechanisms lock CO_2 in the reservoir and gradually decrease the amount of remaining storage potential. This principle holds true for all of the mechanisms except solubility trapping. As injected CO_2 mixes with the native formation waters, a portion of the CO_2 dissolves, taking up less space in the reservoir which increases the storage efficiency by decreasing formation pressure and allowing more CO_2 to be stored in the same pore volume.

In this study it was assumed that injection was continuous and that solubility trapping was a major component of the storage capacity during injection. In both cases (Minnelusa Formation and Qingshankou-Yaojia Formations) about 20%-30% of the storage was as dissolved CO_2 (solubility trapping) after 50 years and increased in percentage as more time passed in the case of the Qingshankou-Yaojia Formations, as convective mixing increased the trapping processes (Table 5). The difference in the predicted percentage of solubility trapped CO_2 between the Minnelusa and the Qingshankou-Yaojia Formations could be attributed to the contrast in brine salinity. It should be stressed that the potential accuracy of the model to estimate solubility trapping depends on the size of its cells. Because of the basin-wide scale of the model large cell sizes were used study. To simulate the mixing process more accurately fine grids are needed which was beyond the scope of this study.

The salinity from each formation was based on published values. The average in the usable pore volume of each case was 242,000 ppm in the Minnelusa and 20,000 ppm in the Qingshankou-Yaojia. As previously stated the difference in salinity concentration may account for the higher percentage of dissolved CO_2 in the Qingshankou-Yaojia formations. The solubility of CO_2 is lower in formations with higher salinities and temperatures.

Minnelusa Formation Comparison of CO_2 in solution compared with Total CO_2 injected after 50 and 500 years injection									
Time	Case 2			Case 6			Case 12		
	Total Injected	Mass CO_2 in solution		Total Injected	Mass CO_2 in solution		Total Injected	Mass CO_2 in solution	
50	1,674	348	21%	742	116	16%	2,263	515	23%
500	8,491	2,000	24%	5,830	1,000	17%	10,558	2400	23%
Qingshankou-Yaojia Formations Comparison of CO_2 in solution compared with Total CO_2 injected after 50 and 500 years injection									
Time	Case 2			Case 6			Case 12		
50	3,067	845	28%	2,578	524	20%	3,312	1,080	33%
500	4,605	1,750	38%	3,936	1,100	28%	4,803	1,870	39%

Table 5, Comparison in CO_2 solubility between the Minnelusa and Qingshankou-Yaojia Formations

It would be very difficult to determine how much CO_2 is trapped residually after injection stops without running further simulations. Solubility trapping will continue after injection stops as convective mixing continues. Additional simulations could be run for a fixed period of time (50 years) post injection and then continued for several thousand years more to see what percent of free CO_2 becomes residually trapped CO_2, solubility trapped CO_2, and mineral trapped CO_2 (mineral trapping was ignored in this study). It cannot be assumed that the residual CO_2 trapped will be equal to the amount that remains after the solubility stops. There will be areas that will have free phase CO_2 that are trapped in structures and stratigraphic traps, there will be CO_2 that is mineral trapped and solubility trapping will continue for a very long period of time in a scenario like this as the CO_2 is spread out widely in the formation.

Expert Review Comments

This study was reviewed by five experts. There was a general consensus that the study has been well-conceived, well-executed, well-written, well organised, and carefully compiled. There were some specific points raised including the selection of the 10,000 TDS threshold as an upper limit for

formation water which should be excluded from CO_2 injection. (This threshold is the US definition of formation water that can be used a source of potable water). The clear explanation of parameters used in models particularly the criteria for porosity cut-off and an explanation of model limitations including the pressure threshold used in models (20%> initial reservoir pressure) were added to the report. Other minor modifications included the clarification of units and footnotes in tables and the inclusion of well densities. The experts proposed the inclusion of key messages specifically analogies with extractive industries like oil and gas. CO_2 storage is a constrained resource comparable to oil and gas production.

Conclusions

The dynamic CO_2 storage resource potential and efficiency was determined through the use of reservoir simulation. In both the volumetric and dynamic approaches, a geocellular model was constructed of the entire storage formations and the overlying sealing formations all the way to the surface. The same geological model was used so that the assessments made could be compared on a consistent basis. For the purposes of this study, three DSFs were selected in two different geographic regions, with different geological conditions, to try to determine the validity of the volumetric estimates and the level of agreement between the volumetric and dynamic approaches.

The simulation results for the upper Minnelusa Formation shows that it behaves in an open fashion, with dynamic CO_2 storage efficiency ranging from 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2,000 years of continuous injection in cases without water extraction. The dynamic results become roughly equivalent to the volumetric efficiency values after about 500 years, indicating that the volumetric efficiency values could be used if enough time were given for CO_2 to be injected. However, analysis of three case studies indicates that between 7% and 12% of the total estimated capacity is stored within 50 years and it would take 500 years to reach over 50% capacity. In contrast the Qingshankou–Yaojia system reaches over 50% capacity in 50 years but the rate of storage would decline significantly after about 300 years.

In the Qingshankou–Yaojia system, the dynamic efficiency varied from 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72%

after 2,000 years of continuous injection in cases without water extraction. These results are in close agreement with the calculated closed-system efficiency values and indicate that the system is closed or semiclosed. This supports the use of a volumetric approach for similar systems, as long as closed-system storage efficiency values are applied.

In the open-system upper Minnelusa Formation, geologic uncertainty and heterogeneity and the use of water extraction had the biggest effect on the effective CO_2 storage efficiency. The number and type of wells did not play such an important role, especially in the long-injection scenarios. In the closed Qingshankou–Yaojia system, the use of water extraction increased the storage efficiency by as much as 475% during a 50-year injection scenario. The other factors did not play much of a role in increasing the storage efficiency, as pressure buildup in the formation was by far the biggest limiting factor on the effective CO_2 storage efficiency.

In open-system cases, the dynamic CO_2 storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO_2 storage resource potential over very long periods of time. This is very similar to other resource industries, namely, mining and the oil and gas industries. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO_2 storage efficiency of a formation is likely take hundreds of wells spaced throughout a formation's area. It is likely that it could take decades or, possibly, thousands of years of injection to fully realize the effective CO_2 storage resource potential.

Recommendations

The results from this study are illustrative and only represent two contrasting depositional environments. It may be worthwhile to investigate additional formations to determine whether the results from this study compare with a wider cross section of geological conditions and depositional environments. Solubility trapping may also need to be investigated more in the future, as it may play an important role in the geological storage of CO_2. One of the

limitations of this study is the size of the cells used in the geocellular models. Models with a larger number of cells that model formations over the same areas should enhance the predictive results. However, there is a compromise between the modelling objectives and the sophistication and computational resources required to run a series of different cases. There are also concerns in this study as to whether or not the physics of the solubility trapping process are adequately captured by the grid dimensions and cell sizes used in this study.

5TH IEAGHG HIGH TEMPERATURE SOLID LOOPING CYCLES NETWORK MEETING (2014-06)

Introduction

The IEAGHG High Temperature Solid Looping Cycles Network (HTSLCN) emerged from the preceding International Workshop on In-situ CO_2 Removal (ISCR) and aims at bringing together researchers and developers of CO_2 capture technologies that operate at high temperatures in cyclic processes using either circulating or fixed beds of solids.

The 5th HTSLCN Meeting was held from 2nd to 3rd September 2013 at Queens' College, University of Cambridge, UK. It was jointly organised by IEAGHG, University of Cambridge and Cranfield University and received support from the UKCCS Research Centre and Johnson Matthey. A number of 60 delegates attended the meeting, which offered 36 presentations organised in three sessions. The first session covered demonstrations and pilot scale trials. The second session was split in two parallel streams that discussed the fundamentals in calcium looping (CaL) and chemical looping combustion (CLC) respectively. The third session presented new process concepts and system modelling and evaluation. A subsequent panel discussion and a site visit to the facilities at Cranfield University rounded off the technical programme.

Thanks to the sponsorship by Johnson Matthey, the Scientific Committee had the ability to give away two awards for the best presentations to Markus Junk (Technische Universität Darmstadt) and Vincenzo Spallina (Eindhoven University of Technology).

The following report summarises some but not all of the presentations from the meeting.

Welcome address – John Dennis, University of Cambridge

John Dennis welcomed the delegates and provided a brief introduction to solid looping technologies and their current status. He then gave an overview of the upcoming programme and opened the technical part of the meeting by handing over to the chairs of the first session.

Session 1: Demonstrations, systems and pilot trials

Chair: Paul Fennell, Imperial College London, and Bernd Epple, Technische Universität Darmstadt

Post-combustion capture with CaO: experimental results from the 1 MWth pilot facility of La Pereda – Carlos Abanades, CSIC-INCAR

A flexible experimental facility to validate the concept of continuous post-combustion CO_2 capture (PCC) CaL technology is in operation in "La Pereda". The pilot plant consists of two interconnected circulating fluidised bed (CFB) reactors at 1.7 MWth scale and has more than 1800 h of operation in coal combustion mode, including more than 400 h in CO_2 capture mode. With standard CaO solids and operating conditions the pilot plant achieved CO_2 capture rates between 80-90% and SO_2 capture rates of over 95%. The good performance depends on the use of low-ash coal for combustion; however, natural limestones are sufficient for these coal-based systems. In addition, a high carbonate inventory (~1000 kg of limestone in the loop) is key to maintaining the high CO_2 capture rate despite sulphation. The successful operation of the pilot plant under a large range of conditions has proven the concept of continuous PCC with CaL technology.

Continuous carbonate looping tests in a 1 MWth pilot plant – Bernd Epple, Technische Universität Darmstadt

The 1 MWth CaL pilot plant at TU Darmstadt, which is part of the COORETEC project, was commissioned in 2010. It has more than 2000 h of operation in coupled CFB mode under hot conditions and more than 300 h of operation in CO_2 capture mode. The pilot plant runs on a synthetic flue gas, consisting of CO_2 and air, with a calciner that is either propane- or coal-fired. The CaL plant will cause a ~6% drop in efficiency, including compression, while capturing ~87% of the CO_2 for a 1052 MWel power plant. The first estimate for the CO_2 avoidance cost is ~20 €/tCO_2. The campaigns undertaken in the pilot plant show stable operation is possible and that there is a strong dependence of CO_2 absorption in the carbonator on temperature. Further work includes optimisation of the operating conditions and investigation of process improvements.

Progress in calcium looping post combustion CO_2 capture: process investigations at 200 kWth pilot scale – Heiko Dieter, University of Stuttgart

The 200 kWth CaL pilot plant at IFK in Stuttgart is a highly flexible facility enabling process demonstration and characterisation with realistic process conditions. The pilot plant is able to operate in two different carbonator set-ups: turbulent or CFB. The CFB set-up allows for high carbonator velocities, high flue gas throughput and high gas-solid contact, whereas the turbulent set-up allows for variable carbonator velocities and flue gas throughput, while still providing sufficient gas-solid contact and carbonator capture rates above 90%. The pilot plant completed over 800 h of operation with high hydrodynamics stability, stable sorbent circulation and high flexibility as it operated over a wide range of temperatures and looping rates. The sorbent calciner was operated with oxyfuel combustion of coal using hot recycled CO_2 enriched with oxygen up to a concentration of 50%. It could be demonstrated that humidity of the flue gas has a significant effect on the CO_2 capture efficiency, and so opens potential for further optimisation of process efficiency. Capture efficiencies of more than 90% are achievable for realistic flue gas containing 15% water vapour at temperatures below 640°C. Sorbent loss due to attrition was observed to be low and sulphur did not cause a significant decrease in capture or process efficiency.

CO_2 capture experiments from CanmetENERGY pilot-scale dual fluidised bed system – Dennis Lu and Scott Champagne, CanmetENERGY

CanmetENERGY's 100 kW dual fluidised bed pilot facility in Ottawa has more than 400 h of operating experience. Testing campaigns proved that more than 90% CO_2 capture efficiency can be achieved over a wide range of sorbent types and operating conditions. The experiments also showed that carbonation with steam enhances sorbent intake performance and helps with predicting behaviour under realistic wet flue gas conditions. Main issues of the process are sorbent attrition and elutriation but optimising sorbent make-up can help managing this. Biomass might be an ideal fuel in oxyfuel combustion mode, due to its low sulphur, low ash and high moisture content. Comparison of the results with a simple reactor model developed by Alonso et al. shows a good fit. Next steps will be investigating real combustion flue gas, process optimisation and integration of CaL in CO_2 capture, gasification and H_2 production.

Fluidised bed calcium looping: the effect of oxy-firing calcination conditions and SO_2 concentration on sorbent CO_2 capture capacity and attrition – Antonio Coppola, CNR

One of the main issues in CaL technology is the decay of CO_2 capture capacity of the sorbent due to sintering and/or presence of SO_2. It is the aim of the Cal-Mod project to model and experimentally validate the CaL CO_2 capture process for application in power plants. This includes a comparison of different sorbents under realistic conditions, i.e. presence of SO_2 under oxyfiring conditions. The experiments consisted of five calcination/carbonation cycles with different SO_2 concentrations (0/0 ppm, 750/75 ppm, 1500/1500 ppm). Dolomite showed a better CO_2 capture performance than the limestones investigated but also had higher attrition rates. Presence of SO_2 generally slightly reduced the extent of fragmentation.

Operation of a 100 kW chemical looping combustor for solid fuels – Anders Lyngfelt, Chalmers University of Technology

Chalmers' 100 kW CLC pilot plant was designed and built in the ECLAIR project and has been in operation for more than 66 h in stable conditions. The system is flexible and allows for variation of a number of parameters. Operational difficulties encountered during the tests were mostly related to external equipment, e.g. steam generator. CO_2 capture rate during the experiments was very high with 98% and gas conversion was up to 84% with bituminous coal and 94% with biochar. In this regard, the solids inventory in the fuel reactor strongly influences the gas conversion rate. The use of pulverised coal showed a large loss of unconverted char of ~40% and a high loss of ilmenite of more than 2%/h. However, this will not be relevant for large-scale plants because of different equipment, such as higher riser, better/additional cyclone and fines recycling. Generally, the test showed that CLC with solid fuels works and that ilmenite is deployable, low cost oxygen carrier. Next steps are now scale-up, optimisation and determination of which process designs would lead to cost reduction.

Pilot plant testing of Fe- and Mn-based oxygen carriers for chemical looping combustion – Karl Mayer, Vienna University of Technology

TUV operates a 120 kW test rig with natural gas as design fuel. The experiments included three different oxygen carriers, one Fe-based and two Mn-based

CLOU (chemical looping with oxygen uncoupling) carriers. Total operation time of each carrier was at least 30 h. During the tests, the Fe-based carrier showed high losses at the beginning and a high solids circulation rate was required. The CLOU carriers showed attrition during either the beginning or over the whole time of the test but with these carriers full conversion was possible. In general, temperature has a large influence on the performance of all carriers, e.g. for the Fe-based carrier methane conversion, CO_2 yield and combustion efficiency increase up to a temperature up to 960°C.

Demonstration of packed bed CLC of syngas using ilmenite as oxygen carrier – Maria Ortiz Navarro, Eindhoven University of Technology

Packed bed reactors offer the advantage that they do not require transport of the solid and gas or particle separation, so they are the preferred option for high pressure operation. This work provides the first lab scale demonstration of packed bed CLC using ilmenite. It is important that the oxygen carrier is able to bear a high mechanical, thermal and chemical stress. The results show a delayed breakthrough of CO, so operation without fuel slip is possible. The experiments also reveal that a higher pressure increases the degree of reduction and the reaction rate. In addition, a numerical 1D model was developed that provides a good description of the H_2 breakthrough and the temperature profiles of the oxidation.

Two-stage CLC: a novel reactor configuration for packed bed CLC with syngas – Paul Hamers, Eindhoven University of Technology

The two-stage CLC process has the benefit of smaller temperature changes per reactor (ΔT max. 400°C). At the same time, the active weight content is lower and the melting point of the oxygen carrier is less an issue, so the process allows for a combination of different oxygen carriers. The main criteria for the selection of the carrier are that the first carrier has a high reactivity at the low temperature (e.g. Cu) and the second carrier is stable at the high temperature (e.g. Mn). This concept was demonstrated theoretically by a 1D packed bed reactor model. Criteria for operation of a two-stage CLC process are a pressure drop less than 5%, prevention of fuel slip and similar cycle times for oxidation and reduction. The simulation results show that the temperature changes at the outlet of the bed are less intense than for a standard process layout and the temperature of CO_2 and H_2O is higher. According to the energy

balance, the airflow send to the gas turbine is only 4% less. Next steps are the experimental demonstration of the process and the detailed comparison of the electrical efficiency with the single-stage process.

Session 2a: Chemical looping fundamentals

Chair: Anders Lyngfelt, Chalmers University of Technology, and Tobias Pröll, University of Natural Resources Vienna

Enhancement of gasification by chemical looping – Marco Saucedo, University of Cambridge

CLC with solid fuels usually involves initial gasification of the solid char, which is the rate-limiting step. Thus, it is important to investigate if and how the oxygen carrier affects the rate of gasification. Batch experiments were carried out in a quartz reactor to compare the gasification rate of lignite coal when using iron oxide carrier particles or inert sand. The gasification rates in presence of iron oxide carrier and sand both show a temperature dependence. At low temperatures, i.e. 800°C, the external mass transfer is negligible and the iron oxide carrier has only a small effect on the gasification rate. At higher temperatures, i.e. 850°C and 900°C, the rates become higher because the presence of the iron oxide carrier seems to eliminate the external mass transfer resistance. In addition, the gasification rate generally increases up to carbon conversions of 20%, where it has a maximum. This effect is even more distinct at higher temperatures. A numerical model was developed that shows excellent agreement between the predicted and the experimentally obtained gasification rates.

Chemical looping combustion of coal for CO_2 capture: process simulation and optimisation using Aspen Plus – Sanjay Mukherjee, University of Surrey

The aim of this work was to develop and optimise industrial scale flow sheet models of IGCC power plants with a CLC process and compare it with conventional CO_2 capture technologies, in this case Selexol and PSA, both for electricity and combined electricity and H_2 production. Selexol and PSA cases have net electrical efficiencies of 36.4% and 37.8%, compared to 42.5% for the base case, and CO_2 capture efficiency of 93.5% and 89.9%, respectively. The CLC case has a net electrical efficiency of 37.2% and CO_2 capture efficiencies of 100%, which clearly indicates the suitability of CLC for CO_2 capture in IGCC power plants. For CLC cases the net electrical efficiency increases by up to

3.03%, when N_2 from the air separation unit (ASU) is used in the air reactor. A sensitivity analysis performed on the CLC process shows that it is favourable to operate the air reactor at higher temperatures and to cool the air reactor by using excess air supply instead of water/steam for more power output. Future work will include the development of a kinetics-based model and a system level cost analysis.

Chemical looping combustion research at the University of Utah – JoAnn Lighty and Kevin Whitty, University of Utah

Current research at the University of Utah is addressing several issues related to the Cu-based CLOU process, including optimisation of the oxygen carrier, energy utilisation and design and operation of a 100-200 kWth process development unit (PDU). The approach covers lab scale experiments, such as oxygen carrier characterization and measurement of carrier oxidation and reduction kinetics, as well as process modelling with Aspen Plus. Analysis of CLOU combustion of Mexican petcoke was used to investigate the comparison of CLOU with CLC. Aspen Plus models for each process have been developed to envision material and energy balance scenarios for the PDU and ultimately larger-scale systems. For a system feeding 100 kg/hr coal, the CLOU system (with fuel reactor at 950°C and air reactor at 935°C) generated approximately 510 kW of electric power, including 5 kW of compressor/pump work. Due to the volume of oxygen carrier needed, the CLC unit has a higher pressure drop, yielding less energy. The next steps are construction and analysis of a cold-flow unit and use of a commercial computational fluid dynamics (CFD) code for scale-up.

Development of promoted ilmenite for high temperature CLC and CuO oxygen carrier for low temperature CLC and continuous 100 h tests in dual fluidised beds – Hongmin Sun, Tsinghua University

Key requirements for oxygen carriers in direct solid fuel CLC are a high reducing reactivity and a low cost. The main issue with ilmenite for high temperature CLC is its low reactivity, which leads to incomplete gas conversion and a large bed inventory. One way to improve the reactivity is the impregnation with foreign ions, such as K+, Na+ or Ca_2+. Results from thermogravimetric analysis (TGA) experiments show that the reactivity of promoted ilmenite increases over 40 cycles and that this increase is more distinct than for raw ilmenite.

K15-ilmenite (i.e. ilmenite promoted with 15% K+) is the best option, as its reactivity is 7 times faster than that of raw ilmenite. In addition, K15-ilmenite demonstrates stability over 100 cycles in a fluidised bed reactor, showing almost no attrition (below 1%) or agglomeration. For low temperature CLC, cement supported CuO shows good stability of reactivity over 20 cycles in TGA experiments and no agglomeration in fluidised bed tests. Attrition was 11.2% loss of the initial mass after 100 cycles. In general, the continuous operation tests demonstrated the feasibility of both carriers for CLC. Future work will include scale-up of the reactor to 50 kW and extended continuous tests with biomass and lignite.

Reducing properties of model bio-oil compound acetic acid on NiO catalyst during chemical looping reforming – Feng Cheng, University of Leeds

Chemical looping reforming (CLR) can produce a highly pure H_2 stream. A benefit of the process is the avoidance of complex heat exchange because the coupling of endothermic and exothermic reactions leads to a low external heat demand. Challenges for CLR are the commercial scale-up, the availability of high performing and stable oxygen carriers with suitable reduction reactivity and catalytic properties for the reforming step. As most existing investigations focus on CH_4 as a fuel, this work wants to study the reducing properties of acetic acid (HAc) on NiO, which is the most suitable carrier/catalyst for CLR. In the experiments, NiO could be completely reduced by HAc in 360s at 650°C, with 550°C being the lowest temperature for reduction to proceed smoothly. Compared with a catalyst reduced by H_2, the catalyst auto-reduced by HAc exhibited a slightly decreased catalytic activity during the subsequent steam reforming. Possible reasons for this behaviour are denser carbon deposits and a larger Ni loss. The next step will be the investigation of the cyclic behaviour of the catalyst in alternating fuel and air feeds.

Bubbling fuel reactor modelling in in-situ gasification chemical looping combustion (iG-CLC) using CFD – Panneerselvam Ranganathan, Cranfield University

Multiphase CFD simulation is suitable a tool to develop validated computational models that describe physical and chemical phenomena in continuous CLC. With such a model, it is possible to determine the performance of the fuel

reactor. The reactions between ilmenite and fuel gases, devolatisation and char gasification of coal are described via kinetics models. The hydrodynamic CFD model was validated against literature data and the hot-flow model was compared with experimental data of ICB-CSIC-500W. However, the model predictions for continuous CLC process operations are not satisfactory yet. Future work will now focus on improving the model, e.g. inclusion of the more complex reactions, such as the water gas shift (WGS), consideration of the changes in coal particle density and rendering the devolatisation and gasification models more precisely.

H2 production via chemical looping: a thermodynamic and kinetic study – Claire Thompson, Newcastle University

As H_2 is essential now and will be even more in the future, it is important to find suitable oxygen carrier materials for CLR. Currently used iron oxide carriers are cheap and have a large oxygen capacity but are unstable over longer cycles and prone to thermal sintering. Perovskites are a potential replacement for iron oxide material as they allow for a more stable operation and regeneration. In this work, an equilibrium model was made for LSF731 (La0.7Sr0.3FeO3-δ) in a packed bed and the bed behaviour was studied, showing infinitely fast kinetics. The agreement of the preliminary kinetic studies and the thermodynamic predictions encourages further research into these new materials, e.g. determination of the heat capacity.

Reactive spray synthesis of metal oxides for chemical looping combustion – Arnold Lambert, IFPEN

The reactive spray technology (RST) was used to produce NiO/NiAl2O4 and Cu0.95Fe1.05AlO4 powders with high surface area (up to 100 m^2/g), small particle size (<10 µm) and controlled porosity. After pelletizing, tests performed using a TGA apparatus showed that the RST produced Ni-based particles showed increased oxidation rates compared to particles with the same composition produced by granulation, while RST produced Cu/Fe-based particles showed higher reduction rates than particles with the same composition prepared by co-precipitation. The increased reactivity of RST-made compositions can probably be attributed to smaller particle size and higher surface area.

Iron oxide-MIEC hybrid materials for hydrogen production using chemical looping technologies – Cristina Dueso, Newcastle University

The steam-iron process traditionally uses iron oxide as the oxygen carrier material because of its favourable thermodynamics, low cost and environmental friendliness. However, the slow reaction kinetics with carbonaceous fuels and the low stability after several redox cycles require the development of alternative materials. Hybrid materials, in this case combining iron oxide, perovskite and a mixed ion-electron conducting (MIEC) membrane, can improve the stability and the reactivity for H_2 production in the steam-iron process. The results show an increase in reactivity during both the reduction with CO and the oxidation with CO_2 with respect to perovskite or iron oxide alone. The MIEC material facilitates the O_2- ion mobility and transport from the bulk to the fuel due to the presence of oxygen vacancies. Moreover, the amount of H_2 produced is higher.

CLC research & development at CERT – Kumar Patchigolla, Cranfield University

The test facilities at Cranfield University include a 25 kW bubbling/entrained fluidised bed reactor for CaL and a 50 kW dual CFB reactor for CLC, which is the first pilot scale demonstration of CLC in the UK. The latter pilot plant is flexible in configuration, either as twin CFB legs or as a single entrained flow riser with bubbling bed. It is possible to run the plant in either oxy-combustion or H_2 production mode, both with a large flexibility of operating parameters. The first trials were completed with natural gas and simulated syngas as fuels and included an extensive characterisation of a Fe-based oxygen carrier. The next campaigns will involve a single reactor phase testing, an assessment of the reactor in full looping configuration and the transition to the CLOU process.

Session 2b: Calcium looping fundamentals

Chair: Carlos Abanades, CSIC-INCAR, and John Dennis, University of Cambridge

Design, construction and commissioning of a pilot-scale dual fluidised bed system for CO_2 capture – Robert Symonds, CanmetENERGY

CanmetENERGY's objective has been to design a pilot-scale facility that is capable of operating over a wide range of conditions and configurations. CanmetENERGY's 0.1 MWth CaL facility was originally commissioned in 2006

and the first continuous CO_2 capture experiments took place in 2007. The plant underwent re-design to improve flexibility and overcome issues, such as the difficulty to control solids transfer between reactors, the gas bypass and the transfer from calciner to carbonator being possible via overflow only. Commissioning trials of the new plant were completed in August/September 2012. Current experiments with steam addition have shown considerable CO_2 capture and sorbent performance improvements as well as reduced sintering due to a lower calcination temperature. Future pilot-scale activities will include the investigation of CLC with several reactor configurations.

Coal combustion in oxygen-enriched atmosphere in regenerator of CaL process – Tadaaki Shimizu, Niigata University

Anticipated problems with the regenerator in a CaL process are the formation of NO_x and char. Coal combustion at high temperature and in high O_2 concentration results in NO_x formation, which can then lead to HNO_3 formation during compression. If char is formed in the regenerator and transported to the carbonator, this can result in the release of CO and CO_2 in the off-gas. Thus, the main objectives of this work are to evaluate the above-mentioned issues and the effect of fuel type on these emissions. Experiments in a bench-scale solid fluidized bed circulation system revealed that high-volatile fuels are favourable for CO and CO_2 control. However, these fuels may have a problem of uncontrollable volatile matter combustion under O_2-enriched and high-temperature conditions. A solution to this problem might be the capture of volatile matter by porous CaO as demonstrated using a fixed bed reactor.

Understanding the enhancement effect of steam on the carbonation reaction of CaO with CO_2 – Zhenshan Li, Tsinghua University

Steam, which is always present in CaL flue gases, can enhance the carbonation, indirect and direct sulphation, and can decrease the oxidation of NH_3 on the CaO. The steam-enhanced carbonation reaction of CaO with CO_2 is a widely observed phenomenon, but its mechanism is still unclear. For this reason, research at Tsinghua University aims to apply the theories of defect chemistry and ion diffusion to analyse the steam enhancement and to discuss the effects of steam fraction and temperature on carbonation. Investigations revealed that OH- formation caused by the dissociation of H_2O molecules might

explain the enhanced carbonation. The relationship of oxygen vacancies with OH- was established and integrated into a new carbonation model. This new model included a simplified rate equation model to describe product island formation and a multi-ion diffusion model to describe product layer diffusion. Experimental studies of carbonation and sorption-enhanced WGS reactions in a fluidized bed reactor validated the new model.

CO_2 recovery from CPU vent of CFB oxyfuel plants by Ca-looping process – Matteo Romano, Politecnico di Milano

Oxyfuel power plants produce concentrated CO_2 streams with some non-condensable gases that originate from several sources within the process. Typically, auto-refrigerated processes based on low temperature flash are proposed for their separation but some CO_2 will be inevitably vented with the non-condensable gases and the CO_2 capture efficiency drops from potentially 100% to 85-95%. This situation leads to the question, whether it is economical to recover this vented CO_2, which is available in a clean stream at relatively high concentrations (~30-45%vol.). In this regard, CaL can be a good alternative because >90% of the CO_2 can be recovered from the vent, thus leading to an overall CO_2 capture efficiency of ~99%. In case of a CFB boiler, the CaL purge can be reused in the main boiler for sulphur capture, so no additional solid material needs to be imported or displaced. As the coal burned in the calciner is converted with approximately the same efficiency as the coal burned in the main boiler, there would be no significant thermodynamic penalty. First simulations show that the energy per kg CO_2 captured is slightly reduced and the capture efficiency rises from ~92% for the oxy-CFB case to ~99% for the oxy-CFB-CaL case. To fully understand the potential of this process and optimize it, an economic analysis would be the next step.

High-purity hydrogen via the sorption-enhanced steam methane reforming reaction over a synthetic CaO-based sorbent and a Ni catalyst – Ben Anthony, Cranfield University

Sorbent enhanced steam methane reforming (SE-SMR) is an important technology able to produce H_2 from hydrocarbons with in-situ CO_2 capture. In this work, SE-SMR was studied by using a mixture containing a Ni-hydrotalcite-derived catalyst and a synthetic calcium aluminate supported

sorbent for CO_2 capture. The catalyst produced a stream of high purity H_2 (99% pure on a H_2O and CO_2 free basis), and the CO_2 sorbent maintained almost double the CO_2 capture achieved by limestone alone after 10 cycles.

Reversible CO_2 absorption by the 6H perovskite $Ba_4Sb_2O_9$ – Matthew Dunstan, University of Cambridge

Desirable properties for CaL sorbents are high selectivity and absorption capacity for CO_2 at elevated temperatures, good absorption/desorption kinetics, good cyclability and good hydrothermal and mechanical properties. Problems with standard CaO or other alkaline metal oxides, e.g. Li- or Na-based, include either a capacity loss during cycling or poor kinetics. Perovskites like $Ba_4Sb_2O_9$ exhibit excellent thermal and mechanical stability and the ability to tune their physical properties through a range of chemical substitutions. However, they were thought to carbonate irreversibly or at too high a temperature, making their application in carbonate or chemical looping challenging. In TGA experiments, $Ba_4Sb_2O_9$ now showed reversible absorption of CO_2 to form $BaCO_3$ and $Ba_sb_2O_6$. The capacity over 100 cycles was stable and scanning electron microscopy (SEM) investigations revealed self-generated porosity upon cycling. Future research will explore use of perovskites as a framework material to alter the properties of conventional sorbents.

An internally circulating fluid bed for attrition testing of Ca looping sorbents – Vlatko Materic, Callaghan Innovation

As most CaL systems use fluidised beds, particle attrition is inevitable. Attrition has negative effects on fluidised bed operation, e.g. due to loss of fines and particle size reduction. To understand and minimize attrition in these systems, it is essential to quantify sorbent friability. Attrition occurs by a range of different mechanisms. At low velocity abrasion dominates, which will result in small fragments, i.e. fines. At higher velocity fragmentation takes place, first by chipping and then by splitting. This causes larger fragments compared to abrasion. There is also a differentiation between primary attrition (initial particle rounding off, thermal shock, etc...) and secondary attrition (steady state characteristic of the particles). Ideally, an attrition testing method should measure friability over a range of velocities and during different phases in the CaL cycle. Tests in an internal CFB prototype showed

that calcined sorbents are more friable than carbonated sorbents, mainly due to increased sintering. Although the $CaCO_3$ content changes with increasing cycle number, this does not affect carbonated sorbent friability. Sorbents reactivated by superheating are comparable to unreactivated sorbents and hydration-dehydration generated weak sorbents, which tend to fragment at low velocities. Future work will focus on improving and upgrading the test prototype.

HBr-enhanced sorbents, reactions with SO_2 – Mohamad Al-Jeboori, Imperial College London

This work focussed on testing different ways to improve long-term sorbent reactivity in the CaL cycle. The experiments were carried out in a small fluidised bed reactor at atmospheric pressure. Application of 0.167 mol% HBr dopant leads to an increase in carrying capacity compared to raw limestone. The combined presence of 10% steam and HBr dopant further improves the carrying capacity. Using seawater also increases the carrying capacity of the sorbent. However, the effect is less distinct compared to doping with HBr. Again, there is a synergistic effect between seawater doping and addition of 10% steam on the reactivation of the limestone.

The presence of SO_2 generally reduces the cyclic carrying capacity of the limestone. Even doping with the most effective HBr concentration of 0.167 mol% and 10% steam only slightly improve the carrying capacity of limestone. X-ray fluorescence (XRF) investigation show that no bromine moiety is left in the HBr-doped sorbent after 13 cycles in the presence of SO_2. The effects of pelletisation and the presence of steam on the carrying capacity of the sorbent are additive too, as in the case of doping and steam. This underlines that pelletisation and steam addition are effective approaches to improve reactivation and long-term reactivity of the limestone.

Session 3: System modelling, design and evaluation

Chair: JoAnn Lighty, University of Utah, and Fabrizio Scala, CNR

Implications of grid codes: challenges for CCS power plants utilising high temperature solid looping processes – Mike Haines, Cofree Technology

The ability of power plants to comply with electrical grid code in respect of short-term response to sudden frequency drops can vary greatly. The UK has

rather strict requirements because of the small grid size, i.e. 80GW, and the few interconnections with other systems. A drop of 0.5Hz over 10 s must result in an immediate primary response of 10% power ramp up over 10 s, held until 30 s. By then the plant must provide the secondary response, which must be maintained for 30 min. After this time, a new response must be possible. General ways to provide this short-term frequency response are throttling steam to the turbine (but this reduces efficiency), condensate stop (which can only provide 2-3% of the 10% needed), auxiliary load-shedding and pre-pulverised coal storage. For CCS plants, there are several load-shedding possibilities: tripping the CO_2 compression, the entire post combustion capture unit or the ASU and stopping steam supply for regeneration. All of these options are potentially disruptive to the CCS process. Solid looping systems have several places, where there is significant energy available for short-term release, i.e. thermal energy in the hot circulating solids, chemical energy in the reduced form of oxygen carriers, and thermal or pressure energy in heat recovery steam generator (HRSG) systems. First calculations show that there is enough thermal energy present, i.e. ~5 MW_{th}, to supply the power required by the UK code for just over 1 min. To extract this energy, the gas flow has to be temporarily increased and the most suitable option to realise this are a recycle of CO_2 in the calciner or increased airflow in the carbonator. Because generating more steam from an HRSG is a slow process, tube selection can have a considerable effect on the primary response capability of the plant. In CLC systems, heat release can be ramped up more rapidly by increasing airflow than in CaL systems. However, both systems have unique attributes, which might help to enhance response to frequency drop disturbances. Further research needs to include the identification, verification and quantification of fast response capabilities in integrated power plant systems.

Development of three-towers CFB Ca looping biomass/coal gasification – Shiying Lin, JCOAL

Fundamental experiments have shown that CaO is also a good catalyst for reforming of hydrocarbons. Based on these results, a three-tower CFB CaL gasification process is developed. The process layout includes a combustor, gasifier and a reformer. It is the aim of the process development activities to produce a low tar, low H_2S syngas to simplify the gas clean-up step and to

recycle the off-gas in order to enhance syngas production. Analysis results from an Aspen simulation show that the tree tower process can produce syngas with a H_2/CO ratio of about 2 and low concentrations of CO_2, CH_4, H_2S and tar. Subsequently, a 2 kW test facility was set up to evaluate the process further and to provide proof-of-concept. First experimental results show that presence of CaO reduces tar generation in biomass as well as coal gasification and thus CaO is a suitable catalyst for hydrocarbon reforming.

Design of a 300 kWth indirectly heated carbonate looping test facility – Markus Junk, Technische Universität Darmstadt

The CARINA project focusses on investigating a CaL process, where an external combustor supplies the heat for the calciner via heat pipes, so the ASU, which provides oxygen for firing the calciner, becomes redundant. Because the ASU in a standard CaL process accounts for a large amount of the energy penalty (2%-points out of the total of 3%-points, excl. CO_2 compression), the indirectly heated process will have a lower energy penalty of ~1 % point. As there is no coal present in the calciner, few additional impurities (e.g. sulfur, ash) enter the system, which reduces the flow of circulating solids and facilitates the further utilisation of deactivated sorbents. Retrofit of the indirectly heated carbonate looping process is generally possible but causes big plant sizes, therefore new-built construction with thermal integration is more applicable due to a reduced plant size and higher efficiency. Pressure characteristics of a cold-flow model confirmed the coupling concept of the planned test facility. In addition, solid flux investigations showed that the heat pipes do not significantly influence the particle flow through the calciner and the required solids mass flow through the reactor is achievable. A 300 kWth test rig is under construction and will start operation mid 2014 at TU Darmstadt. If the concept also works technically, this will be a significant thermodynamic improvement for new-builts.

Reactions of sulphur during chemical looping combustion using iron – Zili Zhang, Imperial College London

When sulphur, in the form of H_2S, enters the CLC system, the following two questions are of interest: (1) How is the sulphur products distribution in air and fuel reactor? and (2) What is the effect of sulphur on kinetics and long-term reactivity of iron oxide? To answer these questions, experiments were

carried out in a closed-system fluidised bed reactor investigating the different fates of sulphur before and after completion of reduction of Fe_2O_3 to Fe_3O_4 at 823K, with 3 vol% CO and 300 ppm H_2S. Most of the H_2S was converted into SO_2 in the fuel reactor before complete reduction of Fe_2O_3, while after complete reduction most of the H_2S was converted into FeS. Because FeS was released as SO_2 later in the air reactor, this shows that sulphation is nearly reversible and Fe_2O_3 seems to be fully regenerable. Quantitative XRF analysis detected elemental sulphur in the downstream trap of the reactor. Increasing the residence time of H_2S only has a significant effect on the reduction rate if the increase occurs after complete reduction. Generally, increasing H_2S concentration has an adverse effect on the rate of reduction. Investigation of the reduction rate of Fe_2O_3 for various CO concentrations in the presence of H_2S confirms a first order dependency with respect to CO. In conclusion, a good process control could avoid the production of SO_2 in the air reactor in the first place.

Chemical looping combustion using Aspen Plus – Raffaella Ocone, Heriot Watt University

It was the aim of this work to develop a fluidised bed model for CLC in Aspen Plus without using a Gibbs reactor model, which is widespread in the literature of CLC. The analysis considers several related issues, such as an adequate contact time between fuel, air and solid oxygen carrier to achieve maximum conversion, the size of the two reactors, a suitable solids inventory and a sufficient molar flowrate ratio between air and fuel. NiO/Ni supported by bentonite is the oxygen carrier system, the fuel reactant is pure methane and the oxidising agent is air. The bubbling bed fuel reactor model is a combination of CSTR's (continuous stirred tank reactor) and PFR's (plug flow reactor); whereas the fast riser air reactor model consists of CSTR's. Results of the bubbling bed model show that conversion increases with the number of stages. Comparison with data from the literature confirms that the observed conversion corresponds to 5 stages. The conversion in the new model is higher because the Gibbs reactor model does not consider gas by-pass in the bubble phase. A set of parameters to achieve a conversion of solids that allows the circulation of solid particles between air and fuel reactor in steady state conditions was obtained from the results of the riser model. Because the new model has a higher accuracy, takes into account hydrodynamics and

kinetics and is able to estimate the main process variables, it will be a valuable tool for efficiency calculations, economic analysis and life cycle assessment (LCA). Future work will concentrate on the integration of Aspen Plus with CFD modelling to study the gas by-pass, the overall efficiency of the process and CLC process intensification.

Environmental evaluation of IGCC-based chemical looping processes – Letitia Petrescu, Babes-Bolyai University

An impact assessment or optimisation of a power plant usually includes technological and economical, but not environmental factors. However, the environmental factors are getting more and more attention, so there is a growing need for evaluation tools. One such tool for sustainability and environmental evaluation is the Process Sustainability Prediction (PSP) Framework by ICS-UNIDO. This programme uses 1D, 2D or 3D indicators, depending on the number of intersections between the three areas environment, economy and society. Examples for 3D indicators are material intensity, energy intensity, potential chemical risk and potential environmental impact, whereas 1D indicators relate to various impact outputs. The use of CAPE OPEN methodology in the approach results in a standard module that can be integrated in almost every process simulator software available on the market. Case studies were undertaken to identify the most environmental friendly and sustainable design from four different process alternatives: (1) IGCC without CCS, (2) IGCC with pre-combustion CaL, (3) IGCC with post-combustion CaL and (4) IGCC with pre-combustion Fe-based CLC. All cases have been modelled and simulated using process flow modelling software in order to generate mass and energy balances necessary for the technical and environmental evaluations. The technical evaluation, based on model data, is made according to key performance indicators, such as net power, energy efficiency, carbon capture rate, specific CO_2 emissions, etc. The environmental evaluation, based on the technical indicators, was performed using the PSP Framework. The analysis shows that IGCC with pre-combustion CaL is the best option regarding material intensity, with the other two 3D indicators being the same for all cases. IGCC with pre-combustion CaL and IGCC with post-combustion CaL have the best performance regarding the 1D indicators. In conclusion, the results confirm that PSP is a good tool for choosing the most environmental friendly design and that IGCC with CaL is a

promising option for future sustainable power generation.

Plenary discussion

Moderators: Ben Anthony, Cranfield University, and Tobias Pröll, University of Natural Resources Vienna

Panel: Carlos Abanades, Paul Cobden, Paul Fennel, Tadaaki Shimizu, Bernd Epple and Mike Haines

The meeting finished with a panel discussion that addressed the broader challenges and future developments of solid looping technologies. CaL with solid fuels seems to require severe calcination conditions to achieve a sufficient performance for industrial applications. As the meeting did not include any detailed discussion about the pressure in combustion in CaL processes, the next meeting would need to include this topic. The most pressing question concerning CaL at the moment is: when will the first large-scale demonstration go online? CLC development, still lying behind CaL, will have to improve the conversion of solid fuels to meet the requirements of industrial applications.

Carlos Abanades said that it was important to carefully design and control experiments to make sure all particles react as they should. In addition, under non-differential conditions a model would be needed for correct interpretation of the experiments. Paul Cobden commented that most fixed-bed CLC projects focussed on IGCC and were not looking for alternative fuels, such as CH_4. However, if the DemoCLOCK project could show that these systems work, then there was large hope. There was also no need to go for coal as a fuel and the cheapest oxygen carrier material only. According to Paul Fennell, post-combustion CaL for power generation was generally solved and just needed an appropriate scale-up. Industrial applications, like cement and iron & steel, still had to be explored and right conditions to be chosen.

Then a small debate broke out regarding the application of bubbling bed (BB) instead of more conventional CFB technology. Tadaaki Shimizu said we should try to employ BBs. The heat removal should not be forgotten over the reaction kinetics and a BB could improve this. Carlos Abandes replied that for post-combustion capture from a power plant only CFB could be used, as BB would be more complicated and costly. Bernd Epple stated he agreed with Carlos Abanades because his own experience from industry indicated a

limitation in scale-up for BBs. In addition, it was no problem to remove the heat from a CFB reactor.

Bernd Epple then went on that in industry customers were used to certain standard applications. They could be convinced to use CFB quite easily but maybe not to apply unknown fixed-bed technology. The mechanical stability of the carrier in CaL needed to be proven in addition to the TGA tests. Natural limestone modification was an interesting option if it would not be too costly. Also, industry was asking for longer test runs, beyond 1000 h, before they would provide further funding for projects. CLC was a bit more complex to operate but also a bit more promising in terms of efficiency. The indirectly heated CaL process would be applicable for 100s MW size. Carlos Abanades commented that it was a challenge to mix the materials as quickly as possible and that the standard CaL configuration needed a lot more optimisation but was already doing well.

Mike Haines then shifted the topic to market conditions for CO_2 capture with solid looping technologies. He said there was no market for CO_2 storage at the moment, only one for use in enhanced oil recovery (EOR). Here, PCC and oxyfuel were the main competitors in the field, so it was important to answer what advantage CaL had over these. One advantage was the lower energy penalty but the niche for CaL in sectors like cement or steel still needed identification. Paul Fennel replied that we needed a sensible price for CCS in general to go forward with any CCS technology. Bernd Epple said in the past there was a reservation towards CaL but now people were convinced by the first results, especially because amine-based PCC had so many different issues. Paul Cobden concluded that you needed to talk to industry in mol steam / mol CO_2. There would always be issues for power plant scale-up but there was a good outlook for application of solid looping in other sectors.

Meeting conclusions

The 5th HTSLCN Meeting provided detailed information about the technical performance of CaL and CLC processes. The results from the pilot plants show that there is further improvement in CO_2 capture efficiencies and fuel conversion rates. The current scale of CaL pilots is up to 2 MW and 200 kW for CLC respectively, with the hours of operation steadily increasing. Certain impurities, such as SO_2 and H_2S, have an adverse effect on the sorbent

carrying capacity in CaL and the reduction rate in CLC. However, other research showed that new hybrid materials, promoted/doped sorbents, pelletisation and steam addition are a way to enhance the performance. In addition, several new promising process concepts have been presented, including an indirectly heated CaL process, a two-stage CLC process and a packed bed design for coal-based CLC. First environmental evaluations demonstrate that, besides having a lower energy penalty, CaL processes can be more environmental friendly than conventional or competing CO_2 capture technologies. A key statement from the meeting is that CaL for post-combustion CO_2 capture is generally proven and now just needs the scale-up to demonstration or commercial scale. On the other hand, there are a number of challenges and next steps lying ahead. For both CaL and CLC only rough cost estimates are available, so it will be necessary to establish and validate techno-economic performance figures. Similar to any other CCS technology, CaL and CLC both need a sensible price for CO_2 to go forward. At the moment, the main market driver is the use of CO_2 in EOR operations but here CaL and CLC would compete with the other CCS technologies. It will be important for the future development of solid looping that CaL and CLC clearly demonstrate their advantages and identify their commercial opportunities.

IEAGHG/IETS IRON & STEEL INDUSTRY CCUS & PROCESS INTEGRATION WORKSHOP (2014-07)

Introduction

This report summarises the presentations and outcomes from the "Iron and Steel Industry CCUS and Process Integration Workshop". The workshop took place from the 5th to 7th November 2013 at the Tokyo Institute of Technology in Japan. IETS (Industrial Energy-related Technologies and Systems), the World Steel Association (WSA) and IEAGHG jointly organised this meeting, which was hosted by Prof Tatsuro Ariyama. The key objectives of the workshop were to review the progress in CO_2 reduction technologies in iron- and steelmaking since the last workshop in 2011 and to provide a discussion forum with focus on the Asian iron and steel industries. The 50 attendees were able to participate in a full three-day programme and the IETS members had the opportunity to visit JFE East Japan Works at Keihin subsequently. The first two days of the workshop ran under the IEAGHG and focussed on CO_2 reduction strategies in the iron and steel industries, whereas the third day was under the theme of IETS and concentrated on process development and efficiency improvements. The following report provides summaries of some, but not all, of the presentations given at the workshop. You can find the agenda and a list of attendees in the Annex of this report, and the presentations are available on IEAGHG's website[1].

Session 1: Welcome & keynotes

Chair: Kanji Takeda, JFE Steel Corporation

CCS: a challenge for the iron and steel industry - Henk Reimink, World Steel Association

The iron and steel industry was accountable for 6.73% of the global CO_2 emissions in 2012. There are three key influences on emissions: raw materials requirements, i.e. high Fe ore and low ash coal, maximisation of scrap usage and application of best practices throughout the industry. CO_2 that needs to be stored per year will be significantly lower, i.e. 0.5-1.5 Gt if the iron and steel industry applies all available improvements, such as increased scrap usage,

[1] www.ieaghg.org/ccs-resources/technical-workshops/19-ccs-resources/technical-workshops/392-iron-steel-workshop (Member's login required)

technical and best practice transfer and the "CO_2 Breakthrough programme". The Climate Action scheme of the World Steel Association currently recognises 212 sites from 49 steel producers, who have submitted data on CO_2 emissions and intensity. Trials using an experimental blast furnace (BF) have been promising but the next step needs to include a full-scale, commercial demonstration of the CO_2 reduction technologies. Public as well as political support and timing are the key issues for the implementation of CO_2 reduction technologies in the iron and steel sector. Any delay in the projects will influence the results and the volumes of CO_2 that require storage. Similar to carbon dioxide capture and storage (CCS) technologies in other sectors, funding will be essential. In this regard, it will be important to increase public and political awareness of CO_2 mitigation in the iron and steel industry.

Development of ULCOS-Blast Furnace: working toward technology demonstration - Jan van der Stel, Tata Steel

With about 30%, the BF is the main producer of CO_2 emissions within an integrated steel plant. Many steel plants already operate close to the theoretical minimum regarding reducing agents, so the possibilities to reduce CO_2 emissions within existing BFs are small. It is the aim of the ULCOS ("Ultra Low CO_2 Steelmaking") programme to reduce these emissions by 50% per tonne of steel through modification of the conventional BF. There are six different options to reduce CO_2 emissions from BF, with recycling of CO/H_2 from the BF top gas (TGR-BF, or ULCOS-BF) and application of CCS as the most promising ones. From this, the programme developed four different ULCOS-BF concepts. Experimental campaigns then included the evaluation of three of these process concepts with varying injection locations and temperatures of the recycled top gas. Carbon savings were up to 25% at the BF level and up to 60% at the whole plant level if CO_2 capture with VPSA/PSA was applied. Other benefits include a 35% reduction in coke rate and an increase in productivity. The tests did not reveal any safety issues regarding operation of the new process, in contrast, operation of the BF and VPSA have been smooth with high recycling ratios, satisfactory gas quality, constant productivity and good hot metal quality. In addition, the tests showed that it is possible to use conventional burden material. The next step of the ULCOS programme will be the development of a demonstration plant at industrial scale including

CO_2 storage.

Current status and future impacts of Japanese steel industry on global environments - Seiji Nomura, Nippon Steel & Sumitomo Metal Corporation

The last of the keynote addresses illustrated the status and future developments in the Japanese iron and steel industry. In the past, Japan has achieved CO_2 emissions reduction through enhancement of equipment efficiency, waste plastic recycling and natural gas (NG) injection. SCOPE21 ("Super Coke Oven for Productivity and Environmental Enhancement Towards the 21st Century") is a programme, which aims to develop next-generation coke making technology. Results from a 6 t/h pilot plant showed a higher productivity, an improvement in coke strength and the possibility to use up to 50% of non/poorly caking coal. In addition, the process can reduce net energy consumption by 20% and NO_x emissions by 30%. A second coke oven developed in the SCOPE21 programme located at Nagoya with a capacity of 1 million t/y produces 0.1-0.2 million t/y less CO_2 emissions. Although Japan's iron and steel industry has already the highest energy efficiency worldwide, and thus the potential for further savings is quite limited, industry will continue to develop energy conservation technologies to move further towards a low-carbon society.

Session 2: CO_2 capture development in blast furnace ironmaking process

Chair: Jean Borlée, Arcelor Mittal

Current progress on COURSE50 project - recent results on H_2 reduction including LKAB's EBF experiments and CO_2 capture, Shiro Watakabe, JFE Steel Corporation

The COURSE50 ("CO_2 Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50") programme targets the development of technologies to reduce and capture CO_2 emissions from the BF. The programme consists of six sub projects that evaluate (1) utilisation of H_2 for iron ore reduction, (2) reforming of coke oven gas (COG) through H_2 amplification, (3) production of optimum coke for reduction of iron ore by H_2, (4) CO_2 capture technologies for BF gas, (5) sensible heat recovery and (6) whole system optimisation. Experimental BF tests verified an improvement of the reduction of iron ore by H_2 injection. Bench-scale test results of COG reforming technologies (H_2 enrichment) indicate the possibility of doubling

the H_2 content. By using a high performance caking additive (HPC) it is possible to produce a high strength coke without relying on blending coke. The results of bench-scale tests for CO_2 capture with chemical absorption show a reduction in energy consumption from about 3.0 to 2.5 GJ/tCO_2, so the development is well underway to reach the target of 2.0 GJ/tCO_2. Physical adsorption trials achieved the target CO_2 purity of 90% and the target recovery of 80%, which translates into 3 tCO_2/d. In addition, the results of studies on various promising waste heat recovery technologies as well as an inventory of unused waste heat indicate the possibility of satisfying the energy demand for CO_2 capture. One of the next steps will be verification of the results from the previous phase to move the technology forward to industrialisation by ca. 2030, pre-requisites being CO_2 storage availability and economic feasibility.

Progress on CO_2 capture pilot plant at RIST - Man Su Lee, Research Institute of Industrial Science and Technology

With about 800 kcal/Nm^3, blast furnace gas (BFG) has a low heating value. Removal of CO_2 from BFG not only decreases the emissions but also increases the heating value by approximately 30%. For application in the iron and steel industry, NH_3-based CO_2 capture offers several advantages over conventional amine-based technology, such as MEA. Generally, the NH_3 process has a lower corrosiveness, chemicals cost and regeneration temperature, which will all lead to a lower CAPEX in the end. Especially the use of waste heat from the iron and steelmaking processes for regeneration is a benefit of NH_3-based CO_2 capture in a steel plant because it eliminates the need for external heat input. However, a challenge is the NH_3 slip due to the high volatility of the solvent. One of the research milestones was the construction of a pilot plant with a capacity of 10 tCO_2/d, i.e. treatment of 1,000 Nm^3/h of BFG, in 2010. Tests in the pilot plant with a NH3 concentration of <10wt% confirmed a CO_2 removal efficiency of ~90%, a CO_2 purity of ~98% and an increase in BFG heating value. Because the experiments in the pilot plant are time consuming and expensive, a rate-based model was developed in Aspen Plus and validated against the pilot plant data to facilitate parameter studies. Results from the simulation show that an upgrade of the heat exchanger can reduce the regeneration energy by ~0.4 GJ/tCO_2. Similar reductions are possible by implementing additional pump around, lean solution cooling and

pressurised absorption. Pressurised absorption can also decrease the NH_3 slip from ~200 ppm to <10 ppm. As pump around and solution cooling are not economically feasible, future work will focus on implementation of the other two options. Next step is the basic engineering design of a commercial scale plant with a capacity of 1,000 tCO_2/d.

Session 3: CO_2 capture and utilisation development in ironmaking process
Chair: J.J. Ou, China Steel Corporation

Development of PSA system for the recovery of CO_2 from blast furnace gas - Hitoshi Saima, JFE Steel Corporation

Another topic in the Japanese COURSE50 programme is the separation of CO_2 from BFG with pressure swing adsorption (PSA). Targets of the PSA project are to reach a CO_2 recovery of more than 80% and a CO_2 purity above 90%. At the same time, the project aims to reduce the CO_2 recovery costs by at least 50%, which translates into a cost lower than 2,000 ¥/tCO_2. Laboratory results show that Zeolum F-9H can deliver the required performance regarding CO_2 recovery and purity. Another observation during the experiments was that a higher CO_2 concentration leads to a higher recovery rate. The high CO_2 concentration in combination with a reduction in cycle time from 630s to 300s decreases the recovery cost from 4,040 ¥/tCO_2 to 2,500 ¥/tCO_2. Trials in the ASCOA-3 (Advanced Separation System by Carbon Oxides Adsorption) pilot plant, which has a capacity of 3 tCO_2/d, confirmed the recovery and purity results from the lab-scale tests. Besides, the pilot plant tests revealed that a higher CO_2 recovery leads to a lower power consumption of the vacuum pump. This is important because the vacuum pump can contribute up to 30% towards the overall power consumption. Further cost reduction is possible by operating at a higher dew point of -30°C. The improvements applied in the ASCOA-3 pilot plant reduce the CO_2 recovery cost to 1,940 ¥/tCO_2 (≈20 \$/tCO_2). These results directly affect the design of a commercial plant because they increase the CO_2 capacity but at the same time decrease the tower dimensions and almost halve the investment costs.

Optimal design and operation of a polygeneration system in a steel plant - Hamid Ghanbari, Åbo Akademi

Modelling for polygeneration systems in a steel plant needs a holistic approach to process design and operation that emphasizes the unity of the process and optimizes its design and operation. It is important to treat the process as an integrated system and to apply a systematic methodology. The superstructure suggested for an integrated steel mill with a polygeneration plant includes a methane gasification unit (MG), a methanol plant (MP) and a CCS unit. The model is implemented in GAMS and considers different object functions, i.e. minimisation of the CO_2 emissions and maximisation of the net present value (NPV). The stepwise approach includes three different set-ups, which vary in terms of oxygen enrichment and top gas recycling rate. The modelling results indicate an increase in NPV and lower CO_2 emissions for the polygeneration plant. The flexibility of the integrated system generally allows for a higher profit. A case study compares the polygeneration properties in cold and warm season. In the warm season (S2), the methanol production is about seven times higher than in the cold season (S1). Besides, S2 has only half of the electricity and district heat production and only one-third of the specific CO_2 emissions per ton of liquid steel (ls) than S1. Steel costs are 246 €/tls in S2 and 367 €/tls in S1. Further work will include modification of the model to investigate all possible cases of reducing agent injection and the integration of a torrefaction process.

Session 4: Process integration and efficiency improvement # in integrated steel mills

Chair: Carl-Erik Grip, Luleå Technical University

CCU technology development at RIST - Man Su Lee, Research Institute of Industrial Science and Technology

With 70 $MtCO_2$/y, i.e. 10% of the total Korean CO_2 emissions, the iron and steel industry is one of the largest emitters among all industry sectors. Over 90% of the CO_2 emissions of a steel plant originate from the coal used in the iron making process. Because the Korean emission trading system will start in 2015, large steel companies like POSCO urgently need to reduce their CO_2 emissions. Considering the geological and industrial environment in Korea, R&D focusses on CO_2 capture and utilisation routes that are custom-made for

the steel industry, rather than on CO_2 storage. The research efforts identified CO_2 capture with aqueous NH_3 solution as the most suitable capture strategy for application in steel plants. For utilisation, CO_2 conversion via COG reforming and reinjection into the BF is a promising approach as it reduces coke consumption in the ironmaking process. Another method to improve the process efficiency and lower the CO_2 emissions is the recovery of waste heat from the boiler stacks and from molten steelmaking slag. Key issues for the latter are dry granulation and fast cooling of the slag. For all concepts presented here, there are pilot plants in operation to validate and improve the processes.

Energy use in the steel industry - Ladislav Horvath, World Steel Association

Energy costs represent about 20-25% of the total input of a steel plant and thus become one of the most important topics for steel producers. The average energy intensity in the steel industry is currently 18.2 GJ/tcs (crude steel) and the average CO_2 intensity amounts to 1.8 GJ/tcs. WSA launched a programme analysing the energy use in the iron and steel industry. It is the aim of this programme to enable steel producers to make a fair comparison and analyse the gap between their own energy consumption and that of a reference plant. They are also able to evaluate the impact of new technologies that they have applied to their plants, monitor their annual performance and build business cases based on performance data. WSA developed the reference plant by merging energy specialist data, core group experience and data collected from 60 sites around the world. Analysis of the data shows that the energy intensity of the coke oven plant varies greatly between all sites and that the BF offers the highest potential for energy savings. WSA then identified 190 energy saving technologies (EST) and investigated their implementation in the steel industry. The four most widely implemented ESTs for BFs are charge distribution control, use of injectants, computer aided control of blast stoves and hot blast stove automation. These measures mainly lead to a reduction in coke consumption and/or an improvement in energy efficiency. The EST that can provide the largest energy saving, namely about 5.5 GJ/thm (hot metal), is BF gas recovery. Other technologies with significant energy savings are pulverised coal injection and waste heat recovery from molten BF slag. The analysis also shows that a high number of implemented ESTs at a site does not necessarily result in a high efficiency. However, the most efficient

sites apply almost all available ESTs. If the industry moved to the reference plant value as their average value, this would result in a 1.26 GJ/tcs, or 6.6%, energy saving for the BF route.

Session 5: CO_2 storage

Chair: Ladislav Horvath, World Steel Association

CO_2 storage experience in Japan including impacts of earthquakes - Ziqiu Xue, Research Institute of Innovative Technology for the Earth

The Nagaoka project is the first onshore aquifer CO_2 injection test and it aims to verify CO_2 storage in a complex geology. The site contains one injection well and three observation wells in 40m, 60m and 120m distance from the injection point. During the injection period from July 2003 to January 2005, the project injected a total amount of 10,400 tCO_2 at a rate of 20-40 tCO_2/d. Based on seismic, logging and core data a reservoir model was developed to evaluate the site pre-injection. During injection, the model was updated and matched with monitoring data to improve model accuracy and enable long-term predictions for the post-injection period. Joint monitoring of p-wave velocity vp and resistivity ρ as a function of CO_2 saturation are key to understand the behaviour of CO_2 in the reservoir. The pilot tests identified that mineral dissolution and mineral trapping of CO_2 are important mechanisms to ensure long-term storage. During the whole project, two larger earthquakes occurred close to the test site: one with M6.8 during the injection period in 2003 and another one with M6.7 during the post-injection phase in 2007. In case of the 2003 earthquake, the injection was automatically stopped. After investigating the incident and confirming safety of the reservoir, the operators continued injection within 6 weeks. Both incidents did not have any influence on the bottomhole pressure of the injection or observation wells. Results of crosswell seismic tomography show that there was no negative impact of the earthquakes on the CO_2 distribution area in the reservoir as well. Overall, the trials underline that it is important to have an alarm and automatic shutdown system according to magnitude and number of seismic events in place. Next step will be capture and storage of more than 100,000 tCO_2 in the large-scale CCS demonstration project in Tomakomai.

CO_2 storage assessment in Taiwan - Chi-Wen Liao, Industrial Technology Research Institute

More than 98% of Taiwan's energy supply rely on imports. According to Taiwan's Nationally Appropriate Mitigation Actions (NAMAs), CCS will contribute about 12% to the required CO_2 emissions reductions in 2025, which translates into 36.7 $MtCO_2$/y. Most power plants and industrial parks are located in the western part of Taiwan, where suitable sedimentary basins and rock formations for CO_2 storage are available. The estimated CO_2 storage capacity amounts to 2,800 Mt in onshore oil and gas structures and 9,000 Mt in coastal and offshore deep saline aquifers. Geomechanical analysis shows that gas injection into the Talu sand of the TCS field anticline will not induce slip on pre-existing mapped faults or fracturing of cap rock. There is no documented evidence of casing failure in 40 wells due to fault reactivation or any reported leakage indicators from monitors deployed in the surface. In addition, there has been no induced seismicity associated with fluid injection over the past 20 years. Continuous monitoring of the site showed that an earthquake of M7.7 in 1999 did not cause leakage of CO_2 from the reservoir. The best strategy to reduce risks in case of an earthquake is to avoid injection into or too close to existing faults.

Session 6: Efficiency improvement and CO_2 utilisation for low CO_2 steel production

Chair: Kouki Nishioka, Nippon Steel & Sumitomo Metal Corporation

Development of ferro-coke process for mitigating CO_2 emissions in ironmaking - Kanji Takeda, JFE Steel Corporation

JFE currently aims at developing an innovative binder for ferro-coke by utilising Kobe Steel's proprietary hyper-coal process (HPC). The main target is to achieve a higher ferro-coke strength compared to conventional asphalt pitch binder (ASP). Features of the innovative binder process include no hydrogenation, mild reaction conditions, product separation by gravity settling and use of recycled naphthalene solvent. The innovative HPC binder showed lower softening temperature and superior fluidity than the ASP binder. Carbonisation experiments in a small-scale apparatus demonstrated that preparation of the HPC binder by solvent extraction of coal at 410°C improved the strength of the HPC compared to the ASP binder. Subsequent

tests in a 30 t/d pilot plant showed that reactivity of both sinter and ferro-coke were best in a homogeneously mixed arrangement. In addition, temperature of the thermal reserve zone was 100°C lower than in the base case. To investigate the effect of ferro-coke on BF operation, a gasification model developed by Kyushu University was combined with the mathematical BF model developed by Nippon Steel & Sumitomo Metal (NSSMC). Finally, JFE carried out charging tests with 2,100 t of ferro-coke at BF No.6 in Chiba Works in March 2013.

Development of new burden for blast furnace operation with low carbon consumption - Kenichi Higuchi, Nippon Steel & Sumitomo Metal Corporation

Two possible approaches exist to reduce the carbon consumption of a BF, i.e. increasing the shaft efficiency and/or lowering the temperature of the thermal reserve zone. Design of new agglomerates with high reducibility and high carbon gasification rates can help achieve the latter. A close arrangement of coke and iron oxide results in a high reactivity, decreases the temperature of the thermal reserve zone and thus leads to a lower carbon consumption in the BF. Laboratory tests with cement-bonded carbon composite agglomerate (CCA) showed that a higher carbon content leads to a higher reduction degree. CCA with a carbon content of 20% worked best, resulting in a new burden called "Reactive Coke Agglomerate" (RCA). In 2011, NSSMC performed plant trials with RCA in a BF at Oita Works. Results confirmed that the basic properties of RCA are comparable to other conventional burden materials and that RCA is suitable as a BF burden. Production of RCA at the site was smooth and use of RCA in the BF resulted in a lower reducing agent rate and in a lower input carbon.

Session 7: CO_2 capture application in alternative iron reduction process

Chair: Jan-Olov Wikström, Swerea MEFOS

Status and future of FINEX process for reducing CO_2 emissions - Min Young Cho, POSCO

FINEX is an ironmaking process that produces molten iron directly from iron ore fines and non-coking coal. The process is a combination of FINMET's fluidised bed and COREX's melter gasifier. Since the kick-off of FINEX R&D in 1992, the process was scaled up to a production capacity of 2 Mt/y in 2013. Characteristics of the FINEX process include flexibility of raw material use and

hot metal production. In addition, FINEX produces fewer pollutants, e.g. SO_x, NO_x and CO_2, than conventional ironmaking technologies and does not require pre-treatment plants, which makes the process less expensive compared to a BF of the same scale. POSCO was able to achieve direct reduction of CO_2 emissions through coal briquetting, CO_2 removal and pulverised coal (PC) injection. CO_2 removal by PSA can cut the coal consumption rate by 150 kg/thm. Application of these process improvements in combination lowered the coal rate from about 1,200 kg/t in 2003 to about 750 kg/t in 2007. A series of technical developments such as a heat recovery system, dry dust collectors and recycling by-products could reduce CO_2 emissions even further.

Update to the development of HIsarna: an ULCOS alternative ironmaking process - Jan van der Stel, Tata Steel

HIsarna is a high risk/high reward innovation that can potentially have a strong environmental and economic impact on the steel industry. The HIsarna technology combines cyclone converter furnace (CCF) technology with Rio Tinto's HIsmelt technology. In the CCF pre-reduction and melting of the iron ore takes place. Injection of pure oxygen generates the necessary melting temperature. The centrifugal force of the cyclone separates the reduced iron from gas and impurities. The final reduction of the iron takes place at the slag/metal interface in the bottom HIsmelt part of the furnace. The HIsarna smelting technology can reduce energy usage as well as CO_2 emissions by 20% per tonne of hot metal compared to the conventional BF-BOF (basic oxygen furnace) route and even by 80% in combination with CCS technology. The process leads to a reduction of other emissions, such as NO_x, SO_x, CO and dust, as well. Further benefits with regard to CCS application are a N_2-free, low-calorific flue gas and a single emission source. Several test campaigns have been run in a HIsarna pilot plant with a capacity of 8 thm/h since 2011. Overall, the trials showed a good plant availability. Two additional campaigns in 2014 and 2015 will test a wider range of raw materials, find the upper production limit, demonstrate the refractory lifetime and check for any issues that might affect scale-up. Industrialisation of HIsarna technology will not take place before 2020.

Potential for CO_2 emissions reduction in MIDREX direct reduction process - Hidetoshi Tanaka, Kobe Steel

The MIDREX process uses natural gas to reduce iron ore without melting in a shaft furnace. Coke is not necessary in this process and it is possible to feed the product, direct reduced iron (DRI), directly to an electric arc furnace (EAF) to make steel. Because of its characteristics, natural gas is an ideal resource for ironmaking. As fuel, it emits only about half the CO_2 per unit energy than coal. As reducing agent, it can remove twice the amount of O_2 than coal, while producing the same amount of CO_2. Due to overall process development and upgrades, the natural gas consumption in MIDREX has gradually decreased by about 30% since the 1970s. Traditionally, MIDREX plants cool and store the DRI for later use. Thus, further reductions in CO_2 emissions are possible by hot charging the DRI to the EAF at 600-700°C. This lowers the electricity requirement per ton of steel produced by at least 120 kWh, which in return reduces the CO_2 emissions from the associated power plant. Another option to lower CO_2 emissions per ton of hot metal is the use of hot briquetted iron (HBI). In conclusion, steelmaking by feeding either DRI or HBI to the EAF together with scrap can decrease the CO_2 emissions by more than half compared to BF-BOF route, while satisfying the steel quality by diluting the impurities in the scrap. The production capacity of MIDREX plants has steadily increased over time and has now reached 2.5 Mt/y. With cheap shale gas available, large-size gas DRI plants start to displace conventional BFs, e.g. in the Nucor Louisiana project in the US. The future model of ironmaking will likely include utilisation of DRI/HBI as an energy container to further decrease CO_2 emissions and provide flexibility in a competitive energy market.

ULCORED: a direct reduction concept for ULCOS - Peter Sikström, LKAB

The lion's share of the CO_2 emissions from the DRI-EAF route arises from the DRI plant. One of the main features of ULCORED is the use of O_2 instead of air to produce an off-gas that consists of almost 100% CO_2. ULCORED might be able to reduce the NG consumption by 15-20% and allow the use of coal, biomass, waste and H_2 as alternatives to NG. Another purpose of an integration of ULCORED into existing steelmaking systems is to have only one CO_2 emission point in the system. In contrast to other DRI processes like MIDREX and HYL, which use endothermic CO_2 or steam reforming technologies, ULCORED implements exothermic partial oxidation (POx). Linde carried out tests in

a POx pilot plant and operated the burner and reactor without problems. ULCORED requires no reformer, no heater and works at high pressure. This results in less fines leaving the shaft and smaller equipment compared to MIDREX or HYL processes. In addition, the recycle compressor needs less electric power and it is possible to use a PSA instead of a VPSA. First estimates show that the CO_2 emissions of the ULCORED process can be about 100 kg/tDRI lower than for MIDREX or HYL. Thus, the new process can be a "quick-fix" for CO_2 emissions reduction at a brownfield site, especially where NG is cheap. Further testing is now necessary to prove the concept.

Session 8: Mitigation potential and techno-economics of CO_2 capture in an integrated steel mill

Chair: Jan van der Stel, Tata Steel

Techno-economic evaluation of capturing CO_2 from a generalized integrated steel mill- Lawrence Hooey, Swerea MEFOS

The objectives of this scoping study for a generalised steel mill are to establish appropriate system boundaries, assess the CO_2 emissions from different sources in the steelmaking process and to estimate CO_2 avoidance costs for several cases. Concerning the system boundaries, the energy input will be in the form of coal (coking and PCI) and there will be no import and/or export of electricity. The techno-economic evaluation focusses on a typical European integrated steel mill producing 4 million tonnes of standard grade hot rolled coil (HRC) via BF-BOF route. CO_2 delivery to the pipeline will be at 110 bar. The financial model uses cost estimates from vendor information, databases and long-term price trends for raw materials. Accuracy is within the range of +/-30%. The analysis includes two different end-of-pipe CO_2 capture cases with 30% MEA solution: LV1 with capture from steam boilers and hot stoves, and LV2 with additional capture from coke plant and lime kilns. A third scenario examines CO_2 capture from an oxygen blast furnace (OBF) with a piperazine activated 40%MDEA solution, as this is more suitable for the high CO_2 concentration of the OBF top gas. The results show that end-of-pipe capture, i.e. LV1 and LV2, can achieve 50-60% CO_2 avoidance at a cost of about 74-81 US$/t$CO_2$. The OBF scenario appears to be favourable with 47% CO_2 avoidance at a cost of 56 US$/t$CO_2$. This is mainly because the OBF case allows for a fuel shift from coking coal to NG rather than increasing the overall fuel consumption as in the end-of-pipe cases. The total capital costs

for the OBF case are also lower. All cases increase the break-even cost of HRC compared to the reference without CO_2 capture, again the OBF case is best in this regard with a 10% rise. Future work is now necessary to evaluate other CO_2 capture options and to investigate the effects of process integration on the reduction of emissions and cost.

Potential for CO_2 mitigation of the European steel industry - Jean Theo Ghenda, Steel Institute VDEh

The European iron and steel industry already reduced its CO_2 emissions between 1990 and 2010 by 25% through a decrease in output of about 12% and a shift from BF-BOF to EAF production route, the latter causing less CO_2 emissions per ton of crude steel. Total CO_2 emissions in 2010 were 223 Mt. Assuming a moderate annual growth of crude steel production of 0.8% and a CO_2 intensity at the 2010 level, CO_2 emissions are likely to reach 305 Mt in 2050. A shift to DRI-EAF route and high availability of scrap can bring CO_2 emissions down to 184 Mt. However, the abatement cost of moving from existing BF-BOF to DRI-EAF route is 260-700 €/tCO_2, thus is not economically viable in the EU at the moment. Full implementation of carbon dioxide capture and utilisation (CCUS) can lower the total CO_2 emissions in 2050 to 130 Mt, which translates to a 60% reduction compared to 1990. This means that the steel industry will not be able to come near the requested 80% reduction target of the EU in 2050 with or without CCUS. Besides their own CO_2 emissions, steel products can help reduce emissions in other sectors and technology applications.

Discussion forum

Moderator: Stanley Santos, IEAGHG

The second day of the workshop ended with a discussion forum emphasising a number of key messages:

- CO_2 storage demonstration is crucial to kick-start any CCS activities in the iron and steel industries.
- A global approach towards CCS is necessary to establish a level playing field among the industries in different countries.
- In the beginning, CCS implementation will increase steel prices but the role of incentives remains unclear.

- Public acceptance for CCS in parts of Europe is currently lacking.
- The technology is ready but the current economic situation prevents implementation of CCS in the steel industry.

Outlook and next steps for different projects and regions are the following:

- The next step in the COURSE50 programme will be the scale-up of the EBF to industrial size until 2017.
- The ULCOS programme aims to demonstrate that smelting processes are viable for CO_2 reduction. LKAB will decide on an ULCORED pilot plant in 2014. The biggest challenge will be the lack of public acceptance for CCS in Europe.
- In Korea, companies are rather looking for CO_2 utilisation options than for long-term storage.
- Australian companies will look in more detail into the mitigation options that biomass offers for the iron and steel industry. The abolishment of the carbon tax by the new government will also influence the CO_2 reduction strategies.
- In North America, CCS is quite a big story at the moment. Current large-scale demonstration projects, like Boundary Dam, might help to bring the costs down and to resolve issues with public acceptance and funding.

Session 9: Process integration and efficiency improvement in integrated steel mills

Chair: Man Su Lee, Research Institute of Industrial Science and Technology

Background of IETS & energy efficiency and process integration in the steel industry - Lawrence Hooey, Swerea MEFOS

The IETS is an Implementing Agreement under the IEA, focussing on energy efficient industrial technologies and systems. IETS currently has 10 member countries and works on a task-sharing basis. The main objective of IETS is to strengthen international collaboration and R&D on energy saving and GHG mitigation in industry. IETS activities are carried out in eight different, so-called Annexes, with Annex XIV dealing with development and use of process integration in the iron and steel industry. Main objectives here are to lower energy use and reduce CO_2 emissions. For this, the Annex provides a network

of experts, bringing together and sharing information on the present state of process integration methods in the industry. The Annex divides into three different tasks. Task 1 "Process integration methods" deals with the modelling and related tools. Task 2 "Energy efficiency" focusses on heat recovery, energy coordination, low temperature streams and excess heat. Task 3 "GHG mitigation" looks into alternative fuels and carbon lean technologies. Advantages of the Annex are that it provides structure and commitment to collaboration and establishes an international network of experts.

Swedish experience of practical application of process integration - Chuan Wang, Swerea MEFOS

PRISMA, the Centre for Process Integration in Steelmaking, is a joint research programme with seven industrial members aiming to enhance energy and material efficiency in iron and steel making. A case study at SSAB EMEA in Oxelösund revealed a cost saving of 6.5 MSEK/y through optimisation of hot stove operation. Optimisation of coal injection demonstrated further cost savings of 60-80 MSEK at a production rate of 2 Mthm/y. Another case study at Ruukki's Raahe Steelworks in Finland showed potential cost savings through optimised coal blending at the coking plant. In an optimal coal blending scenario, total production cost can decrease by 2.3%. An analysis of stove oxygen enrichment (SOE) at different sites also indicates economic benefits through savings in COG for use in other parts of the steel plant, such as the power plant, BF or reheating furnaces. The amount of cost savings depends on the production rate at the site and lies between 1.4-5.8 M€/y. An example for improving material efficiency is the recovery of ferrovanadium from LD (Linz-Donawitz process) slag. Consequences are a decrease in LD slag storage and the requirement of 100% MPBO pellets in the BF burden. Overall, process integration is a useful tool for the steel industry to improve its energy and material efficiency but for CO_2 emissions reduction it is important to focus efforts on a global level.

Session 10: Energy and resource management for efficiency improvement

Chair: Gordon Irons, McMaster University

Process integration: reduction of CO_2 emissions and energy consumption at BlueScope's Port Kembla Steelworks - Habib Zughbi, BlueScope Steel

For a steel plant, assessment of new technologies and alternative operating scenarios can greatly benefit from process integration methodologies, as they allow for an integrated approach rather than a localised, operation-based consideration. ISEEM (integrated steelworks energy and emissions model) is a comprehensive steady state model of BlueScope's Port Kembla Steelworks. ISEEM helps to understand the complex process interactions within the steelworks and to determine the potential for energy savings. The study covers three different emissions scopes, i.e. direct emissions, indirect energy emissions and emissions beyond the control but linked to operations of the plant. Overall, the model shows good agreement with the results observed in Port Kembla Steelworks but still leaves room for improvement. Results of the analysis show that only the "best of class" scenario can provide significant reductions in CO_2 emissions and energy consumption compared to the base case. In October 2011, BlueScope decided to shut down one of its two BFs, shut down the coke oven and cut down the production to half. Introducing such major changes imposes new requirements on the model, as it is configured in a particular way and deletion of certain units, like the BF, can be challenging.

Analysis of low carbon BF by mathematical model - Tatsuro Ariyama, Tohoku University

The key process for mitigation of CO_2 in an integrated steel plant is the BF. For a steel plant using a conventional BF, the total CO_2 emissions are 2,031 kg/t. A set-up with an OBF and TGR can bring the total CO_2 emissions down to 1,848 kg/t. There is a shift in the emission source points, so the power plant emissions increase but the overall emissions are lower due to carbon input savings and CO_2 capture. Another advantage of the TGR is that it reduces the direct reduction zone in the BF from about 30% to 10%. A hybrid model combining DEM (discrete element method) for the solid movement and CFD (computational fluid dynamics) for the gas flow allows analysis of the BF in

3D. The results show that shaft gas injection only influences the peripheral zone and that in a smaller BF the injected gas can easily reach the central part. At low coke rate conditions, it is necessary to improve the charging mode to ensure permeability in the cohesive zone. In a layered charge, a reduction in coke rate leads to narrow coke slits and thus to an increase in pressure drop. A coke mixed charge will be more favourable to guarantee sufficient permeability. In conclusion, the hybrid model is able to close the gap between small and large BF calculations.

Short-term energy management in a steel plant focusing on the use of gases, electricity and oil - Mikko Helle, Åbo Akademi

A short-term management system focussing on fuel usage can help with saving both energy and costs in a steel plant. In addition, it requires no investment, facilitates a better understanding of the system and is a suitable tool for production planning. New production targets can lead to variations in the operation of different units and it is beneficial to optimise stoppages and idle periods. The Excel model uses data from a regression analysis of Ruukki's Raahe Works and includes energy market data as well as fluctuations in production data to reproduce realistic behaviour. The modelled BFG usage shows excellent agreement with the real values. The results show that improved short-time management of the energy flows can create cost savings. For instance, combining the stoppage at a BF with an idle period of the strip mill decreases the need of auxiliary heavy oil in the power plant because more coke oven gas is available.

Session 11: Alternatives for fossil CO_2 mitigation

Chair: Taihei Nouchi, JFE Steel Corporation

Biomass: providing a low capital route to low net CO_2 emissions - John Mathieson, BlueScope Steel/CSIRO

The "Australian Steel Industry CO_2 Breakthrough Program" started in 2006 and is a collaboration between BlueScope Steel, Arrium and CSIRO. The work focusses on two areas: the application of biomass-derived chars in iron- and steelmaking and the development of a dry slag granulation process with heat recovery. LCA studies indicate that net CO_2 emissions for charcoal manufacture can be negative if the biomass comes from sustainable forestry and if there is utilisation of the pyrolysis by-products. Sufficient low-price

forest residues and other wastes exist in eastern Australia to produce 1 Mt/y of charcoal. Brazil already achieved charcoal production at a cost comparable to coal/coke; however, economics are constantly changing. Establishing a low-cost, large-scale pyrolysis process is crucial to widespread implementation of biomass. As no such process that satisfies all requirements exists yet, CSIRO started development. In a standard Australian mill with a steel production of 3.8 Mt/y and CO_2 emissions of 2.2 t/tcs, application of biomass in BF-BOF route can save net emissions of up to 1.3 tCO_2/tcs. A substitution of the BF tuyere injectant with up to 25% biomass is feasible. Laboratory experiments with biomass-derived chars showed the use of organic additives and high-density charcoal might be beneficial. Next steps are full industrial trials, especially BF injection, and scale-up of the pyrolysis process.

Reduction behaviour of iron oxide using woody biomass - Kazuya Kunitomo, Kyushu University

It is important for the Japanese iron and steel industry to reduce CO_2 emissions from the BF and to lower the consumption of fossil fuels. Utilisation of charcoal in the BF process is one option to achieve these objectives. Japanese industry currently neither uses nor produces charcoal, so it might need to import it from foreign countries if charcoal proves useful for application in the BF. The characteristic differences between coke and charcoal are ash content and volatile matter content. Charcoal is significantly higher in volatile matter and much lower in ash than coke. Evaluation of the physical properties shows further differences. Charcoal has less strength than coke and many small pores. This leads to a larger specific surface area and a higher porosity. Tests of gasification reactivity reveal that charcoal starts to lose weight at lower temperature than coke. The different characteristics advocate charcoal as a substitute for nut coke, rather than BF coke. Tests in a BF inner reaction simulator (BIS) show that utilisation of charcoal can lower the temperature of the thermal reserve zone from 1,028°C to 739°C. In addition, the reduction of sinter starts at lower temperature and the reduction degree is higher for temperatures above 600°C. Compared to the base case, use of charcoal reduces CO_2 emissions from fossil fuels by 33% and total CO_2 emissions by about 16%.

Mineralisation of CO_2 using serpentinite rock: towards industrial application - Mikko Helle, Åbo Akademi

CO_2 mineral sequestration offers a leakage-free alternative to CCS, especially in Finland, where no suitable underground storage reservoirs exist. The potential of mineral carbonation is large, as the olivine-containing rock in Oman alone could bind all existing fossil carbon. Estimates of the carbon storage capacity for mineral carbonate start at 10,000 Gt and reach up to 1 million Gt, so outshine the potential of every other storage method. Besides, capture of CO_2 is usually the most expensive part in the CCS chain. Mineral carbonation is beneficial because it can operate directly on flue gas, making the capture step redundant. The process route suggested by Åbo Akademi (ÅA route) consists of magnesium silicate mineral extraction followed by $Mg(OH)_2$ production with ammonium sulphate and subsequent $MgCO_3$ production at >20 bar and >500°C. Total energy and material input for the process per ton of CO_2 is 3 GJ of heat, which is comparable with standard CO_2 capture technologies, and 3 t of rock. The process is also suitable for integration into an industrial lime kiln, requiring 2.6 GJ/tCO_2 of heat, as kiln gas, and 0.9 GJ/tCO_2 of power. An alternative and simpler route is $MgSO_4$ carbonation in aqueous solution; however, this process does not offer heat recovery from carbonation. Next challenge for the ÅA route will be to achieve a recovery of the ammonium sulphate salt of more than 90%.

Site visit: JFE East Japan Works, Keihin

On the fourth day, the members of the IETS Annex Group were able to visit JFE East Japan Works in Keihin. The Keihin site is an urban steel plant, which was Japan's first private steelworks. Today the steel plant is an example of an environmentally friendly plant integrated in a metropolitan area. Participants were able to have a look at the used home electric appliances recycling plant and the waste plastics recycling plant. In the latter, municipal waste plastics are crushed, granulated and then used as a BF feed substituting part of the coke. This way, the plant contributes to a recycling-oriented society and helps reducing CO_2 emissions.

Meeting Conclusions

The workshop addressed the challenges the iron and steel industry is facing when implementing CO_2 reduction technologies. Apart from the technical component, the key issues surrounding CO_2 reduction are funding, political backing and public support. The BF is the main producer of CO_2 emissions in an integrated steel plant, so remains the focal point for most reduction strategies, such as the OBF with TGR, which offers substantial carbon savings. Further emissions reductions are achievable through process integration and efficiency improvements. However, these savings are thermodynamically limited and the Japanese and European steel makers have already implemented plenty of technologies that improve energy efficiency. Although Japan has the world's most efficient steel industry, they assure their commitment to further emissions reductions. Presentations on CO_2 storage showed safe and leak-free underground storage seems possible even if seismic events occur. Safe, publicly accepted storage or utilisation options for CO_2 are a prerequisite for industry to move ahead with any CO_2 capture technology. Alternative iron- and steelmaking routes, including smelting, direct reduction and scrap-using EAF, can also contribute to lower CO_2 emissions significantly. Some of these processes are already commercially available but many still require scale-up and demonstration. When it comes to identifying the potential for further energy savings and CO_2 reductions, process integration with modelling and simulation tools can be of great help. First experimental studies have shown the use of biomass-derived charcoal could provide a promising, low-cost path to CO_2 reductions if sustainable biomass and large-scale pyrolysis are available. Moreover, a global approach towards CCS is necessary to establish a level playing field among the iron and steel industries in different countries.

In conclusion, the workshop has been a great opportunity to catch up with the most recent developments regarding CO_2 emission reduction technologies in the iron and steel industries. The Japanese efforts in particular, such as in the COURSE50 programme or as implemented in the JFE East Japan Works, have been of great interest. IEAGHG recommends organisation of another meeting after a reasonable amount of time, in order to look at future development and progress.

IEAGHG SOCIAL RESEARCH NETWORK MEETING 2014 (2014-10)

Introduction

The overall aim of the Social Research Network is "to foster the conduct and dissemination of social science research related to CCS in order to improve understanding of public concerns as well as improve the understanding of the processes required for deploying projects".

The objectives of the Network are as follows:

- Ensure high quality social science research
    - Elevate reputation and acceptance of social science research
    - Consistency of research
- Identifying gaps
- Promoting a learning environment
- Building capacity within the Network
- Translate information from studies into tools or applied lessons
    - Apply insights to actual projects
    - Interact with technical experts
    - Communicate results to policy makers
    - Ensure application is grounded in theory
- Create a clearing house of social science research

It is worth noting that these objectives have been in place since its inception however there has been no movement on creating the suggested clearing house of social science research so it appears to be an aspirational objective rather than something that has been delivered on.

This 2014 meeting, the fourth of the IEAGHG Social Research Network (SRN), was held at the University of Calgary in Canada, from the 14th to the 15th January. The meeting was hosted by the University's Institute for Sustainable Energy, Environment and Economy (ISEEE) and sponsored by the ISEEE and PTRC. Over 35 delegates from 8 different countries attended the meeting.

Session 1: Scene Setting

This session aimed to review changes in the science and policy debate around climate change that might affect public attitudes.

'Key conclusions of the IPCC 5th Assessment: the cumulative carbon budget and its implications' Professor Myles Allen, Oxford University

Myles shared findings from the recent IPCC report, with the major headline being there are no new headlines. That is, Myles reported the range of emissions had not changed; that uncertainty in the modelling is inevitable and will not go away; and, that we need climate policies that are helped by uncertainty – not just robust to uncertainty. Myles suggested under such conditions the introduced 'carbon tax' that is tied to global temperature may not work as it is intended to. Mainly because people will pay almost any price for the luxury of burning fossil fuels, and after the 'trillionth tonne' any tonne of carbon will need to be sequestered – but the carbon price will never be high enough to enable this.

To overcome these issues Myles proposed the Sequestered Adequate Fraction of Extracted carbon (SAFE) concept. That is, ensuring that generated carbon never exceeds the atmospheric capacity. Paying for the stored CO_2 implies a carbon price, which is then passed on to consumers. As a result of this, they might consume less (making the carbon price lower), without compromising policy. Figure 1 illustrates the concept of the 'trillionth tonne'.

The importance of motivating countries to take action was discussed, with agreement that it is imperative that all try to generate mechanisms for this. It was recognised that a large number of CCS projects have either been stopped or placed on hold –mainly due to public perception issues (for example recent issues in Europe) and the cost of CCS. It was recognised that in the UK, in particular, the focus on energy costs and public perception is currently dominating media attention. It was suggested that while developing CCS technology will leave countries with a strong technology fix, in places like the UK, where renewables are being pushed ahead of other options, it is clearly distorting the market. From the information presented in this talk, it was clear that there is a need to prioritise CCS in the UK, at least.

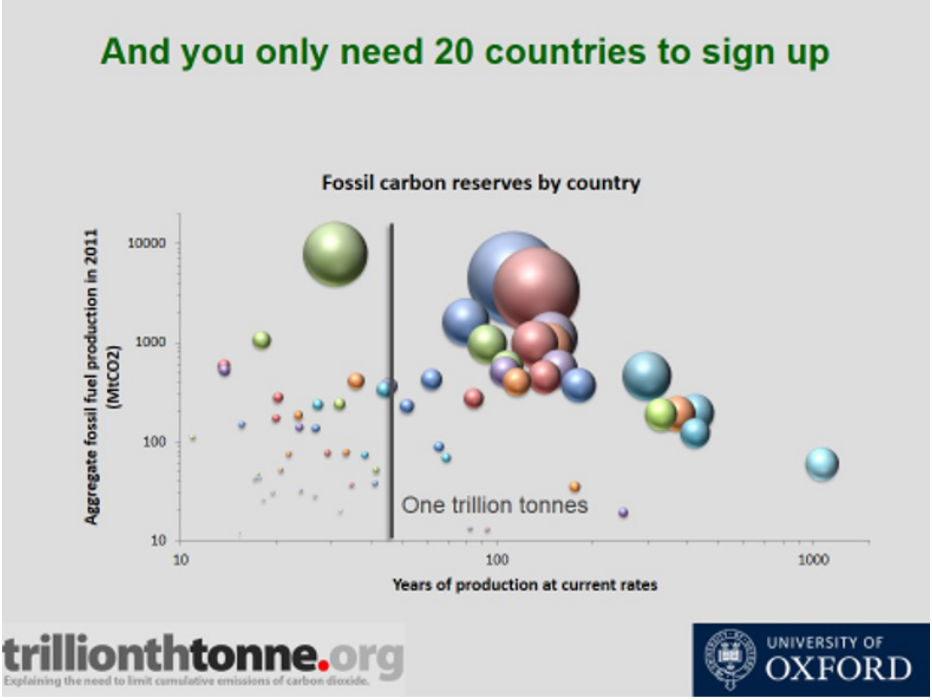

Figure 1, Graph showing fossil carbon reserves by country, and illustrating the 'trillionth tonne' concept

'Addressing adaptation in the oil and gas industry', Arthur Lee, Chevron

Arthur outlined the perspective that adaptation is becoming a recognised climate risk management strategy for many oil and gas companies. Arthur highlighted that there is a growing perspective on the necessary and complementary role of adaptation/climate risk management. This was seen as complimentary to oil and gas companies that already have risk management at the heart of their business decisions. However, Arthur stressed that a climate management strategy requires the development of an adaptation plan. Such a plan would include identifying and evaluating potential impacts; the evaluation of risks; and designing approaches to adapt and manage risks identified. Through a workshop, the International Petroleum Industry Environmental Conservation Association (IPIECA) identified several key messages, including that oil and gas companies continue to adapt to climate risks (whilst assessing a range of related risks); many impacts are

local, therefore local adaptation assessments are needed; a flexible and robust design coupled with adaptive management practices will be critical for managing risks and adapting; and that sharing lessons with society and governments can broaden the recognitions/understanding of risks – and therefore highlight more efficient options.

'ENGO Perspective on CCS', Duncan Kenyon, Pembina Institute

Duncan began by outlining that although there has been some growth in awareness of CCS there is a lack of understanding of what it means, how it works and what the risks are that it presents. He also suggested that there are not any really good publicly available diagrams to help with this. Critical issues were the long term liability and its impact on the individual.

ENGO's agreed on the importance of examining old assets when considering CCS; as it was felt that there was a possibility that some gains could be made from retrofitting to old assets, but Duncan stressed that it would be important to examine the whole chain to understand what the net benefits might be by doing so. It was recognised that unconventional gas extraction has been a game changer for the US as it shifts away from coal. However, although this was recognised as having a climate benefit and some felt that there was no need to fit CCS to natural gas plants Duncan expressed a concern that these discussions do not include the possibility of attaching CCS to natural gas plants.

Pembina and other ENGOs are of the opinion that CCS needs to be part of a portfolio of options, although there was some concern about CCS with EOR and Duncan expressed a view that more work was needed to be done to understand the life cycle of the process – making sure that the step to manage and build was fully accounted for. Duncan stressed that it is crucial to have proper project and Monitoring, Measurement and Verification (MMV) plans in place because long-term liability is a key issue for CCS deployment and acceptability. It is likely that as more projects are planned and deployed, the public will feel more comfortable with the technology. Governments and industry need to be seen to be stepping up, and that appropriate policy, regulations and management are needed to mitigate potential risks before acceptance will occur. CCS is a complex technology, so it often comes down to understanding versus awareness which can be challenging.

In terms of ENGOs' position on EOR, value is seen for building infrastructure but storage may not actually occur. CO_2 is an expensive commodity and there is an unwillingness to keep it underground – is the value of the CO_2 such that operators may need to extract and use it? It was noted that in British Columbia, there is a very large carbon footprint from the gas and LNG developments. Here the concern is about the overall greenhouse gas footprint, and the government here are in a good position to be energy efficient, world leaders on this – which could generate valuable learnings.

Discussion

The interaction of ENGOs with projects and the public opens up a dialogue. Pembina, for example, gives a scientific, technical-based analysis of results – a perspective that is constructive and perhaps more appropriate for industry and stakeholders (like those in IPIECA). Greenpeace, a different ENGO, uses more emotional arguments – which probably results in more influence on the public.

Session 2: Social Science Trends in Canada

Canada is very active in CCS with the implementation of several large commercial CCS projects, as well as major advancements in policy related to climate change and CCS. This session provided an opportunity to explore the social science trends related to these developments.

'Developing the legal and regulatory framework for CCS in Canada', Nigel Bankes, University of Calgary

The legal and regulatory framework (LRF) in Canada has had success in providing certainty for investors and assurance for the public. The success in this area can be attributed to many factors, including that it is an oil and gas jurisdiction (meaning the population are familiar with the risks/benefits of using subsurface resources), that provincial initiatives were brought out by the government (including financial support, vesting of pore space ownership among others) and a collaborative approach was undertaken to ensure correct details. This approach, the Regulatory Framework Assessment (RFA), was a 'multi-stakeholder process to review the technical, environmental, safety and monitoring requirements for CCS and to recommend any changes' to the LRF. The RFA observed that the overall approach to the mitigation of

greenhouse gases is lacking ambition and that the regulator no longer enjoys as much trust as before.

'Deploying a public outreach strategy for the Aquistore project', Aleana Young, Petroleum Technology Research Center (PTRC)

The Aquistore project, managed by PTRC, involves the storage of CO_2 for the Boundary Dam project. The strategic communications plan was established in 2010 and the efforts have undertaken a number of different outreach activities. These activities include external engagement such as kitchen table discussions, an open house, a ground breaking event, site tours and media attention, and internal engagement undertakings such as establishing/ running a communications working group, an annual meeting, site tours and 'lunch and learns'. It was noted that of the concerns raised during the engagement programme, many were not particular to CCS, for example many community members had issues with a seismic company in the area who had not worked well during the project. One family was concerned that the CO_2 underground would affect the value of their mineral rights, but in terms of issues, nothing worrying came up – there were no issues raised regarding groundwater, for example, as it is likely that the site operators and communicators were open about this information from the very beginning.

'Focus group work arising from public questions raised during the Weyburn-Midale Project', Norm Sacuta, PTRC

A Best Practice Manual has been published from the Weyburn-Midale project (WMP) learnings, and The Global CCS Institute (GCCSI) and PTRC have recently worked on a joint project; 'Creating Core Messages'. This project began by reviewing the 2009 stakeholder results (along with a literature, project and web review) from the WMP to identify key questions raised by the local community – 48 most often raised questions were identified. These questions were published in a guidance report, and each question is answered and then backed up with details from the WMP results. Two focus groups (using Weyburn area participants) were held in 2013 to better understand if the public's needs are met through the explanations given in the document and to identify the effectiveness of the answers provided to the 48 key questions.

The results from the groups were positive; it was evident that the answers to the questions – providing evidence of safe storage at Weyburn – created a

more positive attitude towards CCS, although the intent of the booklet was to be informational and not persuasive. There were some negative reactions were concerned with the information source and the long term security of storage. The document and group results were peer reviewed and the following recommendations were made: clearer definition of the intended audience is required; the document should be a source book for use by policy makers and communicators on other CCS projects; and the need for historical context from other projects. There was a group consensus that similar initiatives on other projects with expertise and CCS projects (with current outreach efforts) in different areas would be beneficial.

It was noted that there was a slightly higher level of general CCS knowledge in the WMP area (due to oil and gas history) but the details were not clear for most.

'Scare tactics: contracting out risk amplification', Alan Roth, Alliance Pipeline

Alan discussed the credibility struggles among activists and other stakeholders (for example scientists, regulators and industry). He explained that risk 'amplification' or 'attenuation' refers to the players in such a struggle and their communications transmitters, each of which competes for their own version of the truth. The 'Social Amplification of Risk Framework' (a concept developed by Kasperson et al., see Figure 2 overleaf), a conceptual idea, was developed to analyse risk communication exchanges in the context of the many factors that can amplify/attenuate risk perceptions (psychological, social, cultural etc.).

The struggle between anti-fossil fuel/oil sands activists and pro-fossil fuel industry players is a classic example of such 'risk amplification' by the activists, and this has been particularly evident in Canada. It has been interesting to see the huge influence that such activists, the media and certain ENGOs can have on the Canadian public (risk amplification), despite the fact that the oil sands accounts for just 7.8% of Canada's emissions. Alan suggested that the Internet, for example, has acted almost as an accelerant for such negative attention (note that it could be positive too) and pre-dispositioning can be hard to overcome when trying to gain public acceptance.

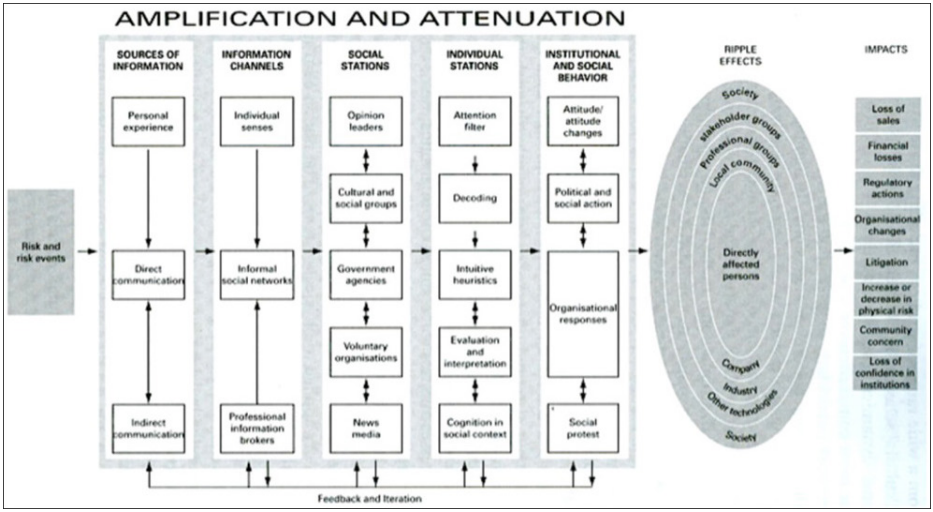

Figure 2, 'Social Amplification of Risk Framework', Kasperson et al., 1988

Discussion

When looking at practical ways to link with trusted information sources, it is important to determine whether the source has constructed the narrative consciously or unconsciously and to understand what the narrative is comprised of (i.e. be aware of your intended audience and think about where they're coming from). Public opinion can have a huge amount of influence on potential or operational projects (as it should – their voice MUST be heard). There is a huge issue with trusted sources and speakers, particularly with celebrities (who have tremendous clout) who can be very influential and become trustworthy to the public. However, it was recognized that this can also be an opportunity for projects to focus on and much of the early work that Emma ter Mors and Bart Terwel have done on trust can be helpful here.

Session 3: Social Science Trends and the International Atmosphere

Moving beyond Canada, this session provided an opportunity to explore social science trends and research related to CCS in the rest of the world.

'Stakeholders' Views on Financing Large-scale Integrated CCUS Projects in China: From Hypothetical to Real', Xi Liang, University of Edinburgh

The development of large-scale integrated CCS projects in China are still all at a very early stage and it is recognised that stakeholder communication is an important area in 'formulating timely policy support and overcoming barriers associated with deploying and demonstrating CCS technologies'. It appears that the Chinese government see this as an essential technology for long term mitigation strategy but for now the focus of storage has been on EOR and offshore storage as the target associated with large industrial projects. This work has demonstrated that Chinese stakeholders have a better understanding of CCUS than previously, but they still hold some concerns about the impacts of extra costs/energy penalties on the Chinese energy system and economy. The Chinese national government has begun work on policies to support a few CCUS demonstration projects and some Chinese banks have expressed interest in financing these early CCUS projects. That is the banks are generally demonstrating a high risk appetite for new, clean energy technologies. There is no comprehensive policy support framework for financing large CCUS projects in China, but alternative choices include carbon markets, capital grants and feed-in tariffs. Therefore, a key component of the project that Xi is involved in is to understand how to finance a large scale integrated CCUS project in China. In the research it was thought by many that the risk of legal and regulatory changes would be a top priority (when in fact leakage was the highest perceived risk), but it was noted that in the Guangdong area, there is a carbon price so a financial liability for emissions.

Japanese experiences, Takuma Mohri, Japan NUS Co. Ltd (JANUS) & Kenshi Itaoka, International Institute for Carbon-Neutral Energy Research (I2CNER)

I2CNER have been researching public perceptions/societal attitudes in Japan before and after the early 2011 Fukushima event and found that the risks associated with nuclear meltdowns had not been officially communicated to the local residents (living close to nuclear plants) or to the general public (including those beyond the official zone of emergency evacuation, but who might be exposed to radioactivity). Work has also been done on the attitude of the Japanese public after the event; the "best-mix" of energy has become a major issue in Japan. JANUS used an online survey in the September of 2011 to gain an insight into public attitudes, using a sample of over 1000 in

the Tokyo area. The researchers found that the Fukushima incident made the Japanese public more energy-conscious; that their preferred energy source would be solar (because it is environmentally friendly – an opinion shared with the global public); but that in reality, this public is more cost-conscious than environmentally concerned.

It was noted that before the event, there was some opposition to nuclear, but this was not a widespread opinion. As a nation, nuclear accounted for 30% of Japan's energy and it seems that attitudes towards the technology is similar to that of CCS – people were not supportive but did not necessarily oppose it. It was interesting in the survey that oil and coal were rated below nuclear (even after Fukushima) and it was thought that this may be because in Japan, fossil fuels are a foreign commodity (99% are imported from other countries) whereas nuclear is run, operated and controlled by Japanese stakeholders.

Discussion

It was noted that across so many different contexts, cost is a limiting factor – it will always have a major influence. CSIRO have undertaken some work (see session 4) that examines where people trade off with costs, which shows that once it becomes too expensive, personal preference does not play such a role. Events such as the Fukushima incident have shown that risk and risk communication is tricky in an active project – much the same as in CCS operations and the notion of transparency around risk is much to do with different people having different perspectives. For example, the Decatur project has done three rounds of risk assessment (pre and during operation) and has looked into how you go about communicating these risks and how you use the risk assessment process to mitigate the risks – tasks which all tie in to each other. It is important to start by defining the risks and looking into worse case scenarios (and remembering that the worst case scenario is unlikely and the more likely incidents would be the low consequence events). CCS projects are complex and multi-disciplined; communicating this fact is a challenge also.

Session 4: Methodologies

This session provided an opportunity for the participants to review and explore different methodologies for social science research related to CCS.

'Looking at alternative deliberative processes: An example of Q methodology in use', Anne-Maree Dowd, CSIRO

CSIRO's social choice project aimed to explore stakeholder engagement models around sustainability and natural resources; to better understand the underlying aspects of sustainability problems; and to build a knowledge base that complements technical, theoretical and policy models for sustainably futures. The Q methodology was used in individual and group questionnaires, and is a quantitative process of capturing personal orientations, enabling the elicitation, evaluation and comparison of human subjectivity on a certain topic. Researchers found that external blame/accountability to the government (or big organisations) was diffused through the collaborative Q sort, and that fragility, climate change, responsibility and action is just as important at the individual level as well as through industry/government. This tool is useful as it can be used to specifically focus on CCS discourses and project contexts, individual Q sorts can be compared with group Q sorts – allowing analysis of the influence of information and deliberation, and it's a different approach to feed into engagement plans.

'Using social media to conduct social science research in an educational context'. Sallie Greenberg, ISGS

Social media is a huge potential mechanism for engagement, but there has been limited empirical work on the effectiveness of social media for this purpose. This work examined the role of social media in an active learning environment and used various measures to analyse attitudes, including monitoring of social media posts, pre- and post-test surveys, self-reports, interviews, and course artefacts. The study concluded that social media use did in fact impact student attitudes about global climate change (the treatment group showed an attitude shift toward greater concern about climate change and reported a higher level of intent to socially engage on the topic); and it facilitated the active learning environment, However, in this study, social media did not impact student knowledge gains. These results demonstrate that social media can be effective when used in an educational context, but that implementation takes time and effort; its use must be purposeful, intentional and meaningful in the educational environment.

'Exploring the use of an interactive online tool for information provision and how it impacts public attitudes to energy technologies', Peta Ashworth, CSIRO

The current rising energy prices in Australia make this a topic of huge interest to the public, and this online tool (the 'MyPower tool', see Figure 3) allows the public to see the impact of different energy mixes on emissions and costs (i.e. energy bills). CSIRO used the values beliefs norms (VBN) theory to try and understand who individuals feel is responsible for depletion of energy sources. The results showed that most felt that this depletion is increasingly a problem for society, but they did not feel any individual responsibility for this, which is despite the fact that we all use the resources indirectly in our daily lives. Not surprisingly, our early analyses showed that renewables for energy generation were the most popular choice, with gas and coal also popular. CCS was fourth after these and nuclear was the least popular choice. On average, people were reluctant to agree to price increases, but when given the options in the online tool, they chose a more stringent emission reduction/price increase combination than their original answer indicated. This may indicate that people are reluctant to give a figure on price increases when asked an open question, but when given specific detail about cost-emission trade-offs and how to achieve them they are more comfortable selecting something with reasonable ambition.

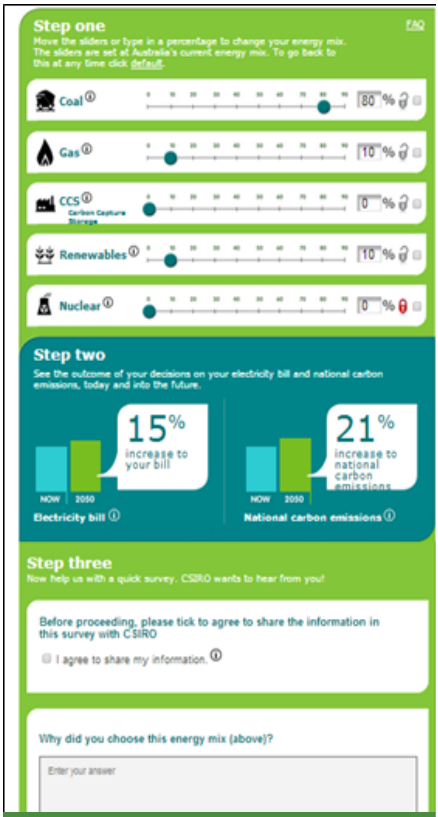

Figure 3, A screen grab of the MyPower online tool, CSIRO

Discussion

Delegates looked further into the research presented in Session 4 and the

reliability of results over time. Surveys are generally a good representation of a certain point in time, especially as attitudes can change very quickly. The Q methodology research was longitudinal in nature, so it can be replicated over time but the work on social media may not be as replicable because the population of concern (i.e. 18 – 25 year olds) constantly evolve the ways in which SM is used. It was noted that group interaction was a key factor in some results and that group interaction has been used successfully as part of the communications process.

Social and group identity can be measured and it is interesting to see how this impacts various things; the group members identify with one another, build trust and then build on their opinions – in public engagement like this, people need to be challenged and the best way to do this is working with others they trust – presenters that are trusted by people are likely to have more influence in the discussion. Much of the qualitative data gained show that in such environments, there was a real sense of community, indicating a certain level of comfort in that those activities were supported by the public and it was observed that the activities under discussion (climate change mitigation etc.) were supported. The work on SM demonstrated that outreach and engagement does not have to be costly – the technology exists and that open forums and groups can be used to facilitate this interaction. CSIRO have been experimenting with using this method for social research, and noted that it is much cheaper and similar results are achieved. One concern, however, is that risk amplification can easily become a problem in the online forum versus the face-to-face forum. It is, however, important to note that there will be certain tools or methodologies that will not work in certain populations – one size does not fit all.

The group discussed the potential positive effects of discourse in small groups and it was asked whether the presenters' experiences have been self-selecting; that people attending an energy group or event are more likely to have positive opinions, therefore leading the results? It was noted that the CSIRO work advertised the group as a 'workshop of national significance' rather than being specific on the topic. The social media research actually saw a vast range in opinions and differences throughout the group, despite the attendees being aware of the topic beforehand. It is possible that when using this methodology, biases may have come into play due to the self-selecting

nature of the effort, but the results seem representative of the real world.

Longitudinal, attitudinal studies would be beneficial to use as part of a project's public engagement plan – this could then be used as a baseline, can be tracked over time and is a reliable method. It was noted that early engagement is important, but often there is no point unless the government is on board and sometimes it may be detrimental to engage too early if there is no chance of the project continuing – raising false hopes so to speak. There are many tools that could be used by social researchers, but there are some fundamental things that must be considered, such as the local population, time you can give to public engagement, acceptable trade-offs in the community etc. It is critical to take the time to understand where you are, how the local community works, what is important to the local community and then use this information to inform what you then choose to do for that specific project.

Session 5: Communication of CCS and Scientific Issues

At the 3rd Social Science Research Network meeting in Noosa, Australia (held in 2012), the group heard preliminary presentations on the in-depth focused studies presented during this session. This session provided an opportunity for the group to reflect on what had been learned over the course of some research projects.

'Framing CCS (-research): Using choice experiments as a novel way to explore communication issues', Kevin Broecks, Utrecht University

Kevin suggested that information on the influence of different types of content on attitudes towards CCS is currently lacking. This particular research used choice experiments to determine the persuasiveness of elements of a communicated message. The first survey showed that a focus merely on arguments about climate change mitigation is not helpful. Arguments should instead focus on appeals to norms (such as 'properly disposing of your CO_2 garbage') and arguments about the role of CCS in the energy mix. The second survey extended the approach to argument frames and sources. It showed that longer arguments with more explanation are more credible and persuasive than one-liners. The third survey showed that citizens can be classified according to their motivation and ability to read CCS information in depth. Interested citizens examine arguments closely, but other mostly

look at information source or social norms (x% percentage of the population agrees). Overall, this work demonstrates that the application of choice models to communication issues is valuable. It enables studying several elements of a message in conjunction and can provide valuable information about population segments when combined with latent class analysis. Critical issues are the selection of elements to include in the study and the language and cultural specificity of the results.

'Motivated audiences: Belief and attitude formation about science topics', Cydney H. Dupree, Princeton University

A lack of knowledge is not the only important issue; research has shown that there is another side of attitudes. Attitudes are evaluations that tap both cognition and affect, and attitudes include motivation and cognitive capacity. This work looked first at communicator credibility, which is comprised of expertise (the knowledge and ability to be accurate in forming an argument) and trustworthiness (the motivation to be truthful). The following are core motives that rule people's social interactions (therefore driving their behaviour): belonging; understanding; controlling; enhancing self; and trusting – with trust being seen to be hugely important. This research used a US sample and looked into where science communicators fall in the 'warmth vs competence chart' (which measures the publics' trust in them) and found that researchers and scientists are viewed as cold but competent – qualities that are actually resented by the public (see figure 4). Generally however, distrust of climate scientists does not run high – such scientists are trusted by the public for reasons of humanity and saving the environment; the main trust issue seems to be with money (i.e. money funds their research, so they are biased). The public seem to trust impartiality rather than persuasive agendas.

The merits of media and communication training was discussed, namely whether 'warmth' is something that could be taught so that communicators are perceived as more trustworthy. Cydney suggested that there are ways to up one's warmth and competence ratings, and people can be trained to improve these qualities, but as perception is very quick, this could be seen as fake. There is evidence that fairly minor things, such as the way the communicator dresses, can affect the group perceptions and feelings of credibility or identity.

'CCS communications: Pitfalls and remedies', Gerdien de Vries, Leiden University
This research by Gerdien and colleagues looked into the extent that the different strategies in CCS communication (scattering; emphasis framing; greening) are used in persuasive communication, and any pitfalls that these strategies may have.

- Scattering (the sharing of a lot of information at one time) aims to persuade the public, but a pitfall of this method is that irrelevant information can weaken the persuasive effect of relevant information. Gerdien found that irrelevant information does dilute the persuasiveness of communication about CCS (positive and negative), but that moderately relevant information does not have a dilution effect.
- Emphasis framing (giving more weight to advantages over disadvantages, or vice versa) aims to persuade but a major pitfall is the subsequent perceptions of manipulation. This research found that emphasis framing is regarded as illegitimate when done by press agencies (because people expect balanced information from this source), but this mediation effect does not hold true for oil companies (which are perceived as manipulative as this is expected by the public).
- Greening (presenting involvement in CCS as environmentally friendly) aims to give CCS a positive reputation, but the pitfall is that people think that a company misrepresents corporate activities as 'green' in order to look more environmentally friendly than it is. When looking at greening, this work concluded that people perceive 'greenwashing' when an oil company invests in CCS, and an economic motive decreases these perceptions but an environmental motive does not. It is interesting to note that an environmental motive is regarded as strategic behaviour.

Gerdien's research suggests that remedies to the pitfalls associated with the three strategies are to be relevant (to avoid the dilution effect), to be credible (to avoid perceptions of greenwashing) and to be cautious with persuasive communications (to avoid perceptions of manipulation).

Discussion

It was interesting to note that other research on trust and competence suggests that when there is a need to be perceived as more warm, people may actively downplay their competence (either consciously or unconsciously)

– so there is a trade-off which needs to be kept in mind. Climate scientists talk about anthropogenic climate change and research shows that people don't want to claim personal responsibility for this, but it must be considered that this is part of the problem – that we're pushing people to think about something they don't want to accept responsibility for. Other recent research suggests that people who know more about global climate change seem to feel less responsible. It is important to find the line between imparting knowledge/information and perhaps pushing people away. It is essential to examine ways that trust can be established – trustworthy communicators could then establish themselves as experts. There is an identified group that believe that NGOs are a credible information source and some work also shows that consortiums work well as an information source, as they are seen as reliable. There is a lot of motivation for companies to join groups/ organisations so that they appear more credible, when in fact scientists are often seen as more credible than organisations themselves.

Often, the public considers climate change as a global problem rather than a local problem – until the issue surfaces in their back yard and then it is interesting to see what extent people will distance themselves from it. In the past there have been pushes in the US to get global climate change more into the public domain (by a range of different methods) and they actually found people were so fatigued by the push of information that they couldn't take it all in.

An important fact to consider in public engagement is that different descriptions or names for terms (i.e. describing CO_2 as a 'pollutant') can affect public perceptions, and the public's response to such differences. There has been some CCS-specific research done in this space, but it is an important area that should be considered when thinking about the gaps in research.

Session 6: Risk Perception

Risk mitigation is an essential element of energy generation – there are risks in all energy technologies. A challenge comes from effectively communicating both the nature of the risk and the mitigation strategies. This session examined a number of activities that related to risk communication and mitigation and public's responses to them.

'Protocol for response to claims of CO_2 leakage'. Katherine Romanak, University of Texas

This work was based on the success of a technical response to the allegation of a CO_2 leak at the Weyburn-Midale project in Canada. In this case, a landowner has complained about impacts from an oil operation for more than 8 years. These complaints cited a number of different causes and problems and had gone largely unresolved. The last complaint alleged that CO_2 injected as part of the Weyburn-Midale project had leaked to the surface and was causing harm to farm animals and the local environment. An international technical team was brought in to determine if injected CO_2 was leaking to the surface. The team developed an innovative and cost-effective method for determining the source of CO_2 detected at the surface (it was finally determined that any present CO_2 was the result of natural seasonal flux). In the course of completing this study, the technical team interacted with the complaining landowner, building enough of a relationship that the final results were trusted and resolved that complaint. The work was developed into a protocol for use at other CCS sites.

The results show the influence of social science. One key learning was that it is important to avoid the battle of going back and forth in the media for various reasons, and this work proposes the importance of a Claim Response Protocol – a response to an 'allegation of an unintentional release of a gas associated with a specific CCS project'. This protocol would be composed mainly of site assessment (to validate the allegation) and risk communication (correspondence and document review). Adopting a protocol for quickly addressing leakage claims in advance of a CCS project is beneficial for avoiding long-running allegations, for avoiding unqualified sources reaching incorrect conclusions, and to avoid inaccurate information affecting public perception of CCS. The tools to implement such a protocol are readily available and relatively simple to use. They include steps like a process-based approach to fingerprinting anomalies (i.e. the process-based soil gas method). However, the key learning is that they need to be initiated from the start and the data collected longitudinally over time.

'Risk perceptions of and emotional reactions to CCS: Forming closed attitudes'
Charlotte Koot, Leiden University

Implementation of new technologies, for example CCS, often do not succeed without acceptance or support by the public. Compared to open (or unfinished) attitudes, closed attitudes – attitudes about which people have achieved a state of cognitive closure – are known to be more stable and more predictive of actual behaviour than open attitudes. As such, closed attitudes are also more predictive of support of and opposition to the issue at stake. The ability to achieve closure (AAC) is the ability to form judgments and decisions confidently and with certainty, and this work examined factors that are important in the context of technologies and that are potentially related to people's AAC – risk perception of CCS and emotional reactions to the idea of CCS. The results show correlations between general and specific risk perception, emotions and cognitive closure achieved, which supports the notion that risk perception and emotional reactions are important for people's ability to achieve closure. From the results, we can tell that both risk perception of a technology and people's emotional reactions are significantly related to people's AAC. Catastrophic potential and outcome uncertainty-related emotions were predictors of the level of closure achieved and results emphasize the importance of focusing on both cognitive and affective influences on the ability to achieve closure. The knowledge gained through this research could be used to improve CCS communication (as we know what aspects should be focussed on to help achieve cognitive closure) and it has emphasised the importance of people's safety concerns (so taking uncertainty emotions seriously).

'More than a message: Connecting stakeholder engagement and decision support for carbon management initiatives', Joe Arvai, University of Calgary
Decisions about energy and carbon management are complex – there are significant technical challenges/uncertainties, you cannot proceed without communication with multiple stakeholders, and this requires trade-offs across economic, social and environmental concerns. There are four key questions that need to be answered:

1. What is the scope and background of the decision that needs to be made?
2. What is the range of objectives that will guide the decision?
3. What is the broad range of alternatives available to decision makers?

4. What are the trade-offs that decision makers/stakeholders need to make?

All of this leads to decision-focused deliberation. Social research for this work was carried out in Michigan, in relation to the decommissioning and retiring of a coal-fired power station, using an online web tool for the survey. The results show that nuclear was the most popular choice, followed by biofuel with CCS and coal with CCS not too far behind that. The researchers aim to integrate this work with other decision support models and look further into holistic versus decomposed judgements.

Discussion

The decision support model is currently being using mostly by governments, but there is the potential that such a model could be used within an organisation or company. There was some surprise that nuclear was rated so high in people's preferences. It was thought that this is probably due to the number of perceived benefits of this technology, such as the cost, the greenhouse gas emission reduction potential, and the use of legacy infrastructure (to name a few). It was agreed by all that local context and individual values and worldviews are key factors to consider when looking at the communication of CCS and it would be interesting to see how emotional factors may influence how different people would respond to models such as the decision support one presented in this session.

Session 7: Responses to CCS

This session presented case studies to explore how communities are responding to real-life proposed CCS projects and the communication and engagement activities that have been undertaken to in conjunction with these projects.

'Social site characterisation: The experience of the SiteChar project in Europe', Leslie Mabon, University of Edinburgh

This work compared two sites (one in Scotland, one in Poland) that are near to potential onshore and offshore CO_2 storage sites, and aimed to build understanding of social context through social site characterisation and to raise public awareness through engagement. Some similarities were observed, such as the importance of context, that public engagement was expected as part of the project development and that both groups felt that

discussions can involve both local and national scales. In Scotland, however, there was more concern and focus on economic benefits and the relationship to renewables, whereas in Poland the most concern was centred on the potential risks and leakage.

The work has implications for governments and developers:

- The public's expectation for governments to clarify their stance on CCS;
- The need for open dialogue on the risks of CO_2;
- The importance of managing public expectations regarding jobs and the effectiveness of participation;
- The importance of effective engagement i.e. that which makes citizens feel listened to and empowered.

'The unique challenges for CCS public engagement with respect to the pilot CO_2 storage project – SACCCS', Polly Modiko, South African Centre for CCS (SACCCS)

The South African Centre for CCS' mandate is to undertake research into CCS and also public engagement. The pilot project has been proposed to demonstrate storage in South African conditions, but to also gain experience and develop South African capacity in handling/storing CO_2, whilst providing an educational facility for the public and stakeholders. The potential storage sites are within the Zululand and Algoa Basins, where the majority of the population does not speak English and where poverty is rife, with many not having access to basic electricity. Language is a difficulty and presents a huge challenge, for example in such areas there is no phrase suitable to describe CCS. CCS is not a familiar concept in South Africa and various recommendations have been made for this pilot project, including the compilation of an Integrated Communications Action Plan (ICAP) and a community liaison working group has been created. The SACCCS have embarked on public outreach programmes with various stakeholders and to date, consultations have been held with national, provincial and local governments and concerns arose around permitting, compensation, jargon used and costs. There is also the challenge in how locals are engaged in South Africa which is quite different from some of the more developed contexts most of the CCS researchers work in.

Discussion

There was some discussion on how realistic it actually is to bring CCS into the public eye in such a poor country and perhaps considered as unrealistic when much of the community itself doesn't even have access to water or electricity. CCS is not a current priority of the government of South Africa, but it is key to raise awareness ahead of the potential pilot project. In this particular case, it is imperative to manage the public's expectations (for example, here it is not likely that the project will create many jobs as the expertise needed is just not in the area). All agreed that more work in developing countries would be extremely useful to the entire Network and beyond.

The idea of engaging the public, in order to understand what they are thinking (and to not push a technology) is an important one, but it can be misconstrued. Whether consciously or not, sometimes a social researcher could come across as if they are lobbying for the technology and it is essential they are clear in their objective for the research, and that the public actually understands how the research works – what are the proposed outputs, outcomes etcetera.

Session 8: Social Science Research Related to Transport/Pipelines

This session explored social science research related to concerns about the surface equipment associated with CCS – namely CO_2 pipelines and injection wells.

'Public perceptions of CO_2 transportation in pipelines', Clair Gough, the Tyndall Centre

The aim of this research was to assess the social impacts arising from, and public perceptions of, CO_2 transport in pipelines. Four different case studies were examined and six key themes were identified as being important:

- History and local context;
- Physical risk;
- The role of scientific argument;
- Trust;
- Contingencies; and
- Procedural/distributive justice.

The COOLTRANS pipeline project has a proposed route corridor in the north of England and the Tyndall Centre used focus groups to assess the social aspects that could potentially affect the project.

Some positive feelings about the concept of CCS came from the focus groups (including benefits in terms of local jobs; acting on the global issue of climate change), along with some negative thoughts, such as that CCS perpetuates the continued use of coal-fired power stations and a lack of confidence in the modelling of the stored CO_2. Some issues that arose specifically on pipelines included potential disruption during construction, safety and trust in the companies involved. These results show that the public do consider the nature and implications of perceived risks, and that there is acceptance of the broader context (i.e. CCS as a mitigation option). An honest and clear approach to communicating motivations is absolutely crucial, trust in the processes (site selection, regulating operations and maintenance) is imperative and it is important to consider how developers and other proponents of the technology are perceived.

'Putting CO_2 well blowouts into perspective: A study of the incidence, impact and perception of loss of well control', Sarah Wade, Wade LLC & Sean Porse, University of Texas

One often cited concern with CCS is the fear that injection wells will explode. Arguably this fear has been stoked by media coverage of CO_2 well blowouts that focuses on the sensational headlines and by an actual dearth of concrete data regarding the incidence, magnitude, and impacts of well blowouts. Coverage of a well blowout in 2013 motivated the authors to attempt to develop a response to public concern about well safety. The methodology used in the study included identifying relevant literature resources, gathering data on the incidence/effects of well blowouts and calculating incident rates based on well populations in respective US regions. There is surprisingly little information available about well blowouts. Based in initial review, it seems that that the risk profile for an oil or gas well is likely to evolve over time. At first, there is some risk of encountering unknown problems in the subsurface while drilling the well (e.g., pockets of gas/fluid, changes in rock density). Risks typically drop during routine operations after the well is completed and reduce even more when the well is shut in. Risk can then increase if the well is reworked for a new purpose. In all of these stages, the incidence of well

blowouts remained very low. Given this preliminary conclusion, the lack of information is even more surprising. This is a story of an identified risk that is reasonably well mitigated – the frequency and impacts of incidents is low. Yet it the industry seems reluctant to share this information. Further work is being conducted to develop more incident information and to begin to better understand the real and perceived risk communications challenges.

The work on well blowouts has raised several interesting social science questions:

- How much of a concern will arise over CO_2 blowouts? Will it have a material impact on timing, cost, and project deployment?
- Are incident data a compelling counter-argument? (How much risk is acceptable?)
- Do incident data move the dread/familiarity scale?
- What are the appropriate methods for sharing this data?

Pipeline infrastructure. Dr Michal Moore, University of Calgary

The goals for infrastructure are mainly that it is adequate, timely, cost effective, flexible and safe. Issues that could potentially arise with pipelines are related to the approval process, competition with other land uses, issues with proximity and regulations/authority, and the public perception issues related to pipelines including location/visibility, press reports, toxic cargos and security. Michael suggested that from experience, what operators may say is not necessarily what the public will hear, so there needs to be some common lexicon to translate the project without actually degrading the actual utility of the systems we have. Michael suggested that the public should be reminded that we use (and rely upon) toxic commodities all the time and provide them with real examples of this to make it easy for them to understand. In terms of public policy, it is important that all stakeholders are involved with the location proposals and hearing process – all will have an opinion but it's about knowing WHO to get involved and WHERE. Emerging issues with public policy in pipelines include metallurgy, inspection and data, the pipeline lifespan, capacity and commodities. How to communicate with the public, and the science of good policy, is dynamic and ever-evolving. It is important to respond and adapt as this evolution happens.

Discussion

This session was good for making all attendees think about a piece of the CCS value chain that can often be overlooked; a value chain of pipelines is a conduit by which we move things, which is optimised when it is full (e.g. for CCS it works best when you take full advantage of it) – pipelines are only making money when transporting a commodity and operating at optimum capacity. Trying to get the approval process for pipelines unified ahead of time is important, in terms of cost and public engagement.

In the UK, pipelines for CCS will affect a large number of people, and many different communities. As the pipeline proceeds, controversy can carry on with it, and in the UK there are current considerations to bury future pipelines to minimise such controversy. However, this should not be generalised to all regions – in less densely populated regions (such as North America), some pipeline projects have still had much controversy (i.e. the Keystone 2 pipeline). Perhaps in the UK, the public are most used to living near natural gas pipelines (which is arguably more hazardous than CO_2), so are therefore more accepting to the prospect of CO_2 pipelines. It was observed that in the US, there was a lot of strategic opposition to aspects of the value chain and it is a way of bottlenecking the project. With infrastructure such as CO_2 pipelines, the likelihood is that they will have a high profile and perhaps controversy during construction, which will then fade as time progresses.

In the incidence of CO_2 well blowouts in particular, it is crucial to not confuse the public – which can be done by giving them the correct, important information (such as clarification as to what the impact may be, the procedures followed when such an incident occurs etc.).

Session 9: Outcomes & Recommendations

This final session provided a recap on all of the presentations and what it might mean for future ongoing social science research. To summarise:

- Session 1 examined setting the scene for social science research in CCS. It was suggested by Myles Allen that having climate policies that can cope with uncertainty are developed. As well it is clear that risk adaptation will play a major role in the future of CCS projects. The idea of a cumulative emission budget is positive for CCS (industry will have to pay for it over

time) and shows that CCS has a goal. EOR is one method of facilitating and perhaps encouraging the implementation of CCS, but researchers are still missing good visual tools to communicate each component. For NGO's it was discussed that there is a potential role for CCS with old assets, when the hidden value of current assets are factored in, but the EOR 'jury' is still out given the total project lifecycle.

- Session 2 presentations, on the policy and practice in Canada, showed that structural arrangements, considerable preparation and a bit of scepticism (!) matters. The policy environment is a driver and provides an important context for the entry of new technology into the public arena. Legal, regulatory and financial decisions can help to frame the significance of an issue. For practicing communicators who want to build a stronger base for practice it is imperative to prepare – to start where the public is, to explore their perceptions, to understand their concerns and use these to inform communication approaches. It is equally as important to understand the framers' interests and strategies for amplifying or attenuating risk.
- When looking at social science trends and the international atmosphere – session 3, a survey (about CCS risk/returns) of Chinese bankers showed that there is an improved understanding of CCS over the last 7 years, but there are still concerns regarding cost and energy penalties. The prioritisation of risks has been acknowledged as a key aspect but there is no policy in place for large CCS projects. A catastrophic event such as the Fukushima nuclear incident (2011) can cast a negative light over other, similar technologies. It is important to understand the limitations of risk assessments and the different views of experts – science and policy need to be 'bridged' to enable decision-making. It is interesting (but not unexpected) to see that after such an event, the public will often change its opinion – in Japan, the public became more energy-aware, had some appetite for increased costs for cleaner (and safer) energy and preferred more renewable energy sources (e.g. solar) over coal and nuclear.
- Session 4 looked into the methodologies used in social science research and CCS. The Q methodology illustrates how people value subjective topics and the individual versus group ranking showed the impact of a deliberative process. It was demonstrated that the active use of social

media can create an enhanced learning environment and interest in action, without increasing (or decreasing) the content learned. The attitudes of those within the environment suggested the value of community formation and deliberation was high. An online interactive tool has been utilised successfully to gain views on energy sources and costs; a tool which requires the users to consider trade-offs and that could be considered as an analogue for deliberative process. The value of creating a group process for social research and public engagement activities in CCS is important and should be considered.

- Session 5, looking at communicating CCS and science, is obviously a hugely important aspect to consider. It is important to know what elements of a risk message regarding CCS are viewed by people as persuasive, but it is much easier to persuade someone with negative arguments than with positive ones. Understanding how people perceive the sources of scientific information – some groups may not be as credible and trustworthy as we think or hope – can also be a critical component of project communication. There are potential pitfalls associated with three of the common risk communication strategies for CCS – scattering, emphasis framing and greening. We saw that the public seem to trust impartiality rather than persuasive agendas.
- The perception of risk (Session 6) is a key topic in communications and is extremely important with CCS. A protocol for response to claims of the leakage of CO_2 has been developed by researchers as a potential way to avoid many communication problems. It was felt this will be beneficial in avoiding long running allegations, and avoid unqualified sources reaching incorrect conclusions. At the same time, preventing (or minimise the amount of) inaccurate information influencing the public. It is well known that public acceptance impacts implementation success and that the emotional reaction to complex technologies is important, as it affects people's ability to make a decision. If there are more perceived risks, it is likely that the public will find it more difficult to form an opinion, which is important to the formation of closed attitudes. Stakeholder engagement and decision support was looked at in Session 6, which considered risk communication as a boundary process (so merging content and intent). CCS is being considered by the public, but their concerns are centred

around costs, greenhouse gas emissions and air quality.

- Much research has been done on the responses to CCS, visited in Session 7, including work on social site characterisation which noted the similarities (i.e. understanding that CCS is part of climate policy) and differences (risk perception or economic benefit being of most importance) in the local public's opinions on two potential CCS sites in different countries. It was recognised that an open dialogue is key. In developing countries such as South Africa, the development of basic infrastructure is still an issue. The language problem for communication needs to be addressed for different cultures and stakeholder engagement is especially important; the government and head of the local community concerned should be involved from the very beginning.
- It was recognised that the perceptions of pipelines (Session 8) was similar to CCS in general and seemed to centre around specific themes including trust, safety, visibility and local impact. The risk profiles for a project evolve with the stages of operation and it is crucial that the safety record of a project is explicit. It was observed that the terminology used in communications can present challenges with many different projects – something which can perhaps be further looked into. Issues recognised at pipelines were similar to those seen in CCS projects – approval, land use, proximity to other activities and regulations.

Suggestions for moving forward

Recommendations

The following recommendations were made at the end of the fourth IEAGHG Social Research Network Meeting:

- Combine conclusions & results together from different levels of research to allow connections to be seen, for example qualitative and quantitative research, different theoretical frameworks, hands-on focus groups etc. Physically drawing these connections together in real time as they occur, and then perhaps mapping the connections together in a virtual space where all can contribute ideas would be beneficial
- Develop a database for research instruments and papers relevant to social science and CCS was recommended – a repository of instruments, measures and researchers carried out by those in the network would be

useful on many levels

- PhD students bring a lot of new research to these Network meetings so it is important to include the next generation in the future meetings and research opportunities
- This network brings together lots of disciplinary perspectives to examine CCS (which is very valuable), but it may be useful to expand the network to other disciplines that are perhaps not present
- The topic of CCS could be reframed by placing it into a larger context that may make it easier for the public to understand, which may also help to expand the network however this would need to be done in consultation with IEAGHG and other SRN members to determine what might be appropriate
- Further research could be undertaken in less developed countries, particularly in relation to understanding the cultural context in which projects will have to operate
- There is also only a small component of work examining the ethics of CCS (particularly in less developed countries) which is an opportunity and something of importance that should become a priority...
- There may be an opportunity to build on current methodologies and tools which could actually come about by expansion of the network to other disciplines and somewhat beyond just a focus on CCS.
- There is an opportunity to focus more on how to communicate about CCS as the related sciences, in particular to understand when personal opinions become group opinions.
- Transport and pipelines is also an important component of CCS research and needs to be considered going forward.

BIOMASS AND CCS – GUIDANCE FOR ACCOUNTING FOR NEGATIVE EMISSIONS (2014-05)

Key Messages

- Certain greenhouse gas (GHG) accounting rules do not adequately recognise, attribute and reward negative emission technologies, in particular biomass with carbon dioxide capture and storage (bio-CCS).
- Most schemes at least recognise negative emissions from bio-CCS by either allowing for net-back accounting on a portfolio level ("pooling") or the generation of credits ("offsetting").
- Regional cap-and-trade schemes generally do not recognise negative emissions from bio-CCS. However, the architecture of most schemes would allow for either pooling or offsetting if the regulating bodies implement these methods in the schemes.
- Consultation among the regulating bodies is essential to clarify the status of bio-CCS and the recognition and reward of negative emissions.
- Incentivising bio-CCS remains a challenge, due to the baseline of many schemes. Currently, there is a debate about whether bio-CCS delivers a double dividend for emissions abatement and thus should receive double credits.
- Land use change (LUC) is a big concern. Especially in developing countries, implementation of monitoring systems for land use and forestry activities is poor or patchy, so "carbon leakage" is likely to occur. Some schemes might accelerate forest clearing in these countries. The opposite can happen as well, i.e. generation of more forest plantation due to increased demand.
- Low carbon fuel standards (LCFSs) include detailed GHG accounting rules for calculating upstream emissions and also consider LUC effects to some extent.
- Parity of treatment between fossil and biogenic CO_2 is necessary with respect to accounting and sustainability issues.
- Two options for the future design of policies exist:
    1. Centrally planned view (i.e. incentivising and prioritising bio-CCS while phasing out fossil fuels)

2. Economic purist view (i.e. letting carbon markets drive the deployment of bio-CCS)

- Regulating bodies in the EU and US are currently discussing how to address the sustainability concerns around bio-CCS. This broader discussion will likely initiate a complex political process.

Background to the Study

Biomass use for energy production in processes such as combustion and gasification, and its use to produce biofuels such as bioethanol, results in CO_2 emissions. If CCS is applied to these emissions, because the CO_2 is recently taken-up by the biomass from the atmosphere, then actual CO_2 removal from the atmosphere can take place. This is referred to as 'negative emissions' (compare Figure 1). At present there is only one technology which may be able to be deployed at the required scale –bio-CCS.

Low-carbon energy technologies are usually incentivized by recognition of their GHG emissions performance, for example within emissions trading schemes (ETS). However, for this to occur, the emissions must be able to be accounted. With the negative emissions potential of bio-CCS, there are several difficulties.

The first is that conventional cap-and-trade schemes reward the maximum for zero emissions, not below zero.

Secondly, for all suggested incentive or support schemes for bio-CCS, a most important factor in the accounting of net GHG balance is the accounting of the emissions from the supply-side of the biomass. In this regard, especially GHG emissions and environmental impacts arising from direct or indirect land use change (dLUC/iLUC) are an issue.

Consequently, there is a need for analysis of the options for correctly accounting, reporting and rewarding all emissions relating to bio-CCS, and of ways of including it in ETS schemes to appropriately recognising its GHG performance. IEAGHG commissioned this analysis to Carbon Counts Company (UK) Ltd.

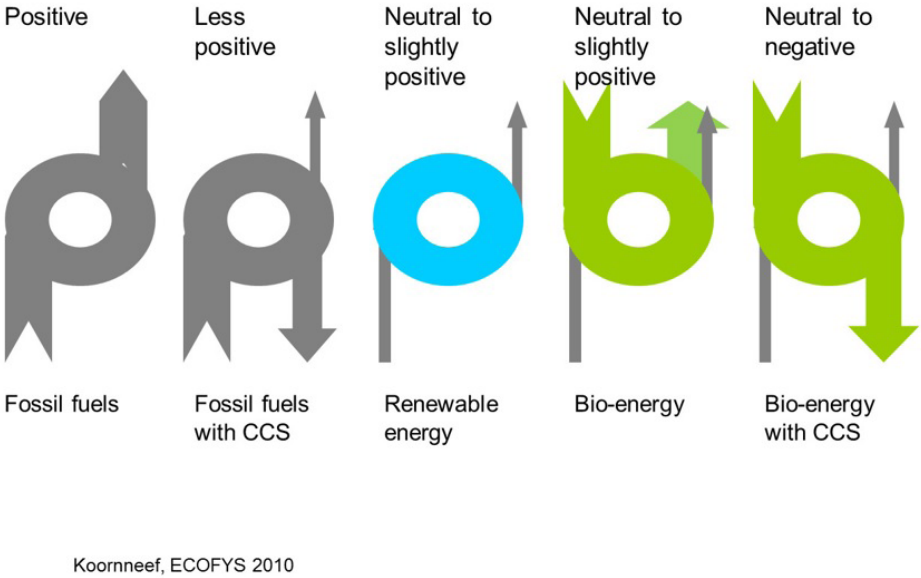

Figure 1, Carbon balance for different energy systems

Scope of Work

The main objectives of this study are as follows:

- *GHG accounting rules applicable to bio-CCS:*

  Understand how they apply, assess their ability to appropriately recognise, attribute and reward negative emissions and suggest potential scope, options and pathways for improvement where necessary. This should include consideration of how other incentive schemes outside ETSs account for GHG emissions associated with bioenergy use, in particular in relation to life-cycle GHG emissions and dLUC/iLUC.

- *Sustainability and potential negative environmental impacts of bio-CCS:*

  Provide an assessment of measures to regulate sustainability impacts and other potential negative environmental effects that could arise through promoting bio-CCS (e.g. leakage, transboundary issues, dLUC/iLUC effects).

- *Options to appropriately reward bio-CCS:*

  Taking into account the GHG accounting rules and issues for sustainability, consider options for modifying policies to appropriately reward operators undertaking bio-CCS.

Therefore the full value chain for different bio-CCS pathways has to be considered, covering: growing, harvesting, distribution, processing, retail and consumption of final products. Within this, the GHG accounting rules for each stage of the value chain are reviewed in order to address how life-cycle GHG emissions are accounted for.

This study reviews the following GHG schemes and accounting rules in detail (the main report provides a detailed description of the schemes in Table 2.1 on p. 12ff):

- 2006 IPCC Guidelines for National GHG Inventories under the framework of UNFCCC and Kyoto Protocol (2006 IPCC GLs)
- EU GHG Emissions Trading Scheme (EU ETS)
- EU Renewable Energy Directive (EU RED)
- EU Fuel Quality Directive (EU FQD)
- US EPA GHG Reporting Program (US GHGRP)
- California Emissions Trading Scheme (California ETS)
- California Low Carbon Fuel Standard (California LCFS)
- Australia Carbon Pricing Mechanism (Australia CPM)[1]
- Kyoto Protocol Clean Development Mechanism (CDM)
- Kyoto Protocol Joint Implementation (JI)

In terms of the sectoral scope, the study covers GHG accounting rules applicable to bio-CCS in:

- Electricity generation,
- Industry, and
- Liquid fuel production.

The geographical scope of the review covers mainly the developed countries,

[1] The Australian Government has introduced repeal bills in November 2013, aiming to abolish the carbon tax scheme from 1st July 2014.

as presently only these are obliged to GHG emission limitations and reduction targets. The following accounting rules are considered within the scope of the study:

- International rules
- Regional and domestic rules
- Project-based schemes
- Product-based schemes

Findings of the Study

Introduction to bioenergy

Biomass consists of any organic matter of vegetable or animal origin. It is available in many forms and from many different sources, including:

- Agricultural crops and residues (e.g. energy crops, food processing waste, animal waste)
- Forestry products and residues (e.g. harvested wood and processing/ logging residues)
- Municipal and other waste (e.g. sewage, sludge, waste wood, industrial waste)
- Microalgae and bacteria

Biomass is the most widely used renewable energy source worldwide, currently accounting for around 77% of renewable energy and around 10% of global primary energy use. Although the use of woody biomass in domestic heating and cooking continues to account for most bioenergy worldwide (often termed 'traditional' biomass), there is an ever increasing diversification of biomass sources and their end uses ('modern' biomass) – with the development of new conversion technologies offering multiple routes for value creation.

Most biomass activities worldwide are focused on energy products and services; however there is growing interest and research into other products such as chemicals and pharmaceuticals, which could be combined with bioenergy production. As a result, the bioenergy sector has witnessed significant growth in recent years, particularly the use of biofuels within the transport sector, which has grown faster than for heat and electricity uses.

Figure 2 presents a schematic overview of the various pathways by which biomass sources can be converted into final energy products or services, and the principal removals and sources of CO_2 emissions arising from the source through to end energy products.

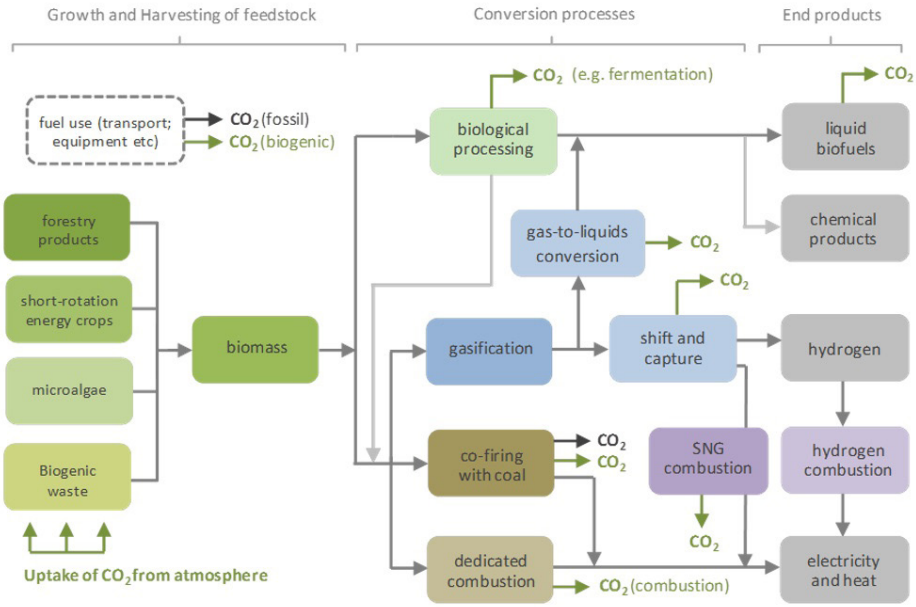

Figure 2, Bioenergy pathways and sources of CO_2 (adapted from Rhodes and Keith, 2005) (Note: Figure is only exemplary and does not include all chemical conversion routes, such as esterification, hydrotreatment.)

Based on the various bioenergy pathways outlined above, bioenergy combined with CCS technology can potentially be applied to a wide range of sectors covering multiple commercial processes. These can be grouped as follows:

- Power generation
  - » Dedicated biomass combustion
  - » Co-firing
  - » Anaerobic digestion
  - » Gasification

- Industry
  - » Biomass combined heat and power (CHP) boilers (esp. pulp & paper industry)
  - » Black liquor gasification
  - » Cement kilns
  - » Iron & steel furnaces
- Biofuels production
  - » Bioethanol
  - » Biodiesel
  - » Biomass synthetic natural gas (SNG) and H_2 production

Recognising and attributing negative emissions

The general principle underpinning climate policy design for CCS support is recognition of captured and stored CO_2 as "not emitted" to atmosphere, and/or recognition of the technology as a "non-emissive end-use". This typically requires the monitoring of CO_2 flows through the whole chain to quantify the mass of CO_2 captured and therefore not emitted, monitoring of the capture and transport system to quantify any fugitive emissions (i.e. leaks), and comprehensive geological storage site monitoring to provide assurances that the injected CO_2 remains in the intended geological formation and isolated from the atmosphere over the long-term and to quantify any leaks that occur. Impermanence can negate at least part of the environmental benefits achieved by CCS, compromising the effectiveness of policies and measures designed to support the technology, and serving to undermine the environmental integrity of any emission reduction units awarded to a CCS project under an emission trading scheme. For this reason, a key focus of GHG accounting rules for CCS is on managing permanence risk.

In general, all of the schemes reviewed allow for the captured CO_2 to be recognised and accounted for as "not emitted". In nearly all cases, this is dependent on monitoring of CO_2 storage sites to provide assurances over the permanence of emission reductions achieved through CCS.

In all the schemes reviewed, there is a general assumption that growth and harvesting of biomass leads to CO_2 removal and CO_2 emissions respectively,

as shown in Figure 3. This is either explicit, through the direct inclusion of CO_2 removals and emissions within the GHG accounting rules, or implicit through the way in which CO_2 emissions from biomass combustion and processing are accounted for. The scientific or technical basis for this zero emissions assumption is correct as capturing and storing CO_2 from biogenic sources should lead to net removals of CO_2 from the atmosphere. The theory is subject to the proviso that biomass carbon stocks (C-stocks) are effectively replenished, and that biomass production is not causing land use changes that give rise to net increases in CO_2 emissions due to reductions in biological C-stocks (compare Figure 3 and 5). However, the asymmetry of GHG accounting rules can create "carbon leakage" because C-stock changes can go unaccounted for. In this case the zero-emissions assumption is undermined.

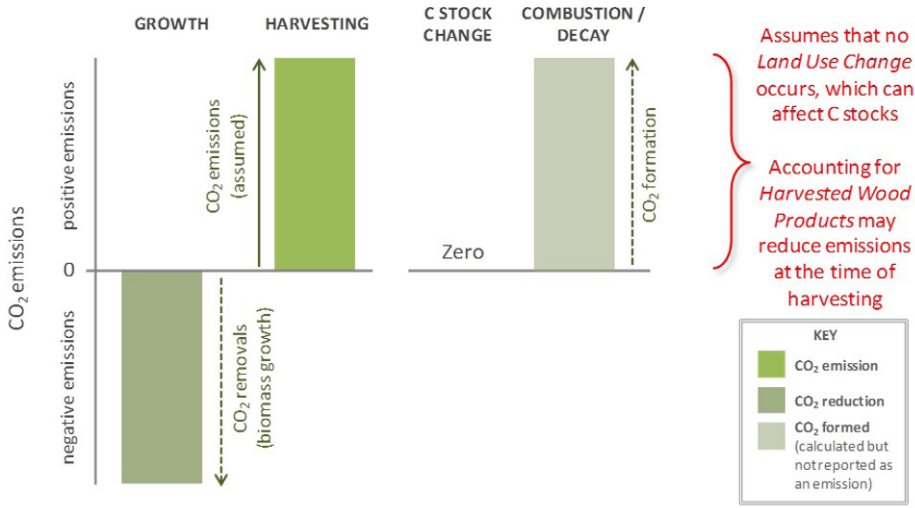

Figure 3, GHG accounting for biomass growth, harvesting and combustion/decay

The aggregate effect of recognising captured and stored CO_2 as "not emitted" and the accounting of CO_2 generated from biomass combustion or decay (fermentation) as zero should result in bio-CCS being recognised as delivering negative emissions under a given scheme. This is on the basis that a covered installation/facility generating CO_2 from biomass produces zero "regulated" emissions, whilst any mass of captured CO_2 that is transferred offsite for geological storage in appropriate sites can then be subtracted from its GHG inventory (zero minus X = minus X; see Figure 4).

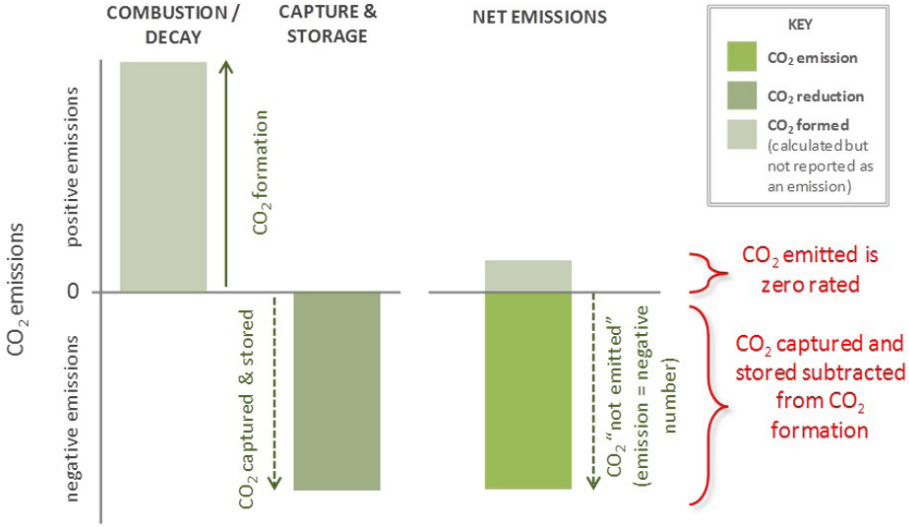

Figure 4, GHG accounting for bio-CCS with negative emissions

The concepts and principles outlined above are the cornerstone of good environmental policy making in the field of carbon pricing and market-based mechanisms, and form an important backdrop to the discussion presented in the following sections regarding how bio-CCS is currently included within various GHG accounting rules for inventory compilation.

To achieve a deeper understanding of the appropriateness of different GHG accounting rules to recognise and attribute negative emissions, the assessment focuses on the treatment of GHG emissions across the bio-CCS value chain in the following five contexts:

1. How CCS is included within a scheme's GHG accounting rules;
2. The way in which biomass growth, harvesting and combustion and processing emission sources from the conversion of biomass to energy are accounted for;
3. Whether and how dLUC and/or iLUC arising through biomass cultivation are effectively taken into account;
4. Whether other emissions occurring in the supply chain are included in the scheme (e.g. emissions arising from the transport of biomass); and,

5. Whether the rules can appropriately allow for negative emissions to be recognised and attributed to the entities included in the scheme.

Points 1 and 2 determine the capacity of the scheme to recognise CCS as an emission reduction technology and biomass combustion or processing as a zero-rated emitting activity (i.e. a renewable energy); points 3 and 4 relate to whether the full GHG emissions associated with biomass production are taken into account; point 5 is essentially the culmination of points 1-4 in terms of whether the scheme can potentially recognise negative emissions, i.e. where the zero-emission of biomass combustion is subsequently deducted when capture and stored, leading to negative emissions.

The review presented attempts to outline the treatment of these aspects under various GHG accounting scheme rules in order to illustrate how the issues link together and highlight where the main challenges for negative emission technologies such as bio-CCS may lie.

International GHG accounting rules in the 2006 IPCC GLs generally allow for negative emissions from bio-CCS to be recorded and recognised in national GHG inventories for Parties to the UNFCCC and Kyoto Protocol. The review did not identify any potential barriers within the GHG accounting rules. Similarly, project-based schemes such as the CDM and JI, the US GHGRP and the LCFSs reviewed – namely the California LCFS and the EU RED/FQD – all potentially allow for negative emissions achieved using bio-CCS to be recognised within the ambit of their respective GHG accounting rules.

However, under the EU ETS, only the mass of "fossil carbon" transferred for geological storage may be deducted from an installations GHG inventory, which prevents negative emissions from bio-CCS being recognised under the scheme. Further, installations exclusively using biomass are exempted from the scheme, implicitly excluding recognition of such activities. Options to address these shortfalls include:

- Amending the EU ETS Monitoring Mechanism Regulations (EU MMR) to include biogenic CO_2 within the ambit of Article 49, where this is for the purpose of geological storage, and modifying the exclusion of installations using biomass so as to include installations using bio-CCS. This could be achieved either through a Commission Decision or possibly via the comitology process under Article 23 of the EU ETS Directive.

- Proposing specific new monitoring and reporting guidelines for bio-CCS installations – which would need to be made by a Member State – for approval through the comitology process. These would need to address the barriers highlighted above, as well as outline any specific methodological issues that must be addressed for bio-CCS projects (e.g. specific rules on life-cycle GHG emissions accounting and dLUC/iLUC issues). It is important to note that the EU MMR allows for such future innovations in relation to the revised CO_2 transfer provisions of the Regulation (see recital 13 of the preamble).

Under the Australia CPM, emissions from the combustion of biomass are not treated as "covered emissions", potentially posing a barrier to recognition of the capture and storage of such source streams. Therefore, further clarification is necessary as to how bio-CCS might fit within the scheme. Applicable domestic offsets – such as the Carbon Farming Initiative – are not relevant to the potential types of bio-CCS applications, although international offsets generated under JI could be a means to recognise and reward bio-CCS within the scope of the CPM.

The California ETS does not allow for negative emissions to be recognised under the scheme for the reason that an appropriate quantification methodology for CCS does not yet exist within the scheme.

The discrepancy between international and some sector specific GHG accounting rules such as LCFSs (which do recognise negative emissions), and regional cap-and-trade schemes (which appear not to allow for recognition of negative emission technologies) suggests that whilst national governments may accrue the benefits of negative emission technologies, e.g. under the UNFCCC, there is only limited means to incentivise the private sector to undertake such activities (e.g. the application of CCS at biofuels refineries could qualify, whilst CCS at biomass fired power plant would not have any benefits). Consultation with the European Commission – DG Climate Action, the Australian Clean Energy Regulator, and the California Air Resources Board (CARB) is recommended in order to clarify the status of bio-CCS and to discuss potential options to recognise and reward negative emissions.

Table 1 contains a summary of the above GHG accounting rules with regards to bio-CCS.

Scheme	CCS	Biomass growth/ harvesting/ combustion/ processing	dLUC/iLUC	Life cycle emissions	Negative emissions
2006 IPCC Guidelines	✓	✓	✓	✓	✓
EU ETS	✓	✓	✗	✗	✗
EU RED/FQD	✓	✓	✓	✓	✓
US GHGRP	✓	✓	✗	✗	✓
California ETS	✗	✓	✗	✗	✓
California LCFS	✓	✓	✓	✓	✓
Australia CPM	✓	✗	✗	✗	✗
CDM/JI	✓	✓	✓	✓	✓

Table 1, Summary of GHG accounting rules for bio-CCS[2]

(Appropriately) Rewarding negative emissions

One of the key objectives of this study was to consider options to appropriately account for negative emissions in GHG scheme rules. For bio-CCS, other factors may be pertinent to the consideration of how appropriate different policies may or may not be for supporting bio-CCS, and what level of reward these should offer. Considerations in these contexts therefore include:

- The level of reward that should be given to negative emission technologies, recognising the benefits they offer compared to other emission abatement technologies.
- Consideration of potential dLUC, iLUC and sustainability impacts of bioenergy projects, and accounting for this element in the level of reward provided to bio-CCS projects given the potential for leakage to occur.

[2] Red cross mark = not included in scheme. Green check mark = included. Light green check mark = included under certain constraints. Please refer to the original table in the report for more information and constraints (Table 2.2, p. 41).

The term "negative emission" elicits the idea that technologies such as bio-CCS deliver a "double dividend" for emissions abatement. To an extent, this is correct based on the following two components:

1. The first benefit is the zero emission from the biomass part of the technology.
2. The second benefit is the negative emission from applying CCS to these source streams.

A wide range of literature, including integrated modelling assessments, has highlighted the benefits associated with the use of bio-CCS and other negative emission technologies (such as direct air capture). Benefits highlighted include:

- *Offsetting the emissions sources that are more difficult to abate*

  Because emissions are negative, they can be used to deliver deeper reductions in global GHG emissions whilst allowing more challenging emissions sources, such as those from aviation, to continue.
- *Reducing the overall cost of mitigation*

  As negative emission technologies can be used to offset emissions from sources that are more costly to abate.
- *Offsetting legacy or historical emissions*

  CO_2 can essentially be harvested from the atmosphere and transferred to long-term geological storage. This could allow for more rapid emission reductions to be made in future, thereby offsetting previous inaction or the effects of "over-shooting" previous emission reduction targets.
- *Putting a price ceiling on CO_2 emission reductions*

  As essentially negative emission technologies could be deployed to offset higher cost emission sources.
- *Involving more countries*

  In cases where countries have only limited domestic CO_2 abatement potential.

These benefits are additional to more conventional emission reduction technologies that can typically only reduce the rate by which CO_2 is added to

the atmosphere towards zero, eliminate it completely, or add carbon to the less permanent biological pool through afforestation, reforestation, avoided deforestation and other land management practices.

On this basis, it is conceivable that negative emission technologies such as bio-CCS deliver a "double dividend", and therefore could warrant additional subsidies or "double crediting" for each tonne of CO_2 captured and stored. Problematically, the benefit from substitution of fossil fuel for biomass is typically forgone under schemes, such as regional cap-and-trade programmes, as it is inherently included within the schemes' baselines. Consequently, only the negative quotient of emission reductions is recognised, which means that bio-CCS effectively competes on a per tCO_2 reduction basis with other mitigation options including substituting coal for biomass or applying CCS to fossil CO_2 sources. Project-based schemes can overcome this problem if the fuel substitution benefits are included within the baseline, although this is predicated on demonstrating that the counterfactual outcome would be a fossil fuel-fired plant. These issues create challenges for incentivising bio-CCS relative to other emission reduction technologies under GHG trading schemes.

In any case, such amendment would need to be accompanied by an appropriate approach for rewarding negative emissions. This could involve either:

- Allowing pooling so that net-back accounting could be applied at the portfolio level;
- Establishing some form of crediting system for negative emissions, either from the New Entrant Reserve (NER) of the EU ETS or a dedicated "negative emission" reserve or credit scheme; or
- Establishing rules and methodologies for bio-CCS to be treated as domestic or community offset projects (DOP or COP) under the EU ETS, or clarifying the scope for the use of JI under the EU Effort Sharing Decision.

Managing LUC effects

Concerns over dLUC and iLUC have been a major issue in the design of policies promoting the use of biomass derived fuels, principally liquid biofuels. Specific concerns relate to potential C-stock changes that can occur

as a result of dLUC/iLUC, such as:

- Clear-felling of forests,
- Conversion of natural forests to plantation forests to provide woody biomass for energy generation,
- The conversion of forest land to agricultural plantations for the growth of energy crops, and
- The conversion of other land to grow food in response to conversion of cropland for biomass production.

Paradoxically, these concerns are being augmented by the expansion of policies to promote the use of biomass and biofuels such as the EU ETS, the California LCFS and the EU RED/FQD. These policies are believed to be accelerating the rates at which potential suppliers – primarily in developing countries – are acting to clear natural forests to make way for high value energy crop cultivation, such as sugar cane, soya and palm oil for biofuels production. On the other hand, it is also possible that increased demand of wood leads to increased production, i.e. more generation of forest plantations building up a larger carbon inventory.

A major concern is the asymmetry between approaches to account for biofuel or biomass use, which typically apply comprehensive MRV requirements for GHG emissions accounting and employ a zero emission factor in order to avoid double-counting, versus accounting approaches applied to the agriculture, forestry and land use (AFOLU) sector, which tend to be far more patchy and mask emissions/C-stock changes arising from both dLUC and iLUC as a result of cultivating and harvesting energy crops and biomass. This is summarised graphically below in Figure 5 (Please see following page).

Two core challenges affect the robustness of measuring dLUC and iLUC effects in national GHG inventories with regards to land conversion:

1. *Lack of data*

This hampers effective tracking of land conversion over time. An example is that where Tier 1 methods are employed to estimate C-stock changes due to land conversion, a default assumption is made that biomass C-stocks stay the same, even though a land conversion is recorded. This generally applies because the previous use of the land is unknown/unrecorded.

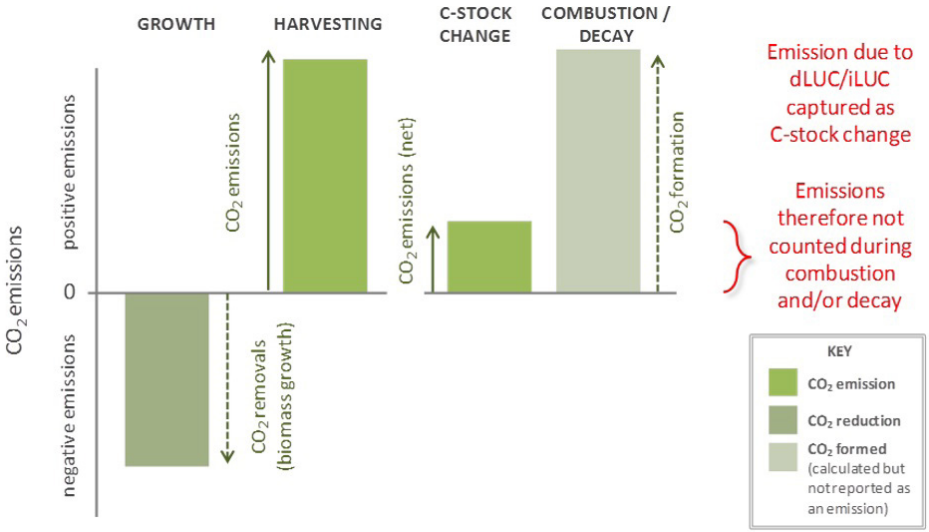

Figure 5, GHG accounting and land use change effects

2. Reporting requirements

In this case land management activities affecting large tracts of land go unreported. This is particularly acute for forest management activities, which could potentially lead to conversion of natural forest to plantation forest with less carbon without triggering a land use change. Other situations would include more intensive forest plantations with more carbon in soil and growing stock, also without triggering land use change and thus leaving this carbon accumulation unaccounted for. This would be exacerbated by reporting at lower Tiers.

These effects can apply in combination, where both poor data and a lack of reporting results in land conversions going completely unrecorded. The impacts of such challenges for dLUC and iLUC in biomass and biofuels policy design can be summarised as two types:

- *Cross-sector impacts*

Within a single country, where accounting for use of biomass and biofuels in e.g. energy or transport sectors of a country's GHG inventory leads to CO_2 emissions totals of zero, whilst the LULUCF (Land Use, Land Use Change and Forestry) or AFOLU sector of the GHG inventory does not appropriately record

C-stock changes caused by dLUC/iLUC, especially where these changes can be linked to the benefits achievable in the energy or transport sectors.

- *Cross-border impacts*

This is similar to cross-sector impacts, although in this case a national GHG inventory may effectively capture the LUC changes occurring within the national jurisdiction, but not where biomass/biofuels are imported from other countries, especially if the supplier countries have less stringent approaches to LULUCF/AFOLU accounting and reporting.

In either case, the asymmetry of approaches to reporting in the different parts of the inventory can lead to leakage, where support measures are applied to biomass and biofuels as zero emission technologies, especially as these potentially drive further land use changes. Two approaches have been adopted in bioenergy policies and GHG accounting rules at national and regional levels to address these issues, involving either:

- *Quantitative approaches*

Quantitative approaches involve setting requirements to include all upstream GHG emissions arising from growth, harvesting, LUC, processing and transport in the emission factor or GHG intensity calculated for a particular bioenergy product. This allows full life-cycle GHG accounting to be included in the emission factor applied to biomass combustion, so as to avoid perverse outcomes and leakage.

- *Qualitative approaches*

As an alternative to requiring full life-cycle GHG emissions accounting, restrictions on certain types of biomass products may be imposed by scheme operators based on the prior assessment of suitable products, or the use of national or international standards for biomass production.

In practice, both types of approaches may be selectively applied under a particular scheme, with restrictions being imposed on certain bioenergy products that fail to meet a certain life-cycle GHG threshold. It is also useful to note that qualitative approaches are often applied in conjunction with efforts to manage sustainability aspects of bioenergy production outside of the GHG emission effects.

The assumption that the combustion or decay of biomass leads to zero

emissions provides the basis for calculating negative emissions for bio-CCS, when such sources are captured and stored. However, the zero emission assumption is predicated on the growth and harvesting of biomass being in equilibrium, which is not necessarily always the case. Significant controversy has arisen regarding the promotion of biofuels in jurisdictions such as the US and EU, and the effects of energy crop cultivation on land degradation and the loss of C-stocks as a result of dLUC and iLUC. Assessing the extent to which this is occurring and being accounted for is dependent on establishing a robust monitoring system for LULUCF and REDD (Reducing Emissions from Deforestation and Forest Degradation) activities, although at present these are generally patchy and poorly implemented across many parts of the world, especially in developing countries. Consequently, bioenergy can be imported into regulated jurisdictions, and GHG benefits accrued upon its use (e.g. under the EU ETS), absent of consideration of the dLUC and iLUC effects and associated GHG emissions occurring upstream in the fuel supply chain.

In order to tackle this issue, policies such as LCFSs include detailed GHG accounting rules for calculating the upstream emissions from biomass growth, harvesting, transport, processing and, to some extent, dLUC/iLUC effects, which are then taken into account in the emissions at the point of use. Such quantitative approaches – although not without controversy – do set out to address the issues presented by inadequate LULUCF and REDD monitoring and reporting around the world.

On the other hand, regional cap-and-trade programmes aimed at regulating emissions in electricity and heat production do not include such considerations. The clear exception is the California ETS, which applies qualitative approaches to limit the application of a zero emission factor to only a few specific biomass types. Further, the EU has clarified the sustainability requirements for biomass use in the EU ETS by aligning it with the EU RED, including requirements to show compliance with voluntary sustainability schemes to demonstrate good practice. The US has considered the scope for introducing measures to take account of the upstream effects of biomass use, although it has not yet implemented such measures. Little information is available regarding measures to restrict biomass under the Australia CPM.

Expert Review Comments

Five reviewers from engineering, research and policy organisations took part in the expert review of the draft report and submitted useful comments. In general, the reviewers stated that the report provided a good description of how various policies take bio-CCS into account and they acknowledged the complexity of the area the study covers. The main suggestions included improvement of the figures showing CO_2 emissions accounting, addition of references, restructuring of some chapters, and removal of the overview on biomass energy to the appendix. Carbon Counts addressed these issues in the final report.

Interestingly, some comments asked for additional background information, whereas others suggested removal of this information. The contractor tried to find the right balance in the final version of the report. Some reviewers requested the report should draw stronger conclusions and provide recommendations for policy makers, i.e. answering what the best incentive mechanism for bio-CCS is. As this was beyond the scope of this study and because IEAGHG wants to remain unbiased and "non-prescriptive" in terms of policies, Carbon Counts did not consider those requests.

Conclusions

Discussions regarding support measures for bio-CCS should include consideration of potential approaches to address GHG emissions from dLUC and iLUC and other sustainability concerns, in addition to the assurance of CO2 storage integrity. On the other hand, in making such considerations of the emissions from the biomass supply chain, it is important to be mindful of the parity of treatment of biomass fuels compared to fossil fuels, which do not need to account for upstream emissions in their supply chain. The scope for opening up this broader discussion is likely to initiate a complex political process. Experiences in Europe in implementing Article 7(a)(5) of the EU FQD (relating to the calculation of life cycle GHG emissions from fossil fuels), which continues to be debated in Brussels four years after adoption of the Directive, suggests the challenges of such a discussion could be considerable. Potential issues under World Trade Organisation rules may also need to be taken into account.

In terms of the design of policies to support bio-CCS, the study presents two potential schools of thought:

1. The centrally planned view, which would take the view that the benefits of bio-CCS need to be prioritised, whilst also phasing out fossil fuels. On this basis, bio-CCS should be given additional incentives compared to biomass or CCS on fossil CO_2 sources;
2. The economic purist view that carbon markets can drive innovation, and that ultimately bio-CCS would become deployed as and when only the most costly emission sources remain to be tackled. Moreover, the latter school of thought suggests the existence of negative emission technologies allows policy makers to be more ambitious in establishing GHG emission reduction targets.

Both viewpoints will need to be considered in discussions regarding the design of policy measures to support bio-CCS and other negative emission technologies.

Recommendations

As IEAGHG is not policy-prescriptive, we encourage related policy-orientated organisations to make use of the relevant information in this report and develop it into recommendations for policy makers. This should particularly include the formulation of suitable incentives mechanism for bio-CCS. This study also does not cover certain issues, such as the timeframe on which negative emissions realise and the question whether all forms of bio-CCS should be promoted equally and over other GHG mitigation measures. In addition, further work needs to investigate if and when biogenic CO_2 should be accounted for and define sustainability criteria for bio-CCS.

IEAGHG should track the developments in this area by continuing its activities and participation, such as in the EU Bio-CCS Joint Task Force. This includes following up with the on-going work around the California ETS and LCFS, as the regulators are currently developing a quantification methodology for CCS.

List of IEAGHG Technical Reviews 2014

Technical Review Number	Title	Date Published
2014-TR1	Horizontal Scanning (Confidential)	09/07/2014
2014-TR2	IEAGHG 2013 RCSP Peer Review Summary	20/05/2014
2014-TR3	*Report Undergoing*	*N/A*
2014-TR4	Emerging Capture Technologies	23/12/2014

List of IEAGHG Information Papers 2014

Information Paper Number	Title	Date Published
2014-IP1	IEA 65th Working Party on Fossil Fuels (Confidential)	06/01/2014
2014-IP2	Carbon Capture Technology Could be Vital for Climate Targets	14/01/2014
2014-IP3	Final Report from COP-19 Warsaw	06/03/2014
2014-IP4	Recent Biomass Related Developments	06/03/2014
2014-IP5	New IEA Industry Initiative (Confidential)	28/03/2014
2014-IP6	Octavius 'International Workshop on Emissions from Post-Combustion CO_2 Capture Processes'	15/05/2014
2014-IP7	Pilot Plant Trial of Oxy-combustion at a Cement Plant	30/05/2014
2014-IP8	The Added Benefit Greenhouse Gas Mitigation has in Reducing Air Pollution	26/06/2014
2014-IP9	Global Institute Europe and Middle East Members Meeting (Confidential)	27/06/2014
2014-IP10	Looking Beyond Demonstration for Oxyfuel Combustion Coal Fired Power Plant	27/06/2014
2014-IP11	Soil Organic Carbon Sequestration	08/07/2014
2014-IP12	IEA Meetings in China (Confidential)	09/07/2014
2014-IP13	Record Electricity Generation from Renewables in Germany	24/07/2014

PROJECT OVERVIEW 2014

Information Paper Number	Title	Date Published
2014-IP14	Guangdong Province China: CCUS and Carbon Trading Initiatives	24/07/2014
2014-IP15	3rd International Conference on Chemical Looping	25/09/2014
2014-IP16	UN Climate Summit - Ban Ki-moon Final Summary	30/09/2014
2014-IP17	Black carbon – a Double-Edged Sword?	31/10/2014
2014-IP18	GHGT-12 Conference	04/11/2014
2014-IP19	Report on London Convention Meeting LC-36 and LP-8	06/11/2014
2014-IP20	Communicating Climate Science	06/11/2014
2014-IP21	NGO and Media Response to IPCC AR5 Summary Report	7/11/2014
2014-IP22	IPCC 5th Assessment Report and CCS	11/11/2014
2014-IP23	US-China Joint Announcement on Climate Change and Clean Energy Cooperation	14/11/214
2014-IP24	IEA World Outlook 2014 – Executive Summary	19/11/2014
2014-IP25	Emissions Gap Report	28/11/2014
2014-IP26	COP-20 Lima	05/01/2014
2014-IP27	The Trouble with Abandoned Wells	23/12/2014
2014-IP28	Orbiting Carbon Observatory	23/12/2014
2014-IP29	67th Meeting of Working Party on Fossil Fuels (Confidential)	23/12/2014

Evaluating technology options to mitigate greenhouse gas emissions

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