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Evaluating technology options to mitigate greenhouse gas emissions

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Date Published: April 2017
Review compiled and designed by Becky Kemp

Front & Back Cover Images

- Delegates at the 4th CCS Cost Network
- Lulworth Crumple - Site vist for the Risk Management Network and Environmental Research Network Combined Meeting
- Delegates at Bridport Sands - Site vist for the Risk Management Network and Environmental Research Network Combined Meeting
- St Catharine's College Cambridge - Location of the 2015 Social Research Network Meeting

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 continues the successful series of the Overview Books which started at the beginning of 2011. It draws together the overviews and executive summaries written by IEAGHG over the course of 2016, 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.

IEAGHG Technical Reviews and Information Papers 2016

Technical Reviews

- 2016-TR1 Evaluation of Barriers to National CO_2 Geological Storage Assessments
- 2016-TR2 Internationals Workshop on Offshore Geological CO_2 Storage
- 2016-TR3 Review of GHG Accounting Rules for CCS
- 2016-TR4 Review of Project Permits under the London Protocol – An Assessment of the Proposed P18-4 CO_2 Storage Site
- 2016-TR5 (CONFIDENTIAL) Pulp & Paper Industry - Papers - Results Overview
- 2016-TR6 National Storage CO_2 Assessment Guidance

Information Papers

- 2016-IP1; Impurities in the CO_2 Stream: Effect on the Storage Complex & Well Materials
- 2016-IP2; 2nd International Forum on Recent Developments of CCS – the Impact of Impurities on the Whole CCS Chain from Capture to Transport and Storage
- 2016-IP3; CERT TCP Seminar (CONFIDENTIAL)
- 2016-IP4; Developments in Renewable Methanol Production
- 2016-IP5; PRESS RELEASE: Decoupling of Global Emissions and Economic Growth Confirmed
- 2016-IP6; A new debate on Increases in Methane Emissions and Terrestrial Carbon Uptake
- 2016-IP7; Update on CO_2 Emissions and Global Temperatures
- 2016-IP8; Turn Down the Heat: Confronting the New Climate Normal
- 2016-IP9; The Air Pollution/Climate Change Conundrum
- 2016-IP10; Annual Science Update 2015
- 2016-IP11; GBEP and IEA Bioenergy Publish Summary of their Webinar on Positive Bioenergy and Water Relationships
- 2016-IP12; Annual Greenhouse Gas Index for 2015
- 2016-IP13; Comparing the Costs of Electricity Supply
- 2016-IP14; Climate Targets for Agriculture in a post COP21 World
- 2016-IP15; Hitting New Highs and Lows and Achieving Goals, News from the USA

- 2016-IP16; The first MRV plan approved by the US EPA for Greenhouse Gas Reporting of CO_2 Geological Storage is for a CO_2-EOR Operation
- 2016-IP17; Bloomberg NEO 2016, Powering a Changing World
- 2016-IP18; Degassing Volcanic Lakes
- 2016-IP19; Study Report on CCS Options in Norway Released
- 2016-IP20; 70th Meeting of the Working Party on Fossil Fuels, June 2016 (CONFIDENTIAL)
- 2016-IP21; Lessons Learned from UK CCS Programmes, 2008 – 2015
- 2016-IP22; Leeds City Hydrogen Project: A new opportunity for CCS in the Heat Market
- 2016-IP23; New Trilateral Agreement on GHG Mitigation
- 2016-IP24; World Energy Outlook 2016 Special Report Energy and Air Pollution
- 2016-IP25; CO_2 Emissions in 2015 65th BP Statistical Review
- 2016-IP26; Health and Climate Change Issues with Maritime Shipping
- 2016-IP27; IChemE Report Future of CCS
- 2016-IP28; International Report Confirms 2015 Earths Hottest Year on Record
- 2016-IP29; Energy Technology Perspectives 2016 - Towards Sustainable Urban Energy Systems
- 2016-IP30; IPCC Outlines its Plans for New Reports
- 2016-IP31; Chinese CO_2 Emissions Have Peaked?
- 2016-IP32; US DOE 2016 Carbon Storage Meeting
- 2016-IP33; New UK Report from the Parliamentary Advisory Group on Carbon Capture and Storage
- 2016-IP34; Technical Lessons Learned from the UK CCS Commercialisation Programme (2012-2015)
- 2016-IP35; London Convention Meeting LC-38 / LP-11 (2016)
- 2016-IP36; Reducing the Cost of CCS
- 2016-IP37; Emissions from Aviation the Next Challenge?
- 2016-IP38; Small Nuclear Reactors
- 2016-IP39; Will Cities Lead the Way on GHG reduction?
- 2016-IP40; Climate Scientists say 1.5°C is inevitable
- 2016-IP41; 1.5°C Degrees – Meeting the Challenges of the Paris Agreement
- 2016-IP42; Latest Information on Global Methane Emissions
- 2016-IP43; Waste Power CCU in Japan
- 2016-IP44; WMO Greenhouse Gas Bulletin
- 2016-IP45; The Stern Report 10 Years On

- 2016-IP46; IEA Medium-Term Renewable Energy Market Report 2016
- 2016-IP47; A Global Zero Carbon Roadmap
- 2016-IP48; BECCS Deployment in the UK
- 2016-IP49; Artic Warming Predicted to Have Catastrophic Consequences Around The Globe
- 2016-IP50;Update on Business Opportunities in CO_2 utilisation
- 2016-IP51; 20 Years of Carbon Capture and Storage: A New IEA Report Highlights Progress but Stresses the Need to Redouble Efforts
- 2016-IP52; MiReCOL Close-Out Meeting
- 2016-IP53; 5th Conference on Carbon Dioxide as Feedstock for Fuels, Chemistry and Polymers
- 2016-IP54; US Announces New Awards of $44 Million for Development of CO_2 Storage Projects under the CarbonSAFE Initiative
- 2016-IP55;The ICEF CO_2 Utilisation Road Map
- 2016-IP56; Feasibility Study for Full Scale CCS in Norway

2016-07 EVALUATION OF PROCESS CONTROL STRATEGIES FOR NORMAL, FLEXIBLE AND UPSET OPERATION CONDITIONS OF CO_2 POST COMBUSTION CAPTURE

Key Messages

- Electricity market models suggest power plants with carbon capture and storage (CCS) will need to adopt flexible operation in the future. Appropriate control strategies will be necessary to ensure their ability to operate in such a market and their profitability.
- An evaluation of process control strategies for normal, flexible and upset conditions of CO_2 post-combustion capture (PCC) processes (considered the leading technology for deployment in the power sector) based on amine scrubbing has been undertaken.
- This work used a high-fidelity modelling tool that can describe the dynamic operation of the CCS chain to investigate 3 different process control strategies for both pulverised coal (PCPP) and combined cycle gas turbine power plants (CCGT), with PCC.
- The power plant modelling showed the performance of the CO_2 capture unit can be maintained even during periods of significant load fluctuation, using industry standard control techniques, thus avoiding other more expensive solutions.
- Manipulating the solvent flow rate generally provided better control of the CO_2 capture rate than varying the solvent lean loading, as it results in less oscillation, i.e. more constant hydraulic conditions in the CO_2 capture plant.
- For the PCPP, a control strategy that manipulates the CO_2 capture rate by varying the solvent flowrate is the more profitable option. For the CCGT, all strategies provided the same benefit, due to the dilute nature of the CCGT flue gas.
- The CO_2 capture plant was able to continue operation for a limited amount of time, i.e. 3.5-5 hours, in case of hazardous events, such as injection shutdown or loss of compression.
- In conclusion, this study has shown that simple and well-tuned control strategies can maintain critical operational parameters of a CO_2 capture

plant.

- The authors recommend further work in this area could include development of advanced control strategies and fine-tuning of the existing modelling and simulation tools. This is not something IEAGHG would take up at this time but could be pursued by model developers and academia. In addition, IEAGHG recommends evaluation of faster power plant ramp up rates and other systems that provide more flexibility and easier integration into the host plant.

Background to the Study

It is important for power plants to be able to operate flexibly to respond to changes in consumer demand for electricity. Flexibility is also becoming increasingly important due to the greater use of other low carbon generation technologies, particularly variable renewable generators. The issue of operating flexibility of power plants with carbon capture and storage (CCS) has been the subject of a previous technical study by IEAGHG[1]. This report contributes to the knowledge base on flexible operation of power plants with CO_2 capture by focusing on process control issues.

A team from Imperial College London and Process Systems Enterprise has undertaken this work for IEAGHG.

The study focuses on performing an evaluation of process control strategies for normal, flexible and upset operation conditions of CO_2 post-combustion capture (PCC) processes based on solvent scrubbing. PCC is currently the leading near-term technology for large-scale deployment of CO_2 capture in the power generation sector.

Scope of Work

The aim of this study is to develop process control strategies, to select appropriate control variables for a PCC process, and design efficient control structures for operation of a PCC process with minimum energy requirements for coal and natural gas fired power plants.

[1] Operating flexibility of power plants with CCS, IEAGHG report 2012/6, June 2012

To this end, the scope of work is:

1. Identify the different operating regions that are relevant to the flexible operation of coal and natural gas fired power plants.
2. Identify sets of controlled and manipulated variables that are commonly used for PCC processes.
3. Develop control strategies for feasible and economically efficient operation of PCC processes under normal and part-load operating conditions.
4. Evaluate the performance of coal fired and natural gas fired power plants with PCC for each of the proposed process control strategies.
5. Evaluate the effect of different process control strategies on the economics of PCC processes.
6. Evaluate the impacts of upset conditions on the full CCS chain.

Findings of the Study

Operating Regimes

Electricity market models (MOSSI and UCCO) were used to produce a set of scenarios for the future operation of CCS plants. A model was then used to identify the dispatch pattern of individual generating units in the period of 2030s to 2050s. Expansion of nuclear and wind capacity during this period forces thermal plants to adopt more dynamic operating patterns, with reduced running hours, more stop/start cycles and greater ramping rates.
Three coal CCS units were studied, with low, mid and high positions within the merit order. Figure 1 shows their operating profiles in the 2030s, 2040s and 2050s. The increase in dynamic operation is evident as time progresses, with more frequent modulation between maximum and minimum stable operation and more time spent not operating. This emphasises the importance of control strategies to cope with changing plant loads.

Similar patterns were observed for gas CCS plants, although they start with a more dynamic operating pattern in the 2040s, when gas CCS plants start to be introduced into the electricity system, due to their being priced as mid-merit as opposed to base-load capacity.

The analysis on the next page shows that coal and natural gas fired power plants will need to be ready for increasing demands of flexibility. These

operating scenarios were used to inform the dynamic operating scenarios employed in subsequent sections of this report. Finally, the implication is that emphasis must be placed upon optimising efficiency and profitability during two-shift operations. The remainder of this study focuses on this assumption.

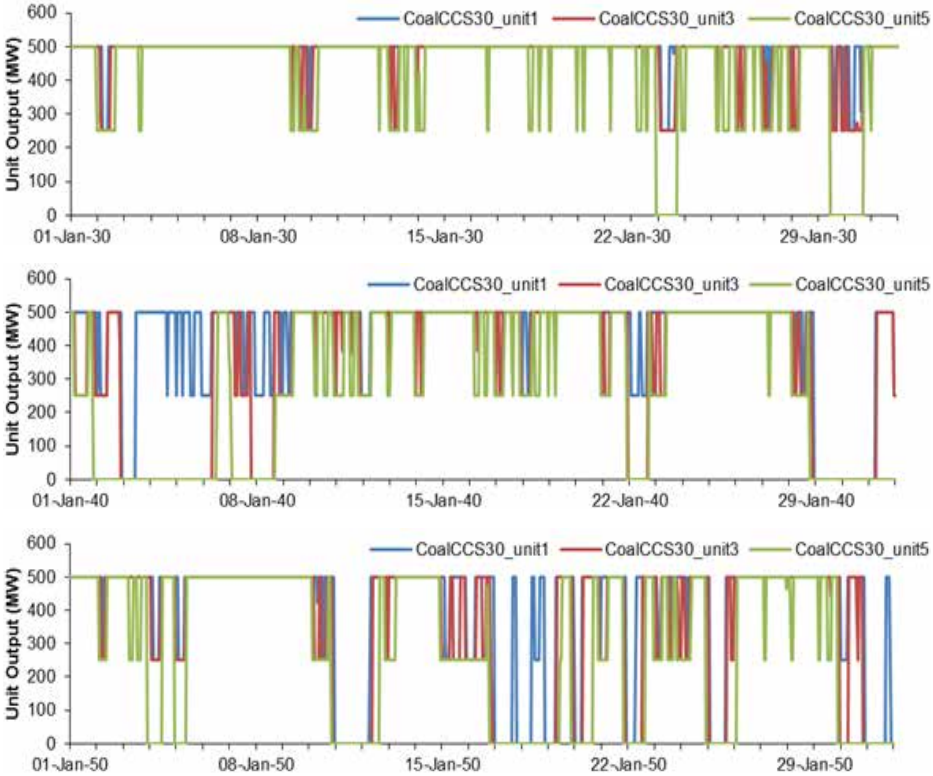


Figure 1 - Operating profiles for three coal CCS units in the 2030s, 2040s and 2050s

Control Strategies

Reference Plant Models

The reference case models of power plants with CCS for this study were developed using the gCCS toolkit from Process Systems Enterprise. This toolkit includes high-fidelity models that describe the dynamic operation of all the stages of the CCS chain: power generation, post-combustion carbon capture, compression, transportation, and storage.

The reference case supercritical pulverised coal power plant (PCPP) developed for this project has a net electricity output of 779 MW at 100% load without CO_2 capture. Adding an amine-based post combustion capture plant reduces the net output to 621 MW and captures 90% of the CO_2 in the flue gas.

The reference model for the combined-cycle natural gas fired power plant (CCGT) has a net electricity output of 740 MW at 100% load without capture. Capturing 90% of the CO_2 reduces the net output to 643 MW.

Control Strategies

The control strategies proposed in this work consist of combinations of controlled and manipulated variables in the carbon capture plant, based on a review of the literature on PCC process control, and on the feedback received from industrial operators and CCS technology providers. Most approaches to PCC process control suggest that the percentage of CO_2 capture should remain approximately constant throughout the power plant operation. This study follows this principle by considering two alternative strategies for controlling the CO_2 capture rate. Additionally, a strategy in which the control loops are dynamically switched during the change in power plant load is considered. The control strategies can be summarised as:

- Control strategy 1: the amount of CO_2 captured is controlled by varying the lean solvent flowrate. The reboiler temperature is kept constant by varying the steam flowrate.
- Control strategy 2: the amount of CO_2 capture is controlled by varying the solvent lean loading. The lean solvent loading is controlled to the required value by varying the reboiler temperature.
- Control strategy 3: dynamic switching between strategies 1 and 2.

Performance of Control Strategies

The performance of PCPP and CCGT plants was modelled for a scenario involving full load operation during the daytime and turndown to 60% capacity factor overnight. Figure 2 (on the following page) shows load factors and electricity prices that are assumed in this study.

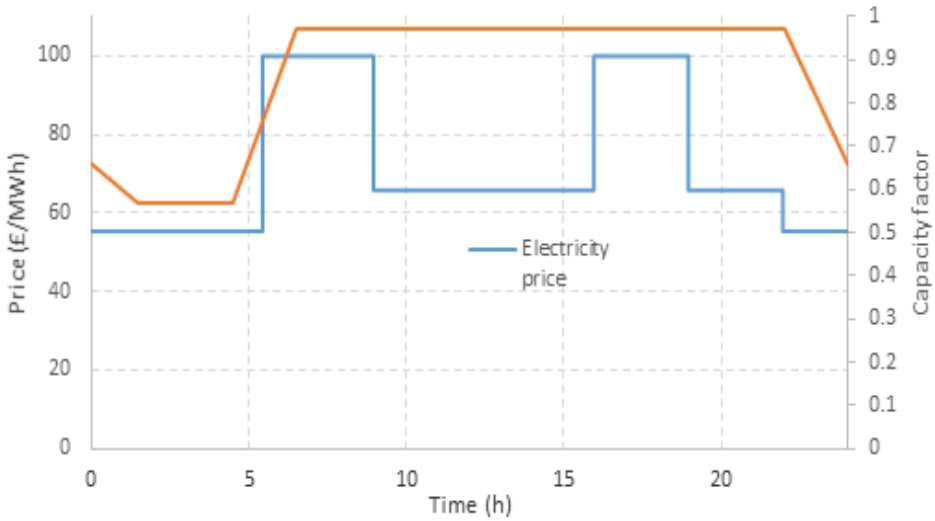


Figure 2 - Variation of electricity prices throughout the day, and typical operation profile for two-shifting power plant

Figure 3 to Figure 6 present the behaviour of some key variables for the PCPP. It was observed that employing Control Strategy 2 resulted in a greater degree of oscillatory behaviour and was difficult to tune. Ultimately, Control Strategy 1 was, in this study, easier to employ and better control was observed. In all cases, it is notable that, following the disturbance, i.e., power plant ramping up or down, the CCS plant returns to steady state relatively quickly. (Please see following 2 pages).

The duration of the relaxation time and the amplitude of the oscillations are however a strong function of the control strategy chosen. Strategy 1 appears to provide the most stable operation of the power plant, Strategy 2 follows, but with an appreciably longer relaxation time, and finally Strategy 3 has a relatively short relaxation time but comparatively greater amplitude of oscillation from the set point.

The performance of the CCGT plants follows similar trends but in general the magnitudes of the variations are lower (see full report for figures).

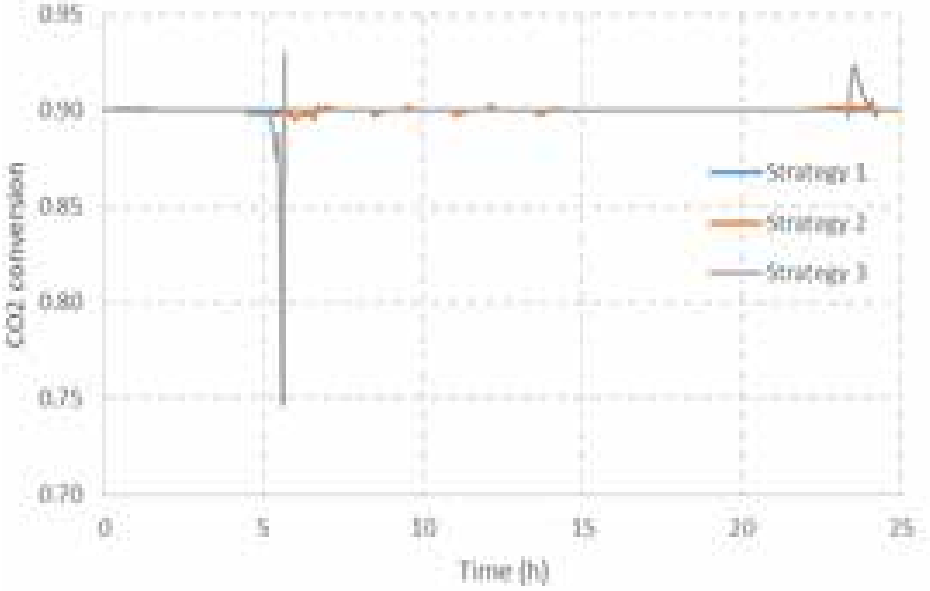


Figure 3 - CO_2 Capture

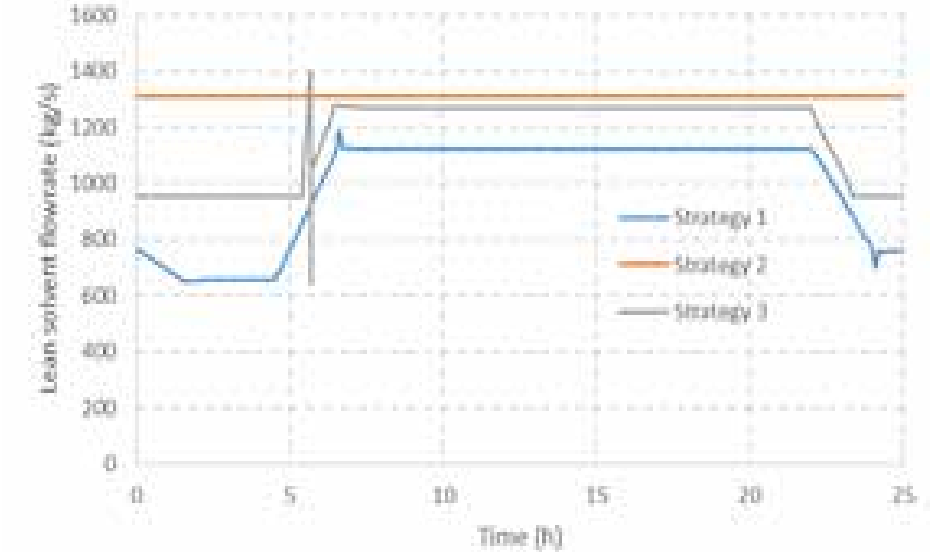


Figure 4 - Lean Solvent Flowrate

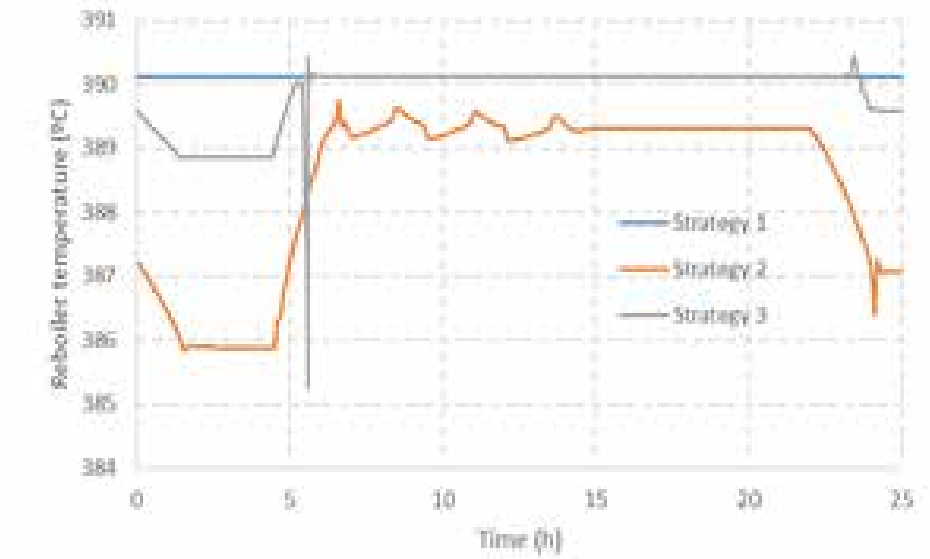


Figure 5 - Reboiler Temperature

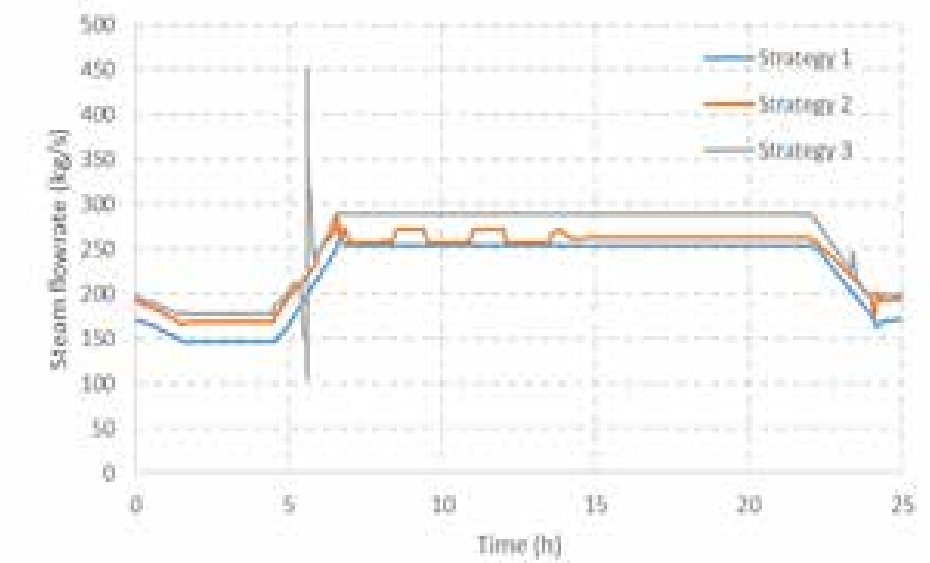


Figure 6 - Steam Flowrate

Economic Evaluation of Control Strategies

The short run marginal operating costs and electricity revenues of the plants were calculated to determine their "profitability" over the course of a day. The marginal operating cost is assumed to consist of the fuel cost, the cost associated with emitting CO_2 and the cost of cooling water utilities. No fixed costs are considered, as they will be same for all of the cases. The electricity price is expected to vary during the course of a day. The plant was assumed to operate in a two-shifting mode, with the electricity prices shown in Figure 2.

The economic assessment found that for PCPP Control Strategy 1 is more profitable than either strategy 2 or 3. The analysis for CCGT showed all control strategies to provide the same profit. This is due to the dilute nature of the exhaust gas and the resulting greater solvent circulation rate relative to the PCPP case. Figure 7 and Figure 8 show the profits for both plants during a given day.

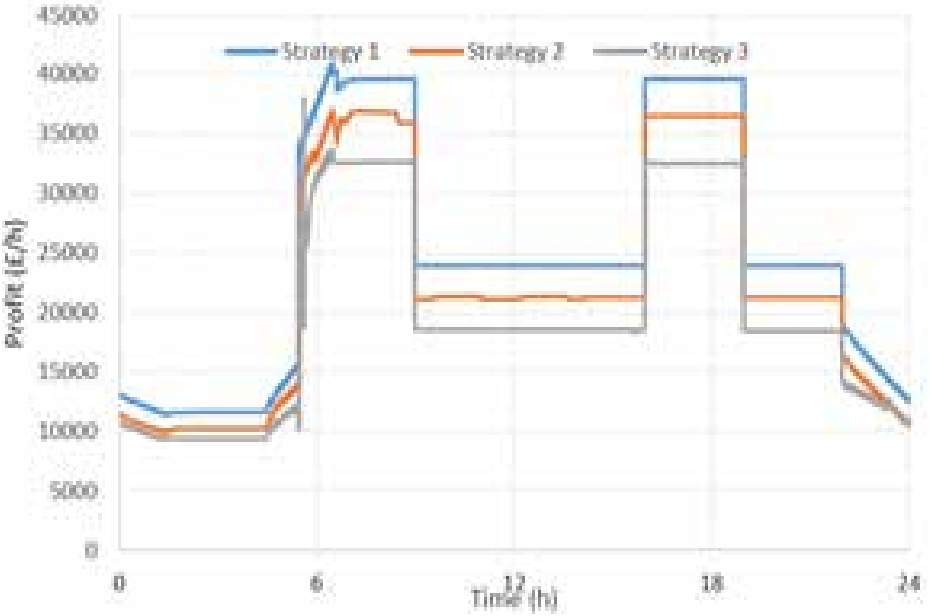


Figure 7 - Profit of PCPP

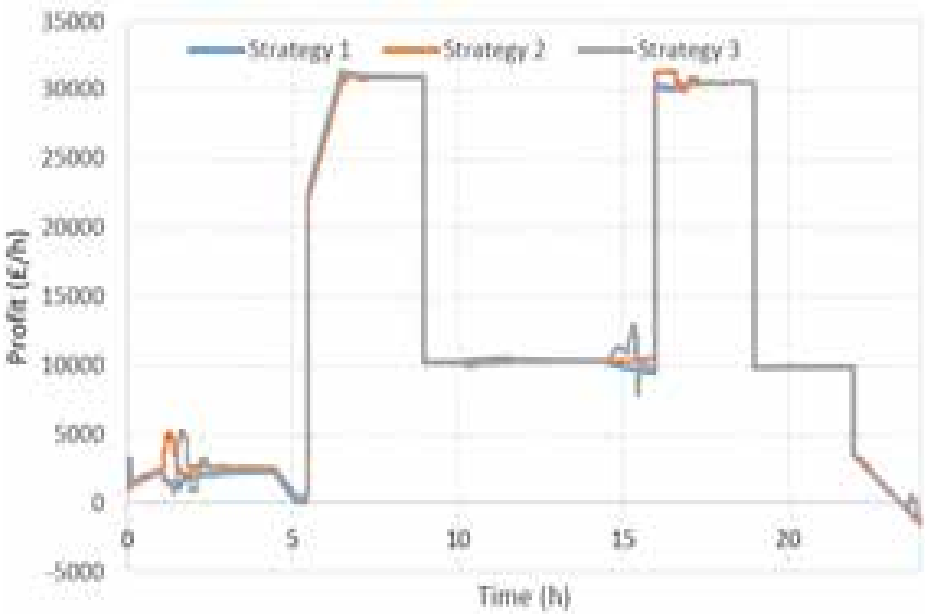


Figure 8 - Profit of CCGT

Outages in the CCS Chain

The study identifies and analyses potential trip, outage and shutdown scenarios and describes the effects on stakeholders up and down the CCS chain. It demonstrates how the process can be safely managed in the event of a system failure. To assess the impact of these hazards, a CCS chain including a coal-based post-combustion capture plant, pipeline transmission of CO_2 and geological storage was simulated. The system was assumed to include a capture and compression plant, a 20km onshore CO_2 pipeline followed by a 200km offsite pipeline, and 4 injection wells. It should be noted that only the downstream part of the CCS chain was considered. Further work will be needed to assess the impacts on the capture plant of upstream outages in the power plant, FGD etc.

The study considered the following scenarios:

- Unplanned shutdown at injection site
- Loss of upstream compression

Unplanned Shutdown at Injection Site

When the injection site is shut down, the pressure within the pipeline and the CO_2 compressor speed will begin to increase. The capture plant could continue to operate as normal for slightly less than 3.5 hours until the compressor reaches its maximum speed, after which the capture plant would have to be shut down or begin venting CO_2.

Loss of Upstream CO_2 Compression

The failure of the compression facility will have the following two significant effects:

1. It will cause the pipeline pressure to drop, leading to loss of injection capability and in due course probably a trip of the injection well.
2. The loss of the ability to remove CO_2 from the capture process, leading to either a shutdown of the capture plant and consequent shutdown of the power plant or initiation of CO_2 venting.

As the first situation will presumably occur very quickly following the loss of compression, this was not included in the scenario.

In order to simulate the loss of a compressor, the flow of inlet CO_2 supply to the pipeline was dropped to zero in a step change. This intends to represent the most drastic situation. Figure 5 shows that it takes over 4 hours for the CO_2 supply at the injection site to reduce to 50% of the design flow, following a complete loss of supply.

During normal operation, it is expected that a CO_2 pipeline would operate above the critical pressure of CO_2, which is 73.8 bar, although the location of the critical point is a function of the composition of the stream, with the critical point of an impure stream typically being at a higher pressure than that of pure CO_2. In the event of a loss of inlet compression, there is the potential for two-phase flow to occur if the pressure of the CO_2 stream drops below the critical pressure. Based on this simulation, it is unlikely that this will occur within 5 hours of loss of supply, as shown in Figure 6 (overleaf).

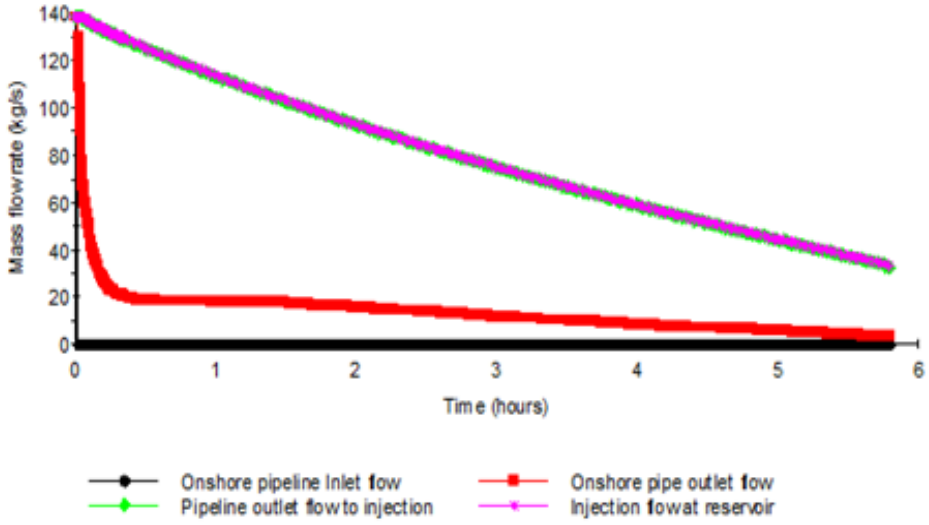


Figure 5 - Mass flowrates at locations in the CO2 transmission and injection sub-systems

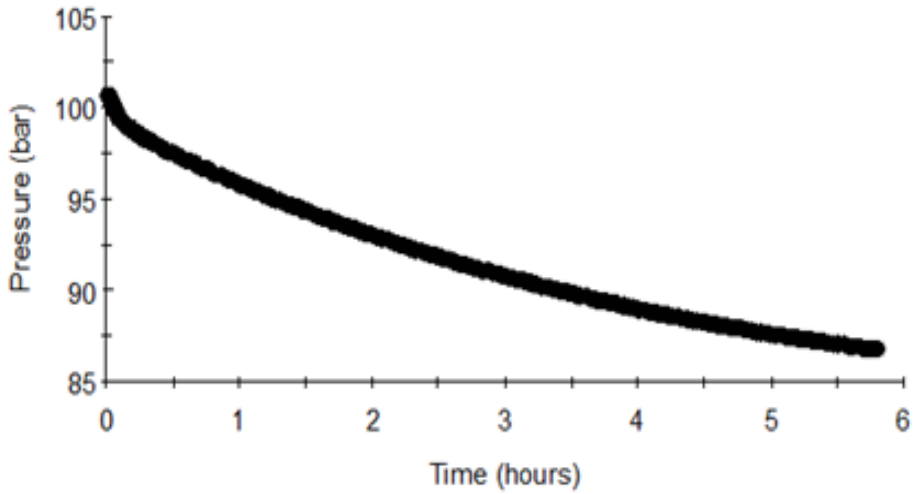


Figure 6 - Minimum pressure in the transmission system

Expert Review Comments

Comments on the draft report were received from reviewers working in the field of control and dynamic performance of capture plants. The contribution of all reviewers is gratefully acknowledged.

The reviewers thought the report was in most respects of a high standard. A small number of particular areas of concern were identified. The contractor has provided responses to the reviewers' comments and made appropriate modifications to the report.

Conclusions

Energy market models support the notion that power plants will need to adopt flexible operation patterns in the future. Fluctuations between full and part-load operation will become more frequent during the day, and therefore an appropriate control strategy is necessary to ensure the operability and profitability of the process.

Several control strategies have been proposed in the literature. There is a need to design conceptual strategies and accurately predict their behaviour under flexible operating conditions using high-fidelity modelling tools. This study has made use of such a tool, gCCS.

The study has shown that with an appropriate and well-tuned control strategy it is possible to maintain critical parameters such as the CO_2 capture rate at the desired set-point, even during periods of significant fluctuation in the power plant load.

Using an appropriate control strategy, even if based in simple and well established control techniques, such as PID, avoids the need for more risky solutions such as adding solvent storage tanks to the process.

From a control point of view, using the solvent flowrate as manipulated variable to control the CO_2 capture rate is a better option than manipulating the solvent lean loading, which has more oscillatory behaviour. Maintaining a constant solvent flow rate results in more constant hydraulic conditions in the absorber and stripper columns.

The choice of control strategy can affect the economics of the plant. For the PCPP, a control strategy that manipulates the CO_2 capture rate by varying the solvent flowrate is a more profitable option than a strategy using the solvent lean loading or a dynamic switching between the two. For CCGT, all strategies provided the same benefit, due to the dilute flue gas.

From a hazard management perspective, it was observed that the capacity of the compressor to add to pipeline pressure in the event of an outage at the injection site is a limiting element in the chain. Under the scenarios investigated here, the capture plant can operate for about 3.5-5 hours in case of injection shutdown or loss of compression.

Recommendations

The output from this report and a critical review of the gaps in the literature related to control of power plants with CCS resulted in the following recommendations from the authors for further research and technical studies:

- *Modelling and simulation aspects* – further developments in high-fidelity modelling and simulation tools to include accurate descriptions of all components in the CCS chain. Additionally, testing of the control strategies proposed in this work for different solvents in the post-combustion capture system.
- *Simultaneous process and control design* – development of appropriate algorithms for including process control design decisions at the process design stage.
- *Advanced process control techniques* – development of hierarchical model predictive control formulations for the integrated system, including power plant and capture plant, in order to optimise the performance and economics of the overall process.
- *Optimisation of control strategy switching* – follow-up to this work, where the schedule of dynamic switching between control strategies is determined by an optimisation problem where the costs and benefits of each strategy are encompassed in the formulation.

The previous points are not something that IEAGHG would take up at this time but could be pursued by model developers and academia. However, IEAGHG adds the following recommendations:

- It would be interesting to investigate cases that represent the impact of a changing energy sector on power plant ramp up rates.
- Other systems such as membranes should be considered due to their flexibility and "lack of integration" with the power plant.

2016-10 TECHNO-ECONOMIC EVALUATION OF RETROFITTING CCS IN A MARKET PULP MILL AND AN INTEGRATED PULP AND BOARD MILL

Key Messages

- The IEA Greenhouse Gas R&D Programme (IEAGHG) have been studying the performance and cost of integrating CO_2 Capture and Storage (CCS) into the energy intensive industries. To date, the programme has assessed the economics of deploying CCS in 5 different energy intensive industries. The present study extends this work to include the pulp and paper industry, with another study on the oil refining industry underway.
- The pulp and paper industry accounts for some 1.1% of the global CO_2 emissions. These emissions arise mainly from its recovery boiler, multi-fuel boiler and lime kiln. The majority of this CO_2 originates from the combustion of biomass, which renders it as carbon neutral if the biomass used as raw materials of the pulp production is grown and harvested in a sustainable manner. If the CO_2 emission from pulp and paper industry is captured and permanently stored, then this could be considered as a potential carbon sink. As such, the pulp and paper industry could be regarded as a low-hanging fruit for the early demonstration of both bio-CCS and industrial CCS.
- This study provides an assessment of the performance and costs of retrofitting CCS in a Nordic Kraft Pulp Mill and an Integrated Pulp and Board Mill. Different configurations of capturing CO_2 (90%) from the flue gases of the recovery boiler, multi-fuel boiler and lime kiln were examined. For the standalone pulp mill, the excess steam produced by the mill is sufficient to cover the additional demand from the CCS plant. For an integrated pulp and board mill, there is less excess steam available for the CCS plant, therefore the addition an auxiliary boiler is required.
- The retrofit of an amine based post-combustion CO_2 capture plant into a pulp mill increases the steam demand by 1 to 8 GJ/adt pulp, depending on the volume of the flue gas to be treated. This translates to a reduction in the amount of electricity exported to the grid by 0.1 – 1.0 MWh/adt pulp for the Kraft pulp mill, and by 0.1 – 0.5 MWh/adt pulp for an integrated pulp and board mill. This corresponds to between 6 and 80% reduction,

and between 10 and 72% reduction in the volume of electricity exported for the Kraft pulp mill and the integrated pulp and board mill respectively.

- The %CO_2 avoided could be in the range of 9 to 90% for the Kraft Pulp Mill and 9 to 73% for the Integrated Pulp and Board Mill (as compared to the corresponding Base Cases). If the emitted biogenic CO_2 is recognised as "carbon neutral" and the captured biogenic CO_2 as "carbon negative", then the %CO_2 avoided could be in the range of 310 to 2340%.
- The retrofit of CCS increases the levelised cost of pulp (LCOP) produced by the market (standalone) pulp mill in the range of 20 to 154 €/adt, and increases the LCOP produced by the integrated pulp and board mill in the range of 22 to 190 €/adt. This translates to a CO_2 avoided cost (CAC) between 62 and 92 €/t CO_2 for the pulp mill and between 82 and 92 €/t CO_2 for the integrated pulp and board mill.
- This study assessed the sensitivity of the cost if incentives to the renewable electricity credit, CO_2 taxes, and negative emissions credit are provided. It can be concluded that the most favourable route to encourage the pulp industry to deploy bio-CCS is by providing sufficient incentives for their negative emissions.

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEAGHG) has undertaken a series of studies evaluating the performance and cost of capturing CO_2 from different energy intensive industries.

The IPCC Fifth Assessment Report calls for solutions that can remove CO_2 from the atmosphere. The concept of sustainable Bioenergy and CO_2 Capture and Storage (Bio-CCS or BECCS) should enable a large scale removal of CO_2 from the atmosphere.

The pulp and paper industry is one of the energy intensive industries that could potentially demonstrate the deployment of both bio-CCS and industrial CCS applications simultaneously. The majority of the CO_2 emitted (around 75-100% of the total CO_2 emissions) from an integrated pulp and paper mills is classified as biogenic CO_2 emissions. If the source of the raw materials of the pulp mill is managed sustainably, these biogenic CO_2 emissions could be

considered as "CO_2 neutral". With CCS technology installed, "CO_2 negative" emissions could be realised.

IEA Greenhouse Gas R&D Programme in collaboration with VTT Technical Research Centre of Finland and ÅF-Consult Oy evaluated the performance and cost of retrofitting CO_2 capture and storage in a modern Finnish Kraft Pulp Mill (Base Case 1A) and Integrated Pulp and Board Mill (Base Case 1B).

This study presents the baseline information in understanding the performance and cost of retrofitting post-combustion CO_2 capture to a pulp mill or an integrated pulp and board mill.

Scope of Work

This study assessed two hypothetical reference mills situated in the west coast of Finland as a basis for evaluation.

The pulp mill (Base Case 1A) has an annual production of 800,000 adt of bleached softwood Kraft pulp (BSKP) which is sold as market pulp. The integrated pulp and board mill (Base Case 1B) has an annual production of 400,000 adt of board. This mill also consumes 60,000 adt/y of the softwood Kraft pulp that it produces, thus only 740,000 adt/y of BSKP is sold to the market.

This study aims to evaluate the performance and cost of retrofitting post-combustion CO_2 capture technology to the pulp mill and understand its implication on the mill's operation in terms of fuel balance and utility requirements (i.e. steam and electricity balance); and to the mill's financial performance.

Both reference cases were evaluated for different options of capturing CO_2 from the flue gases of the recovery boiler, multi-fuel boiler and lime kiln, or a combination of these. A total of twelve different cases were evaluated; six cases each for Base Case 1A and Base Case 1B as listed in Table 1 (overleaf).

Case description	Abbreviation	Case identification*	
		Market Pulp Mill	Integrated Pulp & Board Mill
CO_2 capture from flue gas of the recovery boiler only	REC	Case 2A-1	Case 2B-1^{CO2MP}
CO_2 capture from flue gas of the multi-fuel boiler only	MFB	Case 2A-2	Case 2B-2
CO_2 capture from flue gas of the lime kiln only	LK	Case 2A-3	Case 2B-3
CO_2 capture from flue gases of recovery boiler and multi-fuel boiler	REC + MFB	Case 2A-4	Case 2B-4^{CO2MP}
CO_2 capture from flue gases of recovery boiler and lime kiln	REC + LK	Case 2A-5	Case 2B-5^{CO2MP}
CO_2 capture from flue gases from recovery boiler, multi-fuel boiler and lime kiln	REC + MFB + LK	Case 2A-6^{MP}	Case 2B-6^{CO2MP}
*MP = medium pressure steam at 13.0 bar (a) is used to supply the additional steam required by the CO_2 capture plant. CO2MP = CO_2 compressors are driven by a back pressure steam turbine.			

Table 1: Case studies evaluated

Additionally, six different scenarios were assessed to determine the impact of the cost of CO_2 emissions (in the form of a CO_2 emission tax) and the credit from the incentives to the levelised cost of pulp (LCOP).

This covers incentives provided when recognising the biogenic emissions as CO_2 neutral or if captured as negative emissions. Similarly, the renewable electricity credit is also examined.

This study demonstrates the dynamics on how different financial incentives defined by the policy frameworks on CCS, renewable energy, and negative emissions could impact the levelised cost of the pulp.

Key Findings of the Study

In this work, the retrofit of post-combustion CO_2 capture process using MEA and a variant of a split flow configuration has been evaluated for two different reference mills:

- Base Case 1A – Market Kraft Pulp Mill
- Base Case 1B – Integrated Pulp and Board Mill

The performances of the entire pulp mill and the integrated pulp and board mill were evaluated to provide the detailed mass and energy balances of the different processes involved in the pulp (and board) production. The CO_2 capture and compression plant was assessed to determine the additional energy demand.

This section briefly describes the reference mills and the CO_2 capture and compression plant.

Reference Mills

The reference mills are assumed to have been built and commissioned in 2005. They are energy independent that produce significant amount of excess steam which are converted to electricity and exported to the grid. It is also assumed that the biomass (round wood - mainly consists of 50% pine and 50% spruce) used as raw materials has been harvested sustainably. Therefore, any electricity exported to the grid is considered as renewable energy. It should be noted that the mills evaluated in this study do not produce any district heating.

Figures 1 and 2 (please see full report for these figures due to their quality when downsized) present the simplified block flow diagram of the market pulp mill and the integrated pulp and board mill.

The battery limit of the reference mills include the wood handling yard, the fibre line which consists of a continuous cooking plant (digester), brown stock handling and two-stage oxygen delignification, chlorine-free bleaching (D_0-EOP-D_1-P), and pulp drying; and the chemical recovery line which include the black liquor evaporator, recovery boiler, re-causticizing unit and the lime kiln. Other auxiliary units within the battery limit includes a multi-fuel boiler, a bleach chemical preparation plant, air separation unit, white liquor oxidation plant, steam turbine island and wastewater treatment plant. For Base Case 1B, a board machine is included.

The pulp mills (Base Cases 1A and 1B) consume about 5.8 m^3 of wood/adt. The fibres are extracted from the wood in the cooking plant and further refined in the O_2 delignification plant to produce the brown stock or the raw pulp. The yield from the cooking plant is about 47%. The pulp is (then) bleached based on the D_0-EOP-D_1-P procedure achieving a target brightness of 88.5%. The

chemicals used in the bleaching process and the preparation of bleaching agents such as Nao, O_2, H_2O_2, $NaClO_3$ and H_2SO_4 are imported into the battery limit. The process water used by the pulp mill is ~16 m^3/adt. The amount of waste water treated is about ~18 m^3/adt.

Table 1 (below) summarizes the consumptions of the raw materials, chemicals and others. For Base Case 1B, the board machine imports unbleached and bleached softwood Kraft pulp (USKP and BSKP) from the pulp mill in addition to the heat and electricity it required. Also, it imports other pulps (i.e. Bleached Hardwood Kraft Pulp - BHKP and Chemi-Thermo Mechanical Pulp – CTMP), coating and fillers from outside the battery limit.

Tables 2 and 3 (please see pages 22 and 22) present the breakdown of the steam, electricity and fuel balance of both reference mills.

Fossil vs. Biogenic CO_2 Emissions

The total CO_2 emission from the reference mills is 2.1 million MTPY. This includes both the biogenic and fossil derived emissions (as shown in Table 4).

Both the recovery boiler and the multi-fuel boiler are fired with black liquor and hog fuel (barks), respectively. Thus, these emissions are classified as biogenic CO_2 emissions.

Raw Materials	Units*	Base Case 1A	Base Case 1B
Log (round wood)	[m^3/adt]	5.8	5.8
Bleached hardwood Kraft pulp (BHKP)	[kg/adt]	-	106.1
Chemi-thermo mechanical pulp (CTMP)	[kg/adt]	-	290.6
Filler	[kg/adt]	-	24.0
Coating	[kg/adt]	-	4.0
Chemicals	**Units***	**Base Case 1A**	**Base Case 1B**
NaOH	[kg/adt]	37.2	36.2
H_2O_2	[kg/adt]	7.4	7.0
$MgSO_4$	[kg/adt]	3.5	3.5
CaO	[kg/adt]	5.2	5.2
Chemicals	**Units***	**Base Case 1A**	**Base Case 1B**
H_2SO_4	[kg/adt]	20.0	19.3

$NaClO_3$	[kg/adt]	24.5	23.3
Methanol	[kg/adt]	2.5	2.4
Talc	[kg/adt]	4.0	3.8
Products	**Units***	**Base Case 1A**	**Base Case 1B**
Market Pulp	[kg/adt]	1000.0	923.0
Board	[kg/adt]	-	500.0
Crude Tall Oil (CTO)	[kg/adt]	39.0	39.0
Energy	**Units***	**Base Case 1A**	**Base Case 1B**
HFO	[kg/adt]	35.0	35.0
Electricity Exported to Grid	[MWh/adt]	1127.2	666.0
* Basis of calculation – annual pulp production of 800,000 adt/y			

Table 1: Summary of the mass balances of the reference mills without CCS indicating the raw materials and chemical consumptions and products

Unit No.	Unit Name	Steam Consumption Note 1			Electricity Consumption	Fuel Consumption Note 2
		IP	MP	LP		
		[GJ/adt]			[kWh/adt]	[GJ/adt]
1000	Wood Handling Plant				44	
2000	Cooking Plant		1.800	0.151	43	
2100	Brown Stock Screening & Washing				58	
2200	Oxygen Delignification Plant		0.110		58	
3100	Pulp Bleaching		1.002		77	
3200	Pulp Drying			2.260	116	
4100	B.L. Evaporator		0.627	1.936	29	
4200	Kraft Recovery Boiler	0.346		1.066	58	31.07 Note 4
5000	Recausticizing Plant				55	
5100	Lime kiln				incl. in Unit 5000	1.44 Note 5
6100	Multi-fuel boiler	0.038		0.117	29	9.86 Note 6

Unit No.	Unit Name	Steam Consumption Note 1			Electricity Consumption	Fuel Consumption Note 2
		IP	MP	LP		
		[GJ/adt]			[kWh/adt]	[GJ/adt]
6200	Steam Turbine Island				(1369/398) Note 3	
7100	Bleach Chemical Plant			0.172	2	
7200	W. L. Oxidation Plant				2	
7300	Air Separation Unit		0.002		14	
8000	Waste Water Treatment				29	
0000	Mill Infrastructure / Off-sites				27	
	Total	**0.384**	**3.541**	**5.703**	**641**	**42.37**

Table 2: Summary of the Energy Usage of the Market Pulp Mill without CCS

Notes:

[1] IP, MP and LP steam are available at 30 bar/352°C, 13 bar/200°C and 4.2 bar /154°C, respectively. HP steam at 103 bar/505°C is produced by the recovery boiler (REC) and the multi-fuel boiler (MFB). This is delivered to the steam turbine island

[2] Fuel consumption only covers the black liquor, hog fuel and HFO. Other combustibles burned in the REC and MFB such as non-condensable/malodorous gases, methanol, turpentine, bio-sludge and others are not included (but typically should only account for less than 0.5 GJ/adt).

[3] (X/Y) refers to the total electricity produced by the extraction (HP at 1369 kWh/adt) and condensing (LP at 398 kWh/adt) section of the steam turbine, respectively. The gross electricity production is at 1767 kWh/adt. The total electricity exported to the grid is at 1126 kWh/adt.

[4] Total fuel input of the concentrated black liquor (as fired basis)

[5] Total fuel input of the heavy fuel oil (as fired basis). This could also be referred to as the direct fuel consumption.

[6] Total fuel input of the hog fuel/barks (as fired basis).

Unit No.	Unit Name	Steam Consumption Note 1			Electricity Consumption	Fuel Consumption Note 2
		IP	MP	LP		
		[GJ/adt]			[kWh/adt]	[GJ/adt]
1000	Wood Handling Plant				44	
2000	Cooking Plant		1.800	0.151	43	
2100	Brown Stock Screening & Washing				58	
2200	Oxygen Delignification Plant		0.110		58	
3100	Pulp Bleaching		0.927		73	
3200	Pulp Drying			2.085	107	
4100	B.L. Evaporator		0.627	1.936	29	
4200	Kraft Recovery Boiler	0.346		1.066	58	31.07 Note 4
5000	Recausticizing Plant				55	
5100	Lime kiln				incl. in Unit 5000	1.44 Note 5
6100	Multi-fuel boiler	0.038		0.117	29	9.86 Note 6
6200	Steam Turbine Island				(1371/285) Note 3	
7100	Bleach Chemical Plant			0.163	2	
7200	W. L. Oxidation Plant				2	
7300	Air Separation Unit		0.002		14	
8000	Waste Water Treatment				36	
9000	Board Mill			2.341	350	
0000	Mill Infrastructure / Off-sites				33	
	Total	**0.384**	**3.466**	**7.860**	**984**	**42.37**

Table 3: Summary of the Energy Usage of the Integrated Pulp & Board Mill without CCS

Notes:

*See Notes of Table 2.

	Unit	Recovery boiler	Multi-fuel boiler	Lime kiln
Biogenic CO_2 Fossil CO_2	[MTPY] [MTPY]	1 642 400 -	300 800 -	132 554 86 582
Total CO_2	[MTPY]	1 642 400	300 800	219 136

Table 4: Breakdown of CO_2 emissions from the reference pulp mills

Only the lime kiln is fired with fossil fuel, and in this case, heavy fuel oil (HFO). Therefore, the CO_2 derived from combustion related reactions is the only source of fossil CO_2 emissions from the reference mills. On the other hand, the CO_2 derived from the process related reactions (i.e. calcination of lime mud, see Eq. 5) are considered as biogenic CO_2 emissions.

The chemical reactions presented in Equations 1 to 6 show the simplified pathway of the carbon during the chemical recovery cycle which should explain why the process related CO_2 emissions from the lime kiln are to be classified as biogenic CO_2 emissions.

Wood chips + NaOH + Na_2S –> Fibre + Black liquor (digester) [1]
Organic matter in black liquor + O_2 –> CO_2 + H_2O (recovery boiler) [2]
2 NaOH + CO_2 –> Na_2CO_3 + H_2O (recovery boiler) [3]
Na_2CO_3 + $Ca(OH)_2$ –> 2 NaOH + $CaCO_3$ (re-causticizing) [4]
$CaCO_3$ –> CaO + CO_2 (lime kiln) [5]
CaO + H_2O –> $Ca(OH)_2$ (slaker unit) [6]

It could be illustrated, that the carbon bound in the lime mud is originally derived from the organic matter of the black liquor. During combustion of the black liquor, some of the smelts would react with the biogenic CO_2 to form Na_2CO_3 (as shown in Eq. 3). This is then converted to NaOH by the $Ca(OH)_2$ in the re-causticizing unit to form $CaCO_3$. During the calcination of $CaCO_3$ in the lime kiln, the carbon bound in the $CaCO_3$ is released as process related CO_2 emissions. This should be classified as biogenic CO_2 emissions. Around 60 wt.-% of the CO_2 from the lime kiln originates from process related reactions and 39 wt.-% originates from combustion related reactions. Fossil CO_2 emissions originating from make-up lime is 1% of total CO_2 emissions.

Capture of CO_2 from the Reference Mills

Figure 3 presents the simplified block flow diagram of the CO_2 capture plant excluding CO_2 compression train.

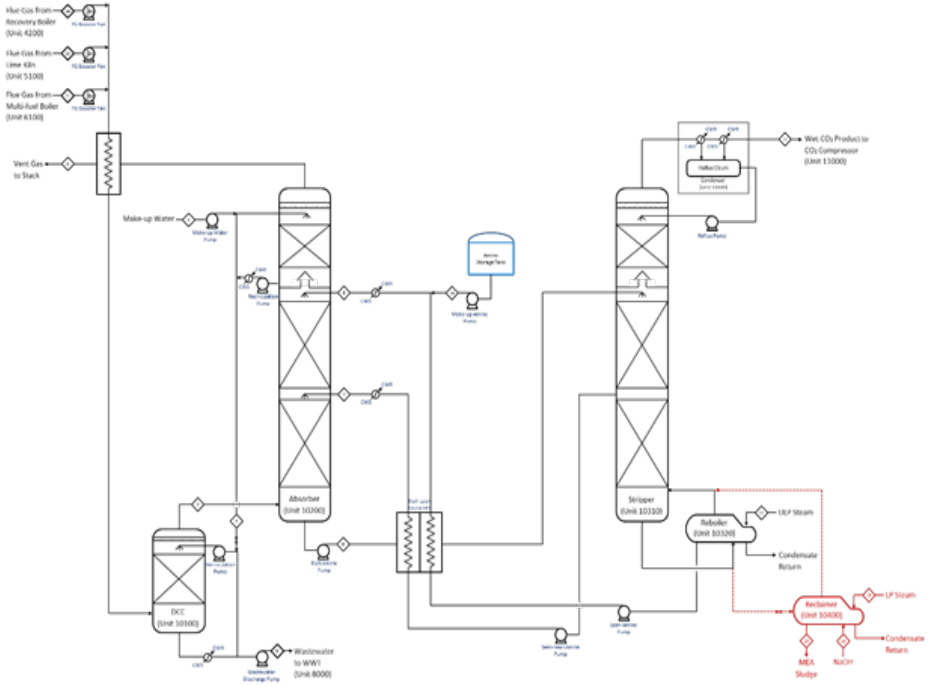


Figure 3: Simplified block flow diagram of the post-combustion CO_2 capture plant

The CO_2 capture plant is based on chemical absorption of CO_2 from flue gases using 30% mono-ethanol amine (MEA) as a solvent with stripping of CO_2 in the regeneration column. The plant is designed based on a variant of a split flow configuration. This is aimed to achieve a reduction in energy consumption (as compared to the conventional post-combustion CO_2 capture configuration).

90% of the CO_2 is captured from the flue gas to be treated. For cases where multiple flue gas sources are treated, it was assumed that the flue gases are mixed and sent to a single CO_2 absorber. The retrofit of the CO_2 capture is assumed to go on-line ten years after the reference mills are commissioned.

The heat required by the regeneration of the solvent is supplied by the reboiler. This utilises Ultra Low Pressure (ULP) steam at 2 bar (saturated) generated by extracting and de-superheating LP steam from the existing steam turbine island. This is described in the next section.

Steam Supply to the Stripper Reboiler

In this study, three different configurations were explored for the modification of the steam turbine island to meet the additional steam and electricity demand of the CO_2 capture and compression plant:

- Configuration I (all cases except 2A-6^{MP}, 2B-1^{CO2MP}, 2B-4^{CO2MP}, 2B-5^{CO2MP}, 2B-6^{CO2MP})
  Extraction of LP steam (at 4.2 bar(a)/154°C) and de-superheated to ULP steam at 2 bar(a) saturated. The CO_2 compressor train is electrically driven.
- Configuration II (for case 2A-6MP)
  Extraction of MP steam (at 13.0 bar(a)/200°C) and de-superheated to 2.0 bar(a) steam. The CO_2 compressor train is electrically driven
- Configuration III (for cases 2B-1^{CO2MP}, 2B-4^{CO2MP}, 2B-5^{CO2MP}, 2B-6^{CO2MP})
  Use of back pressure steam turbine driven CO_2 compressor. This will be driven by extracting MP steam (at 13 bar(a)/200°C) from the mill's steam turbine and supplemented by the MP steam supplied by the auxiliary boiler. The ULP steam (at 2 bar(a)/120°C) required by the stripper reboiler will be derived from the ULP steam produced from the back pressure steam turbine (driving the CO_2 compressor) and complimented by the extraction and de-superheating of LP steam (at 4.2 bar(a)/154°C) from the mill's steam turbine island.

For cases where the excess energy production on-site is not sufficient to meet the additional demand of the CO_2 capture plant, an auxiliary boiler will be deployed. In this case, a bubbling fluidized bed (BFB) boiler will be used. The boiler will be firing waste wood or forest residues which could be supplied by the forest industry within the vicinity of the mill. The boiler will produce MP steam at 13 bar(a)/200°C – this will have the same steam parameter to the existing MP steam network of the mill.

Figures 4 to 6 present the simplified block flow diagram of the three configurations evaluated in this study.

CO_2 Compression and Dehydration Unit

A four stage CO_2 compression train is used to compress the CO_2 product. After each compression stage, a knock-out drum separates any water that condenses out from the wet gas. After the third compression stage, the gas is dehydrated by a molecular sieve dryer. CO_2 exiting the last compression stage is sent to a liquid CO_2 pump for final pressurization.

The simplified block flow diagram of the CO_2 compression and dehydration train is presented in Figures 7 and 8. The molecular sieve is regenerated by recycling and heating part of the dried CO_2 product. The regeneration gas is then return to the first stage compressor.

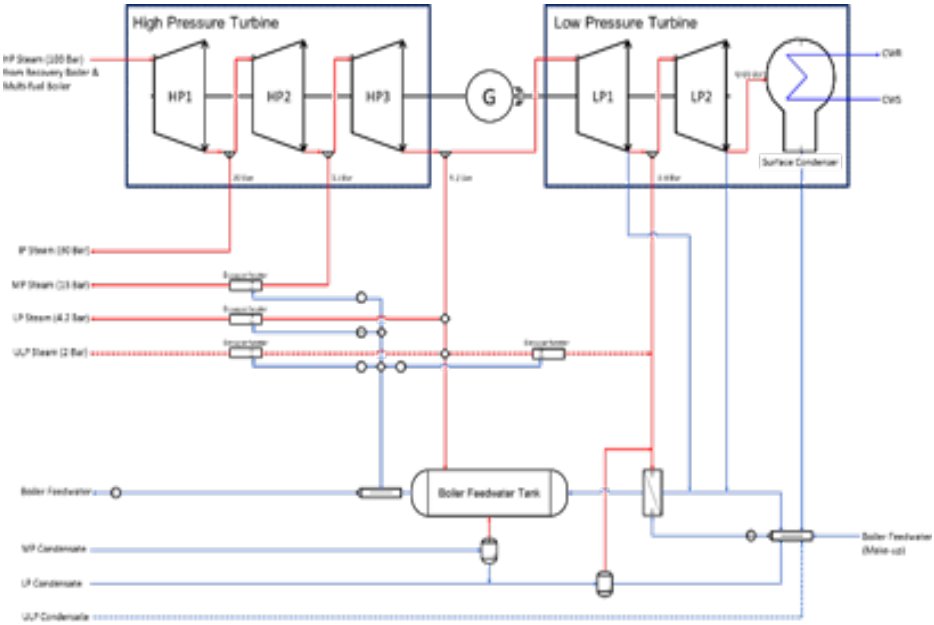


Figure 4: Simplified block flow diagram of the steam turbine island (Configuration I)

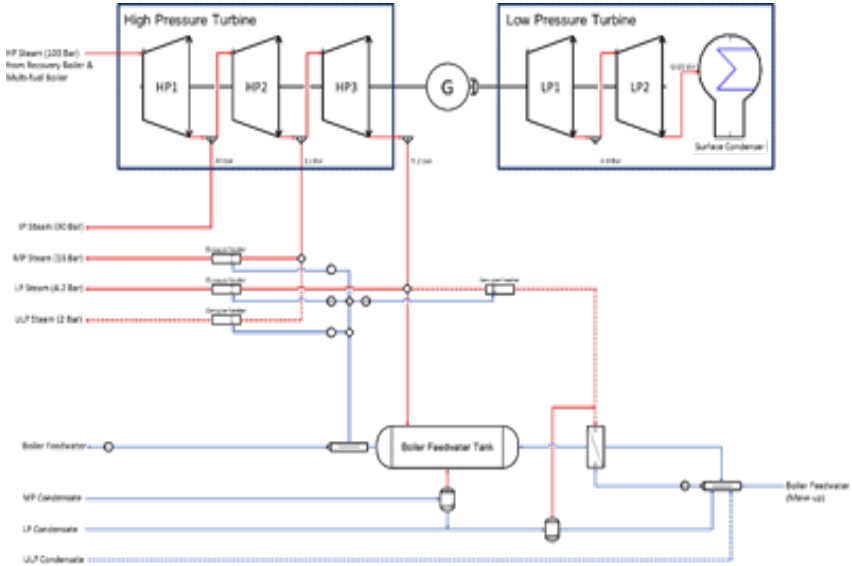


Figure 5: Simplified block flow diagram of the steam turbine island (Configuration II)

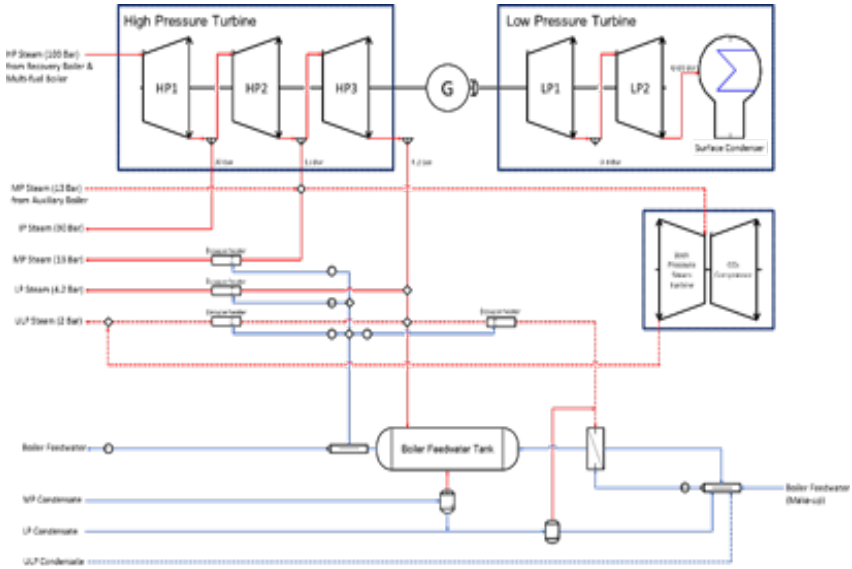


Figure 6: Simplified block flow diagram of the steam turbine island (Configuration III)

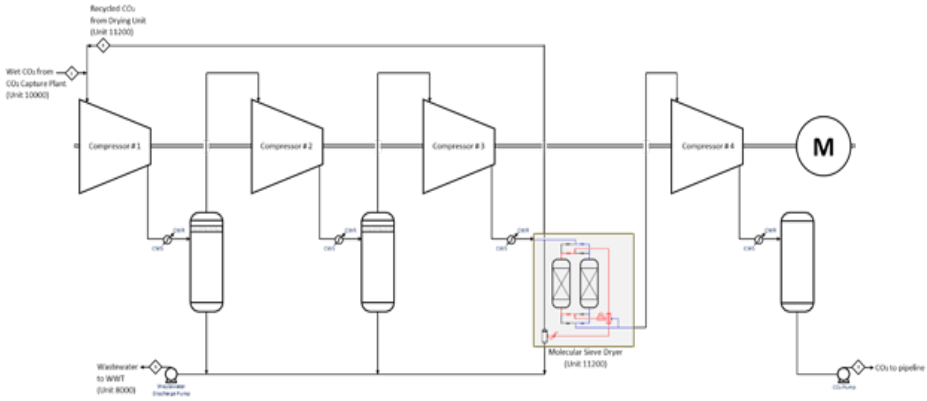


Figure 7: Simplified block flow diagram of the CO_2 compression train for all cases except cases 2B-1^{CO2MP}, 2B-4^{CO2MP}, 2B-5^{CO2MP} and 2B-6^{CO2MP}

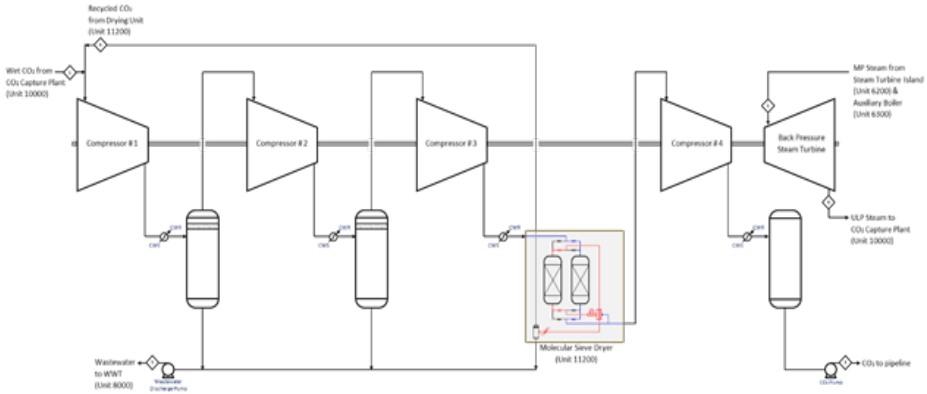


Figure 8: Simplified block flow diagram of the CO_2 compression train for cases 2B-1^{CO2MP}, 2B-4^{CO2MP}, 2B-5^{CO2MP} and 2B-6^{CO2MP}

Performance of the Mills with CCS

Tables 5 summarizes the steam and electricity balances when retrofitting CO_2 capture plant to an existing Kraft pulp mill (Base case 1A) and an integrated pulp and board mill (Base case 1B).

The results clearly illustrate that any retrofit of CO_2 capture involving the recovery boiler would require significant amount of steam to meet the demand of the CO_2 capture plant. In several cases, this would also require the addition of an auxiliary boiler to supplement the steam supply. This is due to the much larger volume of flue gas to be treated; and thus resulting in a higher CO_2 capture rate.

	Base Case	Pulp mill with CCS				
	1A	2A-1	2A-2	2A-3	2A-4	2A-5
Steam						
Pulp Mill						
Steam 30 bar [t/h]	20.4	20.4	20.4	20.4	20.4	20.4
Steam 13 bar [t/h]	171.0	171.0	171.0	171.0	171.0	171.0
Steam 4.2 bar [t/h]	255.2	255.2	255.2	255.2	255.2	255.2
CCS Plant						
Steam 13 bar [t/h]	-	-	-	-	-	-
Steam 4.2 bar [t/h]	-	0.9	0.2	0.1	1.1	1.1
Steam 2.0 bar [t/h]	-	255.8	45.2	31.0	289.3	284.2
Auxiliary Boiler						
Steam 30 bar [t/h]	-	-	-	-	-	-
Steam 4.2 bar [t/h]	-	-	-	-	-	-
Steam						
Ex: Steam turbine						
Steam 30 bar [t/h]	20.4	20.4	20.4	20.4	20.4	20.4
Steam 13 bar [t/h]	171.0	171.0	171.0	171.0	171.0	171.0
Steam 4.2 bar [t/h]	255.2	256.2	255.4	255.3	256.3	256.3
Steam 2 bar [t/h]	-	255.8	45.2	31.0	289.3	284.2
Ex: Auxiliary boiler	-					
Steam 13 bar [t/h		-	-	-	-	-
Ex: Back-pressure steam turbine						
Steam 2 bar [t/h]	-	-	-	-	-	-
Electricity						
Pulp mill [MWe]	61.0	61.0	61.0	61.0	61.0	61.0
CCS Plant [MWe]	-	23.5	4.4	2.8	28.5	26.9
Auxiliary boiler [MWe]	-	-	-	-	-	-
Total [MWe]	**61.0**	**84.5**	**65.4**	**63.8**	**89.5**	**87.9**
Electricity						
Ex: Steam turbine						
HP section [MWe]	130.4	130.4	130.4	130.4	130.4	130.4
LP section [MWe]	37.9	7.7	33.0	34.7	-	4.3
Total [MW_e]	**168.3**	**138.1**	**163.4**	**165.1**	**130.4**	**134.7**

[a] For case 2A-6 MP steam at 13.0 bar(a) is de-superheated to ULP steam at 2.0 bar(a) and the ma

[b] For the CO2MP cases MP steam at 13 bar(a) from the auxiliary boiler is fed directly to the CO_2 c

	Base Case	Integrated pulp and board mill with CCS					
2A-6[MP]	1B	2B-1[CO2MP]	2B-2	2B-3	2B-4 [CO2MP]	2B-5 [CO2MP]	2B-6 [CO2MP]
Demand							
20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
171.0	167.3	167.3	167.3	167.3	167.3	167.3	167.3
255.2	351.8	351.8	351.8	351.8	351.8	351.8	351.8
-	-	189.5[b]	-	-	223.9[b]	213.2[b]	247.6[b]
1.3	-	0.9	0.2	0.1	1.1	1.1	1.3
335.3[a]	-	255.8	45.2	31.0	289.3	284.2	335.3
-	-	1.5	-	-	2.3	2.2	3.4
-	-	2.7	-	-	4.3	4.1	6.5
Supply							
20.4	20.4	21.7	20.4	20.4	22.5	22.4	23.5
171.0	167.4	292.0	167.4	167.4	290.4	285.2	263.2
256.5	351.8	355.4	351.9	351.9	357.1	356.8	359.4
335.3	-	66.3	45.2	31.0	65.3	71.0	87.8
-	-	64.9	-	-	100.9	95.4	151.9
-	-	189.5			224.0	213.2	247.6
Demand							
61.0	94.3	94.3	94.3	94.3	94.3	94.3	94.3
31.4	-	7.8	4.4	2.8	9.9	9.2	10.9
-	-	1.6	-	-	2.4	2.3	3.7
92.4	**94.3**	**103.6**	**98.7**	**97.1**	**106.6**	**105.8**	**108.9**
Supply							
113.7	130.6	124.2	130.6	130.6	124.5	124.5	127.3
-	27.1	-	21.8	23.5	-	-	-
113.7	**157.7**	**124.2**	**152.4**	**154.1**	**124.5**	**124.5**	**127.3**

ass flow is incorporated in the ULP steam demand to the CCS plant.
compression train (compliment with the MP steam from the steam turbine island).

Table 5: Steam and electricity balance when retrofitting a Kraft pulp mill and Kraft pulp and board mill with CCS

For all the cases involving the retrofit of CCS in a market (standalone) pulp mill (except for case 2A-6^{MP}), the excess LP steam at 4.2 bar(a) produced by the steam turbine island should be sufficient to satisfy the steam demand of the CO_2 capture plant. In case 2A-6MP (where CO_2 is captured from the flue gases of the REC, MFB and LK), the excess LP steam is not sufficient for the CO_2 capture plant. Therefore, MP steam at 13.0 bar(a) is used instead; and this is de-superheated to ULP steam at 2 bar(a).

For any cases which include the capture of CO_2 from the flue gas of the recovery boiler, the steam demand increases significantly and consequently, the net electricity export to the grid has been reduced due to the retrofit of CCS. The increase in steam demand ranges from 5.9 GJ/adt (for Case 2A-1) to 6.7 GJ/adt (for Case 2A-5) and 7.8 GJ/adt for Case 2A-6^{MP} and the reduction in the amount of electricity exported to the grid ranges from 53.7 MWe (for Case 2A-1) to 70.2 MWe (for Case 2A-4) and 86.0 MWe for the MP case 2A-6^{MP}.

For cases where the CO_2 is captured from the flue gas of the multi-fuel boiler or lime kiln alone, the amount of steam required by the CO_2 capture plant should be significantly less. Consequently, would only reduce the exported electricity to the grid by around 9.3 MWe or 0.1 MWh/adt (for Case 2A-2).

Table 8 should also illustrates that the amount of steam supplied by the recovery boiler and multi-fuel boiler should be identical for both reference mills - given that the integrated mill (base case 1B) is producing the same amount of pulp as compared to the standalone pulp mill (base case 1A). However, in these cases, the amount of excess LP steam available for the CO_2 capture plant is lesser (by ~96 t/h or ~2.1 GJ/adt) due to the additional demand by the board mill. Consequently, this should also reduce the volume of electricity exported to the grid by ~44MWe or 0.46 MWh/adt.

Therefore, for cases involving the retrofit of CCS to an integrated pulp and board mill, it could be assumed that the excess steam available on-site is only sufficient to cover cases where CO_2 is captured from the multi-fuel boiler or lime kiln only. All cases involving the capture of 90% CO_2 from flue gas of the recovery boiler would require the addition of auxiliary boiler to supplement the steam supply; unless partial CO_2 capture will be considered.

In this study, for cases involving the retrofit of CCS in an integrated pulp and board mill and the capture of CO_2 from recovery boiler, it was concluded that the use of a steam turbine driven CO_2 compressor (configuration III, see Figure 6) is the optimum way to meet the extra demand of the steam by CCS plant and at same time maximize the electricity production of the existing steam turbine. If configuration II (Figure 5) is used and the steam supply is to be supplemented by the auxiliary boiler, it would results to an integrated mill with CCS requiring to import electricity from the grid.

For cases involving the retrofit of CCS to an integrated pulp and board mill and capturing CO_2 from the flue gas of the recovery boiler (i.e. for cases 2B-1^{CO2MP}, 2B-4^{CO2MP}, 2B-5^{CO2MP} and 2B-6^{CO2MP}), the amount of electricity exported to the grid is significantly reduced from 63.4 MWe (base case 1B) down to 18.4 MWe (for case 2B-6^{CO2MP}) to 20.4 MWe (for case 2B-1^{CO2MP}).

CO_2 Emissions – Mills with CCS

Table 6 summarizes the CO_2 emissions of the mills with CCS based on a production capacity of 800,000 adt of softwood Kraft pulp annually and how these emissions are classified in this study.

Case	Case Description	Total emissions (whole Site) [MTPY]	Biogenic based CO_2 emissions [MTPY]	Fossil based CO_2 emissions[1] [MTPY]	Total CO_2 captured [MTPY]	Overall CO_2 capture rate[2] %
Market pulp mill with CCS						
Case 2A-1	Recovery Boiler (REC) only	683,636	597,054	86,582	1,478,700	68.4%
Case 2A-2	Multi-fuel Boiler (MFB) only	1,891,678	1,805,097	86,582	270,658	12.5%
Case 2A-3	Lime Kiln (LK) only	1,965,328	1,965,328	-	197,008	9.1%
Case 2A-4	REC + MFB	412,736	326,155	86,582	1,749,600	80.9%
Case 2A-5	REC + LK	486,414	486,414	-	1,675,922	77.5%
Case 2A-6^{MP}	All 3 (REC + MFB + LK)	215,761	215,761	-	1,946,575	90.0%

Case	Case Description	Total emissions (whole Site) [MTPY]	Biogenic based CO_2 emissions [MTPY]	Fossil based CO_2 emissions[1] [MTPY]	Total CO_2 captured [MTPY]	Overall CO_2 capture rate[2] %
Integrated pulp & board mill with CCS						
Case 2B-1[CO2MP]	Recovery Boiler (REC) only	833,005	746,423	86,582	1,478,700	64.0%
Case 2B-2	Multi-fuel Boiler (MFB) only	1,891,678	1,805,097	86,582	270,658	12.5% 9.1%
Case 2B-3	Lime Kiln (LK) only	1,965,328	1,965,328	-	197,008	9.1%
Case 2B-4[CO2MP]	REC + MFB	644,832	558,251	86,582	1,749,600	73.1%
Case 2B-5[CO2MP]	REC + LK	705,871	705,871	-	1,675,922	70.4%
Case 2B-6[CO2MP]	All 3 (REC + MFB + LK)	564,807	564,807	-	1,946,575	77.5%

[1] Emissions from the mill with CO_2 capture from the lime kiln has been calculated assuming that all fossil CO_2 is captured first before any biogenic CO_2 is captured.
[2] Overall CO_2 capture rate is calculated as total CO_2 captured / total CO_2 Emissions (without capture) of the recovery boiler, multi-fuel boiler, lime kiln and auxiliary boiler

Table 6: CO_2 emissions from the reference cases. The CO_2 emissions are identical for both base cases 1A and 1B

Amount of CO_2 Avoided

Due to the fact that any biogenic emissions from the pulp mill could be considered as CO_2 neutral if emitted or CO_2 negative if captured, the amount of CO_2 avoided could be calculated depending on the accounting of the emitted and captured biogenic CO_2.

Without considering the biogenic CO_2 emissions from the pulp mill, the calculation of the amount of CO_2 Avoided is very straightforward – i.e. this should be similar to how the CO_2 avoided is calculated in other applications:

$$CO_2 \text{ Avoided} = CO_2 \text{ Emissions}_{\text{Ref. Mill}} - CO_2 \text{ Emissions}_{\text{Mill with CCS}} \quad [7]$$

However, with the consideration of the biogenic CO_2 emissions, the CO_2 Avoided should only consider the fossil based CO_2 emissions of the plant and the amount of biogenic CO_2 emissions captured and stored. The amount of CO_2 avoided in this case is calculated as:

$$CO_2 \text{ Avoided} = \text{Fossil } CO_2 \text{ Emissions}_{\text{Ref. Mill}} - (\text{Fossil } CO_2 \text{ Emissions} - \text{Captured Biogenic } CO_2)_{\text{Mill with CCS}} \quad [8]$$

The difference between the answers when calculating the amount of CO_2 avoided using Eq. 1 and Eq. 2 mainly depends on how the treatment to the emitted biogenic CO_2 is accounted for. For example – if the CO_2 reduction credit due to CCS is first allocated to reduce the Fossil CO_2 emissions and all the biogenic CO_2 emissions are accounted as CO_2 neutral, then both equations should give the same answers.

Nonetheless, when considering the level of CO_2 avoided as compared to the reference mill (in terms of $\%CO_2$ avoided):

$$\%CO_2 \text{ avoided} = 100\% \times \frac{CO_2 \text{ Emissions}_{\text{Ref. Mill}} - CO_2 \text{ Emissions}_{\text{Mill with CCS}}}{CO_2 \text{ Emissions}_{\text{Ref. Mill}}} \quad [9]$$

or

$$\%CO_2 \text{ avoided} = \frac{100\% \times \text{Fossil } CO_2 \text{ Emissions}_{\text{Ref. Mill}} - (\text{Fossil } CO_2 \text{ Emissions} - \text{Captured Biogenic } CO_2)_{\text{Mill with CCS}}}{CO_2 \text{ Emissions}_{\text{Ref. Mill}}} \quad [10]$$

The later equation is expected to provide a higher number in terms of %CO2 avoided. These are illustrated in Tables 7 and 8.

	Specific CO_2 Captured (t of captured CO_2 / adt of pulp)*	Specific CO_2 Avoided (t of avoided CO_2 / adt of pulp)*	% CO_2 Avoided	
			Actual**	with considerations for captured biogenic CO_2 as negative emissions***
Case 2A-1	1.848	1.848	68%	1707%
Case 2A-2	0.338	0.338	13%	313%
Case 2A-3	0.246	0.246	9%	228%
Case 2A-4	2.187	2.187	81%	2021%
Case 2A-5	2.095	2.095	78%	1936%
Case 2A-6^{MP}	2.433	2.433	90%	2248%

* calculated based on 800,000 adt of bleached softwood Kraft pulp (BSKP)
** $\%CO_2$ avoided calculated based on Eq. 9.
** $\%CO_2$ avoided calculated based on Eq. 10.

Table 7: $\%CO_2$ avoided for pulp mill with CCS.with and without the consideration of "Negative CO_2 Emission"

	Specific CO_2 Captured (t of captured CO_2 / adt of pulp)*	Specific CO_2 Avoided (t of avoided CO_2 / adt of pulp)*	% CO_2 Avoided	
			Actual**	with considerations for captured biogenic CO_2 as negative emissions***
Case 2B-1^{CO2MP}	1.848	1.662	61%	1707%
Case 2B-2	0.338	0.338	13%	313%
Case 2B-3	0.246	0.246	9%	228%
Case 2A-4^{CO2MP}	2.187	1.897	70%	2021%
Case 2A-5^{CO2MP}	2.095	1.821	67%	1936%
Case 2A-6^{CO2MP}	2.433	1.997	73%	2248%

* calculated based on 800,000 adt of bleached softwood Kraft pulp (BSKP)
** %CO_2 avoided calculated based on Eq. 9.
** %CO_2 avoided calculated based on Eq. 10.

Table 8: %CO_2 avoided for integrated pulp and board mill with CCS with and without the consideration of "Negative CO_2 Emission"

Economic Assessment

The cost estimates were derived in accordance with IEAGHG's standard practise for estimating the cost of the plant without and with CCS.

The cost of pulp production without and with CCS were estimated based on IEAGHG's standard assessment criteria with other assumptions adapted to accommodate the conditions of the location of the pulp mill.

The results of the economic evaluation are reported based on Earnings Before Interest, Taxes, Depreciation and Amortisation (EBITDA). The calculation of the cost of production include the investment cost of the mill and the CO_2 capture plant, the fixed operating costs (labour, maintenance and others), variable operating costs (raw-materials, chemicals, utilities, waste and logistics) and revenues (pulp, crude tall-oil and electricity). Based on the Discounted Cash Flow (DCF) analysis, the levelised cost of the pulp and board production (break-even price of pulp and board) are estimated by setting the net present value (NPV) = 0.

In this study, the following assumptions were used in the economic evaluation of the pulp mill:

- The mill is situated in a brownfield site located in the coastal area of Finland.
- The annual operating hours of the mill is 8400 h/y.
- The capture of CO_2 from the mill's different flue gases started on its 10th year of operation.
- Heavy fuel oil is imported from outside the battery limit. The mill has no access to the natural gas pipeline.
- Seawater cooling is assumed.
- Utilities are assumed not to be included in the Battery Limit. As such, the cost of cooling water, process water, condensates, and boiler feed water are charged as OPEX items.
- Discount rate: 8% (constant money values)
- Operating life: 25 years
- Construction time: 3 years for the pulp mill. 2 years for the CO_2 capture plant (started on the 8th year of mill's operation).
- Cost is estimated based on Euro (4Q 2015). Whereas if needed, the exchange rates used in this study is set at €1.00 = US$1.10.
- CO_2 transport and storage cost: 10€/t stored

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

TPC is defined as the total installed cost of the plant including a project contingency of 10%. For all of the cases the TPC has been determined through a combination of the use of cost database gathered in-house by VTT and ÅF Consult Oy, and quotes from vendors if required. The costs are reported as budgetary quote on a Plant Turnkey Estimate basis. The estimated TPC of the mill is based on the equipment cost reported in the year 2005; the investment cost of the CO_2 capture plant is estimated based on the equipment cost reported in the year 2015.

TCR is defined as the sum of: total plant cost (TPC), spare parts cost, start-up cost, owner's cost, working capital, and interest during construction. These

are estimated mainly as percentages of other cost estimates in the plant.

Table 9 presents the Total Plant Cost of the Reference Mills. Tables 10 and 11 present the total plant cost and total capital requirements of the pulp mills and integrated mills without and with CCS.

Unit	Description	Key Components	Nominal Capacity	Total CAPEX (MEUR 2005)	
				Base Case 1A	Base Case 1B
0000	Mill infrastructure		800000 adt/y (1A) 1140000 adt/y (1B)	67	82
1000	Wood handling	• Wood storage • De-icing • Debarking lines • Chipping lines • Knife grinder • Chip storage with chip piles • Screening lines • Related conveyors	943 m^3/h	53	53
2000	Cooking plant	• Chip bin • Impregnation vessel • Continuous digester • Blow line • Re-boiler • Turpentine recovery system	2795 adt/d	107	107
2100	Brown stock handling	• Diffuser washer • DD-washer • De-knotting • Screening		Included in Unit 2000	Included in Unit 2000
2200	Oxygen delignification	• 2-stage oxygen delignification • Two DD-washers		Included in Unit 2000	Included in Unit 2000
3100	Pulp bleaching and washing	• D^0-Eop-D^1-P stages • Four DD-washers	2667 adt/d	49	48
3200	Pulp dryer	• Screening and cleaning • Dilution head box • Twin-wire former • Combi-press with shoe-press • Airborne dryer • Cutting • Baling	2824 adt/d (1A) 2612 adt/d (1B)	112	107

Unit	Description	Key Components	Nominal Capacity	Total CAPEX (MEUR 2005)	
				Base Case 1A	Base Case 1B
4100	Black Liquor evaporation	• 7-stage evaporation • Malodorous gas collection • tall-oil plant	804 t_{H2O}/h	48	48
4200	Kraft recovery boiler	• Recovery boiler • Electrostatic precipitators • Flue gas stack • Boiler feed water plant • Condensate treatment • Ash leaching plant	4985 t_{ds}/d	160	160
5000	Recausticizing plant	• Green liquor filtering • Dregs washing • Slaker • Re-causticizers • White liquor filtering	11120 m^3_{WL}/d	49	49
5100	Lime Kiln	• Lime dewatering unit • Lime mud dryer • Lime kiln • Lime cooler • ESP filters	t_{CaO}/d	Included in Unit 5000	Included in Unit 5000
6100	Multi-fuel boiler	• FB boiler • Electrostatic precipitators • Flue gas stack	82MW_{th}	56	56
6200	Steam turbine Island	• Extraction / back pressure turbine • Condensing turbine • Generator set	187 MW_e (1A) 175 MW_e (1B)	51	49
7100	Bleach chemical plant	• Reactor • Heat exchanger • Absorber • Salt cake washer	34 t ClO_2/d (1A) 32 t ClO_2/d (1B)	14	13
7200	White liquor oxidation			Included in Unit 7100	Included in Unit 7100
7300	Air separation unit	• Process Air Pre-treatment Unit • Main Air Compressor • Cold box • Product O_2 compression	64 t/d	8	8

Unit	Description	Key Components	Nominal Capacity	Total CAPEX (MEUR 2005)	
				Base Case 1A	Base Case 1B
8000	Waste water treatment	• Mechanical treatment • Active sludge treatment	49000 m^3/d (1A) 57000 m^3/d (1B)	25	27
9000	Board Mill	• Board Machine	400,000 adt/y (1B)	-	136
			Total	€ 799 million	€ 943 million

Table 9: Total plant cost – pulp (and board) mill with 800,000 adt/y annual production capacity

	Total Plant Cost - Pulp Mill / Changes to Mill (for CCS Cases) (million €)	Total Plant Cost - CO_2 Capture Plant (million €)	Total Plant Cost CO_2 Compression (million €)	Project Contingency (million €)	Total Plant Cost - TPC (million €)	Total Capital Requirement - TCR (million €)
Base Case 1A	798.50	-	-	79.85	878.35	1,341.50
Case 2A-1	10.55	227.92	14.48	25.29	278.24	355.44
Case 2A-2	9.81	9.81	3.93	7.54	82.95	105.59
Case 2A-3	9.54	36.10	2.30	4.79	52.73	67.17
Case 2A-4	11.95	253.09	16.08	28.11	309.23	395.22
Case 2A-5	11.78	239.31	15.20	26.63	292.92	374.38
Case 2A-6^{MP}	15.21	264.01	16.77	29.60	325.58	416.61

Table 10: Total Capital Requirement – Pulp Mill without and with CCS (800,000 adt/y of pulp - annual production)

	Total Plant Cost - Pulp Mill / Changes to Mill (for CCS Cases) (million €)	Total Plant Cost - CO_2 Capture Plant (million €)	Total Plant Cost CO_2 Compression (million €)	Project Contingency (million €)	Total Plant Cost - TPC (million €)	Total Capital Requirement - TCR (million €)
Base Case 1B	942.60	-	-	94.26	1036.86	1592.17
Case 2B-1^{CO2MP}	35.53	227.92	28.95	29.24	321.64	412.99
Case 2B-2	9.89	61.67	3.93	7.55	83.03	105.70
Case 2B-3	9.61	36.10	2.30	4.80	52.81	67.21
Case 2B-4^{CO2MP}	47.93	253.09	32.15	33.32	366.49	471.00
Case 2B-5^{CO2MP}	46.76	239.31	30.40	31.65	348.12	447.40
Case 2B-6^{CO2MP}	53.17	264.01	33.54	35.07	385.78	496.69

Table 11: Total Capital Requirement – Integrated Pulp and Board Mill without and with CCS (400,000 adt/y of board - annual production)

The TCR of the mills without CO_2 capture (Base Case) includes the following:

- 1% of TPC to cover the spare parts
- Start-up cost which includes:
  - 2% of TPC to cover the start-up CAPEX
  - 2.1% of annual fuel bill to cover additional fuel cost during start-up
  - 25% of annual operating expense (O&M, Fuel and Raw Materials)
  - 8.3% of chemicals cost
- 7% owner's cost
- 8% interest during construction
- Working capital which covers 30 days of feedstock, fuel and other raw materials; and 15 days of finished products.

The TCR for the retrofit of the Pulp Mill or Integrated Pulp and Board Mill with CO_2 Capture includes the following:

- 1% of TPC to cover the spare parts
- 3% of TPC to cover the start-up cost (including all the start-up CAPEX and OPEX)
- 7% owner's cost

- 8% interest during construction
- Additional working capital covering the inventories of the MEA and the make-up solvent

The OPEX of the plant include the fixed and variable operating cost. The fixed cost consists of the direct and indirect labour cost, annual maintenance cost, other fixed costs which included local taxes, insurance and others.

The variable operating cost are estimated based on the price of the raw materials, chemicals, utilities, waste disposal charges, product logistics, and revenues from the co-product and electricity sold to the grid.

Table 12 (on page 44) and 13 (on page 45) summarised the annual operating of the pulp mill and the integrated pulp and board without and with CCS.

Levelised Cost of Pulp and Board

The Levelised Cost of Pulp Production (LCOP) and the Levelised Cost of Board Production (LCOB) are used to calculate the unit cost of producing the market pulp and board over the plant's economic lifetime. This is defined as the price of the market pulp and the board which enables the present value from the sales of pulp and board (including the additional revenues from the sale of CTO and electricity) over the economic lifetime of the plant to equal the present value of all the costs of building, maintaining and operating the plant over its lifetime. In other words, this is the breakeven price of the pulp or board when the net present value or NPV is set to zero.

The LCOP of the pulp produced from the mills without and with CCS is estimated using the discounted cash flow (DCF) analysis. The DCF calculation is executed based on IEAGHG's economic assessment model developed in-house in cooperation with VTT. Using this method allows the determination of real cost of pulp production and cost of CO_2 avoidance. Furthermore, it also determines the increase in the price of pulp after the retrofit of the CCS on the 10th year of the mill's operation.

The calculation requires the assessment of retrofitting CO_2 capture to an existing pulp mill, the economic assessment model incorporates the following assumptions:

- In all the CCS cases, it is assumed that the new capture plant is built while the mill is still in operation.

	Base Case 1A	Case 2A-1 (REC)	Case 2A-2 (MFB)	Case 2A-3 (LK)	Case 2A-4 (REC+MFB)	Case 2A-5 (REC+LK)	Case 2A-6[MP] (ALL 3)
1. Fixed Cost							
1a. Direct Labour	€ 7,200,000	€ 8,400,000	€ 8,100,000	€ 8,100,000	€ 8,400,000	€ 8,400,000	€ 8,400,000
1b. Indirect Labour Cost	€ 2,880,000	€ 3,360,000	€ 3,240,000	€ 3,240,000	€ 3,360,000	€ 3,360,000	€ 3,360,000
1c. Other Fixed Cost (incl. Insurance & Local Taxes)	€ 20,000,000	€ 22,782,411	€ 20,829,503	€ 20,527,285	€ 23,092,267	€ 22,929,169	€ 23,255,838
1d. Maintenance	€ 35,139,500	€ 43,507,340	€ 37,628,009	€ 36,727,296	€ 44,436,907	€ 43,953,553	€ 44,933,558
2. Variable Cost							
2a. Raw Materials / Feedstock	€	€	€	€	€	€	€
2b. Chemicals	185,600,000	185,600,000	185,600,000	185,600,000	185,600,000	185,600,000	185,600,000
2c. Fuel Cost	€ 27,250,400	€ 30,192,207	€ 27,789,593	€ 27,624,514	€ 30,732,453	€ 30,567,498	€ 31,106,523
2d. Other Utilities	€ 11,200,000	€ 11,200,000	€ 11,200,000	€ 11,200,000	€ 11,200,000	€ 11,200,000	€ 11,200,000
2e. Waste Processing & Disposal Charges	€ 6,646,071	€ 12,056,841	€ 7,859,765	€ 7,327,160	€ 11,566,879	€ 11,920,696	€ 13,379,451
	€ 1,521,925	€ 1,975,956	€ 1,618,132	€ 1,577,345	€ 2,068,834	€ 2,031,357	€ 2,126,974
3. Other Revenues							
3a. Crude Tall Oil (Sold to the Market)	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000
3b. Electricity (Sold to the Grid)	-€ 36,068,800	-€ 18,025,600	-€ 32,928,000	-€ 34,036,800	-€ 13,758,400	-€ 15,724,800	-€ 7,156,800
4. Other Cost							
4a. Marketing, Logistics and Distribution	€ 40,000,000	€ 40,000,000	€ 40,000,000	€ 40,000,000	€ 40,000,000	€ 40,000,000	€ 40,000,000
4b. CO_2 Transport and Storage Cost	€ 0	€ 14,787,000	€ 2,706,577	€ 1,878,042	€ 17,495,997	€ 16,667,082	€ 19,376,079

Table 12: Annual operating cost of the pulp mill without and ith CCS

	Base Case 1B	Case 2B-1^{CO2MP} (REC)	Case 2B-2 (MFB)	Case 2B-2 (MFB)	Case 2B-4^{CO2MP} (REC+MFB)	Case 2B-5^{CO2MP} (REC+LK)	Case 2B-6^{CO2MP} (ALL 3)
1. Fixed Cost							
1a. Direct Labour	€ 14,400,000	€ 16,200,000	€ 15,300,000	€ 15,300,000	€ 16,200,000	€ 16,200,000	€ 16,200,000
1b. Indirect Labour Cost	€ 5,760,000	€ 6,480,000	€ 6,120,000	€ 6,120,000	€ 6,480,000	€ 6,480,000	€ 6,480,000
1c. Other Fixed Cost (incl. Insurance&Local Taxes)	€ 28,460,000	€ 31,676,433	€ 29,290,303	€ 28,988,086	€ 32,124,869	€ 31,941,153	€ 32,317,842
1d. Maintenance	€ 41,478,800	€ 51,149,029	€ 43,969,710	€ 43,068,997	€ 52,494,336	€ 51,949,130	€ 53,079,198
2. Variable Cost							
2a. Raw Materials / Feedstock	€ 345,915,556	€ 345,915,556	€ 345,915,556	€ 345,915,556	€ 345,915,556	€ 345,915,556	€ 345,915,556
2b. Chemicals	€ 26,206,779	€ 29,148,586	€ 26,745,972	€ 26,580,893	€ 29,688,832	€ 29,523,877	€ 30,062,902
2c. Fuel Cost	€ 11,200,000	€ 18,750,940	€ 11,200,000	€ 11,200,000	€ 22,932,999	€ 22,294,073	€ 28,857,582
2d. Other Utilities	€ 5,583,751	€ 11,108,421	€ 6,823,652	€ 6,289,366	€ 11,911,663	€ 11,386,750	€ 13,733,341
2e. Waste Processing & Disposal Charges	€ 1,796,134	€ 2,272,759	€ 1,892,342	€ 1,851,555	€ 2,378,150	€ 2,338,762	€ 2,454,016
3. Other Revenues							
3a. Crude Tall Oil (Sold to the Market)	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000	-€ 15,600,000
3b. Electricity (Sold to the Grid)	-€ 21,312,000	-€ 6,915,247	-€ 18,048,000	-€ 19,156,800	-€ 6,004,878	-€ 6,289,372	-€ 6,194,306
4. Other Cost							
4a. Marketing, Logistics and Distribution	€ 56,920,000	€ 56,920,000	€ 56,920,000	€ 56,920,000	€ 56,920,000	€ 56,920,000	€ 56,920,000
4b. CO_2 Transport and Storage Cost	€ 0	€ 14,787,000	€ 2,706,577	€ 1,878,042	€ 17,495,997	€ 16,667,082	€ 19,376,079

Table 13: Annual operating cost of the integrated pulp and board mill without and with CCS

- It is also assumed that all the tie-ins required and the necessary internal modifications could be completed within the regular maintenance shut down period.
- On the first year of operation for the CO_2 capture plant, the operating hour is slightly reduced to 7560 hours.
- The model accounts for the differentiation between biogenic and fossil based CO_2 emissions.

The cash flow includes the following items:

- Revenues
- Fixed operating cost
- Variable operating cost
- Cost of CO_2 emissions (which includes CO_2 emissions tax, CO_2 emissions credit, renewable electricity credit, CO_2 negative emissions credit).
- Cost of CO_2 transport and storage
- Capital expenditures
- Working capital

As a starting point, the variable operating cost of the mill from year 1 to year 9 was calculated using the break-even price of the pulp of Base Case 1A (i.e. 523 €/adt pulp). The new price of the pulp after the retrofit was estimated using the overall cash flow and by setting the net present value or NPV = 0.

All the calculations assume constant prices (in real terms) for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from lower capacity factors in the mill's first year of operation and the lower capacity of the CO_2 capture plant during its start-up. This study also assumed that the electricity price sold to the grid is constant at 40 €/MWh, and the CTO is also sold to the market at constant price of 500 €/tonne.

With the given information and assumptions, the following were calculated:

- Levelised cost of pulp production or breakeven price of the pulp after the retrofit.
- CO_2 avoidance cost.

To evaluate the impact of the cost of CO_2 emissions to the levelised cost of the market pulp, the following scenarios were evaluated:

- **Scenario #1:**
  No CO_2 emissions tax or any incentives to the biogenic CO_2 emissions (Base Number)
- **Scenario #2:**
  CO_2 emissions tax at 10€/t and the biogenic CO_2 emitted by the mills is not recognized as CO_2 neutral (i.e. biogenic CO_2 is not exempted to the tax).
- **Scenario #3:**
  CO_2 emissions tax at 10€/t and the biogenic CO_2 is recognized as CO_2 neutral – therefore exempting these emissions from the tax.
- **Scenario #4:**
  CO_2 emissions tax at 10€/t, the biogenic CO_2 is exempted from the tax and an additional incentive is credited to the renewable electricity exported to the grid at 10% of the electricity selling price (at €4/MWh for the Base Number).

If CCS is retrofitted, the following additional scenarios were also evaluated to assess the effect of the financial credit given to the negative CO2 emissions.

- **Scenario #5:**
  The same conditions as in Scenario 3 and with the negative CO_2 emissions given an additional credit of 10€/t.
- **Scenario #6:**
  The same conditions as in Scenario 4 and with the negative CO_2 emissions given an additional credit of 10€/t.

It should be noted that the CO_2 tax at 10 €/t reflects the current scenario where the EU ETS price for CO_2 is very low. Additionally, for Scenario #4, the incentive at 4 €/MWh credited to the renewable electricity that is sold to the grid also reflects the current Nordic market where incentives given to the renewable electricity are slowly being withdrawn.

Tables 14 and 15 summarise the LCOP of the pulp mill and integrated pulp and board mill for the all the CCS cases evaluated and subjected to the six

different scenarios as defined above.

	Base Case 1A	Case 2A-1 (REC)	Case 2A-2 (MFB)	Case 2A-3 (LK)	Case 2A-4 (REC+MFB)	Case 2A-5 (REC+LK)	Case 2A-6^{MP} (ALL 3)
Scenario 1	522.6 €	642.8 €	553.5 €	543.1 €	659.0 €	652.0 €	676.5 €
Scenario 2	549.7 €	651.3 €	577.2 €	567.7 €	664.2 €	658.1 €	679.2 €
Scenario 3	523.7 €	643.9 €	554.5 €	543.1 €	660.1 €	652.0 €	676.5 €
Scenario 4	519.2 €	641.6 €	550.4 €	538.8 €	658.4 €	650.0 €	675.6 €
Scenario 5	523.7 €	625.3 €	551.1 €	541.7 €	638.2 €	632.1 €	653.2 €
Scenario 6	519.2 €	623.1 €	547.0 €	537.4 €	636.5 €	630.1 €	652.3 €

*Table 14: LCOP or the breakeven price of the pulp for the mills without and with CCS**
**The breakeven price for all the CCS case represents the price of the pulp after the retrofit of the CO_2 capture plant*

	Base Case 1B	Case 2B-1^{CO2MP} (REC)	Case 2B-2 (MFB)	Case 2B-3 (LK)	Case 2B-4^{CO2MP} (REC+MFB)	Case 2B-5^{CO2MP} (REC+LK)	Case B-6^{CO2MP} (ALL 3)
Scenario 1	522.6 €	670.9 €	556.3 €	545.0 €	695.0 €	687.0 €	713.6 €
Scenario 2	549.7 €	679.9 €	579.7 €	569.5 €	701.5 €	694.4 €	719.1 €
Scenario 3	523.7 €	672.0 €	557.3 €	544.9 €	696.1 €	686.9 €	713.5 €
Scenario 4	519.2 €	669.4 €	553.3 €	540.7 €	693.6 €	684.4 €	711.0 €
Scenario 5	523.7 €	651.9 €	553.7 €	543.4 €	672.3 €	665.4 €	688.2 €
Scenario 6	519.2 €	649.3 €	549.6 €	539.2 €	669.9 €	662.9 €	685.8 €

*Table 15: LCOP or the breakeven price of the pulp for the mills without and with CCS**
**The breakeven price for all the CCS case represents the price of the pulp after the retrofit of the CO_2 capture plant*

Cost of CO_2 avoided

Costs of CO_2 avoided were calculated by comparing the CO_2 emissions per adt of pulp and the LCOP of plants with capture and a reference plant without capture.

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{LCOP_{CCS} - LCOP_{Reference}}{CO_{2Emissions\ Reference} - CO_2\ Emissions_{CCS}}$$

where:

- CAC is expressed in € per tonne of CO_2
- LCOP is expressed in Euro per adt of pulp
- CO_2 emission is expressed in tonnes of CO_2 per adt of pulp

To calculate the cost of CO_2 avoided for the integrated pulp and board mill without and with CCS, it was assumed to use the levelised cost of board (for integrated mill without CCS) constant and calculate the LCOP instead. The reason to this assumption is to make the results consistent and comparable to all cases. It should be noted that indirect CO_2 emissions from the additional pulp (i.e. CTMP and BHKP) imported from outside the battery limit is not accounted for in the calculation.

Tables 16 and 17 summarise the result of the CAC of the pulp mill and integrated pulp and board mill for the all the CCS cases evaluated and also subjected to the six different scenarios as defined earlier.

	Case 2A-1 (REC)	Case 2A-2 (MFB)	Case 2A-3 (LK)	Case 2A-4 (REC+MFB)	Case 2A-5 (REC+LK)	Case 2A-6^{MP} (ALL 3)
Scenario 1	65.0 €	91.1 €	83.1 €	62.4 €	61.8 €	63.2 €
Scenario 2	55.0 €	81.1 €	73.1 €	52.3 €	51.7 €	53.2 €
Scenario 3	65.0 €	91.1 €	78.7 €	62.4 €	61.2 €	62.8 €
Scenario 4	66.2 €	92.3 €	79.7 €	63.7 €	62.4 €	64.3 €
Scenario 5	55.0 €	81.1 €	73.1 €	52.3 €	51.7 €	53.2 €
Scenario 6	56.2 €	82.3 €	74.1 €	53.6 €	52.9 €	54.7 €

Table 16: CO_2 avoidance cost of the pulp mill with CCS for each scenario

	Case 2B-1^{CO2MP} (REC)	Case 2B-2 (MFB)	Case 2B-3 (LK)	Case 2B-4^{CO2MP} (REC+MFB)	Case 2B-5^{CO2MP} (REC+LK)	Case 2B-6CO2MP (ALL 3)
Scenario 1	82.3 €	91.8 €	84.0 €	83.9 €	83.4 €	88.3 €
Scenario 2	72.3 €	81.7 €	73.9 €	73.9 €	73.3 €	78.3 €
Scenario 3	82.3 €	91.8 €	79.5 €	83.9 €	82.8 €	87.7 €
Scenario 4	83.4 €	93.0 €	80.6 €	84.9 €	83.8 €	88.7 €
Scenario 5	71.2 €	81.7 €	73.9 €	72.3 €	71.8 €	76.0 €
Scenario 6	72.3 €	82.9 €	75.0 €	73.3 €	72.8 €	77.0 €

Table 17: CO_2 avoidance cost of the integrated pulp and board mill with CCS for each scenario

Conclusions

- This study has evaluated the technical feasibility of retrofitting post-combustion CO_2 capture plant using MEA as solvent to (a) an existing Kraft pulp mill producing 800,000 adt pulp annually and (b) an existing integrated pulp and board mill producing 740,000 adt pulp and 400,000 adt 3-ply folding boxboard annually.
- Capture cases assessed in this study include the capture of CO_2 from the flue gases of the recovery boiler, the multi-fuel boiler and the lime kiln and various combinations of these.
- It should be highlighted that performance of retrofitting CCS in an existing industrial complex is very site specific. This is also true if CCS is deployed to an existing pulp mill.
- The retrofit of post-combustion CO_2 capture to an existing pulp mill or pulp and board mill is strongly dependent on the existing arrangement for the electricity and steam production on-site.
- In a typical modern Nordic Kraft pulp mill, excess LP steam is often available from the combustion of black liquor and bark. Depending on the volume of flue gas to be treated in the CO_2 capture plant and the partial pressure of CO_2 in the flue gas, the excess steam on-site should be sufficient to meet the steam demand of the CO_2 capture plant.
- However, for any cases involving the retrofit of CCS in an integrated pulp and board mill and 90% capture of CO_2 from the flue gas of the recovery boiler, it could be concluded that the excess available steam on-site is not sufficient. Therefore, an auxiliary boiler should be required to supplement the steam supply. It was also concluded, based on the different case scenarios evaluated, the use of steam turbine driven CO_2 compressor together with addition of auxiliary boiler (based on Configuration III, Figure 6) is the optimum way to meet steam and electricity demand of the CO_2 capture plant and at the same time maximize the amount of electricity exported to the grid.
- It could be noted that the retrofit of the CO_2 capture plant in a standalone pulp mill could increase the steam demand by 0.72 GJ/adt (for Case 2A-3) to 7.78 GJ/adt (for Case 2A-6MP); and could increase the electricity demand by 2.8 MWe (for Case 2A-3) to 31.4MWe (for Case 2A-6MP).

- On the other hand, the retrofit of the CO_2 capture plant in an integrated pulp and board mill could increase the steam demand by 0.72 GJ/adt (for Case 2B-3) to 12.98 GJ/adt (for Case 2B-6^{CO2MP}); and could increase the electricity demand by 2.8MWe (for Case 2B-3) to 14.6 MWe (for Case 2B-6^{CO2MP}).
- In general, because of the additional energy demand of the CO_2 capture plant, the amount of electricity exported to the grid is significantly reduced. This means that the amount of renewable electricity produced is also reduced.
- The costs of pulp production with and without CCS were estimated as far as possible based on IEAGHG's general practice and standard assessment criteria. The methodology on how the economic evaluation was assessed and the assumption used are described in the main report.
- The total plant cost (TPC) and total capital requirement (TCR) of the mill without and with CCS are summarised in Tables 9 to 11. From this study, it could be noted that the TCR of retrofitting CCS in an existing pulp mill could range from 65 to 500 million €.
- The annual operating cost of the pulp mill without and with CCS is summarised in Tables 12 and 13. From this study, the following could be noted:
    - As compared to the base case, the increase in the fixed operating cost is due to:
        - Personnel needed for the CO_2 capture plant
        - Associated increase to the indirect labour cost due to the increase of the direct labour cost
        - Annual O&M is increased due to the added equipment of the CO_2 capture plant and associated modifications to the main mill
        - Other fixed cost is increased by 1% of the TPC of the retrofitted plant (including contingency)
    - The increase in variable operating cost mainly includes:
- Increase in chemical cost due to the make-up MEA solvent and the additional NaOH needed by the CO_2 capture plant.
- Increase in utilities due to the additional process and cooling water required by the CO_2 capture plant.

- Increase in waste disposal due to the processing of sludge from the reclaimer.
- There is no increase in the fuel or raw material cost of the plant (except for cases where auxiliary boiler is deployed, thus additional fuel cost – i.e. forest residue/waste wood – is added).
    - One of the main impacts to the annual operating cost of the mill is due to the reduced amount of electricity that could be exported to the grid. This could result in reduced revenues of around 2 to 30 million €/y.
    - Additional operating cost outside the pulp production would include the cost of CO_2 transport and storage at 10 €/t of CO_2 captured. This could increase the cost by 1.9 to 19.8 million €/y.
- To evaluate the impact of the cost of CCS to the levelised cost or breakeven price of the pulp, six different scenarios were examined.
    - Tables 14 to 17 summarised the estimated levelised cost of pulp production and the cost of CO_2 avoided for all the cases examined under the six different scenarios.
    - It could be noted that the impact of retrofitting CCS to the cost of pulp production (for the market pulp mill and integrated pulp and board mill without and with CCS) could be classified under three different regimes based on the level of overall CO_2 capture rate (of the whole site). This include the following categories:
        - Category A: Overall capture rate between 5 and 15%
        - Category B: Overall capture rate between 65 and 80%
        - Category C: Overall capture rate of greater than 80%
    - On the other hand, the impact of retrofitting CCS to the cost of the pulp production (for the integrated pulp and board mill without and with CCS), the difference between Category B and Category C are minimal. This is due to the added cost of the auxiliary boiler.
    - Under Scenario 1, the cost of retrofitting CCS without any influence of the regulatory framework related to CO_2 emissions, and/or incentives provided to the renewable electricity and negative emission were examined. The results indicated that after the retrofit, the breakeven price of pulp would increase from

523 €/adt (for Base Case 1A) to 540 – 555 €/adt for cases under Category A; pulp price increases to 640 to 660 €/adt for cases under Category B; and increases to 675 €/adt for cases under Category C.

- For cases involving integrated pulp and board mill, the addition of the auxiliary boiler increased the breakeven price pulp in the range of 670 to 715 €/adt (mainly cases under Category B and C).
- With Scenario 1 (for the market pulp mill without and with CCS), it could be observed that most of the price increase could be attributed to the following:

	Category A	Category B & C
CAPEX of CCS Plant including modification to the mill	53-55%	49-51%
Fixed operating cost	21-24%	15-16%
Variable operating cost	8-9%	11-13%
CO_2 Transport and Storage cost	13-14%	21-22%

- Under Scenario 2, where CO_2 tax is set at 10 €/t and the biogenic CO_2 emissions are NOT tax exempt, the increase in the pulp price is considered modest at 4 to 12 €/adt for cases with higher capture rate (i.e. cases under Category B and C) if compared to the corresponding prices reported under Scenario 1.
- On the other hand, under Scenario 3 where CO_2 tax is set at 10 €/t and biogenic CO_2 emissions are tax exempt or Scenario 4 where additional incentives is given to the Renewable Electricity exported to the grid, the increase in the pulp price for all the cases is considered very minimal as compared to the corresponding prices reported in Scenario 1. This further demonstrates that if the biogenic CO_2 emission are recognised as CO_2 neutral and without any incentives to the negative CO_2 emission, then retrofitting CCS will only be seen as an added cost without any benefit to the mill's bottom line.
- Under Scenarios 5 and 6 with incentive provided to the negative CO_2 emissions at 10 €/t, it is expected that this incentive should offset the cost of CO_2 transport and storage – therefore reducing

the price of pulp as compared to the corresponding cases under Scenarios 3 and 4. Nonetheless, it should be noted that this is not true for cases where it involves the capture of CO_2 from the lime kiln where minimal reduction in pulp price is observed.

- Various sensitivity analyses where undertaken to determine the impact of the electricity selling price, CO_2 emission tax, renewable electricity credit and negative CO_2 emissions credit on the breakeven price of the pulp and cost of CO_2 avoidance. These are presented in the main report.
- The pulp and paper industry is a potential candidate for large-scale demonstration of bio-CCS that accounts for the negative CO_2 emissions. This could be considered as a low-hanging fruit and could lead to the first necessary business case for implementation of bio-CCS in the near future.
- However, it is essential to note that the feasibility of retrofitting CCS will strongly depend on the policy framework relevant to the CO_2 emission tax and incentives provided to the renewable electricity exported to the grid and to the negative CO_2 emissions.
- Providing a higher negative CO_2 emission credit may be the most favourable route to encourage the pulp industry to deploy CCS.

Recommendations

For future studies, it is highly recommended to evaluate the following case scenarios:

- Partial capture of CO_2 for any cases involving the capture of CO_2 from flue gas of recovery boiler and examines the performance and cost of the mill with CCS based on the limitation of the availability of excess steam on-site.
- The alternative option of a CCU project rather than CCS for cases with lower capture rates.

2016-11 REGIONAL ASSESSMENTS OF THE ECONOMIC BARRIERS TO CO_2 ENHANCED OIL RECOVERY IN THE NORTH SEA, RUSSIA AND GCC STATES

Key Messages

- Approximately 95% of all CO_2-EOR activity takes place in the U.S., and in 2010, CO_2-EOR projects were producing approximately 300,000 barrels of oil per day, close to 4% of total U.S. oil production. To achieve this quantity of oil, approximately 60Mt of CO_2, is injected annually into oil fields.
- The widespread success of CO_2-EOR in the U.S. could potentially be extended to other petroleum provinces around the world where it is technically and economically feasible. CO_2-EOR also offers the prospect of providing a commercial driver to develop and expand CO_2 storage and even CCUS.
- The main factor that will drive potential of CO_2-EOR uptake is the prevailing price of oil. The injection rate, capital expenditure (CAPEX), operational costs (OPEX) and tax incentives are of secondary importance.
- Investment in CO_2-EOR is highly constrained by the volatility of the price of oil. For EOR projects to remain profitable over their operational life the cost of supplied CO_2 supplied needs to fluctuate. One example from this study, based on the North Sea, shows that the cost of CO_2 could be ~35 €/tonne if the price of oil reached US$150/bbl but it would need to drop to ~2 €/tonne if the price of oil fell to US$50/bbl. In an onshore Middle East location CO_2 could be supplied at a higher cost (€8.2/tonne) at this oil price.
- Offshore production relies on fewer deviated wells with less spatial coverage of producing areas which is less advantageous for CO_2-EOR compared with onshore 5 or 9 spot closely-spaced injection and production well configurations commonly used in North America. This configuration provides a higher density and control for EOR operations.
- Experience with CO_2-EOR shows that the projected incremental recovery ranges from 7% to 23% of Original Oil in Place (OOIP). Estimates for CO_2-EOR recovery rates for the North Sea range from 4 – 18%.

- Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.
- The main factors that currently inhibit investment in offshore CO_2-EOR are the upfront investment costs, loss of oil production during work-overs and lack of significant CO_2 volumes.
- There is growing interest in CO_2-EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2-EOR pilot project into its Rumaitha oilfield and Saudi Aramco launched the Uthmaniyah CO_2-EOR demonstration project in July 2015.
- It is recommended that IEAGHG should conduct a follow up review of actual CO_2-EOR projects in Middle East and proposed projects in China (Offshore Guangdong Province) including the longer-term transition and/or incorporation of storage accounting / infrastructure development. An active watching brief should be maintained and when substantial information released its significance should be reported.
- A Review should also be conducted when North Sea developments reach an advanced stage particularly the deployment of subsea separation and injection systems and platform modification related to CO_2-EOR.

Background to the study

The use of CO_2 for enhanced oil recovery has been recognized as an effective technology for tertiary oil production. The first commercial CO_2-EOR project started in 1972 at the SACROC oil field, which straddles the border of west Texas and southeastern New Mexico. Approximately 20% comes from anthropogenic sources with the remainder sourced from natural fields. It has also been advocated for the North Sea, but economic conditions, particularly for offshore locations have to date, not been favourable. The objective of this study is to explore the economic conditions that would be necessary for a CO_2-EOR project in the North Sea and in the Middle East.

Traditional oil production can recover up to 20-40% of the original oil in place (OOIP). The application of an EOR technique, typically performed towards what is normally perceived to be the end of the life of an oilfield, can increase

the cumulative recovery by an additional 5-15%. The investment decision for a CO_2-EOR project hinges on key factors relating to geological site suitability, capital and operational costs. A number of identified success factors for the well-established CO_2-EOR industry in the U.S. are listed below:

- Depth and oil composition can enable CO_2 to form miscibility lowering viscosity
- There is sufficient unrecovered oil after primary and secondary recovery (usually water flooding)
- There is sufficient access to a reliable supply of CO_2
- Operator knowledge and experience can be applied
- Tax incentives to promote profitable implementation

The use of CO_2 for EOR does invariably lead to some permanent retention in producing fields, but in the longer term there is potential to use the technology to develop a storage infrastructure on the back of commercial or incentivized EOR. One of the main reasons for the limited use of CO_2-EOR outside the US is the lack of a CO_2 supply network. The development of a CO_2 pipeline network in the 1970s and 1980s benefited from oil price control exemption and tax incentives designed to boost US domestic oil supply[1].

An assessment of the suitability of over 50 of the world's largest oil producing basins strongly suggests that considerable technical potential exists for conducting CO_2-EOR in oil fields in multiple geographical regions outside the U.S., particularly in the Middle East, Russia and, to a lesser extent, in the North Sea region of Europe. In light of this, it seems prudent to assess the possible barriers to implementation which focus on the prevailing economic and regulatory conditions in certain regions.

Scope of Work

This report, compiled by the Dutch research organization, TNO, comprises of a literature review of ongoing and potential CO_2-EOR activities in the North Sea region, GCC countries and Russia, and two CO_2-EOR case studies. Current oil production trends and geological suitability have been reviewed to assess the potential of CO_2-EOR, and its future. A key part of this task was

[1] CRS Report for Congress, CO_2 Pipelines for Carbon Sequestration: Emerging Policy Issues, April 19, 2007

to compile and review the existing economic feasibility studies that have been conducted for each of the regions concerned, with an emphasis on the assumptions that have been applied to existing economic assessments of CO_2-EOR. These assumptions have been used within the case study modelling exercise. The literature review also highlights specific challenges for the future progression of CO_2-EOR.

To reflect how site-specific conditions might affect CO_2-EOR, two case studies, one offshore and one onshore, have been produced based on accurate contemporary cost data for CAPEX, OPEX and the cost of CO_2. In each case, a discounted cash flow analysis has been applied to calculate the NPV and the Internal Rate of Return (IRR) to determine the economic viability and identify which parameters have the greatest effect on economic viability. TNO's ECCO Tool has been used to generate each analysis and the impact of each parameter. The ECCO Tool is a software program designed to evaluate quantitatively the post-tax economics of CCS projects for each of the various mutually dependent factors along the CCS value chain. The ECCO tool can be used for studying the economic feasibility of CCS projects to be evaluated by commercial companies under different external and contractual conditions. The tool integrates cost engineering, transport and well/reservoir physics, planning, including the impact of contracts and physics on the sizing and timing of CAPEX and OPEX, and full post-tax economics. The ECCO Tool also provides maximum price, or 'gate-fee', that a CO_2-EOR can pay for a tonne of CO_2 at the well-head for an economically viable project. Each case study includes a sensitivity analysis to determine how different parameters affect the economic viability of a CO_2-EOR project.

Findings of the Study

North Sea

North Sea reservoirs have been assessed extensively for CO_2-EOR opportunities, but, so far, no projects have been implemented. In the Norwegian sector, several fields have been investigated, particularly Draugen, Grane, Oseberg East, Brage, Heidrun, Volve and Gullfaks. In the UK, The Miller and Forties oil fields and a number of others have been assessed for CO_2-EOR, but none have proved to be economically viable. Despite the extensive and successful track-record of CO_2-EOR in the US there are some formidable

challenges with offshore implementation into a mature region like the North Sea. In North America 5 or 9 spot closely-spaced injection and production well configurations are commonly used providing higher density and control for EOR operations. Offshore production relies on fewer deviated wells with less spatial coverage of producing areas.

Not all fields in the North Sea are suitable for this EOR technology. For example the Statfjord and Brent fields are unsuitable because they have been depressurised.

The increased oil recovery rate from CO_2-EOR is dependent on reservoir properties, oil recovery rates of preceding recovery methods and the EOR strategy. Experience with CO_2-EOR shows that the projected incremental recovery ranges from 7% to 23% of Original Oil in Place (OOIP). Estimates for CO_2-EOR recovery rates for the North Sea range from 4 – 18%. A figure of 10% was adopted for the case study models. Previous studies have assumed a recovery rate of between 1-3 barrels/tonne of CO_2 injected[2],[3]. Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.

One of the main barriers to the adoption of CO_2-EOR in the North Sea is the economic penalty caused by lost production over long shut-down times when platforms are modified with additional process equipment (pipes and vessels) and corrosion resistance. Other factors include:

- Timescales for decommissioning (example: when an oilfield is decommissioned, the cost of reinstalling the oil production for EOR is too expensive)
- Limited space and weight margins at the platforms, and high costs associated with close-down in connection with modifications of the platform
- Engineering challenges caused by a mixture of CO_2 and brine which will corrode carbon steel and will demand more expensive corrosion resistant

[2] SCCS, 2015 Enhanced oil recovery in the North Sea: Securing a low carbon future for the UK.
[3] Hill, B, Hovorka S and Melzer S, GHGT-11. Geologic carbon storage through enhanced oil recovery "Energy Procedia 37 (2013) 6808 – 6830

alloys. The engineering of corrosion management is well developed and includes many technologies, including corrosion inhibition additives, cathodic protection with sacrificial electrodes, and various specifications for different parts of the wells in contact with wet CO_2, such as coatings as well as metals such as chrome steel.

- Shared equity ownership of oil fields
- High oil taxation
- Commercial, communication and cultural barriers
- Liability issues
- Diverse KPIs for different stakeholders
- Lack of political support from most environmental NGOs for CO_2-EOR
- Scepticism around early development of CO_2-EOR
- The lack of an established CO_2 supply network either via pipeline or tanker.

Several previous studies have concluded that CO_2-EOR in the North Sea is possible and that there is a considerable potential, however there are significant hurdles. The main factors are the upfront investment costs, loss of oil production during work over and lack of significant CO_2 volumes. Development of the CO_2-EOR supply chain is a major hurdle, which includes platform work overs, CO_2 capture plants, transport infrastructure, and the possible development of a permanent storage site (relief site) for the CO_2. Presently, the economic situation in Europe coupled with the very low EU-ETS CO_2 price (approximately 8 €/tonne CO_2), and an unclear political framework, does little to trigger the much needed large-scale implementation of CCS from the industrial and power sectors.

Both Norway and UK have a relatively high oil tax. The oil tax is 50-75% for UK and 78% for Norway, but there is an investment allowance of 62.5% for Supplementary Charge (see foot note)[4]. It is conceivable that at very low oil prices these rates might change but not necessarily favourably for incentivising investment in CO_2.

[4] In the UK sector of the North Sea the Supplementary Charge is an additional charge on a company's ring fenced profits. This charge only applies to companies involved in the exploration for, and production of, oil and gas in the UK and on the UK Continental Shelf

In a previous example, the BIGCO2 project in 2009, the economic and capacity potential of the North Sea was studied. A techno-economic model was developed for a network consisting of 18 Norwegian and 30 UK oil fields. The project lifetime was set to 40 years with a discount rate of 7%. The case study was based on an infrastructure where CO_2 was collected from sources in Europe, and gathered in Emden (Germany) and Aberdeen (UK). From there, CO_2 was delivered by pipeline to the Ekofisk area and further to the Tampen area. The annual volumes of CO_2 injected were estimated to 178 Mt. After CO_2 breakthrough, the CO_2 produced with the oil was separated out and reinjected. CO_2 was injected into the oil reservoirs as long as the cash flow was positive. The results of this exercise are summarised in Table 1 assuming an oil price of US $80/barrel. The associated breakeven cost for CO_2 is US$44/tonne delivered.

Item	Value	Unit
Total oil produced	4,706	Million Sm^3
Total oil recovery factor	60.6	% HCPV
EOR oil	682	Million Sm^3
Incremental oil recovery factor	8.8	% HCPV
Total stored CO_2	7,254	Mt
CO_2 stored in oil reservoirs	2,284	Mt
Total investment costs	58,234	Million USD
Total operation costs, excluded CO_2 purchase	2,858	Million USD/year

Table 1: BIGCO2 Project Estimate of stored CO_2 in the North Sea due to EOR operations

Although the current economic situation does not favour CCS, there is political support for offshore CO_2 storage in some countries bordering the North Sea. The technology is seen as a potential stepping stone towards full-scale CCS. CO_2-EOR is currently the only utilization option that can offset a considerable amount of CO_2, in addition to plain storage.

Some other innovations may aid the future development by offering flexibility and cost reduction in CO_2 supply. Ship transport has recently seen an increased interest. It is flexible, which is important in a start-up phase.

For smaller volumes, longer distances and a limited number of years, ship transport is more cost efficient than pipeline transport. Another option is subsea processing installations which are currently under development and are expected to significantly decrease the lost production due to a reduction in the time for rebuilding the process equipment, as well as investment cost of CO_2-EOR. Conversion of decommissioned CO_2-EOR oil fields to CO_2 storage projects could also provide delayed decommissioning costs for platforms etc. and even additional revenue after the EOR operations.

Russia

Russia is the second largest oil producer after Saudi Arabia. In 2014 the country's share of global production was 12.7%. However, many of the largest Western Siberian fields have been in decline which has encouraged some Russian oil companies to invest in EOR to sustain current levels of production. The potential for CO_2 is hampered by the lack of climate change mitigation or carbon management policy. Moreover there are no specific policies to develop CCS despite being the world's fourth largest CO_2 emitter.

A range of EOR technologies have been applied to boost production levels with the exception of CO_2-EOR. In the past, there have been trials with CO_2 enhanced production in Russian oil fields. There are reports on large scale pilot tests conducted in the 1980s, using CO_2 from petrochemical plants. Cumulative injected volumes ranged from about 50,000 tonnes to more than 750,000 tonnes of CO_2 that were injected into the Radaevskoye, Kozlovskoye, Sergeevskoye and Elabuzhskoye oil pools. Additional oil volumes in the order of 12% were obtained. The projects faced problems in terms of sufficient CO_2 supply and corrosion of the pipelines and equipment. Despite the relative success in terms of additional oil recovered, these pilots have not led to larger-scale EOR projects with CO_2.

Countries of the Gulf Co-operation Council

The Gulf Co-operation Council (GCC) was established in 1981 to develop intergovernmental and economic union between Arab states that surround the Persian Gulf. Collectively the region is responsible for approximately a quarter of global oil production. With continued production from mature fields there is widespread use of EOR techniques particularly the use of injecting natural gas to reduce the viscosity of oil, although there

is an increasing demand for natural gas for power generation and as a petrochemical feedstock. Consequently, there is growing interest in CO_2 for EOR. Some estimates have calculated that as much as 141 billion barrels could be recovered from Saudi Arabia alone.

A previous screening study to assess the suitability of Middle Eastern oil for CO_2-EOR has suggested that out of 48 reservoirs screened in GCC countries 32 would be suitable candidates for the recovery technique. Oil reservoirs in both Saudi Arabia and the UAE are overwhelmingly suitable for CO_2-EOR applications, with approximately 90% of the oil fields suitable in each country. Table 2 summarises the total number of suitable reservoirs for CO_2-EOR by country.

Country	No. of reservoirs assessed	No. of reservoirs meeting suitability criteria
Bahrain	2	0
Kuwait	5	4
Oman	11	4
Qatar	10	6
Saudi Arabia	9	8
United Arab Emirates	11	10
Total	**48**	**32**

Table 2: Number of suitable fields for CO_2-EOR by GCC Country

There are several large point sources of CO_2 throughout the GCC region which is clearly evident from Figure 1. However, although quite abundant across the region the concentration of CO_2 in flue gases from combine cycle gas-fired power stations is ~3-4%. CO_2 from this source is estimated to be US$80/tonne. At this price CO_2-EOR would only be viable at sustained high oil process. Data from 2007 identified only two possible 'high purity' sources in the region generating 13 Mt/year.

Figure 1: Location of large point sources of CO_2 (≥ 0.5 Mt/year) in the GCC region

A single economic evaluation of CO_2-EOR in a GCC has been completed using generic cost components for capture, transport and injection of CO_2. The study used a 'typical' Middle Eastern sandstone reservoir. The CO_2 source was a large CCGT power plant with the ability to deliver up to 2.5 Mt CO_2 via an 80 km by 30 inch pipeline to the target reservoir. The costs of CO_2 capture from the CCGT assumed as US$38 tonne. Due to the considerable infrastructure needed, the total operational and capital expenditure for the project over 35 years (oil production commenced after 5 year construction) was considerable, at approximately US$7 billion (2010).

The results of the economic evaluation were positive, with an overall recovery rate of 58% (OOIP). Based on a constant oil price of US$75, and a 15% discount

rate, the NPV at the end of the project was calculated as US$3.77 billion. The report also includes an extensive sensitivity analysis, which amongst a range of outcomes, highlights the sensitivity of the prevailing oil price and the effect on the NPV of the project. Specifically, a 50% increase in oil prices increased the NPV of the project by 89%.

The two key factors that will drive potential uptake are the cost of CO_2 and the prevailing price of oil. A previous analysis of the proportionate influence of these two factors is summarized in Figure 2. The relationship depicted in this graph clearly shows that low CO_2 prices and high oil process provide the most favourable economic conditions for CO_2-EOR. It is also clear that high CO_2 prices has the most negative impact on the economic productivity of original oil in place (OOIP).

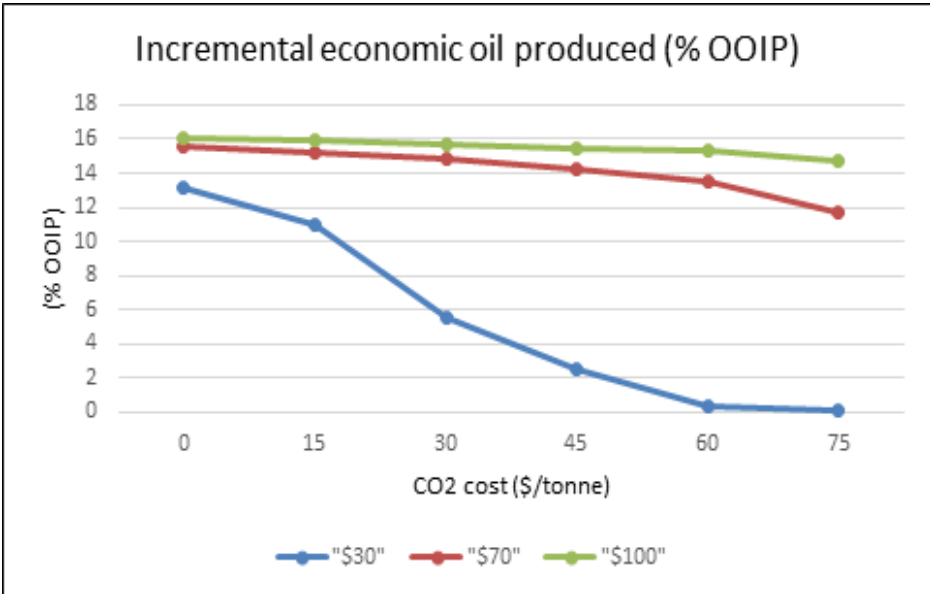


Figure 2: Influence of Oil Price and the cost of CO_2 on economic oil production

There is growing interest in CO_2-EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2-EOR pilot project into its Rumaitha oilfield. The trail achieved a 5-7% increase in oil production

rate prior to CO_2 breakthrough. Saudi Aramco launched the Uthmaniyah CO_2-EOR demonstration project in July 2015. 0.8 Mt of captured CO_2 is transported 70 km by pipeline for injection. There are 4 injection wells, 2 observation wells and 4 production wells.

Case Studies

To test how site-specific conditions might affect the economic feasibility of CO_2-EOR projects, two case studies based on a North Sea and a Middle East scenario were constructed. These case studies were developed using TNO's ECCO tool using contemporary cost data for CAPEX and OPEX. The ECCO Tool is a programme designed to quantitatively evaluate the post-tax economics of CCS projects taking account of the key parameters that are integral to each project. These case studies were developed to test two important questions: what is the maximum CO_2 wellhead price for an economically feasible EOR project in the North Sea and the Middle East; and what is the effect of the different parameters on the CO_2 wellhead price?

In each case a discounted cash flow analysis is applied to calculate the Net Present Value (NPV) and the Internal Rate of Return (IRR). Each case study includes a sensitivity analysis to determine how the key parameters affect the economic viability of the CO_2-EOR project. These models assume a 30 year life for each project. Unfortunately due to the volatile political climate in Europe it was not possible to gain access to information on the Russian oil industry. Commercial confidentiality also constrained access consequently these case studies have been devised using assumptions that are representative of reservoir characteristics in each region. CAPEX and OPEX have been taken from a Zero Emissions Platform (ZEP) study in 2011. The IRR for the North Sea was 12% and 25% for the GCC region to reflect different market dynamics of the two regions. A 0% rate of tax has been assumed for GCC countries as the vast majority of oil production is controlled by national oil companies.

The base scenario in the North Sea provides a maximum CO_2 price at the well-head of €18/tonne, with a range between €1.9/tonne and €34/tonne. The sensitivity analysis indicates that the prevailing oil price and the injection rate have the highest sensitivity on the IRR. The pressure in the box model assumes a constant flow of CO_2 during EOR. A higher injection rate will lead to a higher production rate this explains the high sensitivity on the

IRR. Increasing the injection rate, from 5 Mt/yr in the base case to 9 Mt in the upside case also has a positive effect on the maximum gate fee. With a higher injection rate, the operation facilities (like compressor, injection wells) are more optimally utilized compared to a low injection rate which results in costs savings and allows a higher CO_2 price to be paid.

In the case of the North Sea a 12% IRR can only be achieved if all conditions in case study can be met over the technical life of the project (i.e. 30 years and that operational parameters remain within the boundaries defined in the case study). For example, with a high price of oil at US$150/bbl a 12% IRR could be sustained with a higher price for CO_2 (~35 €/tonne). Similarly at US$50/bbl CO_2 would have to be ~2 €/tonne to sustain a 12% IRR. Therefore for a project to remain profitable (assuming a consistent 12% IRR) the delivered CO_2 price would need to be adjusted with a fluctuating oil price.

The inference of the 'tornado' diagram (Figure 3) implies that increasing incremental oil production (STOIIP) through CO_2-EOR would benefit from a lower price for CO_2, (upside) but increasing the injection rate is also positively beneficial (upside) and should therefore result in higher EOR recovery. This implies that increasing CO_2-EOR production through a higher injection rate also requires a reduction in the price of CO_2 to maintain the 12% IRR. The inference from the 'tornado' diagram is that a higher price for CO_2 can be tolerated if the price of oil, or injection rate, is increased but increasing production from CO_2-EOR only benefits from a decrease in the price of CO_2 for incremental production.

The base scenario in the GCC region (Figure 4 on page 69) provides a maximum CO_2 price at the well-head of €21/tonne, with a range between €8.2/tonne and €48.1/tonne. An increased injection rate has the same impact as in the North Sea. Higher injection rates profit from the economy of scale and the oil operator is able to accept a higher CO_2 price at the wellhead. The lower CAPEX and OPEX of the onshore operations, and the exclusion of taxation and royalties on the additional incremental oil produced, allow higher CO_2 prices to be paid at the wellhead across the range. The higher required IRR at 25% reduces the difference in the CO_2 wellhead prices between the North Sea and GCC region.

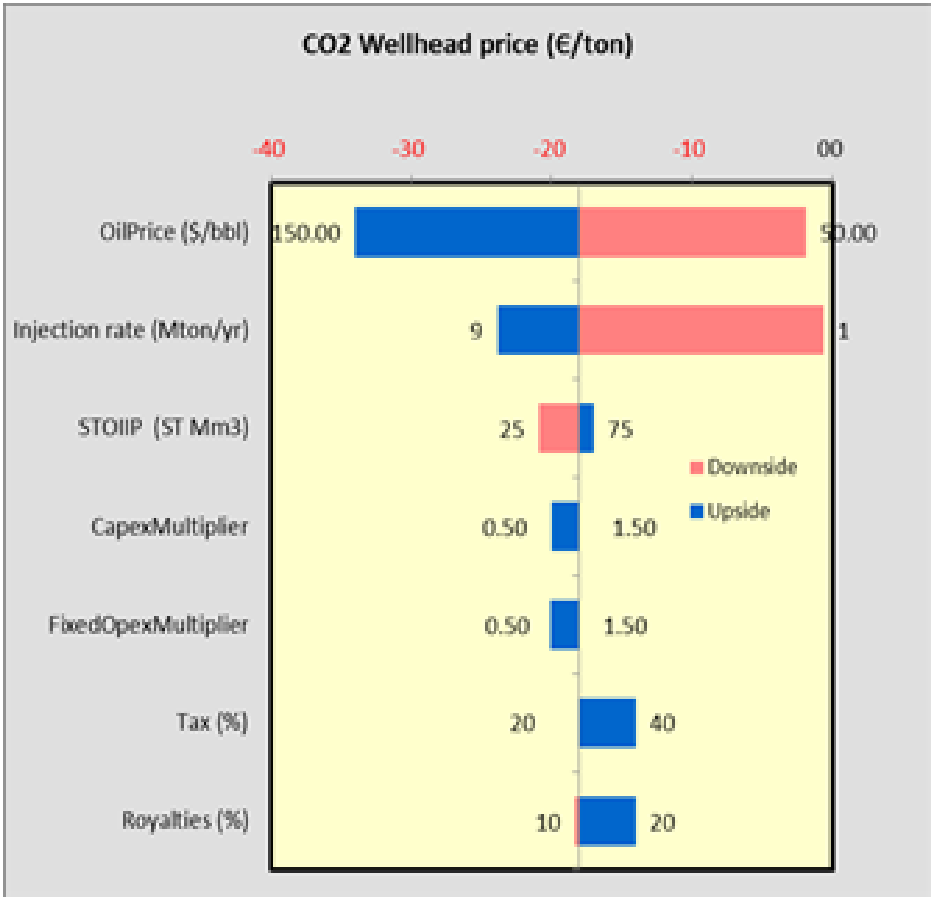


Figure 3: Sensitivity analysis of the North Sea case study

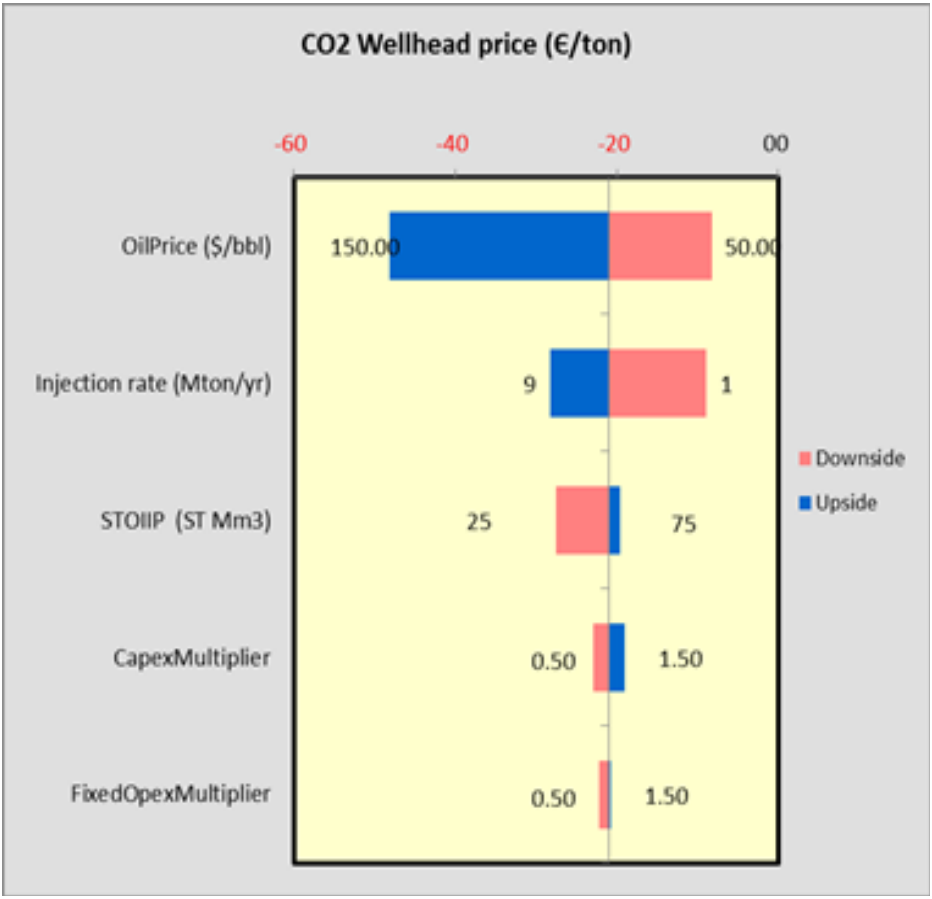


Figure 4: Sensitivity analysis of the GCC case study

Expert Review Comments

- This a well-conceived and well executed study that attempts to integrate a number of different studies and run some consistent economic scenarios to illuminate the value and barrier to CO_2-EOR in several highly prospective parts to the world. The broad conclusions seem reasonable and are well justified. It is unfortunate, but not unexpected, that detailed industry input into the modelling for Russia and GCC was not given.

- At times the approach is overly precise on calculations in the absence of data, and not clear enough on the weaknesses and uncertainties in the approach, given the lack of CO_2-EOR development and experience in the three chosen regions.
- In the case of the North Sea, the report has the opportunity to build upon considerable work from the UK, Norway, and Europe. The review of the current status in the Gulf Cooperation Council region is much better, reflecting the status quo and high level of interest in CO_2-EOR in this part of the world in recent years. In all three regions, the assumptions relating to oil price could be better justified, with perhaps an overemphasis on a $100/bbl scenario.
- There is some uncertainty/incorrect understanding of the concept and importance of recycle CO_2 for EOR, which is different than most other types of secondary and tertiary recovery. In all CO_2-EOR operations, CO_2 is produced with the oil and water. The oil, water and CO_2 must be separated, and the CO_2 compressed from atmospheric pressure. The reuse of produced CO_2 is considered essential for all existent CO_2-EOR projects in order to process more of the reservoir.
- A constant incremental recovery efficiency to CO_2-EOR has been assumed, but changing the STOIIP, does not give a true indiction of this impact. This is an important factor that should be considered, since any set of conditions that support the economic feasibility of CO_2-EOR projects will depend on the potential incremental production from CO_2-EOR.

Conclusions

- In the Norwegian sector, several fields have been investigated, particularly Draugen, Grane, Oseberg East, Brage, Heidrun, Volve and Gullfaks. In the UK, The Miller and Forties oil fields and a number of others have been assessed for CO_2-EOR, but none have proved to be economically viable.
- Based on previous estimates of suitable fields, and a 3 barrel/tonne of CO_2 recovery rate, the estimated incremental oil potential for the Norwegian sector could be 3,535 M barrels that would require 1,180 M tonnes of CO_2. In the UK sector an additional 2,520 M barrels could be recovered with 840 M tonnes of CO_2.

- One of the main barriers to the adoption of CO_2-EOR in the North Sea is the economic penalty caused by lost production over long shut-down times when platforms are modified with additional process equipment (pipes and vessels) and corrosion resistance.
- The two key factors that will drive potential uptake are the cost of CO_2 and the prevailing price of oil.
- Both case studies conducted as part of this study clearly show that the oil price and the injection rate are the two predominant factors that influence the CO_2 wellhead price.
- The most significant barriers to the uptake of CO_2-EOR in all three regions investigated are the high cost of CO_2 supply. The high capital costs of offshore infrastructure, high taxation and lack of fiscal incentives are added disincentives for development in the North Sea.
- There is growing interest in CO_2-EOR in the Middle East. The Abu Dhabi National Oil Company (ADNOC) has implemented a CO_2-EOR pilot project into its Rumaitha oilfield and Saudi Aramco launched the Uthmaniyah CO_2-EOR demonstration project in July 2015.

Barriers to CO_2-EOR Deployment

Experience from North America clearly demonstrates that the use of CO_2 for EOR can be technically proficient and commercially viable. The widespread use of the technology has led to the development of an efficient pipeline supply which now includes anthropogenic sources. All three regions investigated in this study are suitable candidates for CO_2-EOR and would benefit from US and Canadian experience, however significant barriers remain. These include

The North Sea

- High capital costs of offshore infrastructure
- High cost of CO_2 supply
- High taxation of oil revenue
- No specific fiscal incentive for CO_2-EOR operations
- Limited climate policy for CO_2 storage

GCC States

- Limited knowledge of natural CO_2 accumulations
- High cost of CO_2 supply (mainly gas power plants)
- State-owned oil and gas system limits commercial risk-taking for EOR?
- No climate policy for CO_2 storage

Russia

- Limited knowledge of natural CO_2 accumulations
- Large distances between CO_2 sources and oil-producing areas
- High cost of CO_2 supply
- Taxation system not adjusted for mature fields with EOR operations
- No climate policy for CO_2 storage

Recommendations

- Conduct a follow up review of actual CO_2-EOR projects in Middle East and proposed projects in China (Offshore Guangdong Provence) including the longer-term transition and/or incorporation of storage accounting / infrastructure development. Keep an active watching brief and wait until there is substantial information released.
- Review the EOR-MRV example in Texas by Occidental.
- Review in detail when North Sea developments reach an advanced stage particularly the deployment of subsea separation and injection systems and platform modification related to CO_2-EOR.

2016-13 FAULT PERMEABILITY

Key Messages

- CCS requires the secure retention of CO_2 in geological formations over 1000's of years. To achieve this, characterisation of target injection formations, and their structural features including faults, is essential to ensure leakage does not occur.
- Faults can either act as barriers to fluids, or as conduits for migration. Consequently, the properties of faults that dissect or form a boundary with potential CO_2 reservoirs, need to be determined.
- The significance of faults has long been recognised in the petroleum, mining and geothermal industries, but CO_2 storage is less mature and more experience and research related to faults would be beneficial.
- The objective of this study was to review recent research on the permeability (a measure of the ability of rocks to transmit fluids) of faults in CO_2 storage, particularly how different geological processes can either cause faults to help retain fluids within a reservoir, or lead to migration along or across faults. It builds upon an earlier study which looked at the role of geomechanical stress on faults[1].
- There is widespread experience of working with faults and fractures and provided there is sufficient characterisation of their properties they should not restrict storage development.
- If fault zones are present they need to be carefully characterised to ensure the development of an effective containment assessment and to inform the development of operational constraints and monitoring plans.
- A number of mitigation measures have been proposed to counter potential leakage. These include hydraulic barriers, biofilms, reactive cement grout and CO_2 back-production. Changing subsurface pressure has been seen to be effective: there is strong evidence of the reduction in flow of a natural hydrocarbon seep caused by depletion of an offshore oil reservoir hydraulically linked to the seeps.

[1] Criteria of Fault Geomechanical Stability During a Pressure Build-up 2015-04

- This work takes this research area as far as it can be taken without access to more fault-seal calibration datasets. IEAGHG will maintain a watching brief for any new information that comes into the public domain in the future.

Background to the Study

Fault zones are widely recognised as being important to the secure long term storage of CO_2 as they could provide a leakage pathway out of the target reservoir. Fault characterisation within reservoirs, especially where they extend into caprock and other overlying formations, needs to be thoroughly understood as part of any risk assessment for CO_2 storage. The aim of this study is to review what is known about the permeability of fault zones in order to highlight under what circumstances faults may impact overall storage integrity.

The behaviour of fault zones in relation to sub-surface fluid migration is important to many industries and consequently has been comprehensively documented in the literature. CO_2 operations involve the injection and pressurization of reservoirs usually resulting in changes to the state of in-situ stresses which may alter fault properties. Instability can lead to slippage along pre-existing faults or fracture systems, which may be associated with seismicity. In addition, the movement of faults, and the generation of factures within the damage zone adjacent to the core, may create conduits that lead to the leakage of fluids to the surrounding overburden or even to the surface.

In 2015 IEAGHG published a study reviewing the geomechanical stability of faults during pressure build up which provided a helpful background to the behaviour of faults in stress regimes relevant to CO_2 storage. This study is designed to build upon the previous work and provide a significantly broader review of the current state of fault zone permeability and also to investigate what mitigation options may be available to CO_2 storage operations if leakage was to occur.

Scope of Work

This report, produced by GNS Science, provides a succinct and relevant overview of the complexities that control fault permeability in the context of CO_2 storage. It provides a background guide on recent research on fault

permeability in formations that are good candidates for CO_2 storage. In addition it draws from a number of examples of natural fluid/gas leakage along fault zones and highlights what conclusions can be drawn from these observations. The project examines the variables that control fault permeability and reviews the methods that may be available to control leakage should it occur. It also provides a summary of recent and ongoing research at CO_2 storage demonstration sites across the world which relate to fault zone permeability.

Findings of the Study

Fault Zone Structure and Permeability

There is widespread evidence that faults can act as seals and as potential fluid migration routes. Hydraulic conductivity and permeability are positively related to fracture aperture although high pore fluid pressures and/or preferential stress alignments are not a prerequisite for enhanced hydraulic conductivity. Open fractures are most likely to modify bulk conductivity in low permeability caprock and can increase permeability by as much as three orders of magnitude. Fracture permeability decreases with an increase in effective stress which generally increases with depth. Pore pressure is still important, especially in aquifers where it can be increased by fluid injection or decreased in depleted reservoirs by production.

Evidence for the low permeability of fault zones is provided by across-fault pressure changes, compartmentalisation of reservoirs by faults, low measured flow rates in fault zones, the differential subsidence caused by water production, and by the accumulation of large volumes of hydrocarbons against fault planes. Snøhvit CO_2 re-injection is an example where a rapid rise in reservoir pressures due to fault compartmentalisation and impermeability resulted in an operational switch to a stratigraphically higher injection interval.

Fault-zone conductivity and transmissivity are controlled by many interdependent factors including among others; fault architecture and the types of fault rocks present in a given location, mechanical strength and permeability of the host lithology, fracture aperture size and connectivity, fluid composition, pressure and gradients, extent of pre-existing mineralisation and the orientation and magnitude of normal and shear stresses.

The key factor that controls vertical conductivity is orientation of effective stress acting on a fault. There is a risk of leakage where fault zones have no tensile strength and the effective normal stress acting on a fault is near zero. These parameters can be measured and used to predict whether a fault acts a seal or a conduit.

Lateral migration across fault zones is related to the level of impermeable material that gets entrained into faults during deformation and motion. The petroleum industry uses the clay smear potential and shale gauge ratios (SGRs) to estimate this effect. The higher the clay content the lower the permeability and the higher the capillary pressure. However, these factors control flow into a fault and do not influence vertical migration which is influenced by the adjacent stress field.

Parameters Influencing Fault Permeability.

Fault zones are four-dimensional volumes of deformed rock with highly anisotropic and heterogeneous properties that evolve through time. These fault-zone complexities produce variations in structure along strike and down dip, and even over relatively short distances show at least three orders of magnitude (1×10^{-18} to 3×10^{-15} m^2) variation in permeability across a 4 m wide fault zone where both the highest and lowest permeabilities measured are in proximity to the primary slip surface (Figure 1 on page 77).

Fault permeability can be highly sensitive to any change in the effective stress acting normal to the fracture plane (i.e., stress dependent permeability) and, in some cases, may be increased by rising reservoir pressures during CO_2 injection.

Fault-zone structure, mechanics and fluid-flow properties are inextricably coupled and should not be considered in isolation. When the conductivity of a system is considered, the fluid type must be accounted for. However, a distinction needs to be made between lateral migration within pores in a reservoir, or lateral movement into a fault zone, and vertical migration via fractures in a fault zone.

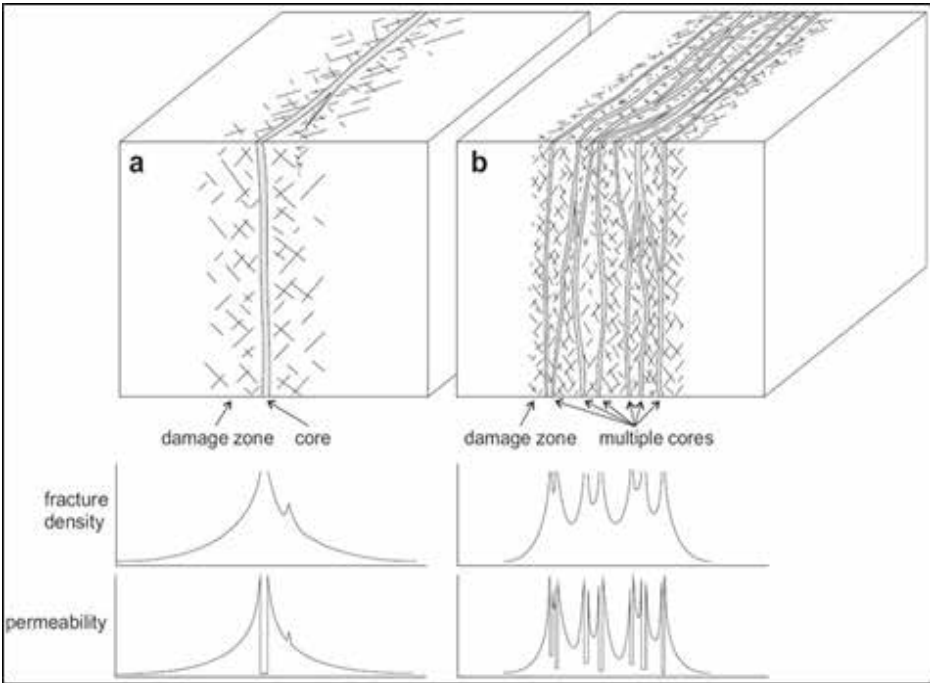


Figure 1: Structure of single core and multiple cores fault and the associated hydro-mechanical properties of fault zones (after Faulkner et al., 2010)

Host Rock Lithology and Fault Displacement

The host rock lithology, depth of burial, as well as fault displacement governs the type of fault deformation and influences permeability. Quartz and feldspathic rich rocks such as sandstones will form cataclasitic (a rock formed by progressive fracturing and comminution of mineral grains) textures within fault cores. At relatively low confining pressures (e.g. near surface depths < 1 km), these lithologies are characterized by grain reorganization without grain fracturing and tend to have comparable hydraulic properties to their protolith sandstones. At higher confining pressures (e.g. burial depths >1 km) cataclastic processes dominate deformation, resulting in higher capillary threshold pressures and lower fault rock permeabilities (typically 2–3 orders of magnitude below host rock) through grain fragmentation and associated infilling of pore-space. At >3 km and temperatures >90 °C disaggregation zones and cataclasites are prone to post-deformation quartz cementation

and clay alteration.

Permeabilities measured in phyllosilicate-framework fault rocks (i.e. impure sandstones with clay content between 15% and 40%) typically range from $< 10^{-19}$ to 10^{-16} m^2. Phyllosilicates are silicate minerals that have a sheet like structure and include clay minerals which are hydrated alumino-silicates often formed through weathering or mechanical deformation including faulting. As the clay content of a rock increases above 40% it will form clay smears. Natural fault gouges measured under laboratory conditions simulating burial depths of ~4 km (100 MPa) show ultra-fine gouge permeabilities ranging down to 10^{-21} m^2. For comparison caprock permeabilities are 10^{-18} m^2 or lower (Figure 2).

Although fractures in the damage zone are a focus of present research, internal fault zones also display high permeabilities (2-4 orders of magnitude higher than the host rock).

- High fluid pressures at depth can be transient resulting in episodic fluid flow.
- Pre-existing mineralisation of faults and fractures can have a greater control on bulk permeability than compressive stresses.
- Supercritical or water saturated CO_2 may increase or decrease permeabilities within fault and fracture networks through dissolution depending on the minerals present. Mineral precipitation caused by CO_2 fluids may enhance sealing properties.
- Shale and other mudrocks are well known for their tendency toward plastic deformation or creep while under stress that may close or seal fractures. Under certain conditions, such as overconsolidation, shales can become brittle and form vertical fractures.

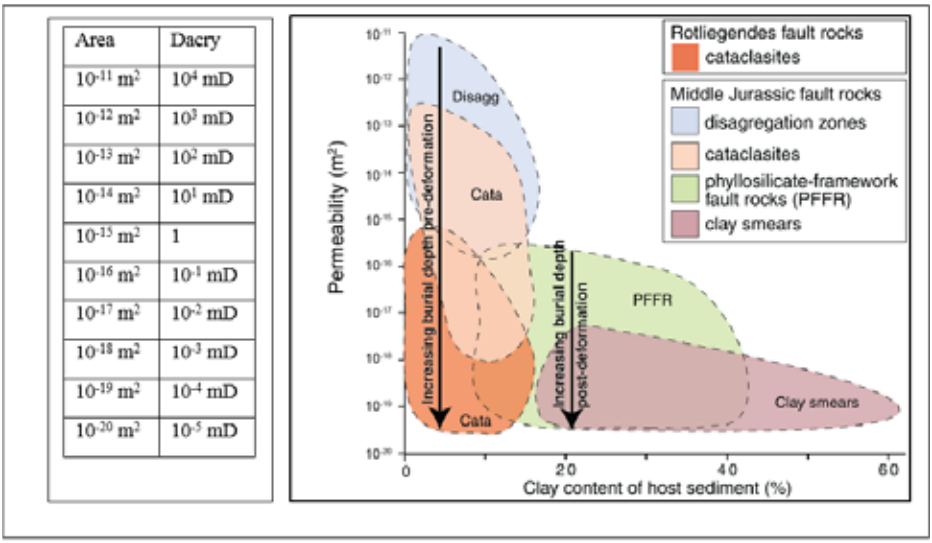


Figure 2: Summary of fault rock permeability data from the North Sea and Norwegian Continental shelf. Permeability is plotted against clay content for the various fault rock types. Also shown are the two main controls on the permeability of the faults in clean sandstones and impure sandstones (PFFR) (i.e. burial depth at the time of faulting and post-deformation burial depth, respectively)

The permeability of faults within siliciclastic petroleum reservoirs of the North Sea and Norwegian Continental shelf show variations of 2–3 orders of magnitude in permeability of clay-rich and cataclastic faults for a given depth (Figure 2 above). Understanding the variability of fault permeability for a given fault or system of faults therefore requires multiple samples of fault rock from a variety of locations along fault-zones, a condition that is rarely achieved in individual studies.

An understanding of the burial and/or exhumation history of a fault is also important when considering its hydrogeological properties (see Figure 3). A range of fault and fracture properties, both hydraulically conductive and sealing, can be present in a single region for example the West Sole gas fields of the southern North Sea. In this area, core samples indicate all early formed faults and fractures were likely to be sealing, particularly those at maximum burial depth and reservoir temperature. Breached or conductive faults formed later during inversion, when brittle.

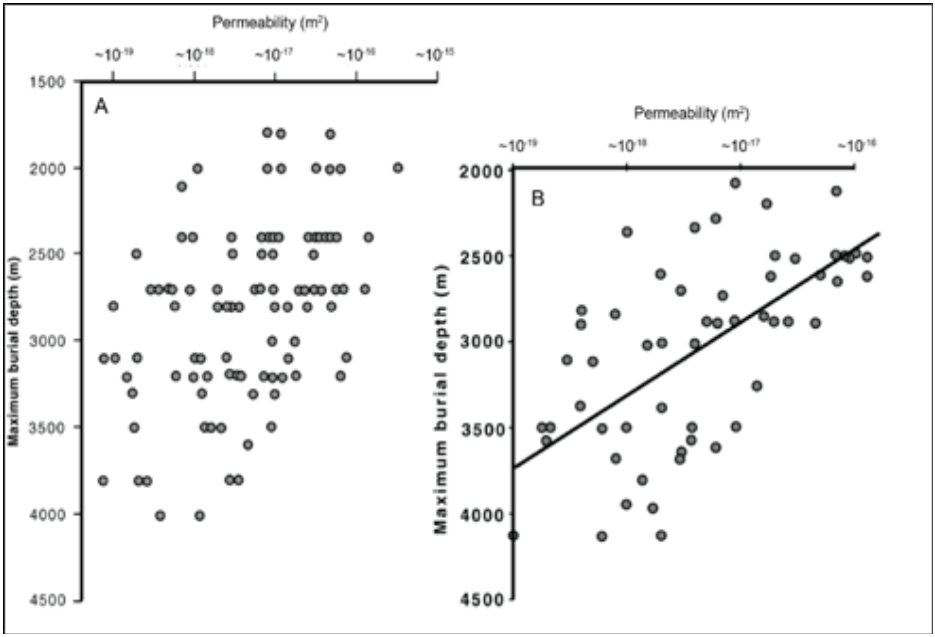


Figure 3: Permeability of phylosilicate-framework and cataclastic fault rocks from the North Sea. A) Permeability of cataclastic fault rock against their maximum burial depth from Rotliegendes of the Southern North Sea. B) Permeability of phylosilicate-framework fault rock against their maximum burial depth from the northern North Sea.

In summary, the primary factors controlling the hydrogeological properties of a fault include:

- the composition and rheology of the host rock and its phyllosilicate clay mineral content
- the maximum temperature and depth of burial during faulting which can affect diagenesis of fault zone rocks by inducing mineralisation.
- the stress regime at the time(s) of faulting, during any subsequent deformation event as well as the present day.
- composition of syn- and post-kinematic fluids and their reaction products

This combination of factors make site specific observations of in situ fault properties critical to understanding the response of faults and their associated fracture networks to elevated pressures induced during CO_2 injection.

Geomechanical Properties

Mechanical stratigraphy – ie. response to mechanical failure of different lithologies (rock types, summarised in Figure 4) can create fault dip variations causing additional fault zone complexities such as splaying and the development of antithetic faults. Dilation of normal faults at lithological boundaries can significantly enhance vertical fluid flow at the surface, and create pathways for along-strike fluid migration in the subsurface. Recognition of the influence of mechanical stratigraphy on fault geometry is an important component of the characterisation of faulted aquifers, hydrocarbon reservoirs, and mineral provinces.

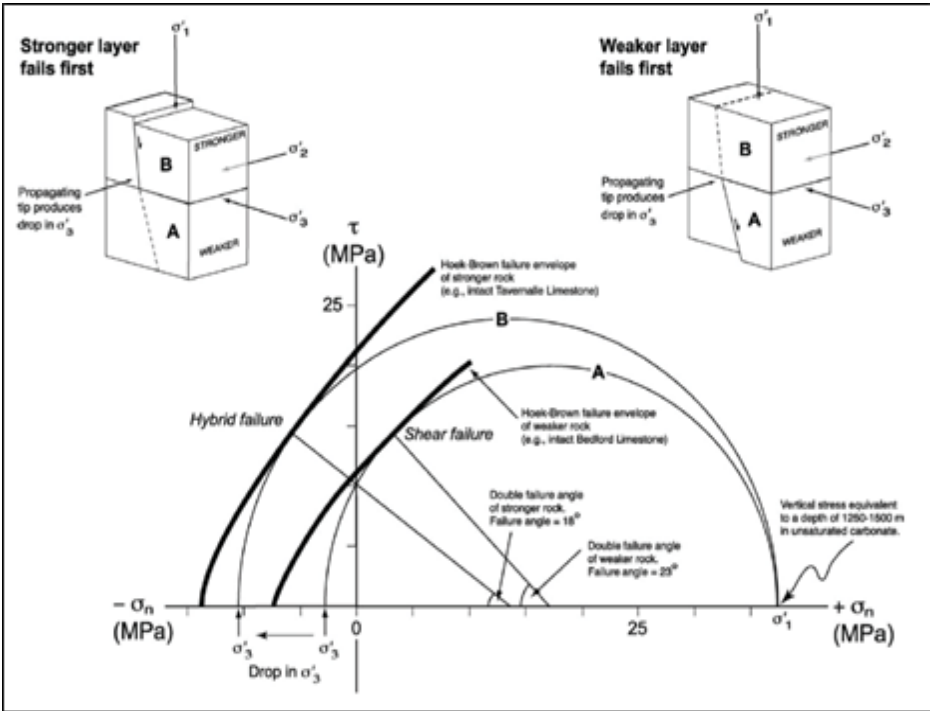


Figure 4.: Mohr-space diagram illustrating how contrasting mechanical stratigraphy leads to different failure mode and failure angles in different layers. A more competent rock is more likely to fail in hybrid mode than a less competent rock under the same stress regime (in this case normal faulting).

The mechanical properties of sedimentary sequences influence failure angles and fault dip, whereas layer thickness influences the height of dip segments. A number of algorithms have been developed to assess lateral migration of fluid across fault zones according to the clay smear and mixing conceptual models (SGR most widely used). In a number of cases these have been positively correlated to oil and gas column heights and capillary threshold pressures although these are rare and more research is needed to reduce uncertainties associated with these models.

This study concludes that understanding the effect of host rock mechanical properties on fault deformation processes, in combination with burial history, is key to the development of realistic fault structure and permeability models.

- Few studies have focused on the geometries and flow properties of faults in caprock sequences and this is a weakness in the literature.
- Polygonal faults overlie many commercial scale hydrocarbon reservoirs, indicating these faults often do not compromise caprock integrity and/or that the faulted mudstones are not the primary seal.
- Estimating damage zone thickness from the displacement or length of faults (e.g. IEAGHG, 2015a) will result in significant uncertainty in estimates of fault zone hydraulic properties.
- Many *in situ* studies highlight the highly localised and convoluted nature of fluid flow through a faulted rock volume.

In general, application of shear stress induces a dilation of the fracture, sometimes preceded by a closure phase, which causes a very large increase in global transmissivity associated with the reorientation of flow sub-perpendicular to the shear direction. Prediction of hydraulically conductive faults and fractures preferentially oriented with respect to the stress field is complicated by fracture healing whereby mineralisation of void space results in the stress independence of the fracture.

Fault Cementation and Dissolution

Within some reservoirs, fracture permeability is shown to be often created by dissolution or partial cementation within fractures. As a result fractures can remain 'locked open' and possess apertures of several millimetres resulting

in high hydraulic conductivities, even in situ under high stress conditions at depth.

Fractures at depths of 4–6 km or more form in environments where hot (>100°C), mineral-laden water promotes the precipitation of partial quartz coatings and spatially isolated, pillar-like precipitate (cement) bridges.

The healing of fractures and faults may also have two significant and competing effects on the porosity and permeability of a sedimentary sequence which may be important for CO_2 storage. Firstly, mineralisation of faults and fractures can strengthen the aggregate by increasing cementation and cohesion, which directly causes a reduction in permeability. At the same time, this lowering of permeability may weaken the rock by elevating fluid pressure, resulting in a reduction of effective stress, which in turn can cause further brittle failure. Any re-fracturing of mineralised zones could increase permeability if fractures, closed by mineralisation, become connected again.

Confining Pressure and Stress Orientation

As differential stresses decrease and reservoir pressure increases, suitably oriented fractures will tend to dilate perpendicular to the fracture walls and fracture shearing will be a less significant process in aperture enhancement. The permeability of the dilated and connected fractures will be enhanced. This type of permeability is also referred to as pressure-sensitive permeability. If pore pressure diminishes, or minimum principal stress magnitude increases, the fracture apertures will tend to diminish or close resulting in a reduction in permeability and productivity. The stress regime that defines these conditions is presented in Figure 5. A shift towards increasing shear stress (τ), caused by increasing pore pressure, will eventually lead to shear failure.

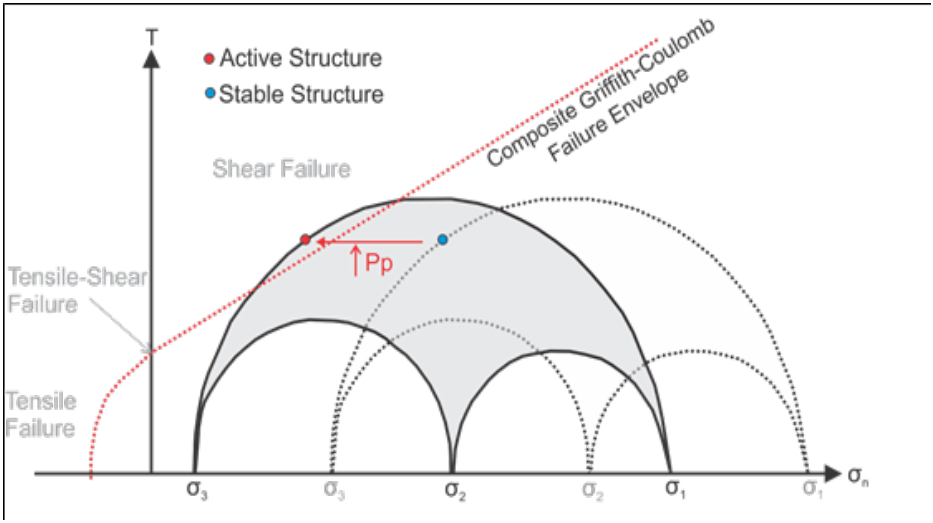


Figure 5: Mohr diagram showing influence of pore pressure increase. The Mohr diagram shows the potential effect that increasing pore pressure (Pp) has on a structures shear to normal stress ratio and where it falls relative to the composite Griffith-Coulomb Failure Envelope.

Field, well, and laboratory observations also highlight that understanding the stress history of a fractured rock mass is essential, and understanding of the present-day stress field alone is insufficient to model the hydromechanical response of in situ faults and fractures to stress changes.

Few studies have been conducted under in situ conditions with simultaneous fracture and permeability measurements at reservoir conditions. Contrary to expectations, results from this study indicate that supercritical CO_2 will not flow through the tight natural caprock fractures sampled, even with pressure differentials in excess of 51 MPa.

Fault Seal Prediction

Hydrocarbon (and CO_2) migration is generally accepted to occur in localized stringers (elongated streams of migratory fluid especially where there are bands of more permeable features such as palaeo-channels) or driven principally by buoyancy forces and opposed by the capillary properties of the rock through which the migration occurs. A seal will remain intact until the capillary pressure (that is the difference in pressure between the oil

and water) at the interface between the reservoir and the seal, due to the buoyancy force of the trapped hydrocarbon column, exceeds the capillary threshold pressure of the water-wet seal. The threshold pressure is the capillary pressure at which the non-wetting (hydrocarbon) phase forms a continuous filament or stringer through the seal.

The most important fault parameter therefore in fault seal analysis is the capillary threshold pressure of the fault-rock which is controlled by the pore throat size. The smaller the pore throat size, the higher the capillary threshold pressure required before migration into a fault zone will occur and the greater the fluid column that can potentially be supported before leakage.

Fault seal analysis and geomechanical modelling are widely used to predict the potential hydraulic properties of fault zones. The Shale Gouge Ratio (SGR) analysis is most widely adopted in the petroleum and CO_2 industries and in a number of cases has been positively correlated to oil/gas column heights using capillary threshold pressures, and this correlation has been shown to vary with depth of burial.

Of particular relevance to CO_2 storage are faults cutting through low permeability strata (i.e. caprocks) that can provide pathways for fluids generated in deep, pressurized rocks to migrate into shallow levels. One consequence of this variability in permeability is that CO_2 flow along faults will often be channelized. In addition, given the complexity of fault zones predicting where, and on what faults, cross- and along-fault migration of CO_2 is likely to occur will be challenging. Temporal increases in fault permeability arising from increasing pressures due to CO_2 injection may be less challenging to predict using geomechanical considerations. However, it will be important to understand the different fluid–fluid and fluid–rock reactions associated with CO_2 migration. It is possible that such reactions will be accelerated within fault zones by grain crushing and an associated increase in grain surface area, although further work is required to confirm this in a CO_2 storage context. The presence of static fluid will result in diffusive movement of reaction products and exceptionally slow alteration.

In the majority of fault seal studies fault rock, that is the crushed rock material that is created by dislocation, is formed by smear along the fault or mixing into the fault zone of clay-rich beds in the host rock.

Further work is required to understand better the processes and quantify the heterogeneity of low permeability fault rock, to test the effectiveness of current fault-seal methods and to improve the predictive power of fault seal analysis. Access to more fault-seal calibration datasets will facilitate future advances in understanding.

Natural Seeps and Fault-Related Flow Rates

CO_2 flux along faults has been widely reported from many areas around the world. One of the most studied is the Paradox Basin on the Colorado Plateau, East-Central Utah, USA. Data analysis here supports a model in which faults promote upward flow of CO_2 with flux rates greatest where small scale faults and fracture densities are highest. Flow simulation also suggests compartmentalisation by low permeability fault rock may increase pressure and promote upward flow of CO_2.

Reported fault zone permeabilities range from 10^{-9} to 10^{-19} m^2 (100 D – 10^{-4} mD) with cross fault permeabilities ranging from 10^{-14} to 10^{-19} m^2 (10 mD – 10^{-4} mD) and along-fault permeabilities typically between 10^{-12} and 10^{-15} m^2 (1 D – 1 mD).

Maximum CO_2 flow rates for natural analogues of CO_2 seeps associated with faults are generally >0.1 t/m^2/yr. For these flow rates volumes of CO_2 leakage could reach 15,000 t/yr, which is similar to the 25,000 t/yr estimated for a submarine seep (Panarea, Greece).

The migration rates of CO_2 are likely to be site- and fault-specific and could vary by at least four orders of magnitude within a given fault system. The rates of CO_2 migration along faults are likely to vary significantly on individual faults, within fault systems and between different sedimentary basins.

These examples (Figure 6 on page 87) are biased and represent, at best, the upper bounds of natural migration rates in faults. They do, however, demonstrate to varying degrees, the surface expression of CO_2 seeps and provide a useful natural reference. These rates are not comparable to fluid migration rates at CO_2 storage sites. However they do provide useful opportunities to study the natural occurrence of CO_2 migration along faults and the surface expression of CO_2 on a surrounding environment.

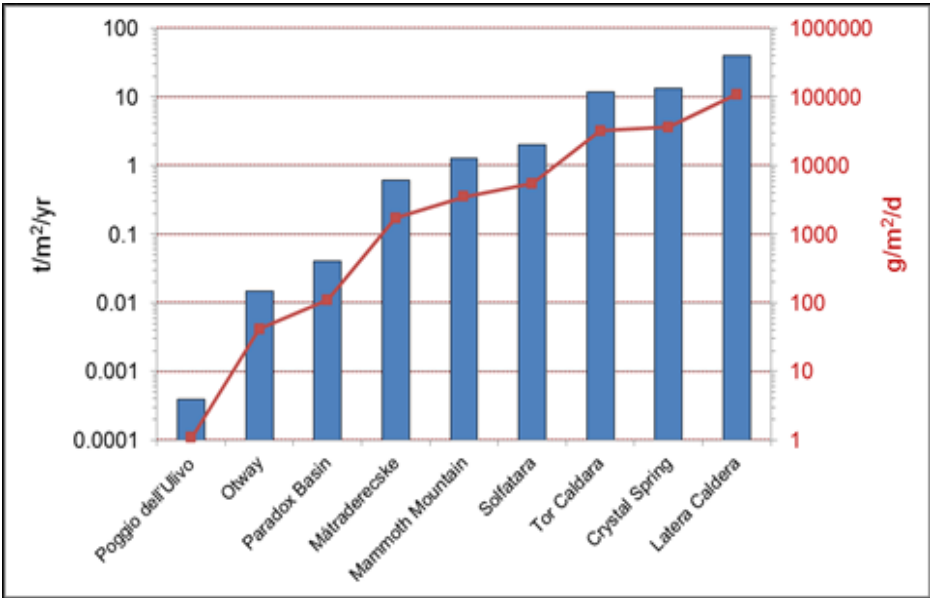


Figure 6. Maximum rates of CO_2 emissions from the analogue studies

Industry Practices for Mitigation of Fault Leakage

Petroleum and geothermal experiences are most pertinent to CO_2 storage. 4D seismic, gravity, microseismic monitoring, borehole image logs and core and geochemical sampling are most common methods used to map fluid migration. Geophysical techniques offer the best opportunity to identify a 3D location of an injected fluid but resolution is too low to document fault-flow relationships. Well-based sampling offers an opportunity to provide detailed information but lacks a 3D perspective.

Fluid-flow simulation studies performed in petroleum, CO_2 storage, water extraction and radioactive waste industries can be highly sophisticated and include faults of various geometries, thicknesses and permeabilities which can be history matched. Outputs are non-unique though and uncertainty of geologic parameters is a universal weakness especially where drilling has not been completed. Rising computer power and adequate time/resources can provide a range of scenarios.

Different fluid management solutions could be employed to temporarily or permanently arrest the pressure increase or decrease the pressure in the storage aquifer. Intervention measures could be used to create a pressure barrier in the overlying geological strata to prevent or minimize CO_2 leakage. Back-production of injected CO_2 might also be considered as an option.

In a case where an overrun increase in pressure has created a new leakage pathway through fault reactivation and/or hydraulic fracturing, for example, newly created fractures and reactivated faults may not totally close with pressure relief, particularly if they have undergone shear displacements.

Other proposed solutions include hydraulic barriers, biofilms, microbially induced calcite precipitation, reactive grout and CO_2 back-production.

Few mitigation options from oil and gas are published in public literature, specifically ones that combat along-fault flow. Pressure relief, hydraulic barrier and chemical/biological sealants are noted as possible solutions but with few trials at storage sites their effectiveness is unknown.

There is a documented case of a decrease in natural hydrocarbon seepage in the Santa Barbara Channel off the coast of southern California. The decline in seepage from structural features beneath the sea floor including faults can be attributed to the production of hydrocarbons from an offshore platform over a period of more than 20 years. This example demonstrates the impact of an increase in effective stress via reservoir depletion and could be employed as a potential mitigation measure.

The innumerable intricacies and complexities of different faults at different sites means that there are limited risk assessment guidelines concerning how faults should be treated in CO_2 storage operations.

Expert Review Comments

Six experts were invited to review the study, four of whom returned comments. There was a general consensus that the study had been well-written and sensibly compiled. All agreed that the study had considered and condensed an impressive volume of literature and therefore provided a comprehensive and valuable review of what is known (and unknown) about fault permeability in relation to CO_2 storage. It was noted, however, that the study overall had been overly influenced by research based on hard rock and

outcrop analysis, not paying enough attention to rheological controls on fault permeability relevant to soft rock environments. The authors agreed and rectified this by adding a number of additional paragraphs detailing the influence of rheology on fault permeability and this enhanced the report overall making it more complete and more relevant to CO_2 storage. Reviewers also highlighted some additional references which had not been included in the study and these have since been incorporated into the final report.

Conclusions

- Fault-zone conductivity and permeability are controlled by many interdependent factors including among others; fault architecture and the types of fault rocks present in a given location, mechanical strength and permeability of the host lithology, fracture aperture size and connectivity, fluid composition, pressure and gradients, extent of pre-existing mineralisation and the orientation and magnitude of normal and shear stresses.
- The key factor that controls vertical conductivity is the orientation of effective stress acting on a fault. There is a risk of leakage where fault zones have no tensile strength and the effective normal stress acting on a fault is near zero. These parameters can be measured and used to predict whether a fault acts a seal or a conduit.
- Properties that are pertinent to the sealing potential and conductivity including the stress regime acting on the fault, the shale gouge ratio, mechanical strength of adjacent rock formations, and fracture formation can be measured and assessed. Provided there is supporting evidence that faults can form effective seals their presence should not prevent the development of CO_2 storage sites.
- A range of fault and fracture properties, both hydraulically conductive and sealing, can be present in a single region. Understanding the burial history of a fault is also important when considering its hydrogeological properties.
- The results of detailed fault studies and in situ permeability measurements are supported by numerical models which show highly non-linear behaviour and flow localization for a wide range of natural well-connected critically stressed fracture networks.

- Pre-existing mineralisation of faults and fractures can have a greater control on bulk permeability than compressive stresses.
- Supercritical or water saturated CO_2 may increase or decrease permeabilities within fault and fracture networks through dissolution depending on the minerals present.
- A number of leakage mitigation measures have been proposed including hydraulic barriers created by injection above the caprock, biofilms, microbially induced calcite precipitation, reactive grout and CO_2 back-production. The decrease in natural hydrocarbon seepage in the Santa Barbara Channel off the coast of southern California has been directly attributed to the production of hydrocarbons from an offshore platform over a period of more than 20 years. This example demonstrates the impact of an increase in effective stress via reservoir depletion and could be employed as a potential mitigation measure.

Knowledge Gaps

- More in situ fluid-flow data and numerical flow modelling are required to quantify the effects of fault zone architecture.
- Further work is required to understand better the processes and quantify the heterogeneity of low permeability fault rock, to test the effectiveness of current fault-seal methods and to improve the predictive power of fault seal analysis. Access to more fault-seal calibration datasets will facilitate future advances in understanding.

Recommendations

The following recommendations are proposed to enhance the existing knowledge related to faults and their significance for CO_2 storage:

- Improved definition and quantification of fault hydraulic properties.
- Developing and sensitivity testing flow simulator models and geomechanical flow predictions.
- Testing and validating models with in-situ data.
- This work takes this research area as far as it can be taken without access to more fault-seal calibration datasets. IEAGHG will maintain a watching brief for any new information that comes into the public domain in the future.

2016-02 IEAGHG 5TH SOCIAL RESEARCH NETWORK MEETING 'ENERGY TRANSFORMATIONS & THE ROLE OF SOCIAL SCIENCES'

Introduction

This 5th meeting of the IEAGHG Social Research Network (SRN) was held at St Catharine's College at the University of Cambridge in the UK, on Monday 6th July 2015. The meeting was hosted by the University and kindly supported by the UK CCS Research Centre. The theme of the meeting was 'Energy Transformations and the Role of Social Sciences' with over 28 delegates from 6 different countries attending the meeting.

The overall aim of the IEAGHG 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
    - o Elevate reputation and acceptance of social science research
    - o Consistency of research
- Identifying gaps
- Promoting a learning environment
- Building capacity within the Network
- Translate information from studies into tools or applied lessons
    - o Apply insights to actual projects
    - o Interact with technical experts
    - o Communicate results to policy makers
    - o 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. Although it was recognised that much of this is now happens through online access portals such as ResearchGate.

Social Science Research and Energy Domain across UK and Europe
Chairs: Clair Gough and Sarah Mander

'Understanding the Role of Place Attachments and Identities in Explaining Public Responses to the Siting of Low Carbon Energy Technologies: implications for Policy and Practice', Patrick Devine-Wright, University of Exeter

This work looked into adopting a place-based approach to better understand responses of the public to the siting of projects involving low-carbon technologies. The research examined public reactions to an offshore wind farm, a power line proposal and a tidal energy project in the UK. Theorising the concept of 'place' has two aspects to it – a place as a locus of attachment/identity and a place as a centre of meaning. With the latter, these meanings are not fixed and people have different thoughts or feelings about them. 'Place attachment' describes the emotional bonds between people and particular environments (which can be attachment or non-attachment), where 'place identity' refers to the ways in which places reflect and maintain identities for individuals or groups. This work argues the value of capturing place attachments and their related meanings to explain local responses to siting of infrastructure proposals, but notes that each in isolation is insufficient to explain why. It was felt that there is value in conducting and comparing multiple case studies across contexts and sectors to further examine the influence of place on consumers.

'Some Findings from Recent UK Public Opinion Surveys', David Reiner, University of Cambridge

The EPRG (Energy Policy Research Group) recently conducted surveys examining the debate around energy including the rise of fracking and the stagnation of CCS in the UK. Results (see Figure 1) show that climate change is thought of as one of the most 'single important problems facing the world as a whole' (behind poverty and hunger). It was interesting to note that the UK public opinion polls on fracking were very similar to the US data but that the US system has allowed a vast amount of fracking to take place – where shale gas makes a small contribution in the UK – despite the tepid levels of public support. The reasons for this may include that in the US, landowners are able to receive compensation for the use of their land – whereas current compensation in the UK is essentially zero. The Crown Estate owns the mineral

rights in the UK, so landowners would not benefit from the exploitation of resources on their property – so the public are less interested and involved because they are not gaining anything.

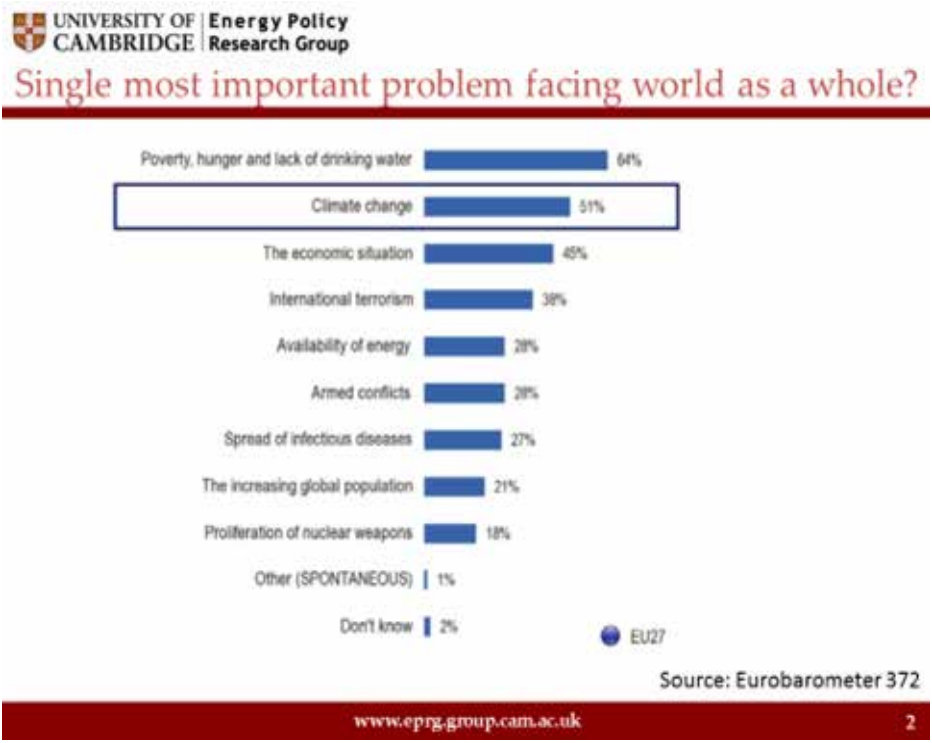


Figure 1: Data showing participants thoughts on key world problems

'Social Science Research on the German Energy Transition: the Research Program ENERGY-TRANS as an Example', Jens Schippl, KIT, Helmholtz Alliance

The Energiewende (ENERGY- TRANS) is the transition by Germany to an energy portfolio dominated by renewables, sustainable development and energy efficiency. ENERGY-TRANS focusses on the societal and technical requirements and the associate implications of such a transition, and will run until 2016. The group has analysed local conflicts and carried out opinion surveys to realise that in general, attitudes toward the energy transition were on the whole positive. This research programme identifies redundancies, inefficiencies and conflicting goals at and between levels of the energy supply

chain. It was observed that inconsistent alignment between representing parties or schools of action can lead to higher costs, excess infrastructure development and the weakening of public acceptance. Federal intervention must be balanced with decentralised activity and it has been found that there is a need for negotiation, transparency and independent monitoring.

The programme re-established the need for the socio-technical perspective and understands the importance that the socio- part cannot be ignored in the scientific and political arenas. It is a challenge to integrate the different strands of research, but an important aspect to consider for interdisciplinary research on socio-technical transitions.

'Framing Effects in the Communication about CCS: an International Experiment', Gerdien de Vries, Delft University

CCS is framed differently by different groups. Voluntary participants (all students) took part in an online framing experiment where they read an introduction to CCS before being given a short statement by a fictional stakeholder – there were 24 such statements, each from the same stakeholder and participants were allocated one of these 24 statements. Their attitudes toward CCS were then questioned. It was interesting to see that the results were slightly more positive, but even more so that where higher risk was emphasised (rather than safety), there was more support – a strange outcome. However, the Gerdien has hypothesised that perhaps when high risks are communicated, people may find the concept more plausible, more transparent – therefore creating more trust. On the other hand, in the anti CCS group, the high risk factors may not be emphasised as much, so people may be less likely to trust the stakeholder. It seemed that people who value power and achievement were more positive about CCS than those who did not. The sample size was relatively heterogeneous (around 800 useable participants), but it is interesting to see these indicative outcomes and this work provides input for further investigation into the role of equivalency framing.

Discussion

It seems that there has been some uptake and interest by policymakers and industry to work on place attachment, but a challenge has been to try to communicate the complexity of people's differing opinions/feelings where some may live close by, and be attached to the area, whereas others not so

much. It was also recognised that the historic aspect can influence people's attitudes. It is also interesting to note that there is a presumption that the people who live beside a potential area of interest are a community – which is not always the case. In terms of 'NIMBYism' there is an emphasis on the costs and benefits that projects bring, and certainly in the UK, policymakers support the idea that local people need to benefit more. The recognition that compensation is needed is positive and welcomed, but has not actually been implemented so far.

It was observed that there was lots going on in terms of fracking and communication, but not so much for CCS – some parties within this Network are looking into why fracking has captured the imagination, but CCS has not – with some recognition that this has probably been influenced by the role of the media. It was thought that the association with fossil fuels is a problem; there is a general unhappiness with the perpetuation of the fossil fuel economy and there has been a concerted effort on the part of the grassroots movements that has started with some protest groups (for example the 'Frack-Off' group in the UK) – the tools that these groups have to alarm and concern the public are very effective, particularly in the US. It was recognised that such public opinions and feelings are site-specific, for example in Germany, CCS has now completely stopped because of public opinion, but the position of fracking remains the same. It was suggested that how sites are located could be important; for example, in Australia and the USA, there is more space so things like pipelines are in big open spaces whereas in Europe, it's more likely that most populations will be closer to any activities, but this concept has not been investigated much in the research. It was noted that the presumption from policymakers is that if it's far away (for example offshore), there won't be a problem – which is not necessarily correct. It could be that CCS goes ahead successfully in some areas of the world, but not all. In Alberta, Canada, there are lots of pipelines and wells, so the addition of CCS infrastructure may not be too different to the norm. However, when you're trying to locate 3000 CO_2 injection sites, it could get complicated.

The discussion turned to procedural aspects and the process of engagement itself. It was recognised that it can be challenging to get people to actually engage with communicators, even when the opportunities are plentiful. It

was agreed that it was underestimated just how complicated this is and can depend on a number of factors (such as the different technologies, sites etc.). All approaches are different, but perhaps a step in the right direction would be to develop some guidelines and try to raise awareness.

Research Findings from the Asia Pacific Region
Chair: Emma ter Mors

'Focus Groups and Interviews with Stakeholders of the Tomakomai Project before the Decision on the Project Site', Kenshi Itaoka, I2CNER

The objective of this work was to help understand how social characteristics of a potential CCS project site can influence the public understanding – and therefore acceptance – of the project. The interviews and focus groups were undertaken on the local community close to the Tomakomai CCS project in southern Hokkaido, Japan, and were conducted before the site selection was completed. Some emergent themes included the feeling of 'why here?', the perception of benefit and risk, experience as an industrial city with a mining industry (and the experience of disasters), and desirable communication. Stakeholders, NGOs and community leaders showed no strong opinions about Tomakomai being a candidate for a CCS project, a vague perception of the risks involved with CCS and the tendency to be neutral or positive to such projects was a common theme. The local community seemed interested in the project and there was some familiarity with the local mining activities which probably made people less concerned about CCS.

'Landscape of Opportunity, Landscape of Risk, or Both? Governing the Public and Stakeholder Dimensions of the Tomakomai CCS project', Leslie Mabon, Robert Gordon University

These interviews were conducted as part of a wider study into energy and risk in the Japanese marine environment and were held more recently, in the summer of 2014, with project managers and local officials in the Tokyo and Tomakomai areas. A mini ethnographic study was also carried out in the Tomakomai area, through informal conversations with locals, observing participants in their environment and simply viewing the area and its community. This research showed that there was an inequality between the ways that sites are decided (for example who deems that a community is a suitable site, and how), and brought up some reflections on potential sites for

CCS projects, including the importance of transparency. There is a need for responsible governance, for example managing expectations and responses to stakeholder concerns.

'Turning Decide Announce Defend on its head: The role of volunteering in radioactive waste management site selection in Australia', Peta Ashworth, University of Queensland / Ash Research

Australia currently has stocks of low and intermediate level waste arising from the beneficial uses of radioactive materials in medicine, research and industry and a responsibility to properly manage the waste created. An independent panel (IAP) was formed to provide the Department of Industry and Science with a broader understanding of the issues associated with disposing and storing such waste in Australia. An opportunity has been extend to all landowners (in all states/territories) with tenure to potentially nominate their land to host such a facility. The landowner would then receive benefits for the use of their land, including being paid up to 4 times the value of their land. The Department has received an encouraging response from landowners and the next stage will be to undertake a multi-criteria site assessment (on all nominations) received to determine which sites are appropriate for short-listing.

This idea of competition also arose in the FutureGen 1.0 project when comparing across CCS projects when it created a situation where the competing communities became invested in winning. It was suggested from that research that 'future project developers might consider adding the competition element and including public acceptance as an explicit criterion in evaluating sites'.

Discussion

What we know about CCS has not really been applied in the Asia-Pacific region and so some communities may not be used to having such questions asked. In terms of applying these questions in the local context, it is important to understand the local community. Local groups or ethnic groups could need different conceptualisations of place, for example, and will have different priorities, different issues, different perceptions of their 'rights' and therefore may need different approaches. It was observed that it is hard to compare CCS with other technologies, such as wind energy etc., because it is

a more challenging technology. The economic effect is important and must be considered, as must the role of the media and their influence in various groups.

Specifically referring to the work with radioactive waste management in Australia, it was noted that this was rather specific to the area, particularly as the focus seems to be with the local community living in the area and whether they will agree or disagree to hosting the site. It is important to remember that the people interested in such technologies, such as fracking, is not limited to the local residents. The importance is for stakeholders – industry, policymakers, regulators and the public – to work together in the way most appropriate for the projects and themselves and to consider how we define the 'community' and care needs to be taken with such a definition

Risk Perceptions of CCS and Other Energy Technologies
Chair: Kenshi Itaoka

'Development of an integrated Risk Management Framework for CCS in the Canadian Context', Patricia Larkin, University of Ottawa

There are many frameworks for CCS risk management (Figure 2 (Page 99) gives an example of such a framework) with the focus of standard elaborated frameworks primarily on injection and storage, with many documents addressing storage site selection and characterisation. Few of these frameworks link with an assessment of emissions, waste or water use and uncertainty, while stakeholder communication and transparency are only discussed sparsely in the regulatory context and frequently in non-regulatory documents.

There have been previous attempts in developing an integrated risk management framework in CCS – see Figure 3 (Pg 6). Using structured expert elicitation (an international expert panel was convened to discuss risks and attendant uncertainties) to contribute to the framework development. This has been shown to be of value when data availability is lacking, as the understanding of relative risk and quantification of collective uncertainty judgments has improved when looking at injection/storage and the risk management of high impact, low probability events. Risk-based decision making needs to look at risk management, economic analysis, socio-political considerations and risk perception in the future to be successful. This

integrated risk framework does include possibilities for practical application. At the population health level, it will encourage wide spread implementation of CCS as a global climate change mitigation option, and at local level it will ensure a blueprint for safe and effective implementation of the technology and wider public acceptance.

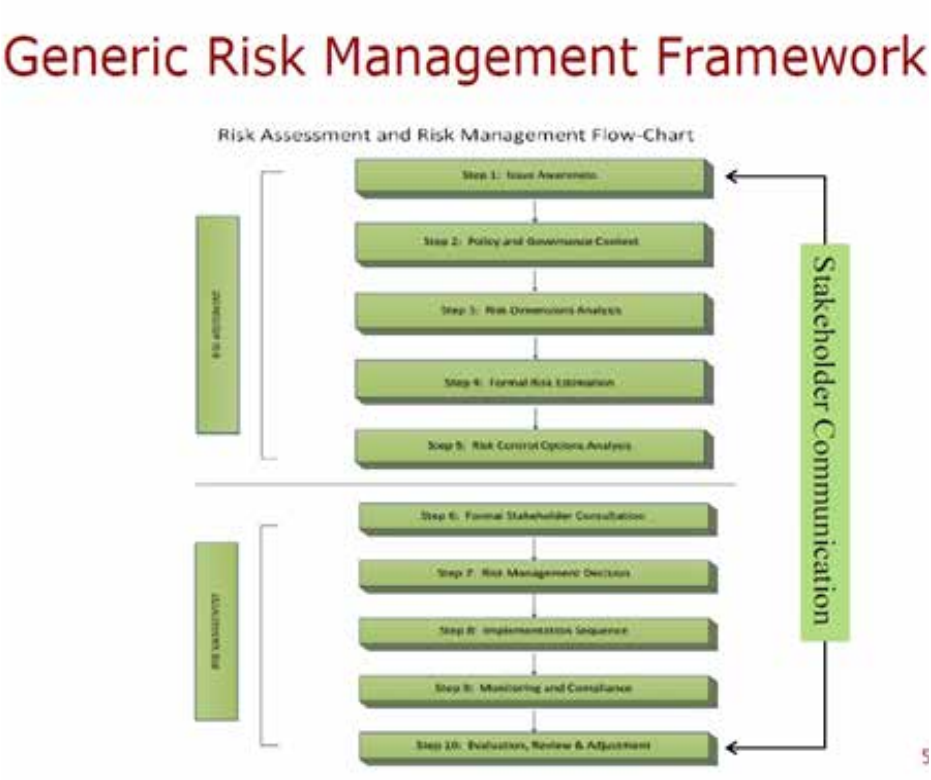


Figure 2: An example of generic risk management framework

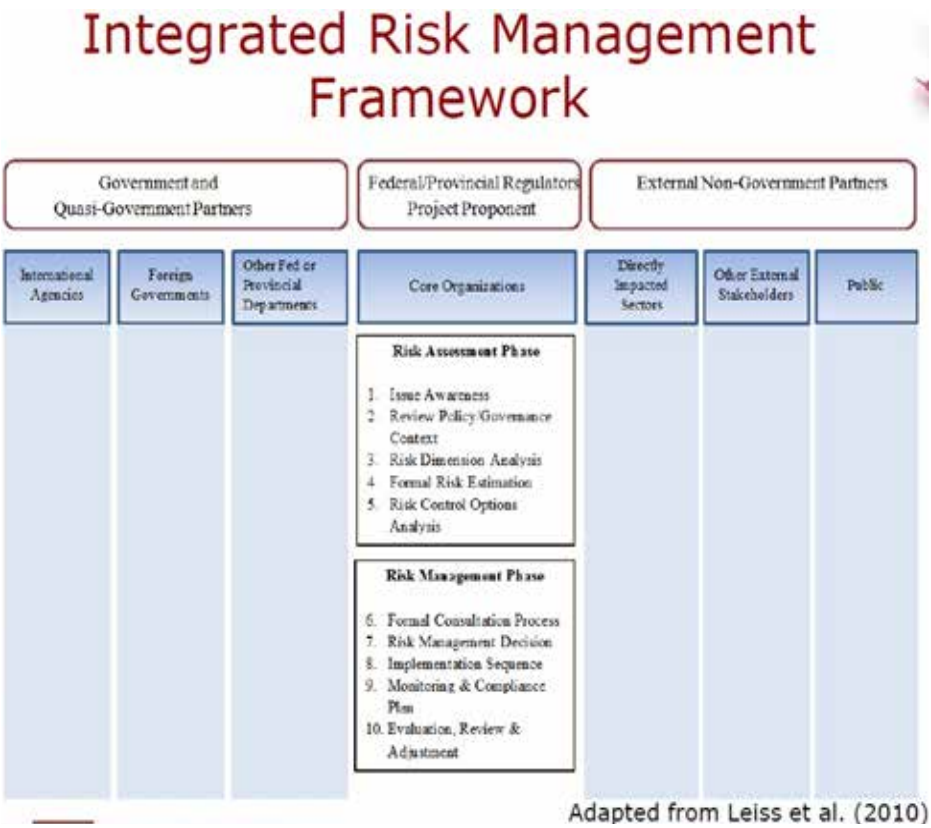


Figure 3: An example of an integrated risk management framework

'In Silico Science for Climate Policy: How Policy-Makers Process and use Carbon Storage Simulation Data', Dirk Scheer, DIALOGIK, Stuttgart

The main objective of this project was the systematic assessment of processing simulation knowledge within policy making. Using a case study approach, this work undertook a simulation in the area of CCS (a geological impact assessment) and carried out a conceptual and empirical analysis to look into how policymakers/stakeholders process (and use) policy-relevant scientific simulation. They found that 'role experts' and 'knowledge experts' have different focusses, allowing them to have different perspectives. Knowledge experts focus on their geo-scientific and simulation-based expertise whereas role experts largely consider socially and institutionally mediated interests,

worldviews and values when processing CCS simulations. In terms of decision making, it was observed that such geoscience simulations are prone to delegitimising strategies and there is a trend toward using simulations as an instrument for evidence.

'Public Perception of CCS and Shale Gas in Germany: Similarities and Differences', Diana Schumann, Forschungszentrum Juelich

There has been a recent effort in technology monitoring, which aimed to survey the awareness, knowledge and attitudes amongst the German public regarding technologies, instruments and impacts of energy systems transformation. The aim of this specific study was to compare public perception in Germany of two technologies – CCS and shale gas extraction. This work used comparison along several indicators (self-reported awareness, factual knowledge, risk perceptions, benefit perceptions and general attitudes) and investigation into which factors determine general attitudes, using descriptive statistical and regression analyses.

The study concluded that public awareness of energy technologies is closely related to the public debate – and media coverage – of the technologies. Knowledge about such technologies increases over time (especially with aspects that are reported in the media), but misconceptions also persist over time. The most important direct determinants of general attitudes to energy technologies are perceived risks and benefits. Such risks or benefits for the society seems to be more important for general attitudes, rather than the perceived personal risks/benefits.

E-TRACK – Facilitating Public Participation in Radioactive Waste Management, Gianluca Ferraro, JRC

The EU Energy – Transparency Centre of Knowledge (E-TRACK) is a knowledge centre that promotes public participation in energy policy implementation, as a reliable source of information and collects and disseminates related EU knowledge and experiences. The objectives of this initiative include to collect information, to connect actors and to share knowledge. In terms of radioactive waste management, E-TRACK have carried out a study to look into the lessons learnt about policy formation, policy design and the implementation process for radioactive waste management. This project contacted? about 280 organisations involved in the management of radioactive waste (with a 55% response rate). The project recognised the need for more information,

for better communications and the need for multi-layer dialogue. It also recognised the importance of resources and formal/informal forms of public participation. Information, communication and participation are likely to build trust or re-build trust where it has been lost. Annual open seminars are held regarding the role of public participation in RWM.

Discussion

This diverse session stimulated much discussion between delegates and a question arose regarding the public perception in Germany, and why perceived societal risks and benefits seem to be more important than personal risks/benefits. It was suggested that, because in the study presented by Diana Schumann there was no specific project in mind, perhaps participants behave at a broader level until they have a recognisable project that they can relate their personal issues and opinions to. It was also noted that different groups of people will class their personal space differently, which will in turn affect their decisions and opinions regarding personal or societal risks and benefits – and it's important to look at whether people may trade-off in their decision making (people may be prepared to trade off on their livelihoods if it means their communities can survive). A recent focus group in Australia (in a rural area where the coal seam gas industry is well-known) showed extremely positive opinions to a proposed coal mine where the society considered some local benefit (there will be some personal gain as a result of this). It was also discussed whether individuals may give more 'desirable' answers to fit in more with their peers, which can create issues as it is not always truly representative. This demonstrates the importance of thinking about how people may answer surveys compared to how they actually take action in real life settings.

Some UK work has shown that people perceive fracking differently to shale gas, which can be a challenge, and terminology has been observed to really affect perceptions. Recognising the extent to which language and terminology may effect public perceptions is critical as there can be severe responses in some cases. The question is, to what extent is it important to bring these considerations in to your risk assessment – and when these risk assessments are made, do you question the public. Research suggests that public perception is more multi-faceted than an expert's perspective.

History, People and Energy Transformations
Chair: David Reiner

'Routes of Power: Energy and Modern America', Christopher Jones, Arizona State University

Christopher reported that the history of energy transitions in the American mid-Atlantic – America's fossil fuel heartland – from 1820 to 1930 was heavily shaped by the building of routes – or infrastructure – along which the energy (coal barges) could be shipped. He suggested that infrastructure is an underappreciated driver of energy transitions. Transport matters because there is an uneven geography of energy cost, where sunk costs drive demand and infrastructure therefore can create inequalities. Infrastructure can throw up technical challenges and high costs, but it does facilitate the expansion of energy flows. The creation of demand and expansion of infrastructure can be viewed as a positive feedback loop – energy resources are often found in rural areas and canals/pipelines etc. are expensive, so demand has to first be created and the owners of transport systems are then incentivised to be energy boosters because of the sunk costs. Consumers increase the demand over time and the subsequent expansion of transport networks lowers the price for the consumer, which in turn increases demand. Transport systems also allow people to benefit without suffering any negative effects – such as NIMBYism, the worry of any issue that could arise; they 'disassociate consumers from environmental harms'.

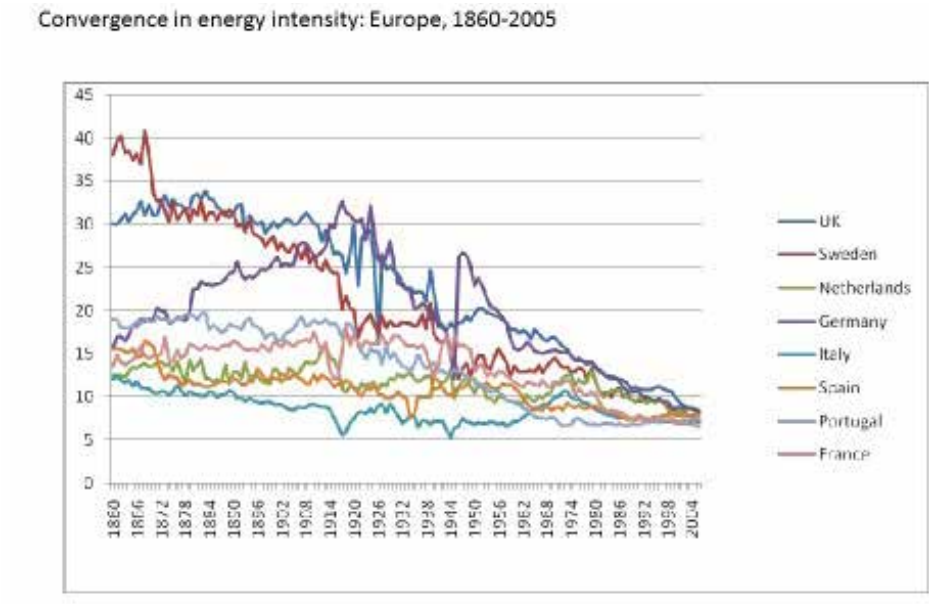
Transport and infrastructure can have significant amplifier impacts for a region. Canals allow multiple products to be transported in two directions to several places, with intermediate points along the route, whereas pipelines move a single product in a single direction, usually to a single place – a difference that leads to less amplifier effects. With canals, you see broad patterns of industrial development in many places (that benefit a number of people and spread economic activity) whereas with pipelines, their characteristics show much more concentrated effects.

Historical lessons can contribute to present learning, and demonstrate the importance of building infrastructure to stimulate renewable energy; the importance of recognising that demand is created over decades; and that infrastructure should be designed to minimise socio, technical and

economical inequalities.

'Energy Transitions: a Long View', Paul Warde, University of Cambridge

This presentation gave an overarching analysis of the energy system in the UK and Europe from a historical aspect, an insight into the last 500 years and looking in detail at quantitative data to understand shifts in the system. The delegates of the SRN meeting were given an overview of total energy consumption in Europe, the consumption and primary energy use per capita, the convergence in energy intensity and the energy system of 20th century Britain and Europe (see Figure 4, below). A closer look was taken into the history of the UK's energy system and transition, looking at the long view of the UK, historical fuel prices and per capita energy use.



Data from Warde, Kander, Gales, Warde, Malanima, Henriques.

Figure 4: The Energy System of 20th Century Europe

The figure on the previous page shows the energy system of 20th century Europe; a period of time where Britain dominated the energy sector. There is a massive dominance of coal until after World War II, following which there was a visible expansion of oil and aggregate. Moving along the timeline, there is then divergence into other sources such as natural gas and primary electricity. Now, renewables are advancing quickly and the tapping into cheap stocks of fossil fuels makes more energy available. Following the 1970s where the oil crisis occurred, energy is now relatively expensive and there is more diversification of energy systems with a more conscious policy response being sought from the public.

Creating Value from CCS Research, Kevin Broecks, Utrecht University

Valorisation is the notion of 'producing value out of research' – which can be viewed from three perspectives: the value for society, value in university-industry interaction and the value in research programmes. This work wanted to look into why participation occurs, how collaboration can happen and the opportunities and barriers involved, and did so by analysing social networks, conducting semi-structured interviews and carrying out inductive analysis.

In terms of motives and resources, research programmes can increase the legitimacy of a particular research type, for example social research. Universities' motives/resources could include funding, insight into opportunities and community, and governments' motives/resources may include knowledge, the legitimacy of CCS and public attending. Industry's motives/resources would be concerned with knowledge shopping, legitimacy research, insight into opportunities and contributions to strategy.

The main barriers observed included that there are often multiple disciplines involved and the connection of different perspectives, which can be challenging as many disciplines can throw up different perspectives. Knowledge dissemination was a challenge, and often falls to the social sciences for dissemination and coordination. The research suggests that it is key to learn how to align perspectives of different stakeholders and disciplines.

Discussion

There seems to be a common theme that working with such energy

transitions needs careful attention as to what is actually happening; there are a number of actors that need to be aligned and a level of complexity is also often evident. Energy transitions in the past have been energy accretions – whereas now we're trying to reduce levels, even create new technologies to do so and use bigger infrastructure, where we have little experience and where there are significant obstacles and barriers. CCS, like nuclear and offshore wind power, comes in big chunks and is very expensive, making the potential of this learning challenging – more so than some other technologies, and a historical timeline such as those presented in this session is particularly relevant for a technology like CCS.

It is difficult to ascertain which kind of cost is best. There are many uncertainties; we don't know the future of gas, what's happening with climate change and we cannot predict the future of technologies and their learning curve – it was thought that projections can't be based on previous prices, for example, as the current energy situation is so different and therefore flexibility is an important factor. It was suggested that price does matter a lot, but when consumption and methods of getting energy are looked at, there are many long term fixed costs. The use of forecasts and predictions can often be incorrect – but they are crucial (and sometimes a legal requirement).

There is a need to acknowledge the spectrum of these projections being correct/incorrect; for example in 2009, CCS was predicted to be much more developed than it actually is. Many of the current predictions are backed by those who have the financial risk and investment behind them – perhaps demand is more predictable? The price of energy can explain (to some extent) the demand, but the scarcity of resources also makes a difference.

Looking at the work into the value in CCS research, it was wondered how much of this could be because of the engineers' view of the world – which they expect technologies and projects to take off and perhaps not necessarily account for the long time it takes to build a plant due to concerns, oppositions and permits etc. It was wondered to what extent more accurate projections would be realised by taking into account more sensitivities such as consumer behaviours, preferences, technical factors etc.. It was noted that if there was a 'hype', some researchers are more likely to spend their time and resources on it – which may lead to an increase in the technologies' progress.

Getting access to energy is a basic human right in the first world mind set, but there is nothing that reinforces that people do have this right. In the long term, choices and access to energy is a part of citizenship. In the short term, the range of energy options seems limited. Current energy practices are so unique, one can see a lot of contingency in where we are. Renewables may not be great for the energy system as they're not available to be used all the time – whereas the expectation is that electricity is now constant and consistent, which has taken a huge amount of effort from the electricity companies. Energy sources are needed to support the shifts in supply and demand.

Reflections, Outcomes and Recommendations

Chairs: Peta Ashworth and Samantha Neades

The 5th IEAGHG Social Reserarch Network (SRN) meeting was another successful Network event, packed with interesting presentations on the latest outcomes in the field and full of thought-provoking discussions.

Delegates were provided an insight into social research in the UK, Europe and the Asia-Pacific region - a look into the perceptions of risk in the arena of low carbon technologies and the history of people and energy transformations.

Discussion in the final session examined the outcomes of the meeting, the value of the Social Research Network and the merit of the activity continuing. In summary, all meeting delegates (and therefore a large representation of the SRN members) were enthusiastic about the continuation of the Network and felt it was an important resource for all involved.

Similarly to previous SRN meetings, it was felt that a broader focus on the range of climate change mitigation technologies could be beneficial to increase the learnings in this area and raise awareness of findings. Collaboration with other disciplines would be beneficial for many reasons and could be of assistance when writing research papers – it was noted the inclusion of historians in this meeting had in some parts demonstrated the value of this. In addition to broadening the information dissemination, it may be useful to move the Network emphasis away from 'public perceptions' research to consider the wider CCS community – including stakeholders, practitioners, academics etc.

The dissemination of research from the Network outside the academic

arena was also seen to be important and it was suggested that for future meetings, more focus should be placed on inviting speakers and researchers who would be able to talk on a wider – but relatable – areas of interest. This broadening may make it easier for policymakers to actually access the information emerging from this Network, and it was suggested that a quarterly summary of the Network activities – perhaps in the form of an IEAGHG Information Paper (IP)[1] – would be a very useful tool to assist with this dissemination. In addition to sharing outside of the social science area, it was deemed important that the Network stir future research and noted that the three potential new projects will provide opportunities for this – it was agreed by all that the lack of new demonstration and commercial projects of late is impacting social science research into public acceptance and engagement and CCS – industrial projects are crucial to aid learning and therefore progression. It is crucial to be always considering what knowledge gaps – and so research questions – need to be addressed in the realm of public engagement and over a portfolio of mitigation technologies.

It was felt that more on methodology would be advantageous or perhaps using more common methodologies and metrics across the CCS research network would be beneficial. It may be useful to look more into the implementation of strategies; how the research can be transferred for use in outreach and communication efforts. For example in cases of valid perception and acceptance, how can this data be turned into communication strategies and furthermore implemented?

Recommendations

The following recommendations were made by attendees at the end of the fifth IEAGHG Social Research Network Meeting:

- Continue to broaden the Network's focus by inviting delegates from the general energy sector
- Broaden focus also by examining other low carbon technologies and related, applicable social science research across the whole realm of climate change technology – not just CCS

[1] IEAGHG Information Papers (IPs): Free-to-access, short publications from IEAGHG on a variety of interesting topics, as part of a response to Members' wish for timely reporting on current issues.
IPs from 2012 – present can be found at http://ieaghg.org/publications/information-papers

- Produce a quarterly summary of those in the Networks' current focus of research and disseminate as appropriate
- Encourage more research into the methodology of social science research in climate change
- Consider future research questions by trying to identify current knowledge gaps.

International Steering Committee

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Samantha Neades, IEAGHG (Co-Chair)
David Reiner, University of Cambridge (Host)
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Becky Kemp, IEAGHG

IEAGHG would like to thank the Steering Committee for all their hard work throughout the organisational process, along with Laura Davis (IEAGHG) for her assistance.

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2016-03 SUMMARY OF THE IEAGHG / CSLF WORKSHOP ON LCA IN CCUS

Summary

A workshop on Life Cycle Assessment (LCA) in Carbon Capture Utilization and Storage (CCUS) was held in London, UK, 12th and 13th November 2015, hosted by IEA Greenhouse Gas R&D Programme (IEAGHG) and the Carbon Sequestration Leadership Forum (CSLF). The workshop built on the IEAGHG report 2010/TR2 and review work by the CSLF.

The workshop looked at the state-of-the art of LCA for CCUS in terms of goals and scope definition, inventory analysis, impact assessment and interpretation as well as social LCA and Life Cycle Costing (LCC).

The workshop showed that progress is being made in the field of LCA. It revealed that the interpretation and use of LCA is variable and that there is a need to better communicate the benefits and limitations of LCA, also when applied to CCUS.

The workshop concluded that transparency is a must and that improvements are needed in the way the goal, scope and assumptions behind an LCA are presented. A checklist on how to document scope, functional units, data inventories, allocations, weighting (if used), uncertainties and how to communicate results would be useful.

Introduction

The background for the workshop was the report IEAGHG 2010/TR2, which looked at 17 LCA studies and identified 14 papers that represented relevance and significance in terms of Carbon Capture and Storage (CCS). These papers were examined in more detail to compare scope, methods and outcomes.

A similar survey by CSLF in spring 2014 included several more recent LCA studies of CCS but the common outcomes were:

- There are many LCA studies on CCS but the transparency is not always as one could wish
- There is a need for consistency between studies (e.g. functional unit, reference system, system boundaries and impact categories and impact

assessment methods)

- Impacts other than Global Warming Potential (GWP) show large variations (e.g. toxicity potential, eutrophication, acidification, resource depletion)
- Impacts like water and land use and abiotic depletion seldom included
- Aggregation and end point results are seldom included
- Scale-up and uncertainties must be handled
- Policy-making needs (attributional vs. consequential LCA) and market effects should be included

The IEAGHG 2010/TR2 concluded:

"IEAGHG could consider playing a role in setting up some reference points to allow benchmarking and hence proper comparison of LCA studies."

CSLF challenged IEAGHG to follow-up on this conclusion and the IEAGHG Executive Committee decided to have a workshop to explore the need to develop guidance on the above points.

Aim and Organisation of the Workshop

The aim of the workshop was to explore the needs and possibilities to set-up guidelines for benchmarking and transparency of CCUS LCA with respect to e.g.

- Description of reference systems
- Battery limits
- Functional units
- Time horizon
- Climate and non-climate impacts (e.g. land use, water use, abiotic depletion)
- Inventories and weighting methods

In addition, the workshop set out to explore LCA for CCS for bioenergy, Life Cycle Costing (LCC) and social LCA.

The workshop was divided in five sessions, each with an introductory presentation followed by discussions. Originally, the intention was to have the discussions in groups, with an ensuing plenary discussion. However,

with 23 eloquent participants all but one session discussion (Session 4) was conducted in plenary.

Session 1: Setting of the Scene

The purpose of this session was to set the scene by having a keynote presentation on the state-of-the-art and recent developments in LCA and have key stakeholders present their perspectives on CCUS LCA.

State-of-the-art and Current Developments in Life Cycle Assessment, Bhawna Singh, Norwegian University of Science and Technology, Norway

LCA is a holistic and systematic environmental impact assessment of a product, process or system. The term 'life cycle' indicates that all stages in the product's life, viz. resource extraction, manufacture, distribution, use and end disposal, are taken into account. Uses of LCA include:

- Technology/product selection
- Optimizing environmental performance of a product/company
- Green labelling, marketing
- Support to policy decisions

The LCA methodology includes goal setting and scope definition, inventory analysis, impact assessment, including the selection and use of indicators, and interpretation. The presentation gave a thorough review of LCA methodology and the recent developments in LCA, including different types of LCA, Life Cycle Inventories (LCI), impact characterization and assessment, and indicators.

Stakeholder Perspectives were presented by Christopher Balzer, Shell Projects and Technology, representing industrial users of LCA; Sean McCoy, International Energy Agency (IEA), representing "consumers" of LCA; and Aicha El Khamlichi, Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME), representing expertise and advisory services.

The session showed that LCA can be a useful tool to assess environmental sustainability, to identify the needs for environmental change, to look at trade-offs and possibilities for environmental improvements in product development, and that the research frontier seems to be that LCA integrates

with techno-economic assessments and Integrated Assessment Models (IAMs).

It also revealed that some users, policy makers in particular, do not fully understand what LCA is about and the results may therefore be misused. Aspects of concern include:

- The right questions need to be asked, e.g. so that system boundaries of the LCA meet policy requirements
- That LCA is just one of several tools
- That there is a difference between generic and specific LCAs and that generic ones do not give results at the same detailed level as specific ones, rather trends
- That there is a difference between attributional and consequential LCA and that e.g. a changing energy system and supply chains may need the latter
- If an "LCA" considers GWP as the only indicator, then it is not LCA but carbon/GHG accounting or foot-printing
- GWP has a global coverage but most other indicators would ideally need a regional resolution, e.g. water stress
- That uncertainties are not always sufficiently communicated.

Session 2: Goal and Scope Definition

This session set out to explore the importance of goal and scope definitions and started with the presentation **A Life Cycle Analysis Perspective of CCUS – Goal and Scope Definition, Timothy Skone, National Energy Technology Laboratory, USA.** The complexity and diversity of LCA outcomes was illustrated by application of LCA to Enhanced Oil Recovery (EOR) using CO_2 as a driver. The use of CO_2 creates a complex life cycle system, and the result will depend on whether CO_2 is treated as waste or a product. Furthermore, the case allows for defining more than one product, e.g. electricity, crude oil, refined fuel, captured CO_2, or some combination of the above. The outcome will depend on which of these is considered the product and which other service/product it will replace, as well as the degree of substitution. Thus, it is necessary to redefine the system boundaries or apply an assignment that splits life cycle burdens between products when performing LCA on each of

the possible products, and rather detailed models will be necessary to give confidence to broader system applications.

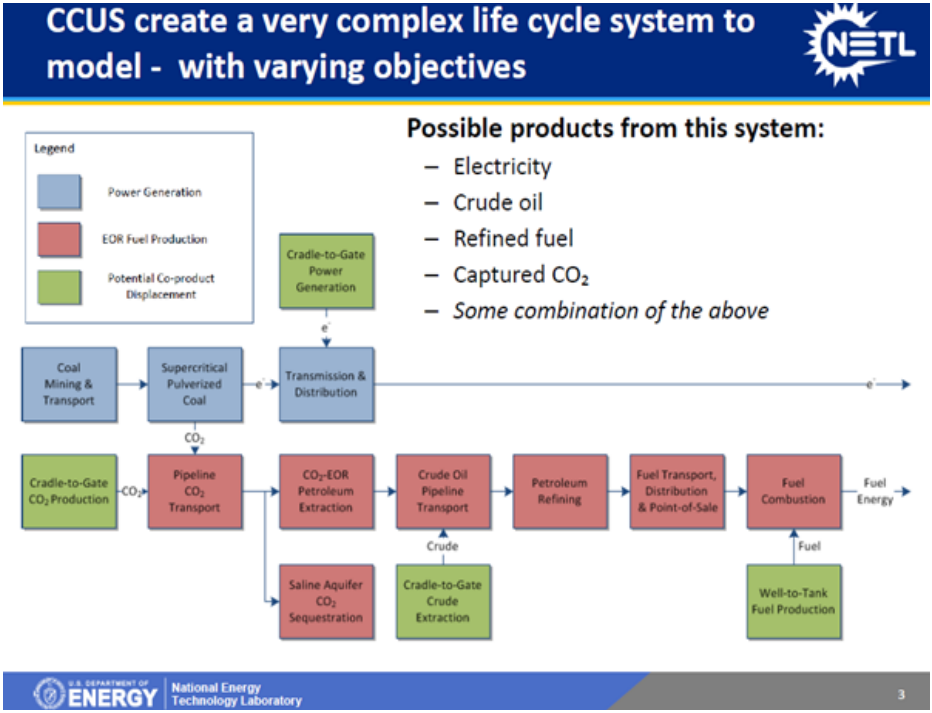

Figure 1: Slide presented by Tim Skone (USDOE NETL)

The presentation and the following discussion brought out several points that suppliers and users of LCA must be aware of in addition to the points from Session 1. The points include:

- The results are driven by the choice of boundaries and the desired outcome, which is often dictated by policy, and there is the possibility to tweak these boundaries
- It is important to define the value chain
- There are common elements to LCA and Risk Assessments (RA) and thus experience transfer should be possible

- Integrated Assessment Models (IAM) do not capture sufficient impacts
- There may not be sufficient data to do a consequential LCA, and one may have to look only at trends
- A consequential LCA can build upon an attributional LCA or direct data sources, such as industry or technical documentations. Crucial point is the quality of the process data
- Transparency is a MUST (CAVEAT: transparency does not automatically infer the LCA is of high quality)
- Communication of how and why LCA has been performed is necessary to avoid apparent inconsistencies in results (may not remove all inconsistencies, though)
- Data quality is not sufficiently discussed – may need to apply traffic lights to databases
- The databases are usually five or more years behind and this needs to be

With displacement applied, LCA results can be generated and compared across technologies

- **Advanced coal with carbon capture may exists in a world where generators would take just about any price – or even pay – to get rid of CO_2**
- **Strong case for displacement of natural dome CO_2 production**

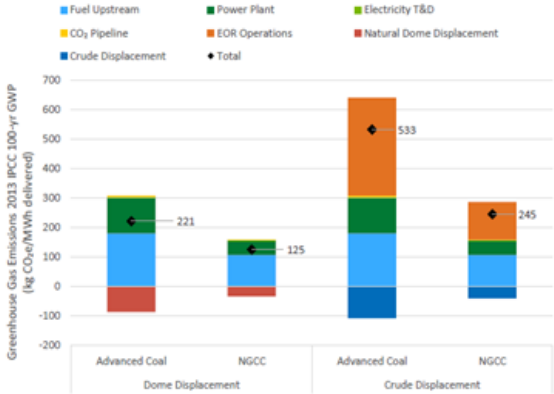

Figure 2: Slide presented by Tim Skone (USDOE NETL)

No clear and unified answer on the question "What guidelines are needed to set up system boundaries and increase comparability among studies?" was received from the group.

Some statements contra guidelines included:

- If CCUS does not require special approaches to LCA, guidelines may not be needed
- ISO TC265 has already put the topic on its agenda for WG4
- Should not dictate specific LCA methodology via guidelines
- Potential to end up with a mix of guidelines for different CCUS technologies
- Transparency more crucial than guidelines or standards

There were also several positive views, including the following:

- Guidelines can be a very useful tool to educate non-experts
- As the inconsistency in LCA studies creates problems regarding comparability and communication of benefit and drawbacks, guidelines might be a way to improve the situation
- Guidelines can allow for flexibility, e.g. implementation of different methods, as long as any deviation is documented and justified
- They could encourage practitioners to report everything in a transparent way (e.g. boundaries, goals, databases)

Session 3: Inventory Analysis

Questions for this session included "What about multi-functionality, allocation rules and harmonisation approaches?" and "How to deal with and communicate uncertainties?". The presentation **Current, Best and Future Practice of Life Cycle Inventory Modeling for CCUS, Arne Kätelhön, RWTH Aachen University, Germany**, addressed these questions and discussed issues connected to data collection, such as availability of data and LCI approaches at different stages of data collection, expansion of systems, avoided burdens, allocation and consequential LCA. The presentation also

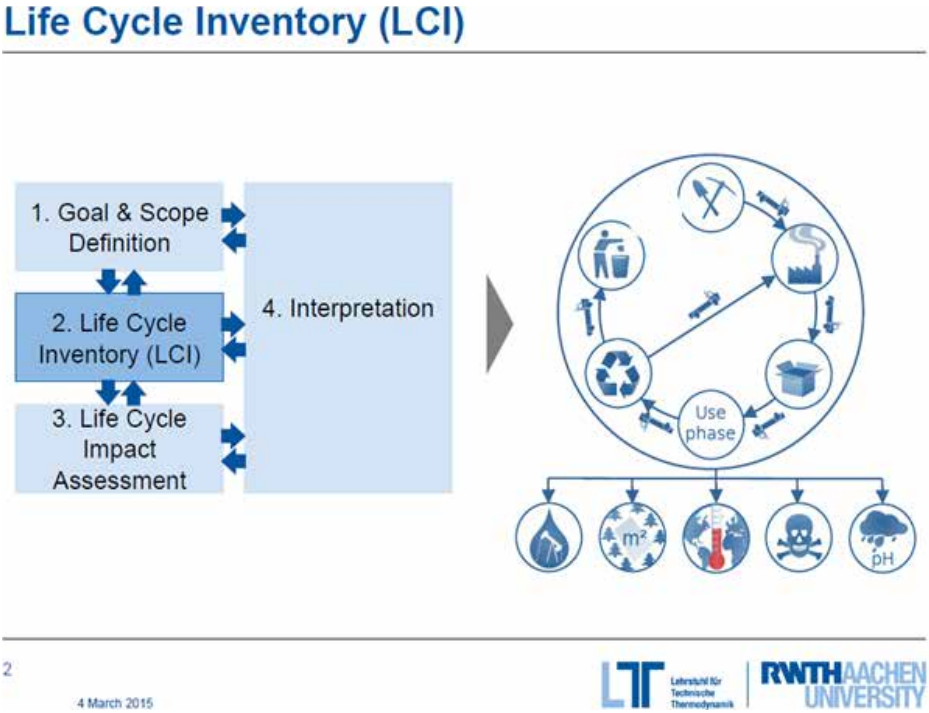

Figure 3: Slide presented by Arne Kätelhön (RWTH Aachen)

highlighted that LCA is not only useful for environmental assessment but is also a powerful tool for process optimisation.

The ensuing discussion re-enforced several of the topics from earlier sessions. Additional points included:

- Uncertainties are as much a result of circumstances as of amount of data
- One must be aware that the variability/uncertainty in natural systems is larger than in human engineered systems
- One approach could be to report error bars reflecting the uncertainty range instead of single numbers
- Laboratory results are not necessarily representative of full scale systems; a fact of importance to CCUS, where most data are from small scale systems or even only parts of the a system

- Reverse engineering can be a helpful exercise to better understand the development of uncertainties
- As more data become available it must be decided how these can best be included
- It is crucial to have both high quality data and models
- Sensitivity analyses are needed to get a grasp of which factors count and which can be excluded

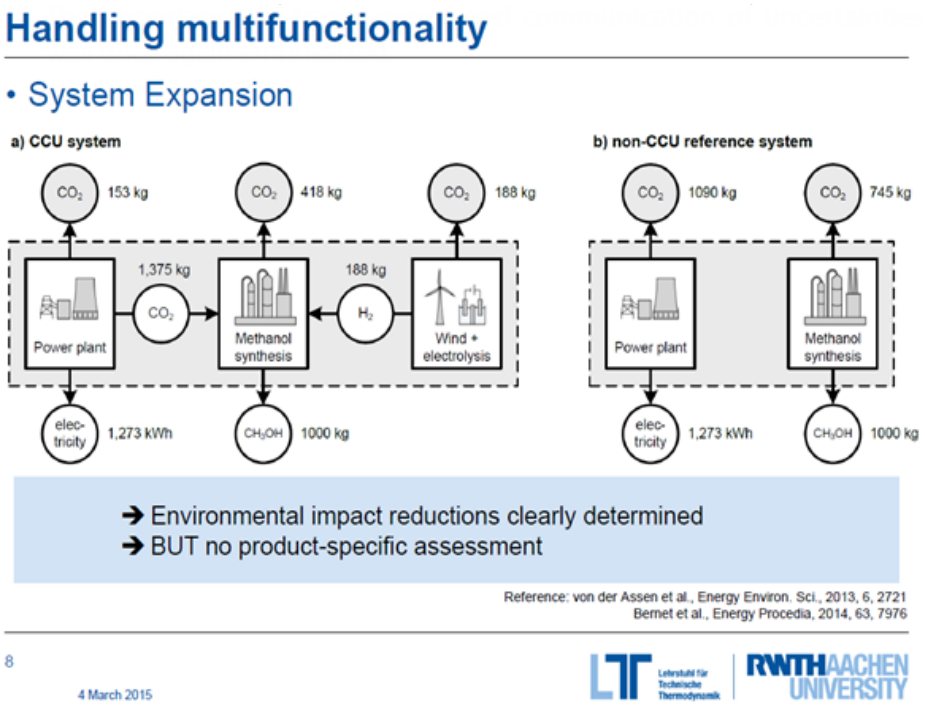

Figure 4: Slide presented by Arne Kätelhön (RWTH Aachen)

Session 4: Impact Aseeseement and Interpretation

The intention was to introduce this session with the presentation **Some Thoughts and Questions Related to Bio-CCS (bioenergy with CCS) in LCA,**

Hanna Pihkola, VTT, Finland. Unfortunately, the presenter was prevented from attending the workshop and Jasmin Kemper took the audience through the slides. Hanna's presentation highlighted that usually current climate policies did not consider Bio-CCS and guidelines for carbon footprinting only considered fossil CO_2. There was also an ongoing debate regarding carbon neutrality of biomass. An approach to tackle this could be the use of specific "GWP_{bio}" factors for different types on biomass feedstock but it might require some changes in LCA practices. Land use change (LUC) issues were very relevant for Bio-CCS and bioenergy in general but difficult to address within LCA frameworks. In addition, there were several other sources of uncertainty, and aspects to consider would include CCS technology applied, type of biomass feedstock, location, (by-)products and the reference case. In this regard, a case study approach might be helpful. For Bio-CCU, it would be important to avoid double counting. In existing EU regulation, transferred and utilised CO_2 could not be subtracted from operators' emissions. However, this would still leave open how to calculate and incentivise replaced products.

The rest of the session was dedicated to group work, for which the participants were split in two and posed with answering the questions

1. How to increase transparency in weighting? Do we need guidelines here?
2. Is it possible to agree on aggregation or end-point methods?
3. Is there a need for connecting to other regulatory requirements (e.g. toxicity to REACH, the EU regulation on chemical substances)?
4. How to communicate uncertainties in results?

One challenge in weighting and the end results is to decide who should weight – end user or people doing the LCA. This is often not revealed in published results but is important for transparency and confidence in results. One suggestion was to agree on weighting up front, before data collection. It was pointed out that no weighting is the same as assuming equal weights to all indicators. Further, there seems to be some confusion in the LCA community whether aggregation is really possible. The participants clearly stated their preference for mid-point methods but acknowledged that end users and decisions makers often demand end-point results. Regarding REACH, the expected increase in availability of toxicity data could strengthen LCAs but the regulation comes with its own complexity and issues. The

discussion on how to communicate uncertainties mostly reflected earlier views, with the addition to not only look at stochastic uncertainty but also to grasp how good the model representation and the understanding of the underlying processes is.

In short, the answers to the four questions were:

1. No
2. No
3. Generally yes
4. Varying views

Session 5: Beyond Environmental LCA: LCC and Social LCA

Day 2 and Session 5 opened with the presentation **Social LCA, Andrea Ramirez, Utrecht University, the Netherlands.**

Stakeholders for social LCA include a variety of persons and organizations, including workers, consumers, local communities and the society at large. This mix of stakeholders leads to several challenges related to what and how to include e.g.

- Child labour
- Wages, e.g. legal minimum wages
- Gender and other aspects related to discrimination
- Corruption
- Human rights
- Health, safety and environmental issues

There is little guidance on how to do impact assessment or what indicators to use and a related question is whether jobs or economy can be used as indicators.

Social LCA involves a certain degree of subjectivity, due to the complexity and qualitative nature of many of its components, and it is unlikely that one will see harmonization on how to carry out and value social LCA. A common checklist may still be possible. Although many stakeholders/end users prefer a single resulting number, the current recommendation is to do environmental and social LCA separately due to their different levels of maturity. Because of

the more qualitative nature of social issues, social LCA might never reach the same level of quantification as environmental LCA.

It was not quite clear how social LCA relates to CCUS but some possibilities were pointed out:

- Storage may take part in low income areas
- Social LCA does not work well for a single plant, the whole energy system should be subject to social LCA

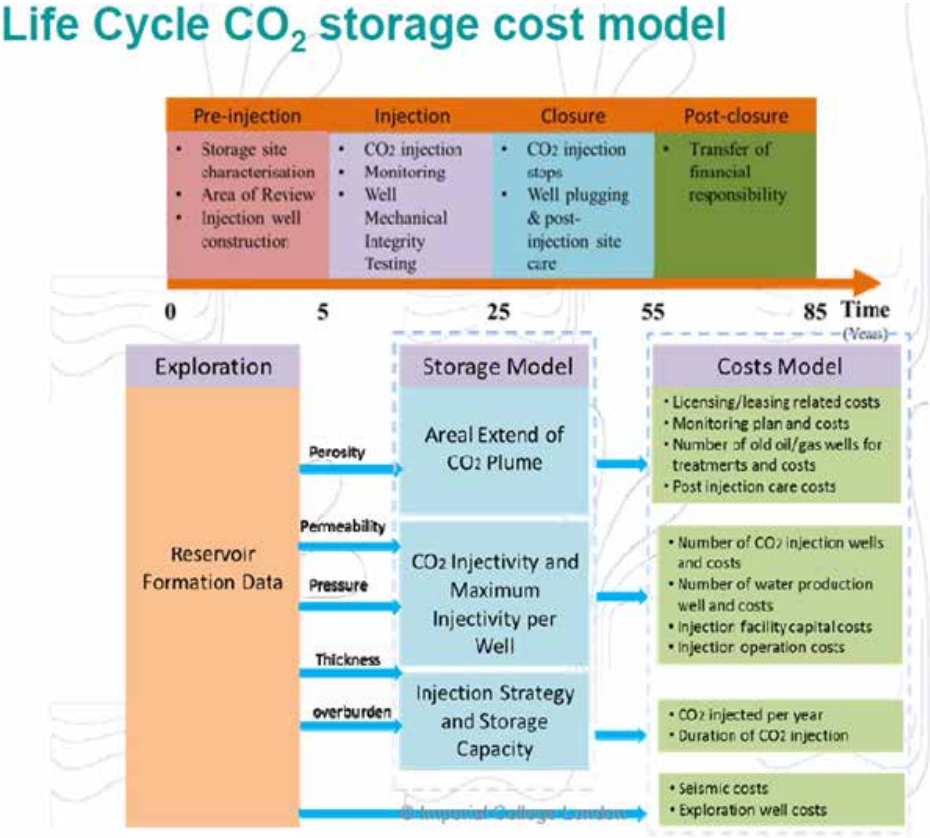

Figure 5 Slide presented by Anna Korre (Imperial College London)

- Changes in the energy system, energy security, access and liability are factors that may require social metrics to be included in an LCA.

The final presentation in the workshop was **Benchmarking LCA Studies for Fossil Fuel Based Power Generation Value Chains & Life Cycle Costing in CO_2 Storage, Anna Korre, Imperial College London, UK**, in which she presented an LCC model applied to CCS for conventional and non-conventional fuel sources. In the financial sector, LCC refers to the wide temporal aspect of the assessment, and hence this term clarifies the difference from the standard point-in-time costing for a product/service. Due to much natural variability in the fuels and technical details of the processes and relative immature LCC methods for CCS, LCC will in this case only give sign in change from a baseline. LCC may be used to compare sites but not for the technology in general. Harmonization may be difficult and probably not needed. As before, the importance to know the uncertainties in input data and other parts of the

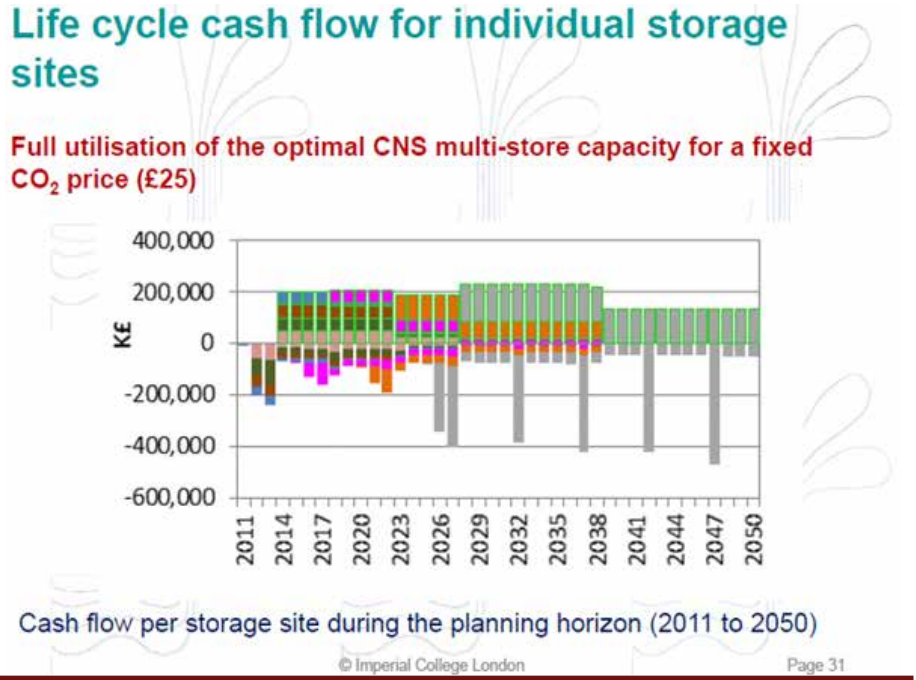

Figure 6 Slide presented by Anna Korre (Imperial College London)

chain was stressed, e.g. the cost of characterization of the storage site may vary a lot depending on what data exist and what new data are needed. A still open question is what the cost implications of CO_2 storage liability will be.

Key Points, Conclusions and Recommendations

Conclusions

The workshop concluded on the following general topics:

- There is a need to communicate how and why differences in LCA come about
- Key principles
    - Transparency is essential and must be improved (but be aware that transparency does not equal quality)
    - The questions to be answered must be decided before the LCA work starts. It is also important to know who asks the questions.
    - Be aware why an LCA is performed – it is not for the sake of LCA itself
    - Clearly distinguish an LCA from carbon/GHG accounting and foot-printing
    - Generic LCAs are only useful for indicative comparisons
    - Preference for mid-point indicators
- Harmonization
    - No clear answer from the group due to different views
    - Can be a good tool to provide insights and deeper understanding but should be used with great care
- Weighting
    - May be done if assumptions and intentions are clear but caution is needed in use and interpretation
    - No weighting means to assign equal weights
- CCUS specific issues
    - Generalisations not possible due to a multitude of different

CCUS technologies and their locations
    - Overall energy system related issues will apply
- Bio-CCUS
    - More LCA work is necessary here, as the biomass component brings along a set of new issues and increases complexity (e.g. land use change, food-water-energy-climate nexus)
- Social LCA
    - Is an emerging area but less mature and quantifiable than environmental LCA for the time being, so should be a parallel rather than an integrated exercise
- Guidelines
    - Definition of guideline varied between participants
    - No formal guideline prescribing a specific framework, methodology or tool is needed
    - A check list on how to document scope, functional units, data inventories, allocations, weighing (if used), uncertainties and how to communicate results would be useful
    - Guidance on how to read and interpret LCA studies for non-experts and end users, such as policy/decisions makers would also be helpful

Recommendations

The workshop participants

- Did not see the need to update the IEAGHG 2010/TR2 report
- Did not see the need for a special LCA session at GHGT-13 but recommended a keynote or plenary presentation to raise awareness
- Agreed to make the presentations from the workshop available on the websites of IEAGHG and CSLF
- Welcomed IEAGHG and CSLF to produce a summary report from the meeting
- Thought that IEAGHG could consider developing a guidance/good practice document with feedback from the workshop participants and publish it, e.g. in a journal
- Suggested to have another LCA event after a reasonable amount of time,

e.g. to introduce the guidance document

Based on the comments and suggestions, IEAGHG will revisit the need for producing a guidance document and for future meetings/activities on this topic.

International Steering Committee

Lars Ingolf Eide (Research Council of Norway/CSLF)

Andrea Ramirez (Utrecht University)

Anna Korre (Imperial College London)

2016-08 RISK MANAGEMENT NETWORK AND ENVIRONMENTAL RESEARCH NETWORK COMBINED MEETING

The three days of presentations and discussion in the Risk Management Network and Environmental Research Network meeting had an offshore theme, and was hosted by the National Oceanography Centre in Southampton. The sixty attendees discussed over 38 presentations on the latest work on topics including risk assessment methodologies, mitigation strategies, projects' risk management, impacts of CO_2 in the ocean, natural variability in environments, pipeline environmental impacts, formation fluid release, overburden features, international initiatives, and environmental impact assessments.

Of particular note was a session on formation fluid release into the marine environment, and the development of sensors for marine monitoring. Attendees were given tours of the AUV workshops (autonomous underwater vehicles). One of these is being kitted-out for Carbon Capture and Storage (CCS) monitoring research. Great advances in offshore monitoring are being developed and applied.

The meeting concluded that the risk assessment for CO_2 geological storage is maturing, recognising that with leaks from storage, if they occur, are likely to have low environmental impacts. Wellbore issues are still the predominate risk, and although this is an area of known technology solutions, more work to test and apply these alternatives was suggested. There are great developments in understanding environmental aspects in the marine environment. A sense of perspective was also seen by comparison of potential impacts caused by CO_2 with those from other activities. Further work looking at formation fluid releases was encouraged, and field tests of new sensors eagerly anticipated.

Overall good progress has been made in all areas and the meeting facilitated constructive discussions and the development of new collaborations.

Introduction

The IEAGHG's Research Management Network and Environmental Research Network held a combined meeting at the UK's National Oceanography Centre (NOC), in Southampton. The meeting was attended by 62 delegates from

11 countries. The three day meeting included themes on risk assessment methodologies, risk communication and mitigation strategies as well as environmental research. There was an emphasis on potential impacts of CO_2 in marine environments, natural variability and the unscheduled release of CO_2 from pipelines. Coverage also included formation fluid release, overburden features, international initiatives and environmental impact assessments; notably the Peterhead – Goldeneye project.

After the meeting some of the delegates visited two key sites on Dorset's Jurassic Coast.

Day 1 – Risk Management

Session 1: Welcome; Professor Ed Hill, NOC Executive Director, Ian Wright, NOC Director of Science and Technology and Tim Dixon, IEAGHG

The Executive Director of the UK's National Oceanography Centre (NOC), Professor Ed Hill, opened the meeting. Professor Hill stressed that the centre is at the forefront of marine science and research in the UK and is ranked third or fourth in the world. He remarked that oceanography is becoming an increasingly important subject particularly in the context of a resource that can sustain a global population of nine billion people and the impact that they have on ocean ecosystems. The impact of climate change on oceans is an additional factor that needs to be taken into consideration hence the importance of offshore storage. The Director welcomed delegates and stressed the interesting and varied programme.

Ian Wright then addressed the meeting outlining the intensive effort by the European countries including the UK into CCS supported by the European Union (EU) as well as the UK's Department of Energy and Climate Change (DECC) and the Energy Technology Institute (ETI). Ian stressed that the meeting is a timely opportunity to present and discuss risk management and environmental research with an emphasis on marine conditions.

Tim Dixon concluded the opening remarks by also referring to the offshore theme. He observed that this was the eighth risk management meeting and the third environmental research meeting. Tim later then mentioned that 2015 marks the 10th anniversary since the publication of the IPPC special

paper on CCS. IJGGC has recently published 17 review papers on advances in CCS since 2005.

Session 2: Risk Management Updates from Projects
Chair: Charles Jenkins

Peterhead – Goldeneye - Owain Tucker, Shell

Shell's Peterhead – Goldeneye project planned to use an amine post combustion capture technology from a gas-fired power plant on the coast. This was planned to be the world's first full-scale CCS project linking a power plant to an offshore depleted gas field and would have tested a broad spectrum of technical and non-technical risks including duration, regulation and political risk. The project planned to capture 10 to 15 million tonnes of CO_2 over a 10 to 15-year period (90% CO_2 capture from one turbine). The initial site selection depended on the technical and commercial opportunities offered by the depleted gas field including reservoir capacity, seal integrity and infrastructure. The ability to monitor the project and demonstrate compliance with regulators is also an essential requirement. A comprehensive risk register had to be devised and was designed to be actively managed.

The comprehensive risk assessment programme has been designed to determine the level of uncertainty of specific risks and then the measures that are needed to mitigate or counter them. The basis of the risk register is evidenced supported logic. For example, is there supporting evidence that CO_2 can be contained by the caprock. Shell have instigated a series of bow-tie workshops to identify risks at each stage in the project. The evidence for a risk is then compared with the evidence against the impact of a risk. If uncertainties still remain further investigation is initiated. Monitoring has been then been designed to detect, for example, leakage routes and to inform the corrective actions that might be necessary. The detailed risk assessment programme has been used to identify which monitoring techniques are most suitable for specific leakage risks. Shell have conducted a validation exercise with the BGS and Herriot-Watt University and shared their knowledge with a wider academic community.

Risk Management for a CO_2 Superstore - Mervyn Wright, National Grid and Richard Metcalfe, Quintessa.

National Grid are setting out to create a CO_2 transportation business based on a large secure offshore reservoir linked to multiple carbon point sources in the Don Valley area of Yorkshire and Humberside. National Grid have been working with the Don Valley and White Rose projects to link CO_2 sources with a potential sink. The company identified a suitable structure, Endurance (previously known as 5/42), within an offshore deep saline aquifer (DSA). The reservoir is located close to the shore and has a large storage capacity. In 2013 an appraisal well was drilled and a comprehensive data set acquired including cored caprock. The wellbore also provided a section through the overburden which has provided information for a regional model of the seal, reservoir and connected aquifer. The primary seal is halite, but there are a series of secondary seals which extends to the top of the Lias.

A Quantitative Risk Assessment (QRA) based on a three value logic model has been developed to build confidence for and against projected outcomes. The aim of QRA is to identify the impact of uncertainty. The QRA can be used to demonstrate how risk assessment has been conducted and what specific measures could be applied. QRA is also useful for analysing specific uncertainties and what their impacts could be. Data is collated and specific features identified. The expected evolution of the store's development was then composed. Alternative scenarios, associated risks and impacts were also considered even if there was a low probability of such occurrences. The QRA was checked against the EU CCS Directive to ensure that all the selected scenarios met regulatory requirements.

The risks were categorised within a matrix defined by a scale of least to worst possible outcomes compared against a probability scale from very low to very high. The risk assessment decision tree developed for the project can be tracked back to the underlying evidence. By embedding the rationale for the QRA, confidence can be built with stakeholders and investors.

In conclusion the risk assessment has produced a very high level of confidence in the long term containment of CO_2 and that the system will achieve long term stability which are key requirements of the CCS Directive. The commercial prospects for the UK CCS industry are based on

the development of a very large and secure offshore storage. High levels of confidence in a large store needs to be communicated to potential follow on power generation and industrial CO_2 sources to offer them a long-term solution for captured emissions.

Risk Management updates from Tomakomai - Jun Kita, RITE

The Tomakomai demonstration project, 800km north of Tokyo, will be in operation in 2016. A costal onshore site has been selected which will capture CO_2 from an oil refinery hydrogen facility and will inject 100kT / year into two offshore reservoirs: a sandstone layer at 1,000 – 1,200m; and a volcanic formation at 2,400-3,000m depth, via two deviated wells.

The regulation that covers offshore CO_2 storage in Japan is the Act for the Prevention of Marine Pollution and Maritime Disasters which is based on guidelines from the London Protocol 1996. The Act stipulates that CO_2 must not cause an adverse impact from a leak. The Act also requires an environmental impact assessment (EIA) including migration into the overburden and CO_2 dispersion into the sea. Selected scenarios using TOUGH2 with ECO2M (LBNL) have been run over different periods of time to simulate migration through virtual faults. Leakage dispersion into the sea has also been simulated including dissolution of CO_2 bubbles in sea water. Simulations have been run for summer and winter to evaluate oceanological seasonal impacts. Marine organisms showed varying degrees of response to high-CO_2 environment. Overall evaluation suggests that a pCO_2 increase of 100-200µatm can be a safe level for ecological impacts. The monitoring plan must be able to demonstrate conformance, containment and contingency. The Act also demands that a three tiered monitoring plan must be implemented depending on the severity of changes that could occur following CO_2 storage. Normal time monitoring defined as no indication of leakage or change from natural variability; suspicious time monitoring where possible leakage is suspected and should be confirmed; and Abnormal time monitoring where leakage has occurred and the extent of any impact should be known. The biggest concern for the project is technical not political.

The Value of Multiple Rounds of Risk Assessment to CCS Project Planning: The Fort Nelson CCS Project as a Case Study - Nick Azzolina, PCOR

Fort Nelson, situated in the north-east of the Canadian provience of British Columbia, is one of several CO_2 storage projects within the Plains CO_2 Reduction (PCOR) Partnership region. The project will inject 2.2Mt/year of CO_2 from the Fort Nelson Gas Plant into a saline aquifer 2,100m deep.

This presentation reviewed the process and results from two rounds of risk assessments that were conducted for the project in 2009 and 2010. An iterative approach from initial site characterisation to CO_2 injection was adopted. In 2009 a risk assessment was conducted based on two reference periods consisting of 50 years of injection followed by 50 years of post-injection monitoring. 32 risks were identified of which 20 related to containment, four each to injectivity and strategic issues, plus three related to capacity and one to seismicity. Expert opinions were solicited from a group of experts to derive frequency and severity estimates for each risk. Values for these two parameters were cross plotted to produce a Risk Criticality Score which compares the relative ranking of each risk and helps identify moderate- to high-criticality risks. During the first round of risk assessment, several moderate- and high-criticality risks were identified related to containment, injectivity and capacity. This process then led to a requirement for additional information and alternative measures to understand the risks in greater detail. The risks were then re-assessed in a second round risk assessment in 2010.

The 2010 risk assessment included a detailed geological and laboratory assessment; a geostatistical model and numerical simulations; an assessment of an alternative CO_2 injection location; and a Monte Carlo simulation. The improved site charaterisation led to the formulation of a new model. New simulations at the alternate injection location showed that there was a reduced chance of CO_2 having an impact on pre-existing gas pools. This re-evaluation has indicated that the risk of leakage and seismicity are very low. The risk assessment was also used to define the monitoring, verification and accounting (MVA) programme. For example the locations of potential monitoring activities were developed in relationship to predicted CO_2 plume geometries from the simulation studies.

The second risk assessment led to risks and probabilities that were better defined. Shifting the injection location 5km to the west of the original location significantly reduced the risks of impacts to pre-existing gas pools. The process used at the Fort Nelson site illustrates the value of multiple rounds of risk assessment to CCS project planning.

Session 2 Discussion: How do we Better Communicate Risk Management Plans to Regulators?

The evidence of the examples presented in this session indicates that as more information becomes available the initial perception of the magnitude of some risks is reduced. However, oil industry experience shows that risks can increase when more detailed information becomes available. For example projects that were thought to be viable can turn out to be uneconomic with greater technical investigation. It is also clear that uncertainty is not the same as risk and the distinction between the two needs to be clearly communicated. Expressing risk in terms of likelihood can be misleading therefore the phraseology needs to be carefully presented to convey the severity of risk.

The interaction of developers with regulators was raised. Shell has explained the results of risk assessments to regulators but they rely on specialist consultants to explain the process of risk assessment. Regulators will not have a detailed background in the relevant technology but all background information is open to them. Examples from the oil industry can help. The Canadian system based on investment where risk assessment is tied to financial assurance can successfully mitigate risks.

Session 3: Qualitative and semi quantitative risk assessment methodologies
Chair Owain Tucker

Peterhead – Goldeneye Bowtie Model. Sheryl Hurst, Risktec Solutions

The bow-tie method of risk assessment has its roots in the chemical and the oil and gas industry. There is a reference to its application by ICI in 1971. The methodology is now widely adopted globally throughout the oil industry, and in the UK's railway industry and offshore wind power industry, as well as being referenced in risk assessment standards and guidance. The assessment starts with building a bow-tie diagram with the primary hazard, CO_2, and then

the subsequent consequence which could be loss of containment or control. Possible causes of the loss of control are illustrated on the left of the diagram, together with engineered, geological and procedural preventive measures. To the right of the diagram are the potential mitigation measures which could limit the impact of the consequence. This framework provides a structure that can be used to collate potential hazards, link them to preventive and mitigation measures to reduce their impacts, and evaluate the effectiveness of such measures in managing the hazard. Qualitative effectiveness gradings can be indicated by a colour-coded traffic light system and displayed on the bow-tie. Issues which might undermine specific preventive or mitigation controls are termed escalation factors, and trigger additional measures that might be necessary.

For the Peterhead-Goldeneye project, a preliminary bow-tie risk assessment initiated in 2011 has been progressed to a refined, semi-quantitative bow-tie model consisting of seven separate but interlinked bow-ties. The methodology has been communicated to stakeholders and peer reviewed by BGS and Herriot-Watt University.

The bow-tie analyses covered releases at different depths, and releases arising from geological and geomechanical causes, and via injection and abandoned (legacy) wells, such that all possible release paths were assessed. The bow-tie method allowed the multi-disciplinary risk assessment teams to not only to identify causes and consequences but also to spot any gaps or weaknesses in the prevention and mitigation measures. The effectiveness grading for each mitigation/prevention measure is supported by detailed documentary evidence linked to the bow-tie diagrams.

The bow-tie workshops also investigated the potential for further risk reduction. The teams tested the effectiveness of each risk reduction measure and the cost/effort involved in its implementation. This approach was also used to determine the most effective monitoring.

In the semi-quantitative assessment, each bow-tie cause is given a numerical score ranging from very likely to statistically insignificant. The overall frequency of a loss of control arising from a specific cause is determined by the cause likelihood multiplied by the probability of failure of each independent prevention measure. Similar calculations on the right side of the bow-tie,

allowing for dependencies between detection and mitigation measures, provide a numerical estimate of the likelihood of each defined consequence.

Plots of each bow-tie consequence arising from the different causes and the effectiveness of mitigation measures/monitoring are plotted through the lifetime of the project to show changes with time. The model has been compared with published data for well leak frequencies and shown to be in good agreement.

The outcome from this risk assessment shows that the likelihood of a release of CO_2 from the storage complex is judged to be low. The semi-quantitative analysis suggests that the injection wells would make the biggest contribution to the risk of a CO_2 release until they are abandoned and, after this point, the abandoned wells make the biggest contribution. The model also shows that the probability of CO_2 release decreases after cessation of injection.

Session 3 Discussion: Do we need Probabilities from Risk Assessments or does ALARP (as low as reasonably practicable) Suffice?

Regulators and other stakeholders like bow-tie analysis because it illustrates hazard scenarios and the related prevention / mitigation measures in an easy-to-understand graphical format, and clearly shows where there are gaps / weaknesses. It is also possible to use qualitative bow-tie analysis to demonstrate that risks are reduced to ALARP levels. The bow-tie assessment used for this CO_2 storage project is comparable with oil and gas analyses of major accident scenarios, in terms of the number of bow-ties and level of detail. However, could there be an issue with providing too much information, particularly to non-risk specialists, inadvertently giving the impression (e.g. by a large/complex bowtie) that the risks are high? (refer to Session 4 discussion on the following page).

The confidence that can be placed on risk is informed by the probability of its occurrence. There is not much quantitative data for CO_2 storage projects, particularly for release paths which do not involve well- and equipment-related failures, so accurate, fully quantitative risk assessment is difficult and risk assessment needs to be based on qualitative information. There is an interdependence of different risk assessment techniques so it is important to identify the covariance of risks.

Commercial entities based on CO_2 storage operations will have business models that include the impact of risks. Quantitative measures will be necessary to underwrite financial risks. Quantification is also necessary to estimate the amount of money to set aside for mitigation or barrier implementation.

In some cases, ALARP could lead to overdesign of some mitigation barriers, whereas they only need to mitigate in proportion to the actual risk level (which is computed from the probabilities and severities).

Session 4: Risk Communication
Chair: Bob Dilmore

Risk Management Approach for CO_2 Storage: Focus on Risk Assessment in an Uncertain Context - Thomas Le Guénan, BRGM

The first goal of risk management is to prevent harm to the environment or people and to earn the trust of stakeholders. For example the risk and impact caused by induced seismicity may be very low but this can be difficult to explain to stakeholders who are wary of technical experts. Therefore, experts need to know what the magnitude of these risks are and how to explain them. Understanding the natural environment is complicated by spatial heterogeneity and temporal variability but there may also be epistemic uncertainties (i.e uncertainties related to our knowledge). With limited access to data or model limitations risks may be difficult to quantify but improvements are possible. Communication needs to convey how risk management is conducted beginning with context, identification, analysis and concluding with treatment. This is a two-way process leading to further refinement.

The risk assessment adopted by BRGM had 11 main events which were developed into generic bow-tie diagrams. These were then adapted to a studied site to develop a risk register. The next step was the application of an example of a risk analysis for a simulated brine leak for an abandoned well caused by pressure increase in a reservoir. Every possible probability distribution from different parameters was input into a model. Then all the uncertainties were propagated to produce a span, representative of epistemic uncertainty, from a worst case scenario (a cumulative distribution) to a best case scenario. A standard probability distribution will not represent

a span of probabilities.

Risk evaluation depends on the stage of project development. Risk reduction may require more technical evaluation. The results can be difficult to understand so uncertainties need to be explained without maths.

Perspective of Environmental Impact Modelling of CO_2 Leakage for Public Acceptance - Toru Sato, University of Tokyo

Natural seismicity in Japan means seismicity is a very important consideration for CCS development. Public attitudes are important in Japan and vary depending on location. Local fisheries associations, in particular, are not enthusiastic about CCS. Consequently bigger storage prospects, further offshore, are now being considered to avoid confrontation. Ship transport would be used as an alternative to pipelines. Further offshore, low temperatures and relatively high pressures favour the formation of gas hydrate within the hydrate stability zone which could act as a barrier to migrating CO_2. Using a numerical model to predict potential impacts is good tool for EIAs but models need to be verified. There is a natural analogue in the form of a submarine volcano where CO_2 emissions can be compared with a modelled release. However, it can be difficult to detect the location of a seep. A joint probability can be used to determine the location of seeps.

JQICS is the next phase of a planned controlled leak experiment in deep water.

Session 4 Discussion: Is Risk Communication Effective and can Negative Perceptions be Counter Balanced?

The large investment in risk assessment and risk management should increase public confidence in CO_2 storage, but this needs to be positively communicated. There could be a mixed message from the use of a detailed bow-tie risk assessment which shows that although the risks are low they might be perceived by non-experts as high. Public reaction to new technology can be irrational, for example, shale gas fracking. Using more positive terminology such as “increasing confidence and understanding” instead of negative terms such as “reducing uncertainty” should help to convey a balanced perspective. Experience shows that informed regulators do understand risk assessment methodologies, however, in a relatively new industry there is less full-scale experience for comparison. Clear and

unequivocal communication to explain risk is therefore essential. What needs to be stressed is the key motivation for CCS, that is climate change mitigation, and the risks should CCS not be adopted, alongside discussion of the risks associated with CCS. The value of demonstration projects to test the technological validity of the concept at full-scale, and therefore advance its deployment, needs to be emphasized. Risk perception is partly cultural for example the comparison between Japan and UK on seismicity. In the UK minor seismic events invoke worry because the population has limited experience of earthquakes. In Japan familiarity with large earthquakes mean minor events do not cause adverse reactions.

Shell have been actively engaged in stakeholder engaged with the Peterhead – Goldeneye project. Their experience with the proposed Barendrecht storage project in The Netherlands focused on direct engagement with local political representation, however, the project lacked local support and did not proceed. This experience suggests communication needs to be clear and simple. Initial consultation could benefit from less detailed material, supported by more detailed technical information to address any public concerns that might arise. Public perception can lack scientific rationality leading to an emotional response especially if community livelihood is affected. Local issues like water supply or detrimental effects to properties are often major concerns so local issues need to be understood and addressed. It is also important to convey that there may be uncertainty however low. If there is any misdirection then a negative perception can easily take hold so it is important to present a positive image early on.

Session 5: Mitigation strategies
Chair: Lee Spangler

MiReCOL project - Filip Neele, TNO

If significant irregularities occur, as defined by the EU Storage Directive, such as CO_2 migration through the overburden then mitigation measure must be implemented. The aim of the MireCOL project is to provide background information on mitigation measures to rectify CO_2 migration out of a storage complex or wellbore. The project has developed a toolbox of techniques to mitigate and remediate undesired migration or leakage of CO_2 within the deep subsurface. The project also aims to support the definition of corrective

measures plans and help build public confidence in deep subsurface storage of CO_2. Currently available techniques include pressure management, the back production of CO_2 and well remediation techniques. Other techniques such as immobilisation gels and foams have also been investigated. Data from field tests at the Ketzin site and the offshore K12-B will be used to develop specifications for remediation techniques. In one hypothetical exercise foam was injected along a spill point. The effectiveness of the blocking mechanism was modelled which showed the CO_2 migration could be controlled. The concept of the mitigation approaches was tested to determine whether the unmitigated risk was reduced by intervention. The mitigated risk was then re-evaluated to determine whether the level of risk had been improved.

The project will study mitigation and remediation techniques on a range of real or realistic storage complexes, to derive a series of site-specific results, from which more general conclusions will be drawn. A workshop is planned for Spring 2016 probably at the Open Forum event in Venice to present the results of the project and explain when to implement mitigation measures.

NRAP Approach to Quantifying Wellbore Leakage Risk - Bob Dilmore, NETL

The National Risk Assessment Partnership (NRAP) is a collaborative research effort led by the U.S. DOE and comprising researchers from five National Laboratories focussed toward developing defensible, science-based methodologies and modelling tools to quantitatively assess environmental risks associated with long term, large-scale geologic carbon storage (GCS). Risks of primary concern include potential release of CO_2 or brine from the storage reservoirs, and potential ground-motion impacts caused by the injection of CO_2.

The programme is focussed toward modelling critical behaviour of this complex engineered natural system using an integrated assessment approach. Numerical models of key system components (including storage reservoir, caprock, wells, fractures and fault, groundwater aquifers, and atmospheric leakage) are developed; many realizations of those numerical models serve as the basis for development of computationally efficient reduced order models (ROMs). ROMs of various system components are then linked within an integrated assessment model (IAM) to predict whole-system risk performance. Field and laboratory data can then be used to validate and

calibrate both IAM and component models. Model predictions allow strategic monitoring protocols to be developed to verify system performance.

NRAP have developed seven different tools to evaluate different system components including storage reservoirs, caprocks, faults and seismicity, wellbores, thief zones, ground water aquifers and leakage to the atmosphere. Of particular relevance to legacy well leakage performance are NRAP's Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS), and the Well Leakage Analysis Tool (WLAT). NRAP's Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS) simulates long-term full system behavior from reservoir to receptor, and can used to produce risk profiles, estimate storage permanence, and identify key drivers of risk. For example, evolution, over time (e.g., 1000 years) of risks of atmospheric leakage or groundwater impacts in response to wellbore leakage can be calculated for different storage site configurations and wellbore scenarios, including: open wellbore, cemented well with discrete effective permeability (with or without a thief zone to attenuate leaking fluid), multi-segmented wells, and CO_2-saturated brine flux through fractured well cement with geochemical alteration. In another example leakage into a thief zone has been incorporated into a ROM. The WLAT is a stand-alone tool – decoupled from reservoir and receptor ROMs – that can be used for rapid performance assessment of well leakage over time.

NRAP is actively seeking interested individuals from the GCS community to serve as beta testers, to evaluate the effectiveness and useability of these tools. NRAP continues to improve the tools by addressing science gaps, developing more robust ROMs, and incorporating feedback from beta testers into a new version of tools. NRAP will advance its risk assessment tools and methodologies to incorporate mitigation and monitoring for risk management and uncertainty reduction.

Well Assessment at Cranfield Field - Andrew Duguid, Battelle

CO_2 EOR implies a significant number of wells need to be quantified for field scale risk assessment. The risk of well leakage is a significant consideration for CO_2 storage in association with EOR. This collaborative research project, including the University of Louisiana at Lafayette, Battelle, and Schlumberger, conducted a comprehensive risk quantification that involved logging, testing

and sampling to quantify wellbore properties over the same zone. Data acquisition could then be used in well-scale and field-scale risk assessments. The research was centred on SECARB's Phase II Gulf Coast Stacked storage project from the Cranfield Field, Mississippi. One of the three wells used in the study, Ella G Lees #7 (EGL7), is 70 years old. Evaluation used different cement bond logs (CBLs) and other logging tools. The two newer wells, CFU31F2 and F3, are monitoring wells that have fibreglass cased sections. EGL7 has had a lot of work overs since it was first drilled in 1945 including cement squeezes. The wells were first logged to find zones of interest to test. Reservoir saturation tools were run to detect the extent of CO_2 saturation in the reservoir.

Sidewall cores from more recent wells were taken for analysis. One sample has a noticeable vertical crack in cement. A sample of cement cored from a production level has CO_2 within it that caused it to break. Highly altered cement from the EGL7 well shows evidence of carbonation but this was not caused by CO_2. Well construction or materials choice not CO_2 reactivity is the probable reason for the alteration of the cement.

The constriction in the fiberglass casing in the injection zone in CFU 31F3 is likely to be related to CO_2 interaction with the casing. Cement mapping tools can be used to identify defects but cannot by themselves quantify pathway sizes in three dimensions. The existence of defects in some places within a well does not mean that the overall integrity is problematic but it might indicate that further investigation is required.

Session 5 Discussion: How Could we Evaluate Mitigation Strategies and are there Gaps?

Experience from CO_2 EOR operations can provide an insight into mitigation practices. Some operators do manage CO_2 movement to minimise losses and complete wellbore workovers before EOR. Others wait to see what happens in the field before taking action. The approach depends on how risk averse the operators want to be. There are well established techniques that can be used to minimise CO_2 leakage. DOE are about to launch a series of new projects on pressure management leading to field demonstrations over the next year. Salt Creek in Wyoming is an example of where all the wells were fixed before flooding to minimise leakage. For first of a kind it pays to

be risk averse to ensure CCS can be deployed effectively. In the future when injection rates are ~200Mt/year then a plethora of techniques will be required to fix problems if they occur because of the scale of injection required.

Plugged and abandoned (P&A) wells could present problems. The status of casing and completion records might give an indication of the wellbore integrity. There may be evidence from adjacent wells. Ultimately individual wells may need to be re-entered if serious deterioration is suspected. Pulse Neutron (PN) logs can detect leakage. Large scale anomalies at reservoir or field scale will require monitoring wells. With small leaks that are undetectable then mitigation may not matter.

Remediation techniques that can guarantee a solution to a leak would be ideal. A very high level of confidence in an ameliorative measure is necessary otherwise potential storage candidates may have to be ruled out. Legacy areas could present a significant risk if legacy wells cannot be remediated.

Session 6 Panel Discussion: How is the Importance of Leakage Risk, Environmental Impact and Storage Capacity Balanced

Panel: Ian Wright, Owain Tucker, Filip Neele and John Frame

CCS will still be required to minimise CO_2 during cement or steel production even if CO_2 capture is not implemented for power generation. Small-scale leakage is not likely to be dangerous given the evidence from natural seeps in Italy. The technology could be much more expensive if additional mitigation or treatment measures like desalination are required.

Experience from Australia shows that environmental protection does allow some degree of flexibility. The regulator and developer can abide by the same legislation provided there is no evidence for leakage into adjacent resources. Otway is a good example where CO_2 injection has not had any impact on a higher aquifer or buildings which are protected by legislation.

The EU Regulations are very strict on CO_2 containment and therefore operators have to learn to live with minimal leakage as a condition of any permit. The depleted P18-4 gas field has already been identified as a potential demonstration site for the ROAD project. Depleted gas fields are a logical choice but the selection will be driven by economics.

The first demonstration projects need to be successful and have a very high

level of containment to avoid negative perception. Risk management needs to be thorough but operator error and technical failure is still a remote possibility. If an operator goes bust then mitigation will not be possible and a negative perception becomes ingrained. Regulators will not want to pick up costs. One solution is to insist on investment bonds to pay for any contingency. A contingency budget is a requirement of the EU CCS Directive. Mitigation measures need to be clearly documented and there needs to be transparency in any decision making.

Even with present day remote sensing technology it is only possible to quantitatively measure about 90% of the CO_2 stored in the deep subsurface under 2km of rock. The EU regulations recognise the technical and practical limitations of remote sensing measurement of CO_2 in reservoirs. The CO_2 that is injected needs to be metered to a very high degree of accuracy at the surface prior to injection, and there needs to be a monitoring programme to track the overall behaviour of the CO_2. If modelling and monitoring evidence suggests that the CO_2 is secure then a zero leakage assumption is judged to be valid under IPCC green-house gas guidelines 2006. This principle is reflected in the European regulations and UNFCC system.

The European EC Directive is thought to be complex and demanding but the proposed monitoring programme for the ROAD project is relatively simple and has been accepted. This example demonstrates that there are feasible solutions that allow a CCS project to proceed. The P18-4 field of the ROAD project is an 8Mt site, but the future challenge will be the development of 800Mt sites in the southern North Sea. This could mean that characterisation of larger sites with features such as faults which may or may not be transmissive. In these circumstances fault properties would need to be ascertained with a targeted monitoring programme. The extent to which CO_2 migrates across faults could be tested by injecting into small leaky reservoirs. This has been proposed in the US but the plan was not approved by regulators.

A key question to address is how to balance the cost and risk of CCS compared with the impact on climate change caused by unabated CO_2 emissions. IPCC models for 2100 projections of CO_2 reduction assume that capture rates of 85 – 90% will need to be reached. The overall development costs for a CCS project may lead to the avoidance of poor quality wellbores. If credit is avail-

able then full project economics will be improved. Regulators might want excessive monitoring to cover project risks, however, this could be moderated by regulatory discretion. Experience from Canada shows that the regulations for CO_2 storage are more stringent compared with the demands placed on acid gas disposal. Acid gas (H_2S) has been successfully stored which shows that CO_2 storage can be controlled. Disposal operations have not needed reservoir models or modified wells despite the gases' corrosive and toxic properties. Gas in reservoirs is not actively monitored.

In Germany current environmental regulation favours other uses for subsurface resources over CO_2 storage.

Research proposals should include deliberate injection to induce migration under controlled conditions. A second potential project was also proposed for a social science approach to gauge risk assessment of CO_2 storage compared with the impact of anthropogenic climate change. One objective of this proposal would be to develop language that can be understood by the wider public starting with local primary schools.

Wrap -up: Charles Jenkins / James Craig
Highlights

- Maturity of risk assessment methodology (even probabilities!)
- Clarity about the prominence of wellbore risk
- Beta test for NRAP assessment tool
- Biofilms

Gaps

- Diagnosing wellbore risk
- Remediating wellbore risk
- Setting thresholds ("normal" -> "suspicious")

Summary

- Bow-tie methodology clearly demonstrates highly detailed assessment of different risks and barriers but this perception can lead to an unintentional negative perception.
- Risk Communication - Phraseology needs to be carefully presented to convey severity of risk.

- MiReCOL and NRAP are developing predictive tools that need to be road tested.
- Legacy wells which have been plugged & abandoned could present significant challenges. There is a need to be sure mitigation measures work.

Day 2 - Environmental Research

Session 7: The Impact of CO_2 in the Ocean: what is the Magnitude of the Impact and how Would Marine Ecosystems Respond
Chair: Doug Connelly

Relationship between Sea Floor Emission Rate and Environmental Perturbation - Jerry Blackford, PML

The impact of CO_2 on the marine environment needs to consider two components: biological sensitives to high CO_2 concentrations; and secondly the chemical and spatial extent of plausible scenarios. The CO_2 footprint in the ocean depends on leak rate and how is it dispersed, especially by tidal mixing. Plausible scenarios of leakage still have large uncertainties.

The following three scenario classes have been widely discussed in the literature:

- Abandoned well 0 – 1t/day hard to detect, potentially long-term.
- Leakage via a geological feature 10 – 500t/day on a decadal scale if not mitigated.
- Pipeline scenario ~5,000 t over a short time span and very sudden.

Hydrodynamic modelled scenarios have tested impacts over several orders of magnitude of leak rate. Modelling reveals that post leakage, chemical recovery is rapid provided mixing occurs as is the case in the North Sea which has high tidal mixing. Most CO_2 is eventually released to atmosphere and is not retained in the sea.

The area of impact has been plotted against different leakage rates. For small leaks (<1t/d) impacted area (as defined by a change of pH exceeding 0.1 pH units) ranges from cms to 10s m, trivial on a scale of an area of the North Sea. Leakage rates of 10 – 1000t/day would impact 1 – 100km^2. The annual

impact of trawling in the North Sea is two to three orders of magnitude greater (~100,000km^2).

Any plume of dissolved CO_2 will move radially with tidal mixing and the resulting pH perturbation can be rapidly and cyclically variable. The biological impact is less clear under these circumstances. Episodic exposures on fauna have not been widely researched.

On the basis of this research we can assess that all but the largest leak events would be very unlikely to impart significant regional environmental impacts. The primary environmental impact of large scale CCS development, which mitigates climate change, would be hugely positive.

Chemical Transformations in Shallow Sediments associated with Leakage - Henrik Stahl, Zayed University, Dubai

Chemical transformations within shallow marine sediments were monitored before, during and after the QICS in situ release experiments. 4.2t of CO_2 was released over 36 days. Sediment was sampled to a depth of 30cm around the release point and from a reference site. Surface sediments have bacteria, epi-fauna (star fish) and macro fauna that respond to changes in pH caused by the release of CO_2.

Seepage of bubbles through the sediments into the water column was observed. An estimated 15% of released CO_2 reached the sea. 85% was retained in pore water forming carbonic acid and calcium carbonate in solution. Alkalinity increased post injection reaching a maximum one week after injection. At D42 high dissolved inorganic carbon (DIC) saturated the pore water. By D54 a rapid decrease in DIC had occurred which might be caused by advection or even biological irrigation processes. Spatial variability within the sediment may also influence these observations. The change in pH did lead to some iron and manganese ion mobility but there was no increase in the mobility of heavy metals which are present in very low concentrations. This controlled release experiment, and subsequent chemical analyses, have demonstrated that chemical transformations in sediments could be a good indicator of CO_2 leakage.

Predicting the Impact of Sub-Seabed Leakage of CO_2 on Benthic Microbes and Microbially-Driven Processes: Lessons Learned from Mesocosm and Field Studies - Karen Tait, PML

Key indicator taxa that are sensitive to the presence of a CO_2 leak within coastal environments were detected at the QICS site. Changes were observed in benthic communities in samples exposed to CO_2 at the QICS release point and also at progressive distances from it. There was a reduction in biological diversity at the release site but, contrary to previous reports showing impacts to ammonia oxidation with decreasing pH, elevated CO_2 stimulated an increase in ammonia oxidation.

Two groups of microbes are responsible for ammonia oxidation. In an Arctic sediment mesocosm, it was shown that ammonia oxidising archaea are tolerant to pH changes but ammonia oxidising bacteria were sensitive to the CO_2 change and their activity declined. This suggests that the impact of CO_2 on local nitrification may depend on the ratio of archaea:bacteria present.

Ammonia oxidation in burrowing shrimp burrows was investigated to assess how changes in CO_2 concentration might affect this process. The animal draws oxygenated organic matter into its borrow leading to increased ammonia oxidation when compared to surface sediments. Elevated CO_2 has a strong and significant effect on nitrification rates in burrow wall sediment but not in the surface sediment. This is attributed to the shrimp's irrigation behaviour.

A microphytobenthos bloom (identified as cynobacteria, together with diatom species) was caused by CO_2 reaction within pH range 7 – 7.5. Carbon concentrating mechanisms are evident in some microbes and observed in mesocosm experiments. Field observations from a site in the Mediterranean revealed an increase in microbe activity but not in abundance suggesting that although CO_2 can affect photosynthetic kinetics other mechanisms can restrain growth. To be certain that CO_2 is affecting microbes the effects need to be stronger than any natural background variation. Indicator species may be useful as a monitoring tool but impacts may only be temporary.

Responses of Key Benthic Megafauna to Real and Simulated CO_2 Leaks in the Marine Environment, with Implications for Establishing Environmental Baselines - Chris Hauton, University of Southampton

A biodiverse, resilient, and productive ecosystem is seen as a key indicator of Good Environmental Status (GES) (EC Marine Directive Article 3). GES descriptors include: maintenance of biodiversity, an integral sea floor that supports a functioning ecosystem, and contaminant concentrations which produce no effects on marine organisms. Furthermore, and as stated with high certainty in the Millennium Ecosystem Assessment of 2005: 'biodiversity, including the number, abundance, and composition of genotypes, populations, species, functional types, communities, and landscape units, strongly influences the provision of ecosystem services and therefore human well-being.'

Research has shown that increases in sea water pCO_2 can impact the physiology and performance of marine organisms, and so influence biodiversity. It is therefore essential that, before sub-seabed CO_2 storage becomes widely adopted, the potential risk to the marine environment is quantified in the unlikely event of any leakage.

In situ field experiments have shown that larger faunal species living at the surface of the seabed, including species such as mussels and scallops, do not suffer detectable impacts when subject to limited releases of CO_2, which mimic a short-lived and small scale release from a reservoir. This has been attributed to the rapid dispersion of the CO_2 plume by tidal forcing.

Mesocosm and laboratory based experiments, with more extreme perturbations in environmental pCO_2 (up to 20,000 ppm), have demonstrated significant impacts to marine species including severe spine dissolution in epifaunal urchins and shell etching of infaunal bivalves, including cockles. Often these exposures have been accompanied by behavioural avoidance of the CO_2 plume, either seen as escape behaviours or reduced activity of infaunal species. Infaunal species emerging from sediment in response to CO_2 exposure will be prone to predation from scavengers.

In general, infaunal species in sediments appear to be more impacted by CO_2 releases whereas epifauna are less impacted. In all cases, however, the larval and juvenile stages of marine species are more susceptible to exposure to

elevated pCO_2 than adult life stages. The response of organisms to elevated pCO_2 also varies as a function of the nutritional status of the affected individuals. Well-fed individuals may have sufficient energetic reserves to tolerate periods of elevated pCO_2, whilst starved individuals may be more susceptible to exposure. As a consequence of both of these factors, the season in which a leakage occurs may be pivotal to the magnitude of the impact of that leak.

Ultimately, however, the marine benthic system represents a dynamic environment that does not necessarily respond linearly or predictably to natural or anthropogenic forcing. Therefore, in order to accurately discriminate natural changes in benthic ecosystems from the impacts of CCS reservoir failure, and so ensure that operators are protected from wrongful litigation, it will be necessary to establish multiple 'reference sites' to compare against the biological community overlying any injection reservoir. Any directional change in the composition of the biological community at an injection site will need to be compared to the directional changes simultaneously recorded for multiple reference sites to definitively identify impact. As a consequence, it will be imperative that all reference sites will need to monitored for as long as economically possible, both during and after the injection phase.

Megafauna Responses to Chemical Transformations in the Sea - Jun Kita, RITE

The response to the CO_2 release on benthic megafauna were also monitored at the QICS site. Sea ferns, sea stars, snails, crabs and juvenile fish were observed using time lapse cameras. Sea stars and crabs were frequently observed next to a bubble stream for many hours without discernible abnormal behaviour. No adverse effects on fish were observed during the CO_2 release phase. They even swam amongst bubble streams. Changes in brown mats of microphytobenthos at the release site, and a control site, were caused by natural variations.

Multi-dimensional scaling (MDS) plots showed that chemical changes at the QICS site were not severe enough to have adverse effects on megafauna. A hermit crab recorded adjacent to CO_2 bubbles seemed attracted by a bubble stream.

Japanese flounder were exposed to elevated CO_2 at 10,000µatm, 30,000µatm and 50,000µatm for 72 hours in a laboratory. This experiment demonstrated

that fish can compensate blood acidosis by taking bicarbonate from surrounding seawater. In other experiments the tolerance levels of ivory-shells were tested. In the adult stage a high degree of tolerance to CO_2 is observed but the larval stage of this species is sensitive to acidification.

CCS has potential as a climate change mitigation option if leaks are small, rapidly detected and occurring in more resilient habitats even should it leaked. Thus appropriate base-line surveys on marine environment are essential in site selection procedures and monitoring programmes for CO_2 storage reservoirs.

Session 7 Discussion: What Further Research is Needed?

There is a research requirement to improve the understanding of the mechanisms that cause infaunal responses to changes in conditions. Physiological and behavioural responses may be induced by increased CO_2 concentrations or other pollutants. Formation water and brine change could be more important than changes in CO_2 concentration. A reduction in pH will also have an impact leading to an increase in H_2S inducing infaunal movement.

Field observations show both avoidance and attraction to bubble streams which might be induced by vibration. However, the limits of this stimulus are unquantified. Evidence also reveals that mega fauna display diverse responses to CO_2 in marine environments. Automated imagery to analyse infaunal responses is a potential area for development.

In tidally dominated regions induced mixing leads to highly dynamic plumes, therefore the environmental response of fauna to rapid cyclic change is an important topic for investigation. Many organisms have the ability to tolerate short periods of environmental stress. However, if conditions become chronic through prolonged exposure then physiological stress could be detrimental. Some work has suggested that oscillating exposures could impart additional challenges for organisms as they continually need to adjust to changing chemistry. The evidence from both controlled release sites and natural CO_2 seeps shows that impacts are highly localised.

Reference risk cases which researchers could use to analyse the magnitude of impacts would be a helpful starting point for simulations. This approach

would be more relevant than hypothetical and unrealistic scenarios. Multiple reference sites would provide background evidence of spatial and temporal variability.

A second stage QICS type project, over a longer time period (~50 t release), would be able to demonstrate impacts and monitoring techniques over a greater scale. Community acceptance could still be a challenge even with rapid dispersion. The broader question of environmental impacts from leaks needs to be put into context. The probability of leakage is very low ~1:10,000,000. The probability of climate change and increasing ocean acidification will continue without intervention. Consequently the impact of simulated releases should be emphasised to the wider public (~10-5 per year) to put the risk into context.

Session 8: Understanding Natural Variability and CO_2 Impacts: how can Natural Variability be Distinguished from Induced Anomalies in Environments?
Chair: Jerry Blackford

Natural Variability of Biological Communities in the Temperate NE Atlantic and North Sea - Steve Widdicombe, PML

Seasonality is a key influence in the marine environment. In spring rising temperatures plus nutrients increase biological productivity causing phytoplankton blooms. In the north-east Atlantic and North Sea stratification also occurs between the warmer surface waters and deeper cooler waters. Then in the autumn storms break down stratification and nutrients are brought to surface resulting in a second annual bloom. Stratification and therefore biological productivity is partially governed by depth. Shallow waters in southern North Sea and eastern English Channel are regularly mixed and not stratified.

Detailed site-specific sampling at the L4 observatory station in the English Channel off the coast of Plymouth has also revealed a stratification pattern observed elsewhere. 2012 observations from this site showed that it was the most productive year since records began several decades ago. Macrofaunal abundance co-incides with the spring bloom leading to an increase in diversity which can be used as an indicator of change. Oxygen demand caused by blooms can lead to hypoxic depletion. In abundance some marine organisms are better able to tolerate abnormalities therefore tolerance to

environmental stress will depend on the time of year. This seasonal cyclicity also varies on a yearly and even decadal scale. Stochastic events like storms can also have big impacts. Consequently, additional impacts such as elevated CO_2 concentrations will depend on the time of year, locality and climate.

Climate change is creating biogeographical changes in the coastal seas around the UK leading to an increase in the prevalence of warmer water species. Changes induced by CO_2 could be different in 20 years' time. There are broader environmental changes which CO_2 releases will not affect, for example the diminution of cold water corals from acidification.

Environmental assessments of the impacts that might be attributed to CO_2 releases in the ocean need to be fully conversant with natural variability and be able to distinguish this phenomenon from any change induced by CO_2 leakage.

Environmental Variations in Dissolved CO_2 Offshore Gippsland related to Equivalent Leaks from Storage - Charles Jenkins, CSIRO

There is ample power generation potential from brown coal in the Australian state of Victoria. There is also offshore CO_2 storage potential in the Bass Straight off Victoria's coast which also has important ecological and fisheries interests. Consequently a CarbonNet research project has investigated the impact of a CO_2 leak and the natural occurrence of dissolved inorganic carbon (DIC).

Water samples were taken from a ship transporting cars to Melbourne over a five year period. DIC is very variable over the seasons, changes of up to 100µmole/kg are common DIC is also spatially variable. Samples show DIC fluctuates to the east but is more stable to the west. The dip in DIC values is related to an annual front.

A hypothetical leak on the scale of 20kt/year into 40m of water was modelled in coastal waters. The cumulative distribution of DIC signals from the leak shows virtually nothing above ~10µmole/kg. Windy conditions in the Bass Strait cause mixing and any change induced by CO_2 is likely to be very minor. Naturally-caused DIC changes are much larger than those resulting from an intense, spatially-concentrated leak. The environmental impact is therefore not likely to be a large risk. The results also suggest that finding leaks from

marine chemistry changes will require sensitive measurements.

A new way of Looking at Baselines - Katherine Romanak, BEG

A new approach to baseline monitoring in the unsaturated vadose zone in the near surface is essential. Environmental impact is greatest in this zone as it affects the general public, and land owners, and it is the interface onshore which defines leakage to the atmosphere. Research is showing that there is a need to rethink baseline monitoring especially following the Kerr Farm allegation at Weyburn.

The standard approach to leakage detection is to compare pre-injection CO_2 concentrations to post-injection concentrations to discover if an anomaly signals leakage or is in line with natural variability. However, background measurements at all locations are not always possible, weather parameters need to be taken into account, complex statistical analysis needs to be performed and baselines can be spatially dynamic over the lifetime of a project.

As an example, monitoring at the Weyburn Project involved rigorous research with a very high temporal and spatial sampling density. It also included rainfall measurements and geostatistical analysis. A landowner claimed leakage from the CO_2 injection. Three teams investigated the leakage: one funded by the operator, a BGS-led team as part of the Weyburn-Midale Project and an IPAC-CO_2 team involving the University of Texas and others.

CO_2 measurements at Weyburn, Kerr Farm and background locations could, by themselves, be interpreted as leakage. However, CO_2:O_2 and CO_2:N_2 ratios measurements clearly showed that anomalies were consistent with biological respiration. This was confirmed by radiocarbon and noble gas analyses. This example highlights the importance of having a method for signal attribution that is accurate and timely for responding to public claims quickly. Subsequent research at the ZERT site has revealed leakage patterns which can be differentiated from natural patterns of CO_2 release using simple ratios. The approach has now worked at 3 – 4 different sites. Although concentrations of these gases change the ratios remain consistent.

Differentiation between Natural Processes and Induced Leakage in an Offshore Environment – Bio-Oceanographic Approach to CO_2 Leakage Detection. Latest Research Findings - Jun Kita, RITE

Monitoring CO_2 in seawater is essential for leakage detection near offshore storage sites. Exogenous leakage needs to be distinguished from naturally occurring background CO_2.

Photosynthesis in the water column leads to high O_2, low CO_2 and high pH in surface waters. In contrast, degradation in the proximity of the sea floor leads to low O_2, and pH, but high CO_2 concentrations. This stratification becomes pronounced during the summer when biological activity increases. pCO_2 measured in Tokyo Bay was relatively uniform during the winter (200 - 300µatm) but revealed a vertical gradient from 100 – 900µatm in summer. The high measurements in summer mean that it would be more difficult to distinguish leakage from background observations. An appropriate methodology is therefore needed to detect leakage.

Environmental monitoring in Osaka Bay has been conducted for over 30 years. Bay waters have been sampled for a series of parameters including salinity, dissolved oxygen (DO) and pCO_2. Alkalinity was calculated from a linear relationship with salinity. TCO_2 / DO have a weak statistical relationship, but a log pCO_2/ DO% saturation plot shows that a quadratic trend-line is evident. This relationship can be used to detect leakage.

The natural background of pCO_2has been measured at a depth of 50m near Niigata off the west coast of Honshu. pCO_2concentrations are regularly high at mid-night and low at mid-day when the sun's radiation is strongest. Photosynthesis influences pCO_2even at a depth of 50m. This fluctuation is also evident from the high concentration of benthic phytoplankton during June and July. The fluctuation in daily pCO_2 concentration declines from August. Although the pCO_2 / DO% correlation can be used for leakage detection, background characterisation deduced from site-specific monitoring is essential. Leakage monitored at release sites shows a distinctive pattern that can be distinguished from natural background trends.

Session 8 Discussion: What are the Main Drivers on Environmental Impacts?

Marine site characterisation will depend on location, depth and season.

Regulators will want to know if a signal is a leak or whether it can be attributed to background variability. A minor CO_2 leak may not have a significant impact on the environment. Moreover, the scale of the impact needs to be determined. Regulators will become concerned if a catastrophic leak occurs which leads to environmental change or damage to a specific receptor. Regulators could demand an impact assessment.

The uses of tracers might be an option but tracking them and CO_2 through 1000s of meters of overburden might be impossible. CO_2 will react with some of the mineral content in the overburden formations and could be retained in traps. Tracers are also expensive. Data from QICS and other marine sites could be used to see if natural variables can be distinguished from leaks. Variability can be addressed by statistical treatment of covariation between different variables associated with natural processes, but not leaks. But natural variability takes place over multiple timescales, and co-variability may be partially uncoupled in space or time, making this more challenging than initially hypothesised. A geophysical parameter could offer an alternative to variable biological parameters. Key reference sites or habitats could be used to compare changes that might occur elsewhere.

Other biogeochemical parameters could be refined to demonstrate natural baselines especially in a marine environment, i.e. establishing ratios between DIC, O_2, nutrients etc. This approach could help to overcome the difficulties of distinguishing an anomaly from spatial and temporally variable natural baselines. Processes are complex in a marine environment and need to be better understood. Mesocosm experiments to test whether ratios can be used to define natural conditions is one possible solution, models can also provide insights, but there will be no substitute for high frequency multivariate time series with both a seasonal and spatial coverage.

Session 9. Environmental Impacts Related to the Transport of CO_2
Chair: Dave Jones

COOLTRANS Project - Julian Barnett, National Grid (NG)

The National Grid COOLTRANS research programme was a three year Research and Development (R&D) project which took place from 2011 to 2014 and was co-funded by the EU. It started with considering the CO_2 pipeline specifications, then identified gaps in technical knowledge and what R&D was relevant to dense phase CO_2 pipeline transportation. A series of R&D work streams were set up to address these gaps. Experimental work including a programme of over 100 tests into above and below ground releases, simulated pipeline punctures at full scale and full scale fracture propagation tests were conducted. The results were used to develop best practice and safe long term CO_2 pipeline transportation.

National Grid has also completed an environmental impact assessment (EIA) for a proposed pipeline across the Yorkshire and Humber regions. The EIA follows the UK Planning Act for the planning of major infrastructure projects in England and Wales. The company has also consulted with statutory authorities, non-statutory consultees including the general public. One example of the care and attention applied to the planning of the proposed pipeline is the routeing of the pipeline under a possible archaeological site which could be a medieval village.

A series of field and laboratory experiments by Nottingham University have also been conducted. Controlled releases on crop plants have been used to monitor the impact of CO_2. DNV-GL has carried out similar experiments on sphagnum moss with no observable detriment effects. The level of impact depends on the area of exposure, rate of release and its duration. Computational Fluid Dynamic (CFD) models of atmospheric dispersion of CO_2 from venting operations have formed part of the R&D programme. CFD models have been refined after comparison with observations from experimental releases to improve future simulations.

An unplanned release of CO_2, although very unlikely, has been simulated. Third party interference is a risk, which might lead to a failure mode such as a small leak from a puncture although standard pipeline procedures will be adopted to manage this risk. The impact of a major event such as a

pipeline rupture has also been considered. A comprehensive Quantified Risk Assessment (QRA) has now been developed for CO_2 pipelines which meets the principles of UK design codes and the prevailing legislation.

Quantitative Hazard Assessment for CO_2 Pipelines. Solomon Brown, University College London

Concern over pressurised CO_2 pipelines has led to EU funded research to assess hypothetical risks of ruptures. A sudden release of CO_2 would 'flash' (vapourise from supercritical state). Solid CO_2 would also be released and then disperse from the rupture. Experimental campaigns were conducted to represent CO_2 releases at different scales including a 256m length of experimental pipe at a Chinese test site in Darlean. Transient conditions were measured during these experimental releases.

Pipeline decompression can occur followed by a risk of ductile and brittle fractures. The modelled CO_2 release episodes are then linked to the dynamic modelling of ductile fracturing. This approach can then be used to influence pipeline design.

FLACS high fidelity simulation to predict the impact of a CO_2 plume across ground has been produced by HSE. The impact of CO_2 can be highly topographically dependent. The model output has been used to produce risk assessment guidelines for pipelines.

Subsea release simulations have been conducted by the research team. Rapid Decompression can lead to the loss 15,000 kg/sec and the uncontrolled release of 10,000s tonnes of CO_2 followed by the ingress of seawater before remedial action can be undertaken. Impurities, particularly noncondensable gases, will influence fracture propagation.

High Pressure CO_2 Pipelines: CFD Simulation of the Consequences of Puncture and Rupture - Christopher J. Wareing, University of Leeds

Research at the University of Leeds has concentrated on the near-field sonic dispersion (2m from the release point) of CO_2 from high pressure pipelines. Thermodynamic conditions of solid and liquid phases are not in equilibrium at the time of release. Consequently a novel complex equation of state is required. Mach Shock, turbulence models simulate the sudden release of CO_2 which requires a dense grid and is computationally demanding. Dense

phase release escapes at 500m/sec at 177.8 K -80°C 4m above the vent. The models were validated against experimental observations. In the gas, phase good agreement between the model and experiment was also achieved.

Conditions that might be experienced with underwater pipelines are a key knowledge gap. There is also the question of the formation of hydrates and solid CO_2 and CO_2 dispersion in the water column. A full-scale rupture at 13.5 MPa at -100°C, would create a release at 100m/s. A 0.6m diameter submarine pipeline, 100 km in length, would release 100,000 tonnes of CO_2 before the shut off valves were activated. This equates to a 10% concentration CO_2 gas cloud 7 miles in diameter. A research proposal is being prepared to seek fundamental scientific research funding from the UK EPSRC. This ERUPT proposal is designed to address the key knowledge gap regarding offshore CO_2 pipelines and the risk of their rupture. Interested stakeholders are invited to become involved.

Session 9 Discussion: Can Environmental Impacts caused by a Leak from a CO_2 Pipeline be Quantified?

Large CO_2 releases from pipeline ruptures can be limited by safety procedures. At Quest the pipeline is shut down automatically if there is a large pressure drop. National Grid has pipeline controls to shut down systems using remote valves. Experimental work has aided the understanding of CO_2 releases. A plume will entrain air and therefore dilute the CO_2 before it eventually disperses. Natural turbulence will cause CO_2 dispersion even on a still day, although wind will facilitate more rapid dispersion. Venting would only be done on windy days to ensure safe dispersion.

Full blown pipeline fracture tests have been conducted by National Grid. Results have been used to define a minimum toughness test, equivalent to a 250 Joule pipe. The material standard for a future pipe would be in the order of 300 Joule. National Grid have also simulated a digger accidentally damaging a pipeline.

Session 10: The Impact of CO_2 in the Terrestrial Environment: Magnitude of Impacts and Baseline
Chair: Katherine Romanak

A Review of Recent Research on Potential Environmental Impacts of CO_2 in Terrestrial Environments - Dave Jones, BGS

Legislation stipulated in EU Directives and the US Class VI wells means that operators need to be aware of the consequences of leakage on terrestrial ecosystems despite the very low risk of leakage. The effects of elevated CO_2 on soil microbes and plants has been investigated at a number of different test sites and laboratory experiments, plus naturally occurring CO_2 seeps, including CO_2GeoNet, RISCS, CO2 Field Lab, ZERT (USA), Ginninderra (Australia), Ressacada Farm (Brazil), MUSTANG and PISCO$_2$.

Results from a Norwegian site trial showed that with high soil CO_2 oat growth was reduced. The CO_2 flux was correlated with a stressed vegetation index. At the ASGARD test site in the UK autumn-sown barley showed stress after two weeks exposure to CO_2. However, autumn-sown oil seed rape was not strongly affected because the plant was well established before exposure to CO_2 but there was a greater impact on spring-sown oil seed rape. Modelling at the ASGARD site is consistent with discreet CO_2 migration pathways through the soil. A natural CO_2 seep site at Florina in Greece revealed a plant species distribution based on the degree of tolerance of plants to CO_2 exposure. The effect of CO_2 on microbial activity was also evident at this site but could not be separated from seasonal effects at ASGARD.

The overall conclusions from these experiments is that different species have varying degrees of tolerance to elevated CO_2 levels in soil. Impacts are restricted spatially to a few meters to 10s of meters. The development stage of plants, as well as seasonal and annual variation, influences the effects of CO_2. The impacts appear to be manageable compared with climatic factors or pests.

Assessing the Potential Consequences of CO_2 Leakage to Freshwater Resources: from Experiments to Predictive Models - Julie Lions, BRGM

The potential impacts of CO_2 on a shallow ground water aquifer could be compounded by direct and indirect consequences including brine migration, the presence of immiscible hydrocarbons and the modification of the

geochemical equilibrium within an aquifer. CO_2 may lead to acidification and the release of trace elements or sorption of trace elements from minerals. Modelling changes induced by CO_2 shows a large variability in published results.

Further research has attempted to improve the understanding of CO_2 impacts on groundwater quality. CIPRES is a French national project to evaluate these impacts. One objective was to identify geochemical reactivity to examine the significance on temporal and spatial impacts induced by CO_2 intrusion. Laboratory experiments were combined with modelling using the Albian Greensand formation within the Paris Basin as a case study. This formation is a strategic reserve for drinking water supply. The iron-rich phyllosilicate glauconite within the formation has high surface properties that are sensitive to changes in pH. Isotherms on glauconite were used to test the dissolution of glauconite and ion exchange properties of nickle, zinc and arsenic. Laboratory data was used to build geochemical models that include the kinetic dissolution of minerals and surface processes. Two different processes were modelled: ion exchange; and a surface complexation process. CO_2 changes the pH and therefore both reaction processes need to be correctly assessed to improve the prediction of trace element mobility. Surface complexation is sensitive to pH and water chemistry while ion exchange is mainly controlled by water quality.

A 3D reactive transport model was used to simulate the progression and impact of a leak. Three different leakage rates (0.001 to 0.1 kg/s) were modelled over a 100 year timescale. Above the leakage point gas saturation and the dissolved inorganic carbon (DIC) accumulates at the top of the aquifer. Downstream the density effect of the dissolved CO_2 causes the plume to accumulate at the base of the aquifer, but after 100 years the plume has almost completely dispersed. pH buffering is very low within the aquifer in the absence of carbonates. Even if gas saturation recovers to zero, the pH does not revert to a neutral level. Good geochemical characterisation is essential before any monitoring programme to determine the presence of a leak. Initially there will be changes in gas saturation and pH, but in the longer term a drop in pH will cause dissolution of glauconite and an increase in ions such as aqueous silica. The delay in the response of the water chemistry is controlled by the kinetic dissolution of silicates that is relatively slow. Such

indicators could therefore be used to detect a CO_2 release.

The correct assessment of geochemical reactions in aquifers, caused by potential CO_2 leaks, is important to aid the design of monitoring plans. The location and separation of sampling points and the frequency of monitoring could be estimated with a 3D reactive model if the hydrogeology and the geochemistry is known.

Session 10 Discussion: What are the Most Important Terrestrial Impacts and which Impacts Lead to the Greatest Concern?

The evidence to date from controlled releases on crops shows that elevated CO_2 concentrations have limited impacts. There is also limited evidence from soil sampling that microbial communities can respond to a rise in CO_2 levels in some locations although it is not clear if longer term fertility could be affected. Surface changes are the most visible to the public but these are likely to be spatially limited. CO_2 or brine impacts are the greatest concern especially in the USA where shallow aquifers are a major source of drinking water. There is evidence that water quality will not be adversely affected by a leak from a well 100m away. However, it could be very difficult to detect the impact of CO_2 on a potable water supply from a monitoring well. Consequently, the monitoring location does not necessarily mean a change in water quality will be detected.

There is currently an EC funded CO_2Quest project which has an objective to track CO_2 with heavy metals to model/monitor their dispersion within an aquifer in the Paris Basin. Despite the close proximity (20m) of the monitoring point it was very difficult to detect the presence of released CO_2 which had fallen to 10% of the concentration at the injection point.

Greater public debate about brine ingress into fresh water aquifer would be beneficial. Monitoring potassium mining, and the associated brine disposal operations, has provided a useful insight into the impact of brine disposal on ground water.

Wrap-up Day 2: Ian Wright and Lee Spangler

Terrestrial

Potential environmental impacts caused by CO_2 leaks in terrestrial locations are highly localised and relatively limited. Evidence from controlled release

experiments suggest rapid recovery is likely to occur but further research is necessary. It is clear that saline water ingress is a key issue.

Pipeline safety is a key public concern given the scale of potential impacts. Catastrophic failure such as a rupture will have a big impact but over short period of time. Minor leaks caused by corrosion might affect vegetation in the vicinity of pipelines.

Marine

Research suggests that small leaks in a marine environment will have a limited localised empheral effect. Natural turbulence induced by currents will cause mixing and dispersion dissipating the impact of released CO_2. The approach to base-line monitoring needs to take account of site-specific conditions. It may be better to use molecular ratios to distinguish the origin of CO_2 rather than more complex methods which could be less effective.

Pipeline rupture in a marine environment needs further investigation. Biochemical changes induced by CO_2 within shallow marine sediments and the water column is another area for further investigation.

Day 3 – Risk Management and Environmental Research Combined Themes

Session 11: Fluid Production and Release into the Marine Environment: Management, Issues and Impacts
Chair: Ian Wright

A Perspective on Hypersaline Fluid Management Introduction - Ian Wright, NOC

Ian Wright introduced this section. He made three key points:

- In the North Sea and other offshore petroleum provinces there are natural seeps of brine and other fluids from aquifers including hydrocarbons,
- CO_2 injection into saline aquifers may displace brine in the far field,
- To go beyond 1% injection into saline aquifers, brine is likely to require extraction i.e. produced waters.

Impacts of Formation Water Release on Benthic Ecosystems – Preliminary Findings - Ana M Queirós, PML

In the North Sea 50% of the aquifers are saline and about 30% are hypersaline.

This has important implications for CCS because of the potential impact of the release of saline formation fluids into the marine environment. A series of mesocosm experiments were conducted at the NIVA Marine research station in Oslofjord, southern Norway as part of the EC FP7 project ECO_2. Mesocosms can be used to test artificial simulations of biogeochemical conditions on different sedimentary assemblages and sediment types. The impact of CO_2 was measured over comparatively short periods of two weeks and over longer periods of several weeks. Exactly the same experiments were then conducted on the same communities but under hypersaline crossed with hypoxia conditions[1].

Formation salinity in the central and Northern North Sea varies from between six to nine times seawater and in some cases ten times sea water salinity. Hypersaline conditions were set up in a mesocosm to evaluate the effect on marine fauna. A control tank was established for comparative purposes close to the oxygen and salinity levels of the Oslofjord collection site. Three condition sets were tested and compared with control conditions: brine (48 ppt) with normal oxygen; low oxygen (hypoxia) conditions with normal salinity; and brine with low oxygen. A tidal influence was simulated by flushing an extra treatment set of tanks (with brine and low oxygen conditions) with controlled water conditions. A short term three week exposure experiment was conducted to see if there was any physiological stress expressed by the levels of fauna diversity, bioturbation (a process measuring the general activity of fauna and their health); and sedimentary chemical processes. Hypoxia led to an increase in sulphides suppressing biological conditions. Hypoxia limits ammonia oxidation in sediment whereas high salinity has the opposite effect. The activity of fauna was reduced by 50 – 100% under high salinity conditions compared with the control. The relative abundance of fauna was affected by high salinity after three weeks. The overall impact of hypersaline conditions after three weeks equated to that observed under extreme CO_2 leakage conditions (20,000 ppm) tested during a 20 week experiment. Only tested a moderate brine (48 ppt c.f. normal salinity of circa 35 ppt) was tested given the salinities observed in formation fluids across the North Sea. The combined roles of other components of brines could

[1] AQ sea bed ecologist. First formation impact assessment from ECO2 projects. See IJGGC special paper V40 1-458 Sept 2015

additionally be potentially detrimental, however dynamic flushing may have an ameliorating effect but this condition needs to be tested and supported by model development. Spatial modelling of brine dispersal and dissolution is the next step to gain a better understanding of brine impacts. The impact on different species and sediment types also needs further investigation.

Precursors of Leakage: Formation Fluid and Pore Water Release from a Leaking CCS Reservoir - Doug Connelly, NOC

Bubble detection is relatively simple using a number of shipboard acoustic approaches, but fluids can come from a variety of natural sources. Natural fluxes through pockmarks, geological fractures and submarine groundwater discharges are well known in the North Sea and other shelf seas. Chimneys observed on seismic images may reflect palaeo fluid migration routes, which may or may not be still active. In addition there is ~1M m3/day of formation fluids discharged into the North Sea from existing production operations. The source and composition of different fluids needs to be identified and characterised to avoid false positive association with storage sites.

Gaseous and dissolved CH_4 discharges are well known and have been detected by AUV surveys across the Hugin Fracture, thought to be 10M years old. These methane sources may be biogenic or thermogenic in origin and may indicate a link to a submerged hydrocarbon reservoir, or simply a pocket of natural gas. Pore waters displaced ahead of a rising deeper fluid have distinctly different chemical signatures from seawater and can be monitored using chemical approaches as a precursor of leakage.

The release of formation fluids from reservoirs may indicate overpressure in the storage complex, and displacement of the fluids. The composition of Sleipner and other North Sea formation fluids can be very similar to seawater, making simple monitoring more difficult. Formation fluid composition also changes as it ascends due to gas dissolution. Carbonate mineralisation can remove metal ions and under reduction condition the fluids may increase the concentrations of trace metals. Additional hydrocarbons may also be released along with the fluids allowing these trace contaminants to be used as an indicator of release. Minor elements (Si, Li, B), not present in sea water in the same concentration, can be used as tracers in released formation fluids, but can be expensive to analyse. In the case of the Hugin Fracture fresh water,

probably of meteoric origin, is being emitted which clearly distinguishes it from Sleipner formation fluids. In conclusion it is important to characterise formation fluids, pore waters and background chemical conditions and variability in seawater to understand if a leak has occurred.

The use of Biochemical Sensors to Monitor Fluid Emissions - Matt Mowlem, NOC

The primary chemical signatures associated with a CO_2 leak are pCO_2, DIC increase and pH decrease. Natural seasonal and diurnal fluctuations have the potential to mask any signal caused by an increase in CO_2. The team at NOC have been developing a multiparameter and spatial and temporal filtering system to distinguish natural variability from an anomaly. An illustration of a simple anomaly detection algorithm was demonstrated at a subsea hydrothermal vent site using a Eh sensor. The Eh measurement can be analogous to a CO_2 leak signature and can show significant temporal and spatial variation. The signal can be processed using a temporal filtering (high pass filter) to enable unambiguous location of the vent site.

Multiparametric assessment could be used to separate naturally occurring (e.g. biological activity) DIC anomalies from a leak derived signal. For example observation of oxygen, nutrients (phosphate and nitrate) and the carbonate system (two of DIC, Total Alkalinity or pH) can enable prediction of the portion of DIC signal that is attributed to biological processes through the use of Redfield ratios, or other established or measurable stoichiometric ratios for natural processes. Any deviation from expected stoichiometric relationships would then be attributable to a suspected leak. This approach has been demonstrated in natural marine CO_2 vent sites as well as at terrestrial CO_2 storage sites.

In a marine CO_2 storage context, a very small leak will be hard to detect unless the sensors (and host vehicle / platform) pass directly through the plume. Depending on the turbulence (mixing) and vertical mass transport (advection) at the site, a small leak expressed as a DIC plume may spread across, or near the sea floor. For example in the North sea in typical conditions the plume might only be detected 2 – 3m above the sea floor and therefore would not be detected at the surface. However, a persistent leak may lead to accumulation when tides result in the same water masses repeatedly moving

over the leak (typically leading to an elliptical plume). This condition would aid detection, and because of the increased time for vertical transport, may enable detection at or near the surface.

A further complication is that formation fluids may vent at the seabed, and may have an effect on DIC and stoichiometric ratios. However, the effect of this may be mitigated by measurement of the chemical signatures associated with formation fluids, which might include increases in salinity, Eh, Sr, Si, Li, B, Cl but a decrease in SO_4 ions. This signature is different to both CO_2 leaks and biological activity, and hence multiparametric measurement should enable discrimination between these processes.

There are a number of sensors available to measure these parameters. DIC can be measured routinely in the lab, and by prototype submersible sensors to an accuracy of 2µM which is sufficient to detect a small leak. The submersible sensors are in their infancy, and are slow (minutes) limiting their use as the primary sensor for plume detection. In contrast current electrochemical (ISFET) pH sensors are mature, fast (0.5Hz) and can resolve <0.001 pH. However, they can suffer from instrument drift and can take several days to produce a stable signal. This can be mitigated by using spatial / temporal filtering (as above with the Eh sensor) and / or by combining with a drift free and accurate pH sensor such as the slower (minutes) spectrophotometric technology. pCO_2 can be detected by mature commercially available sensors but the response (minutes) is not as fast as for pH.

In terms of contextual sensors for multiparametric assessment oxygen levels can be accurately detected to micromole level with either optical (optode) or electrochemical commercially available sensors. Nitrate measurement via UV spectroscopy currently lacks the precision and accuracy required in this application. The NOC nitrate and phosphate analysers do have sufficient metrology performance, but are too slow (minutes) for use as a primary plume characterisation tool. Eh signatures can be measured effectively with commercial and research sensors.

Instrumentation now available varies in Technology Readiness Level (TRL) from 3 – 8. NOC are currently integrating detection equipment into different platforms and automomous underwater vehicles (AUVs) for marine survey work. A number of different chemical parameters and salinity

can be measured simultaneously within a self-contained unit to enable multiparametric sensing for unambiguous leak detection.

Session 11 Panel Discussion: Formation Fluid Leakage and Release into the Water Column: Risks and Mitigation Strategies
Led by Owain Tucker

There are pre-existing fluid releases from natural sources as well as formation water discharges from production facilities. There can be significant contrasts in salinity and temperature between some formation fluids and sea water. These factors plus the quantity of discharged fluid need to be taken into account to determine the risks and mitigation that might be necessary. An injection rate of ~1M t/year of CO_2 equates to 2,500 t of CO_2 per day. To keep a reservoir pressure neutral ~3,000m3 i.e. 3k t of formation fluid per day would need to be discharged, equivalent to an Olympic size swimming pool. As a rule of thumb 1-2% of the pore volume in a reservoir can be used for storage without any extraction before the tensile strength of the caprock is approached. Sites can generally accommodate small injection volumes of around 30Mt (although it is all dependent on the geological and hydrodynamic conditions) without pressure relief, however, storage volumes are required, say over 100-200M tonnes, then pressure relief will reduce the number of injection sites required.

The scale of any impact on the environment will depend on the composition of produced water as well as the volume. These fluids can also be oxic/anoxic and can contain trace elements. The rate and pattern of dispersion can mitigate impacts. In a tidal driven system such as some areas of the North Sea, dilution can be achieved relatively quickly but only if sufficient near bed mixing occurs, which may not be the case particularly in deep areas. Localised accumulations of dense/highly saline fluids are possible. Local conditions as well as fluid composition needs to be understood and modelled so that the pattern of dispersion can be predicted. Model development is needed to support this.

Produced water today from oil and gas platforms tends to be discharged at or close to the sea surface. This ensures mixing and homogenisation, but future operations might involve discharge at the sea bed. The fluid could be denser and hotter than the surrounding sea water causing convection induced

mixing. Dispersion of saline formation fluids is not accurately simulated by current models and therefore further research will be useful.

There are potential analogues, particularly reverse osmosis desalination discharge which creates hypersaline conditions, that could be tracked to study the pattern of dispersion and mixing. The impact of salinity depends on fauna or ecosystem within the vicinity of discharges. Some species are more tolerant of high salinity conditions and could be potential environmental indicators. These species are unlikely to occur in deep environments where salinity tends to be stable. The magnitude and variation in saline discharges, and the extent of mixing and dispersion, needs to be known. One possible solution to manage saline discharges is to manage wells on duty cycles that allow periodic releases to allow mixing and dispersion at different states of tidal cycles.

The monitoring strategy needs to be designed with specific objectives and needs to provide public reassurance. The impact of discharges on broader ecosystems or fisheries is still unclear. A good example is the analogy of the spillage from the Macondo well blow out in 2010. The genuine impact on commercial fisheries is unclear particularly in the context of natural seeps in the Gulf of Mexico.

Session 12: Overburden Features - What do these Represent and how do they Affect risk
Chair: Robert Dilmore

Seismic Imaging and Environmental Monitoring of Chimneys in the Gulf of Mexico - Implications for Geologic CO_2 Storage - Tip Meckel, BEG

There is growing interest in potential prospects for storage options in the coastal waters and inner continental shelf of the Gulf of Mexico. Approaches to addressing near-offshore risks on continental shelves are different compared with onshore. One major difference is that the risk of CO_2 leaks to marine environments has been shown experimentally to be minor, whereas concern about CO_2 interactions with onshore water resources (updip salt water encroachment) and resource competition remains moderate. Shallow sediments are not of commercial interest and therefore not well investigated historically, despite their importance for CO_2 storage permanence. Sediments are still accumulating on the continental shelf, compared to onshore, where

surficial erosion is dominant. This results in an active sediment compaction regime in which pore fluids (sea water and hydrocarbons) are expelled. Current or geologically-recent leakage points from the compacting basin can be more readily identified than the equivalent relict leakage points onshore. Existing technologies such as sidescan sonar can identify "pock marks" where fluids are leaking and shallow high resolution 3D seismic can identify "gas chimneys" where fluids may have damaged stratification during escape provide evidence of long-term containment performance. This relative ease of leakage path determination is a major risk reduction mechanism for offshore storage.

The Gulf Coast Carbon Center (GCCC) at The University of Texas at Austin has focused on a near-shore area where Miocene sandstone formations with very high capacity have been documented in recent multi-year capacity assessment studies. It is important to recognize that existing technologies are very useful for reducing storage risks by interrogating the overburden above potential storage reservoirs. The GCCC team have been deploying novel P-Cable high-resolution 3D seismic acquisition to further characterize the overburden above potential storage prospects. Initial interpretation shows that some reservoirs are devoid of hydrocarbons either because seals have been compromised or the reservoirs were never charged. Higher resolution data in the overburden reveal shallow features such as minor faults, and their role in historic fluid migration and future performance during CCS projects can be interpreted. In some settings, detailed investigation suggests salt dome intrusion probably disrupted natural seals. Consequently, some potential storage reservoirs in those settings are unsuitable. High resolution seismic, near the coast, has revealed fluvial channels ~140,000 years old. Chimney structures and faults are also evident. At least one fault has an offset of 3-4m and extends to within a few meters of the seafloor. There is also evidence of shallow gas accumulation which contributes to our understanding of long-term fate of migrating fluids, although the time-frames of migration are less clear. Shallow seafloor sediment cores with low concentrations of methane have been taken from a survey vessel in water depths of 15m above shallow anomalies identified in high-resolution 3D seismic data. The CH_4 isotope ratio signature suggests a thermogenic source plus some biogenic interaction. CH_4 from depth suggests gas migration to surface over geologic timescales.

The underlying structures in this specific setting are therefore less suitable for CO_2 storage, while other settings without such feature become more prospective. Further investigation is required to check storage potential especially as there are small scale features that are potential natural conduits. Migration rates are also open to question from relatively rapid to geological timescales.

Near Surface Characterisation of the Goldeneye CO_2 Storage Site using High Definition Seismic Data and Attribute Analysis. -Owain Tucker, Shell

Shell have investigated the shallow overburden to characterise Pleisticene-Pliocene sediments in the upper kilometre of the overburden. Although these features are too shallow to ever come near the storage complex, they do form natural pathways for migration of shallow gas, and also cast seismic "shadows" on the deeper formations making. The lateral boundaries of the storage complex were defined by potential migration distance of CO_2 after 1,000 years were half of the stored volume to migrate were it introduced into secondary storage volumes. High definition reprocessed seismic has been used to identify features within the most recent succession. This has revealed a Pleistocene tunnel valley channel 240m deep. Lensing effects of this valley have generated a seismic image artefact which could be misinterpreted as a chimney. This investigation has demonstrated the importance of differentiating seismic image artefacts from defined features.

Palaeo sea floor peircements within shallow sediments are also evident. These pockmarks in the seafloor represents points where gas has or could be escaping. These features could be channels for CO_2 migrating from a deeper reservoir. High definition reprocessed seismic has also revealed ice-scour marks produced by continental-scale glaciers. Large outwash glacial channels were also formed. Seismic interpretation has revealed the complexity of these channels which might influence potential shallow migration pathways. The detailed picture of glacial and post-glacial phenomena then influences the future monitoring strategy.

The Internation Ocean Discovery Program (IODP) is to explore shallow attribution for overburden features pertinent to CO_2 storage.

CO_2 Retention and Migration in Shallow Marine Sediments QICS - Jon Bull, NOC / Melis Cevatoglu, University of Southampton

QICS was a shallow marine controlled CO_2 release experiment at a site off the west coast of Scotland[2]. The release point was 11m beneath the sea bed. A controlled release (~100skg/day) was conducted over 34 days. 2D high resolution seismic was implemented before, during, and two years after the release. Soon after release, on Day 1 amplification at the H_2 horizon revealed the presence of trapped CO_2. On Day 2 a columnar structure leading to a small pockmark on the seabed became evident. At Day 12 a chimney structure had become established and by Day 34 the chimney structure was fully developed from release point to surface. A survey two years later showed that the chimney structure had disappeared. Observations during the release experiment showed that the gas flux varied through each tidal cycle. Comparison of observed gas in the water column and the amounted released showed that ~15% reached the sea. Evidence from reverse polarity of post release seismic images indicates that CO_2 is still trapped. After 100 years all CO_2 will be dissolved.

Surveys from the North Sea show that a large number of chimney structures are present in the South Viking Graben 300-600m in width and ~800m – 1km deep. These structures could act as migration paths. The internal permeability of chimneys is unknown and could be a topic for future research. Coring part of a chimney might reveal some of its petrophysical properties but this might be technically challenging. The use of seismic anisotropy is another possibility.

Polygonal Faulting across the Petrel sub-Basin, Australian shelf and its relevance to CO_2 storage - Eric Tenthorey, Geoscience Australia

Polygonal faulting, particularly in the context of fluid migration pertinent to CO_2 storage, has not been the subjected of detailed investigation.

Polygonal layer bound non-tectonic faults are created by elevated pore pressure during dewatering and compaction. These phenomena are very common in continental marginal basins including the Bonaparte basin off the north-west coast of Australia. A few occur onshore in North America

[2] Blackford et al. 2014 Nature Climate Change - doi:10.1038/nclimate2381.; Cevatoglu et al. IJGCC - doi:10.1016/j.ijggc.2015.03.005

and Australia. They cover large areas of 100,000s km^2. The Petrel sub-basin near Darwin has natural gas reservoirs high in CO_2 hence the interest in potential storage reservoirs in the basin[3]. The seal, the Bathurst Island Group, is a micaceous mudstone approximately 700m thick. It is heavily polygonally faulted. Fault length is ~1.5km but they strike in all directions. These structural features tend not to propagate between stratigraphic tiers, although this can occur. Displacement is similar to tectonic faults with maximum displacements of 40-50m. Faulting occurs sequentially as each tier of sediment builds. Fault position tends to determine the position of overlying faults. Hydraulic connectivity will depend on permeability. A rare onshore example from the Cretaceous Khoman Formation in Egypt exhibits polygonal faults with carbonate mineralisation. The multiple generation of mineralisation suggests a series of conductive fluid migration episodes, but over geological timescales. The presence of voids also suggests that dilation occurred.

A gas leak in 1969 created acoustic turbidity in seismic sections which shows what a large scale leak might look like. There is some evidence of vertical gas migration via polygonal faulting in the Petrel sub-Basin but on a geological timescale. It is unclear if these features are significant conduits for CO_2 and further research is needed.

Some thoughts on Potential CO_2 Migration along pre-existing Fluid Flow Pathways in Overburden Successions - Andy Chadwick, BGS

Seal by-pass systems (SBS) could consist of faults, chimneys/pipes or even naturally injected bodies such as sand diapirs or igneous intrusions. Whether these systems could compromise storage sites over sufficiently extended timescales is a key question.

Fault flow properties will depend on the effective stresses and pore pressure which determines fault permeability. Reactivated faults could become transmissive if tectonic stresses interact with pore pressure changes. Chimneys and pipes are clearly evident from seismic surveys. They reflect upward migration of fluid due to pressure decrease or gas expansion but their current flow properties are not well understood. Faults are likely to be the main SBS in the syn-rift overburden succession in the southern North

[3] Marine & Petroleum Geol 60 (2015) 120-135 Hannu Seeback, Eric Tenthorey, Chris Consoli, Andrew Nicol

Sea, but significant faults are rare in the post-rift sequence in the northern North Sea. Chimneys are likely to form the main conduits in this area. The hydromechanical response to overburden loading-unloading cycles, caused by successive glaciations, is a significant factor, but whether chimneys are still active with high permeability pathway networks or, more likely, dormant at roughly hydrostatic pressures, is less clear.

There is evidence of a small chimney feature above the Sleipner CO_2 plume, evidenced by a CH_4 accumulation within the overburden. The CH_4 has in the past flowed into the overburden due to a combination of advection buoyancy and diffusion through the mudstone, but the accumulation has not changed since CO_2 injection began in 1996, suggesting that no high permeability pathways currently exist. Modelling suggests advection through intact caprock would lead to CO_2 progressing 17m in 3 million years. Diffusion in the aqueous phase would take CO_2 3 million years to reach the sea floor. This rate of migration equates to 2 - 68 mm / century through advective transport and 23 – 100 mm/ century via diffusive and advective transport depending on the assumed scenario. In conclusion there is no current evidence of CO_2 out-of-reservoir migration at Sleipner along presumed earlier fluid flow pathways.

Session 12 Discussion: Overburden Features - what do these Represent and how do they Affect Risk?

Permanent storage implies retention of CO_2 within a reservoir but over what timescale. There are features within overburden successions, for example, polygonal faulting which could potentially act as conduits for CO_2 if it leaked from a reservoir. Vertical migration via faults is hard to determine and based on the stress regime across and along the fault as well as the lithology. Otway modelling shows little movement of CO_2 across a fault at low pressure rates. Natural migration rates are not known and only estimated from oil source lithologies to reservoirs. Evidence from gas storage in natural reservoirs is successful indicating that secure retention is feasible. Some tentative modelling suggests multiple conduits and seals where there is transgression enroute to surface shows little evidence of rapid migration to the surface. Capillary migration is also slow on a human scale. Multiple barriers are critical as they avoid dependency on any single barrier.

One possible description of secure storage is the retention of CO_2 in a defined storage complex within a given time-span. Safe storage within 10,000 – 100,000 year time span would be significant in the context of climate change mitigation.

Two analogues that that may provide some useful insights for CO_2 storage fluid migration are: hydraulic fracturing and steam injection into bitumen deposits (i.e., steam assisted gravity drain process). The creation of new routes, or augmentation of existing pathways for unwanted vertical fluid migration (fractures and faults) by hydraulic fracturing in unconventional reservoirs with low-permeability matrix (e.g., shale), may provide insights into how stress-dependent permeability changes can impact leakage performance. Steam injection into bitumen deposits might also provide some indication of fluid movement rates. 4D and 3D / VSP seismic surveys can provide reassurance but this adds to the cost of monitoring an entire storage complex. VSP is especially helpful for checking potential leakage from a well bore, however, this is not an option for legacy wells that have been plugged.

Session 13: International Risk Management Activities and Initiatives – Offshore Environmental Research
Chair: Thomas Le Guénan

Initiative for an Offshore Demonstration Project in the Gulf Of Mexico - Tip Meckel, BEG

The US, and some other countries, are interested in an initiative to develop an offshore demonstration project. US DOE cannot afford to fund a demonstration alone and is therefore seeking international involvement but not necessarily in the Gulf of Mexico. BEG has selected 10 potential offshore basins. Most have or are near large oil and gas fields. In the Gulf of Mexico there are suitable candidate sites with old platforms in near-shore locations that could be linked to EOR. CO_2 storage in the Gulf of Mexico might help with the decision to allow the extension of the Keystone pipeline which could, in future, bring oil from Canada and northern US to the US Gulf coast. Other offshore candidates include: oil fields off the coast of California near Los Angeles; the Pearl River mouth basin an area of ~185,000km2 off the coast of Guangdong province, China; the GlaciStore IODP bid: Joint drilling

programme project to core glacial overburden in the North Sea; the Brazilian Lula CO_2 EOR development; the Petrel Basin which forms part of Australia's north-west shelf; and Tomakomai in Japan.

An international collaborative demonstration project could investigate commonalities relevant to all offshore storage such as integration and association with CO_2 rich gas fields, post-closure monitoring, leakage scenarios and demonstrate containment. International co-funding could reduce costs as well as sustain the global discussion on CCS as an atmospheric emissions mitigation option.

International Offshore Initiatives within the CSLF - Katherine Romanak, BEG

The Carbon Sequestration Leadership Forum (CSLF) is a government-level international climate change initiative with a mission to facilitate development and deployment of CCS. The CSLF identifies research directions and reports to a policy group on required actions. It also makes recommendations to its ministerial group to provide policy and technical direction. In November 2013, the Bureau of Economic Geology at The University of Texas at Austin brought a proposal to the CSLF to form a task force to assess barriers and technology needs for offshore CO_2 storage with the ultimate aim to create multinational collaborative field tests. A finalised report reviewing technical barriers and R&D opportunities in offshore CO_2 storage was presented in November 2015 at the CSLF in Saudi Arabia. Seven countries including the USA, UK, Japan, Australia, China, Norway, and the Netherlands all contributed to the final report which concluded that significant opportunities exist to increase understanding of offshore storage; and that there is a growing wealth of research developments and practical experience in offshore storage. It also made the following recommendations and needs:

- National storage capacity assessments at the basin level
- Investment in offshore transport infrastructure
- R,D&D into offshore CO_2 EOR
- Expand knowledge of CO_2 impact in the marine environment
- Monitoring technology development
- Improvement in quantification and shallow-focused monitoring

- International knowledge sharing through workshops and international collaborative projects

To act on the recommendation for knowledge sharing, an international workshop was held in April 2016 at the Gulf Coast Carbon Center at the BEG to build a community of countries interested in deploying offshore storage and to move towards multinational collaborative projects.

Discussion: Building a Framework for International Initiatives and Cooperation – what are the Next Steps?

There will be an EU call for pilot projects valued at 10 – 15 M €. These plans include a new project called STEMM-CCS (Strategies for Environmental Monitoring of Marine CCS) which will build on from the ECO_2 project. This new project will develop and test offshore monitoring techniques for offshore site environmental characterisation, leakage detection and quantification. A test release of CO_2 will be used in the seabed 100m under the North Sea to test the monitoring techniques, so it will be like a deeper version of the QICS project, and will involve use of sensors mounted on AUVs (autonomous underwater vehicles). The project is to be led by NERC's National Oceanography Centre, and involves Shell, Geomar and ten other partners.

There is offshore potential in developing countries and opportunities to develop big projects but getting the right direction is imperative. The aim is for a generic approach that helps developing countries invest in CCS. The UK's COOLTRANS experience shows that there was a specific issue, understanding the impact of a sudden release of CO_2, that was clearly addressed with a £1M project, including full-scale experiments to find out key issues.

One of the key aims for a good demonstration project in a target developing country like China or India is to motivate investment in CCS. The perception is that CCS is too expensive in developing economies and therefore there is a need to show that the technology can be implemented successfully. Where there are commercial projects novelty research can be tested at a demonstration site. However, novelty has to have potential for cost saving and low risk. R&D needs to identify key aims that should also be specific to achieve successful outcomes.

Session 14: Environment Impact Assessments
Chair: Tim Dixon

An Operator's Perspective; Shell Goldeneye - Paul Wood, Shell

The environmental impact assessment (EIA) for the Peterhead – Goldeneye project covers the full chain from capture to storage. The key permits include onshore planning from the local authority, the Pipeline works authorisation (PWA) and Marine Licence for offshore operations.

The leak path scenario includes routes from the wellbore, directly through the caprock and laterally within the formation adjacent to the reservoir. CO_2 is not expected to leak. The greatest risk is through a plugged and abandoned (P&A) well or up the side of a wellbore annulus. The survey plan includes P&A wells as well as the platform. A risked based approach to assess risks of these wells has been implemented. Geochemical probes of the seafloor sediment-gas flux have been conducted to establish baseline data and avoid a potential false positive. A mid-life survey is planned unless down hole logging shows an unusual indication of irregularities or leakage. A survey to look for the presence of bubbles would be conducted. Side-scan sonar would also be used for reassurance.

The EIA was submitted to DECC 9th January 2015 and then to the European Commission on 24th August 2015. The EIA is in the public domain although the monitoring plan is not.

An Australian Perspective of EIAs - John Frame, EPA Victoria

The regulator for CCS in the Australian state of Victoria is the Environmental Protection Authority (EPA). CO_2 storage is based on the Otway test site. The EPA's main remit is to set standards and encourage high performance and act as a monitoring authority. Australia has two levels of environmental protection legislation and is subject to many laws. The first stage of an application is to start with the proposal and then compare it to the standards that might be required. Additional assessment may be necessary before approval if not the proposal is rejected. The regulator is concerned with the detail but regulators do not have time to read every document. There could also be multiple regulators who may not know what best practice means and the terminology is not always explained. CO_2 is already in the environment and is difficult to treat. Standards are not always quantitative and processes

can occur out of sight. The other main consideration is that CO_2 storage will be for a long time (10,000s of years). There is also the possibility that CCS is confused with other industries.

To get a permit the site must be low risk and must be fit for purpose. It must have plans, procedures and monitoring in place. Indicators can be good surrogates of environmental quality. Mitigation measures should be included before a permit can be granted.

Offshore legislation is dealt by the Federal government in Australia and state legislation is then identical. There is no national environmental regulator but there is a federal petroleum regulator.

Session 14 Discussion: What are the gaps in EIAs?

In Europe a review of EU CCS Directive concluded that the directive was fit for purpose and did not need to be re-visited.

For EIAs the best approach would be to integrate international experience. The Global CCS Institute has been trailing a regulatory tool kit in the CarbonNet project in Australia, Scotland, Trinidad and Tobago. When trialled in Scotland the tool kit was refined down to ~70 permits from over 200.

The EIAs for Gorgon, Goldeneye and Otway found no significant gaps and all applications have been approved. Regulators check that EIAs comply with regulations. There is an assumption that in granting a permit the operator will implement EIA measures.

Emissions from formation fluids into sea are not covered. Goldeneye is a sub-hydrostatic pressure reservoir because it is a depleted gas field so no fluid exclusion is likely. The Gorgon EIA specifies that formation fluids will be reinjected into a different formation. In the USA, formation fluids are covered by water EPA criteria to avoid contamination of fresh water resources under Class VI regulations.

Session 15 Panel Discussion: Mitigation: How do we decide when to Mitigate? - The route to making decisions on appropriate mitigation.

Panel: Filip Neele (Chair), Paul Wood, Robert Dilmore, Lee Spangler, John Frame

Appropriate mitigation contingencies need to be planned before a project is approved. Within the Area of Review it is possible that brine and/or CO_2

could migrate to and contaminate an underground source of drinking water (USDW). The potential fluid migration routes need to be adequately characterized, and performance of candidate remedial actions need to be understood. If there is no receptor of concern (e.g., no underground drinking water aquifer) no action need be taken. The likelihood and magnitude of potential impact on receptors also needs to be predicted. Environmental regulators emphasize the critical importance of protecting groundwater resources, and require assurance that storage activity will not result in their impact. This calls for deep level monitoring to detect early difficulties, and allow effective interventions to mitigate unwanted conditions before receptors are impacted.

Experience from CO_2 EOR has provided confidence in CO_2 injection and field management. The practice of steering plumes and reacting to leaks has provided valuable experience in fluid flow control. The monitoring regime needs to be of sufficient quality to detect fluid flow and understand conformance of model predictions to real-world performance so that impactful deviation can be identified and mitigation can be implemented, if required, in a timely and effective manner. Corrective measures are applied on the basis of monitoring information and can include a cessation of injection.

In the case of CO_2 storage there is a relatively low risk from leakage outside casing and induced seismicity. A traffic light system alerting operators to the risk of this phenomenon is necessary to avoid felt seismic events; there may be value in augmenting traffic light protocols with site-specific forecasting tools. Induced seismicity should be anticipated from monitoring and modelling of subsurface risks; effective and probabilistic methodologies and predictive tools are being developed to support such assessment.

Session 16: Overall Meeting Conclusions / Gaps / Recommendations
Panel: Tim Dixon, Ian Wright, Charles Jenkins

- Risk assessment for CO_2 storage sites has matured significantly, as compared with five years ago. Wellbores still represent the most-likely pathway for unwanted fluid migration in most storage scenarios.
- Very substantial work on pipeline safety has been achieved. Pipelines have the potential to cause big acute impacts or small leaks.

- Field experiments indicate that, in the event of CO_2 leakage to the surface, terrestrial environmental impacts are likely to be low.
- The discharge from offshore storage sites needs to be kept in proportion. 1Mm3 of hypersaline brine is discharged daily by Saudi desalination plants.
- Fluid discharges from the oil industry and natural seeps need to be distinguished from leaks. Natural seeps also occur in Australia, the USA and Europe.
- Environmental assessment in the marine environment can leverage great scientific understanding, datasets and techniques.
- Environmental impacts of CO_2 leakage at the seaflore are localised and fast recovery is evident in shallow, coastal areas with tidal flushing. The complexity of natural variations in marine environment is a significant factor when attempting to establish a baseline and monitoring programmes.
- Chimney characterisation is better understood. Pockmarks often represent palaeo fluid channels. The absolute value of sub-surface permeability, and relative differences inside and outside a chimney structure, is poorly defined.
- CCS in comparison with other industries is being held to higher standards.
- Reference risks cases should include cases with probabilities.
- The potential impacts of scaled-up impact need to be placed into context i.e. risk per mega tonne of mitigation should be a parameter.
- New sensors are under development and will need to be tested and reviewed.

Identified Further Work and Opportunities

- A serious full-scale experimental investigation of wellbore leakage (like the COOLTRANS model).
- Structure research on impacts to be better connected to risks, and vice-versa. Reference to risk cases would be helpful.
- There is a need for a consistent narrative about relative risks (climate, other environmental impacts vs CCS). In this context, there needs to be a clear understanding what baselines are, and how they will be applied (for

leakage signal detection over background variability, or for measurement of impact, or both).

- Scaling up to large deployment needs more attention.
- Wellbore risk and remediation needs more detailed investigation.
- Unlike onshore pipeline failure, where entire projects (e.g. COOLTRANS, CO2PIPEHAZ, CO2QUEST) have now achieved considerable understanding through comparison of simulations and experiments, offshore CO_2 pipeline failure has not been studied and is not well understood. An opportunity exists to rectify the current knowledge gap.
- Formation water leakage – monitoring, impacts, EIAs, of analogous releases would be beneficial (eg produced water from oil and gas operations).
- Empirical research on the characterisation of brines, their potential impact on natural systems and modelling of their dispersion in marine environments needs further research.
- Sensors for formation fluid leaks are being developed and will need to be field tested. A review of new sensors and their potential benefit to early detection is recommended.
- Effects of leakage on soil fertility are not yet known.
- Development and testing of new ratio-based techniques (aka process-based) offshore to distinguish leakage from natural activities.

Recommendations

- Address the further work above.
- More R&D attention on the performance of alternative mitigation and other corrective measures?
- Net Environmental Benefit Analysis (NEBA) for CCS in event of leaks? A NEBA is a methodology for comparing and ranking the net environmental benefit associated with multiple mitigation alternatives to an environmental incident such as a CO_2 leak.
- Further research is required to quantify the impact on the CCS chain and marine environment of an offshore CO_2 pipeline failure.

Tours of The National Oceonography Centre's technical facilities and the field trip to Dorset's Jurassic Coast

Throughout the three day meeting, the director of the National Oceanography Centre (NOC), Ian Wright, and other staff, conducted tours of the centre's technical facilities particularly its compliment of Autonomous Underwater Vehicles (AUVs). NOC can deploy advanced AUVs that depending on their design, can drift, dive or glide through the ocean without real-time control by surface operators. AUVs are capable of simultaneously testing sea water for key parameters such as Eh, pH, DIC and then recording data that can be download for later analysis.

After the meeting some of the delegates visited classic geological sites exposed along the Jurassic Coast beginning with the Bridport Sands. Thes extensive cliff exposure of this formation shows clear evidence of bioturbated horizons within a shallow marine shoal sandstone. These horizons are known to coincide with low porosity calcified bands. This formation is an important reservoir rock for the Wytch Farm Oilfield further to the east near Bournemouth. The reservoir properties of this formation have revealed that the calcified bands act as baffles. Subsequent tectonic events have created vertical fractures which could allow vertical migration. These features are important to understand because they influence fluid movement and help to explain the challenge of monitoring CO_2 injected into similar reservoirs.

Delegates then visited Lulworth Cove where there is a succession from the Portland Limestone of the Upper Jurassic through the Purbeck Beds into the Cretaceous Wealden, Gault Clay, Greensands and finally Chalk. The location also displays evidence of significant folding caused during the Alpine Orogeny known locally as the Lulworth Crumple. These two locations, and other exposures along this World Heritage coast, enable geoscientists to gain a broader insight into subsurface complexities which are inferred from geophysics and wellbore sequences. The identification of secure, long-term storage reservoirs for CO_2 ultimately depends on understanding such geological complexities.

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2016-09 CCS COST NETWORK 2016 WORKSHOP

Organised Under The Aegis Of The:
CCS Cost Network
IEA Greenhouse Gas Programme, Cheltenham, UK

By Steering Committee Members:
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John Davison, IEAGHG
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Wilfried Maas, Shell Global
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Introduction

The fourth meeting of the CCS Cost Workshop (also known as the Expert Group on CCS Costs) was held on March 23th - 24th, 2016 at the Massachusetts Institute of Technology (MIT) in Cambridge, Massachusetts. This function is now designated as the CCS Cost Network under the auspices of the International Energy Agency Greenhouse Gas Programme. The meeting was organized by a Steering Committee including representatives from: Carnegie Mellon University (Ed Rubin), Electric Power Research Institute (George Booras and Richard Rhudy), IEA Greenhouse Gas Programme (John Davison), Lawrence Livermore National Laboratory (Sean McCoy), Massachusetts Institute of Technology (Howard Herzog), National Energy Technology Laboratory (Lynn Brickett), NaturalGas Fenosa (John Chamberlain) and Shell Global (Wilfried Maas).

The purpose of the workshop is to share and discuss the most currently available information on the cost of carbon capture and storage (CCS) in electric utility and other industrial applications, as well as the current outlook for future CCS costs and deployment. The workshop also seeks to identify key issues or topics related to CCS costs that merit further discussion and study.
As shown on the previous pages, the first day of the workshop was a

plenary session addressing four general topics, each addressed by invited presentations, followed by a discussion among workshop participants. The second day pursued three topics in more detail via parallel breakout sessions, followed by a plenary session with group reports and discussion.

This document presents brief summaries of each of the four sessions from Day 1 and the three breakout sessions from Day 2, together with the full set of presentations by invited speakers on Day 1. The proceedings of previous workshops are available at: **www.globalccsinstitute.com/publications/ccs%2520cost%2520workshop**

Presentation Summaries

Session 1: Framing the Issue

The purpose of this session was to frame the issue of CCS cost estimates by providing background on the current status of these estimates. The first talk presented the results of a review of recent cost studies found in the open literature. The second presented the methodology that goes into a detailed CCS cost estimate. A brief description of each talk follows.

The Cost of CCS: A Review of Recent Studies

Presented by Edward S. Rubin, Carnegie Mellon University

This presentation was based on a paper written for a special edition of the International Journal of Greenhouse Gas Control[1] that celebrated the tenth anniversary of the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS).[2] The paper included costs of four capture technologies: Supercritical Pulverized Coal (SCPC) with post-combustion capture, SCPC with oxy-combustion capture, Integrated Coal Gasification Combined Cycle with precombustion capture, and Natural Gas Combined Cycle with post-combustion capture. Costs for CO_2 transport and storage were also included. The current reported range of costs were presented and compared to the costs found in the SRCCS after adjusting all costs to a common 2013 cost basis. While current capital costs were generally higher than adjusted SRCCS costs, the cost of electricity comparison showed little change primarily because of

[1] Rubin, E.S., J.E. Davison, and H.J. Herzog, "The Cost of CO_2 Capture and Storage," International Journal of Greenhouse Gas Control, 40, pp 378- 400, September (2015).

[2] IPCC, 2005: IPCC Special Report on CCS. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

lower fuel prices and higher assumed capacity factors in recent studies. The ranges of CO_2 avoidance costs also were similar to adjusted SRCCS values after accounting for some changes in CO_2 transport and storage costs. The talk concluded with a discussion of the outlook for future cost reductions.

Methodology of a Detailed CCS Cost Study

Presented by Jeff Hoffmann, National Energy Technology Laboratory (NETL)

NETL has produced a series of baseline studies on the cost and performance of various state-ofthe-art CCS power plants.[3] These studies are very detailed and provide a valuable reference for the CCS community. This presentation reviewed the methodology that goes into generating a baseline technology cost estimate for the "next commercial offering." The seven key steps are:

1. Develop a technology analysis plan and solicit feedback from stakeholders.
2. Create a performance model of each power plant based on NETL process models.
3. Integrate carbon capture technology models based on literature and developer input.
4. Adjust balance of plant as needed per the new technology demands.
5. Estimate the capital, operating and maintenance cost of all plant components using the method described in NETL's QGESS documents and elaborated in the Baseline studies.
6. Apply plant financing and utilization assumptions to develop a cost of electricity.
7. Perform sensitivity analyses and provide R&D guidance.

After describing each step in detail, a case study was presented based on a SCPC plant with an amine-based post-combustion CO_2 capture system.

Session 2: Project Costs – Industrial Applications

John Davison introduced the session on industrial capture project costs. He highlighted that there is increasing interest in industrial CCS but cost estimation can be complex, for example due to integration with existing sites and in some cases multiple CO_2 sources. Also, many industrial plants are located in developing countries, where cost data are not easily available.

[3] http://www.netl.doe.gov/research/energyanalysis/baseline-studies

There are examples however some successful industrial CCS projects and presentations were made on two of them: the Quest and Illinois Basin/ Decatur projects.

Wilfried Maas of Shell made a presentation about the Quest CCS project and its costs. The Quest project involves capture of CO_2 at a hydrogen plant at the Scotford upgrader near Edmonton, Canada, which processes hydrocarbons from oil sands fields. The capture plant uses Shell's ADIP-X amine process. The captured CO_2 is compressed in a multistage centrifugal compressor and is transported 65km to a saline reservoir storage site. Modular construction involving 69 modules was used for the capture and compression plant, which minimises site construction.

The plant has operated continuously for 6 months during which time 0.5Mt of CO_2 has been injected, exceeding the target rate. The FOAK facilities cost forecast is CAN$812M, equivalent to 752 $/tpa captured. A substantial part of the costs (CAN$137M) is venture costs which could be reduced substantially in NOAK plants. There is an extensive knowledge sharing part of the programme, as described in the presentation slides. Some key messages were:

- It was emphasised that adequate support is needed to demonstrate CCS and reduce costs from FOAK to NOAK to deliver a competitive and viable technology in a decarbonised world.
- For FOAK plants, capital grants (to support build) and OPEX support (to ensure the plant operates) are required, plus other temporary measure (e.g. CCS certificates) if the uptake rate continues to be disappointing.
- Non-financial measures (enabling regulations, liability agreements etc) are also important.
- The main requirement for NOAK plants is expected to be a robust CO_2 price.

Sallie Greenberg of the University of Illinois and Ray McKaskle of Timeric Corporation presented insights into costs of CCS gained from the Illinois Basin – Decatur Project. This project involves compression, dehydration, transmission and storage of high purity CO_2 from a bio-ethanol plant at a rate of 1,000t/d. The pipeline is realtively short (1.9km) but it had to be above ground and insulated. The Illinois project uses reciprocating compressors. An

important issue in the selection of reciprocating compressors, rather than the multi-stage centrifugal compressor used at Quest, was greater familiarity and proximity to a local supplier for support and spares. The project costs were presented in detail, showing a cost for compression, dehydration and transmission of $31/t. The capital cost was amortised over the 3 year injection period, costs for a commercial project would be amortised over much longer period, resulting in lower costs. The capital costs were higher than the initial estimate but operating costs were lower. Some significant conclusions are:

- CCS is a major undertaking involving many types of industry, government and financial professional, as well as many industry trades.
- First mover projects can provide useful benchmarks and lessons learned that will benefit future projects.
- Incorporating CCS into existing operational plants comes with additional case-specific challenges and costs.
- Permitting timelines and general economic conditions may impact costs of future projects in ways that are difficult to predict.

Session 3: Project Costs – Power Applications

This session focused on cost estimates for CCS applications in electric power generation applications. The overall session objectives were to learn about the cost of actual CCS projects, including a summary of lessons learned and opportunities for future cost reductions. The projects included one operating postcombustion capture project, and two large-scale oxy-combustion projects that were in the advanced stages of development at the time the projects were cancelled.

Boundary Dam Carbon Capture Project

The first speakers were Max Ball and Peter Versteeg who joined the workshop via teleconference from SaskPower's office in Regina, Saskatchewan. Peter started with a summary operating statistics for the first-of-akind Boundary Dam Carbon Capture Project. In 2015 the net power output averaged 107 MW, with the plant being down for maintenance during the month of September. The daily average amount of CO_2 captured was 1,739 tonnes in 2015, however that increased to 2,726 tonnes in February of 2016.

The major factors impacting the capital cost of the project included site-specific, first-of-a-kind (FOAK), and market factors, as well as specific plant

design features. The small size of the plant resulted in dis-economies of scale relative to the larger plant sizes assumed in most conceptual studies. Firing lignite also imposed a cost and performance penalty relative to higher rank coals. At the time the plant was constructed, an abundance of other heavy industrial activity in the Province resulted in higher hourly labor costs and reduced productivity. A heavy emphasis was placed on maximizing power output, as opposed to minimizing capital cost.

FOAK issues included schedule extensions due to conducting three parallel CO_2 capture plant FEED studies, additional regulatory requirements to be met, development of operating and environmental health & safety standards for a power plant integrated with a CO_2 capture system. Contingency provisions and design margins were impacted by an "it must work" philosophy. And finally, some components did not perform to their design expectations. A chart showing the wide fluctuations in the price of steel illustrated one example of how market factors adversely impacted the cost during the time period when Boundary Dam plant was constructed.

Based on the learnings from construction, startup, and initial operation of the Boundary Dam capture plant, SaskPower expects the cost of the next capture plant to be substantially less. Max also noted that their next plant would be designed to reduce CO_2 emissions to essentially natural gas equivalence to meet the Canadian Federal requirements, as opposed to the nominal 90% CO_2 capture capability at Boundary Dam.

FutureGen 2.0

Ken Humphreys, CEO of the FutureGen Alliance gave an overview of the project and the many milestones that were achieved prior to the project being terminated. Unit 4 of the Meredosia Energy Center in Illinois was to be repowered with oxy-combustion and CCS technology. The net plant output was expected to be 167 MW, while capturing 90+% of the CO_2 (or about 1.1 MMT/yr). A 28 mile pipeline would transport the CO_2 to a deep geologic storage site. Some of the many milestones achieved by the project team included:

- Power purchase agreement signed
- Final permits were issued for air, water, pipeline and CO_2 storage

- Subsurface rights were acquired and CO_2 liability management was addressed
- Mega-FEED was completed (70-90% of final design, at a cost of $90 million)
- Project labor agreements were signed.

Unfortunately the federal co-funding expired and the project had to be terminated. The EPC costs were well known due to the fact they had fixed price contracts. The total as-spent capital cost of the power plant was estimated to be $1,256 million, which excludes the over-thefence ASU and the $423 million cost for the CO_2 pipeline and storage facilities. Ken presented detailed breakdowns for the Owner, Financing and Start-Up costs. Plant operating costs were estimated to be $128/MWh on a 20-year levelized basis. The major operating cost drivers included oxygen, fuel, purchased power, ash disposal & consumables, and CO_2 transportation & storage. The total 20-year levelized LCOE including capital recovery was estimated to be $179/MWh. However, after the MISO energy/capacity sales credit the net cost to the ratepayers would have only been $138/MWh, representing less than a 2% average rate increase.

Lessons learned during the project included how to deal with a very large number of landowners for the CO_2 pipeline right-of-way, and the CO_2 storage subsurface rights. They also found that the EPC negotiations took much longer, and the balance of plant (BOP) was more complicated than originally planned. Future oxy-combustion plants will have reduced capital costs and improved efficiency due to retrofitting newer, larger USC plants that will benefit from economies of scale. CO_2 transportation and storage costs will also benefit from economies of scale.

White Rose CCS Project

The final speaker in this session was Dr. Leigh Hackett from GE Power, who talked about the White Rose CCS Project. The White Rose project is a new ultra-supercritical oxy-combustion plant with a gross output of 448 MW. The plant was designed to capture 90% of the CO_2, or about 2 million tonnes CO_2 per year. The plant would have been the "anchor" project for National Grid's regional CO_2 transport & offshore storage network, where the infrastructure was sized for 17 million tonnes CO_2 per year to enable future projects. The

captured CO_2 was to be stored in a deep saline formation offshore, beneath the North Sea.

The UK Department of Energy & Climate Change (DECC) will publish 41 White Rose project keyknowledge reports later in 2016, including the full-chain FEED summary report, FEED lessons learned, FEED risk report, and full-chain project cost estimate report. The term "full-chain" refers to the oxy power plant, the onshore & offshore pipeline networks, and the CO_2 injection & storage systems. The full-chain project cost estimate was classified as an AACE Level 2 estimate for the majority of items, with 90% of the costs based on vendor quotes.

For the DECC reports, the actual White Rose project cost estimates were adjusted and normalized to take out project specific data and allow comparison to other published data. For example, the site was adjusted to US Gulf Coast basis and site preparation costs were removed. The normalized project cost estimate was broken down into externally supplied utilities, the oxy boiler/ASU/gas processing unit, power generation equipment & BOP, onshore pipeline, offshore pipeline, and storage facilities. Dr. Hackett then showed a chart illustrating the savings achievable for follow-on projects here they can take advantage of the existing CO_2 transportation and storage network. The White Rose Project resulted in lessons learned in the following four key areas:

- Full-chain commercial structuring and management of cross-chain risks
- Non-EOR CO_2 storage business model
- Oversizing and sharing CO_2 transportation & storage infrastructure
- Potential insurance gaps

Key take-aways from the White Rose project were that no significant technical barriers remain to project implementation, full-chain aspects were adequately defined and developed, and the next step is a large-scale commercial project. Dr. Hackett concluded by saying that the UK Government's decision to cancel the UK CCS Competition has stalled commercialization in the UK and Europe and "dented" confidence in CCS.

Session 4: CCS in the Context of Changing Electricity Markets

In the fourth session of the workshop, speakers took a step back from the topic of CCS cost estimation to look at the context for CCS in future electrical systems, what this implies about the value of CCS-equipped generation, and some alternative metrics that might better convey its value to decision makers. The session began with a presentation from Andy Boston (Energy Research Partnership), which was followed by responses from Neil Kern (Duke Energy) and Geoffrey Bongers (Gamma Energy Technology), and then general discussion.

The presentation from Andy Boston captured the lessons from an ERP analysis of future United Kingdom electricity systems, and highlighted three key messages:

- A zero- or very low-carbon electricity system with variable renewables (e.g., solar, wind) needs dispatchable, lowcarbon technologies to provide firm capacity
- Policy makers and system operators need to value services that ensure grid stability to establish a market for new providers
- A holistic approach that accounts for the cost of balancing the system would better recognize the importance of firm low carbon technologies than conventional measures of individual technology cost To illustrate the final point, Andy presented results from his analysis showing that, even though gas-fired generation equipped with CCS had a relatively high LCOE, addition of capacity could result in a net reduction in system cost. His results also clearly showed, however, that the value of a technology is dependent on the existing generation mix and the grid services it provides, which makes these results difficult to generalize. His provocative conclusion was that this value cannot be captured by LCOE.

In the first invited response to the initial presentation, Neil Kern highlighted that Duke Energy sees a paradigm shift in the way traditional utility planning takes place as a result of the growing trend towards distributed generation. The result is that Duke is placing an increased emphasis on flexibility of centralized generation, and seeking to identify nontraditional markets for central stations. In the second invited response, Geoffery Bongers highlighted the multi-attribute comparisons of generating technology in the

recently published Australian Power Generation Technology Study. In that study, technologies were evaluated not only on their LCOE, but also on their capital cost, water requirements, CO_2 emissions, waste products, availability and flexibility.

In the ensuing discussion, participants debated whether LCOE is an inadequate metric or is simply being used inappropriately, such as by comparing baseload plants with intermittent renewable that do not provide comparable services (ignoring the additional integration and backup system costs that would be required).

Others felt the true value of dispatchable generation, like fossil-fuels equipped with CCS, can best be measured by the reductions in system-level cost that results as such capacity is added. Others noted that many decision makers want simpler metrics like LCOE. While most participants agreed on the need for ways to make better technology comparisons, and to more clearly quantify the value of CCS, there was no consensus on how this should be done.

Break-Out Session Summaries

Session A. Reconciling Real and Estimated CCS Plant Costs

Questions: Can we reconcile real project and Nth plant costs? How should we present this information to policy makers?
Co-chairs: Ed Rubin, CMU; George Booras, EPRI; assisted by Kristen Gerdes, NETL

This session focused on identifying the factors that typically contribute to higher costs of initial full-scale installations of CCS and other newly commercial technologies (often referred to as FOAK, or "first-of-a-kind") relative to the longer-term (NOAK, or "Nth-of-a-kind") costs commonly reported for mature technologies. Additional thoughts on how this information should be presented to policy makers follow the presentation of the factors identified.

Reconciling Actual vs. Nth Plant Costs

In general, the cost of a specific project is affected by several classes of factors, including:

- Site Specific Factors
- Market Factors

- Design Basis Factors
- Project Execution Factors
- Financing/Contracting/Owner's Costs
- FOAK Factors (Planned & Unplanned)

Each of these categories can be further expanded to identify more specific factors that influence actual costs. Given the focus of this workshop on CCS costs, the factors whose cost is exacerbated by FOAK installations are highlight with an asterisk (*).

- Site-Specific Factors
  - Labor Costs, Productivity, Availability/Skill Requirements*
  - Materials cost
  - Seismic activity
  - Ambient conditions (temperature, etc.)
  - Water availability & quality
  - Fuel availability & quality
  - Proximity to CO_2 storage
- Design Basis Factors
  - Scope and battery limits: base plant, capture, transport, storage
  - Fuel type
  - Plant size
  - Pipeline capacity
  - Storage capacity
  - Cooling system design
  - Ambient conditions
  - CO_2 capture rate
  - CO_2 purity requirements
  - Emission standards
  - Brownfield vs. greenfield vs. retrofit
  - Flexibility of operations *
    - Load following*
    - Start-up/shutdown*
    - Flexible capture*

- Market Factors
  - Commodity prices
  - Labor costs
  - Engineering costs
  - Competition and availability
  - Currency exchange rates
  - Construction equipment and services availability
  - CO_2 value
  - Offtake agreements*
  - Regulations and policies
  - Private sector incentives?
  - Public sector tolerance for R&D
- Project Execution Factors
  - Scheduling*
  - Re-design in mid-construction*
  - Modular vs. stick build (shop vs. field fabrication)
- Financing and Other Factors
  - Financing (risk premiums)*
  - Permitting-related costs and delays*
  - Regulatory and legal issues
  - Plant availability, capacity factor, and dispatch expected (when assessing financial viability)*
  - Owner's costs*
  - Contracting strategy (where is the risk?)*
- FOAK Factors (Planned)
  - Schedule length
  - Contingency/over-design
  - Development of training, simulators, maintenance protocols
  - Extended ramp-up
  - Chemical plant operation in a power plant culture
  - Performance guarantee limitations
- FOAK Factors (Unplanned)
  - Performance shortfalls

Presenting to Policy and Decision Makers

Rather than showing how various factors add to FOAK plant costs, our approach should be to show how removing various cost escalation factors that are unique to, or exacerbated by, FOAK projects will reduce the cost of subsequent projects. This could be illustrated, for example, with a set of bar graphs like those presented by SaskPower, but in the reverse order, starting with the high cost of an FOAK installation, with costs then coming down as various cost adders are removed with increasing experience and know-how.

Session B. Challenges of CCS Cost Estimation and Financing

Question: What are the main challenges of industrial and power CCS cost estimation and financing?
(Co-chairs: Jeff Hoffmann, NETL; Howard Herzog, MIT)

The breakout started by asking each participant to respond to the question for this breakout session. The responses and additional questions generated follow:

- How do you capture the global market competitiveness for internationally traded industrial products made with processes including CCS?
- For projects with government support, how do you capture government subsidy (and risk) as it relates to financing?
- How do you capture costs of real world projects?
- How do you effectively estimate project contingencies?
- How can we best assure cost estimates are used in an appropriate manner?
- Since industrial processes are more heterogeneous than fossil-fueled power generation, how to develop a novel plant for policy modeling and market deployment studies that is widely representative?
- The cycle times for industrial processes are long. The developed world is not building new plants and the typical business model is to replace rather than refurbish and retrofit.
- It is difficult to estimate costs in non-OECD countries.
- Policymakers view CCS and renewables as interchangeable. Cost estimating using LCOE support interchangeability.

- Time factor (permitting, etc.) can drive costs higher.
- Credibility of publically available cost estimates is difficult to assess because of frequent lack of transparency in assumptions. The lack of transparency makes it very difficult to calibrate, compare and validate individual published studies.
- Even studies that seem to be reasonably transparent are complicated, and a primer to methodology and intended purpose would be helpful in addressing how to use the studies.
- Studies are made in the context of "something" (i.e., specific policy scenario, fuel price scenario, anticipated future capacity needs), but the "something" is often changing.

After some discussion in trying to get a handle on these many disparate issues, the group focused on two areas to gain some insights.

Cost vs. economic analysis

A major issue for cost estimation is how to develop costs to compare CCS to other technologies. Right now there is an over-reliance on the levelized cost of electricity (LCOE), which is not always a very good metric for comparison. Therefore, there is a need to go beyond the LCOE.

Cost estimates can generate what we term "hard" numbers, as well as context specific numbers. Examples of hard numbers include capital costs and heat rates. While capital costs can vary over time (e.g., inflation) and geography, these variations can generally be captured through sets of cost indices. Other hard number metrics can include process inputs (e.g., water), process effluents, and availability for dispatch.

Doing an economic analysis, such as one that produces an LCOE, requires context. The plant's capacity factor depends on dispatch, which can only be known in the context of the utility system in which the plant operates. There are many project specific factors that depend on the plant's location, permitting requirements of that location, labor environment, access to utilities, etc. The monetizing of risk and the valuation of ancillary services (e.g., capacity) will also vary widely depending on the context.

For comparing CCS to other technologies, developing methods based on the relatively hard numbers involved in a cost estimate (both cost and performance metrics) are preferred. Much more care must be taken when omparing technologies using context dependent numbers like LCOE.

Industrial processes

A big challenge in trying to determine the costs of Industrial CCS (ICCS) is the significant amount of process heterogeneity, both between industrial sectors and within industrial sectors. The appropriate technological approaches for CO_2 capture may vary greatly across industries. While at first blush it may seem that postcombustion capture with amines will always be an option, this may not be so. Impurities associated with exhaust streams may pose a significant challenge to amines. An example is the exhaust stream from the catalytic cracker at the Mongstad refinery, where the SO_3 in the exhaust gas caused the amine process to fail.

A potential major issue with ICCS is maintaining the integrity of the product. While this may not be an issue for post-combustion capture, other pathways that integrate CCS with the process must make sure that they maintain product integrity. As a result, there is a need for more detailed engineering assessments for capture options for the various industrial sectors and a need for more engagement with the industries.

An additional potential barrier to deployment of CCS technologies in the industrial sector is the approach that many industrial business take regarding existing and new assets. Several of the breakout participants suggested that it is more common for industrial sector businesses to run existing capacity to the end of its useful life "as built" or replace with new state-of-theart infrastructure rather than modify (i.e., retrofit) existing (and potentially outdated) capacity with new add-on processes. Therefore, it is likely that any back-end CCS technologies would compete against 1) alternative lower carbon intensive industrial processes and 2) location for replacement industrial facilities (either regionally or globally). Ultimately, the selection will be for the scenario that leads to the least-cost production of the industrial product and CCS is expected to play a role only if a low-carbon "benefit" can be monetized.

Session C. Making CCS More Competitive

Questions: What can be done to make CCS more competitive? What are realistic expectations for CCS cost reductions over next 10-20 years? By 2050?
(Co-chairs: Wilfried Maas, Shell; Sean McCoy, LLNL)

Round-table comments

- We know how much stuff costs; getting it financed and built is the hard part.
- Real questions about accuracy of public literature costs for capture (e.g., the US government can't even agree on a number) and we're not sure how to addup the costs. But, from a practical industry standpoint, this isn't a big deal because they're in the right ballpark.
- Variability of costs is, however, a surprise; also, surprised at the cost of compression and injection.
- Worried about risks associated with storage. Looking at risk separately is convenient, but the whole chain matters; what about injection and monitoring costs? What are the costs when we have surprises (e.g., OK seismicity from w/w re-injection, BC seismicity from fracking)?
- The big issue facing CCS is getting the whole thing together; system costs are important.
- Commercial structures are key in getting CCS built but…
- …the commercial case for CCS isn't there, at least in global aggregate near- term; creates an issue of timing, since we to need to work technology development today.
- In a really tough place on the technology development curve: need to de-risk technologies and get policy support. Need some data points.
- Current technologies not socially acceptable, and learning-by-doing won't cut it
- Nonetheless, there is a strong societal case for CCS; but massive market failure means there is no business case for individual developers. Need policy to address the failures.
- Perhaps early projects were too ambitious: they tried to solve both

capture and storage simultaneously.

- What is the right scale for CCS: little with high unit cost (and lower risk) or high with low unit cost (and higher risk). Does this argue for small-scale?
- Busy talking about cost, rather than revenue maximization. How can CCS have value to those who are doing it?
- Need to move towards system costs and away from LCOE; however, as bad as LCOE might be, but we don't have a good alternative.
- Don't be too negative on recent progress: much in the technology space has improved over the last decade.

What do we do?

- Marginal value of additional paper cost studies is very low.
- UK CCS cost reduction taskforce found that 25% reduction from technology improvement, 50% economies of scale in T&S, 25% from reduction in finance costs; all that is needed are a handful of
- plants in the UK to reach their cost reduction targets…
- Comments suggest main issue in risk is not capture related: it's the transport and storage that is the problem and where focus needs to be. History is filled with programs focused on capture/plant side justified by technology development, few (noteworthy) successes; has this been the wrong focus?
- Need government action to handle T&S problem or no real way to manage risk – fundamental difference between CCS and other technologies in power generation.
- Much of the past CCS focus was based on the presumption that there was going to be a rush to building coal that was going to happen in US and Europe.
- So, what is the state support package for development of a CCS industry? One answer is regulatory frameworks to push deployment: accelerate learning-bydoing and technology innovation. Create a market pull.
- Opposite commercial logic between US and Europe: US wants cheap CO_2 and low-cost sources fill the need; Europe want emissions reductions from expensive sources, who are begging oil and gas to play. For example,

in the US physical CO_2 has value, but in Europe it is paper contracts that have the (uncertain) value.

- In the absence of EOR/CCUS, Europe has no revenue in the transport and storage chain.
- US thinking is that the storage side is well understood (from a technology
- perspective) based on R&D and current operations. Agreement that this is a trans-Atlantic difference, where Europe is more concerned with the transport and storage risk.
- With LCFS, issue is that there are cheaper ways to meet the requirements
- today via biofuels. Need to hit blend wall before CCS comes into play. However, LCFS in one jurisdiction that can drive CCS somewhere else – opposite to discussion with economic leakage.
- What about carbon takeback obligations? Thinking about this in Europe.
- Energy systems analysis (e.g. IPCC) says CCS is critical and lowest-cost. But analysis is complicated, and question is how to sell it to the public and to policy makers.
- China and SE Asia are wild cards acknowledged by all – huge potential, but capability gaps.
- Another wild card is advanced nuclear technologies; technology and resource availability enables targets to be set (e.g., REGGI, CPP).
- Other drivers (e.g., reductions in water use) may put us in a position to deliver cheaper capture as a co-benefit – like molten carbonate fuel cells.

<u>Question to the group:</u> Will CCS be at 100 USD/MWh and commercially available by 2030?

- 5 No – timing of needs and business case, scale-up cannot be rapid enough; supply chain collapsed and will need to be rebuilt; competition from other technologies; government not willing to acknowledge that prices need to go up (or justify increased prices) to make this all work
- 12 Yes – prices will rise, and CCS will be marginal technology; Asia will do it, initial regulations will spur a discussion of what happens next that will lead to CCS; potential for breakthrough technology; CCS with gas will be where cost happens; cost might be there, but not widely demonstrated;

new way of pricing energy in future enables CCS; costs for capture on gas are already there.

- 1 Abstention – don't know enough

Report to Plenary Session:

1. We asked the question: will CCS be commercially available for power generation in 2030 at a cost of $100- 120/MWh? 12 responded "yes"; 5 said "no"; and 1 abstention. Disagreement on whether it will actually be deployed, though.
2. Difference between EU and US perspectives on where cost reductions are going to come from: capture technology, versus T&S infrastructure (particularly in regards to risk).
3. Cost reduction requires learning-by-doing which implies markets; need markets!
4. 4. Market for CCS was going to be new coal, but now, not much new coal—at least in developed countries—so now there is a gap before we get to gas.
5. 5. Tension between small-scale with high unit cost but low project cost, hence, lower risk; or large-scale with low unit cost but high project cost, hence higher risk.
6. Marginal benefit of additional cost studies is low.
7. Need to come up with effective means (messaging) to convey importance of CCS in a system context.
8. In the meanwhile, industrial CCS—oil and gas sector—will continue be a big driver. Wild card: what China decides to do is a huge deal.

Presentations

Introduction

- CCS Cost Network Workshop Overview
  Howard J. Herzog

Session 1: Framing the Issue

- The Cost of CCS: A Review of Recent Studies
  Edward S. Rubin

- Methodology of a Detailed CCS Cost Study
  Jeff Hoffman

Session 2: Project Costs – Industrial Applications

- Quest Project and Its Costs
  Wilfried Maas
- Insights into Cost of CCS Gained from the Illinois Basin-Decatur Project
  Sallie E. Greenberg, Ray McKaskle

Session 3: Project Costs – Power Applications

- Project Costs Power Applications
  George Booras
- Factors Impacting Capital Costs at SaskPower's Boundary Dam Integrated CCS Project
  Max Ball and Peter Versteeg
- FutureGen 2.0
  Ken Humphries
- White Rose—Oxy-fuel CCS Project
  Leigh A. Hackett

Session 4: CCS in the Context of Changing Electricity Markets

- The Value of Flexible, Firm Capacity on a Decarbonised Grid
  Andy Boston
- Duke Energy
  Neil Kern

2016-01 IMPACT OF CO_2 IMPURITY ON CO_2 COMPRESSION, LIQUEFACTION AND TRANSPORTATION

Key Messages

- The study identified twelve worst-case but plausible impurities scenarios that are representative of the main CO_2 capture processes.
- Impurities greatly affect the thermodynamic and transportation properties of CO_2 streams.
- Apart from pure CO_2, the CH_4-rich scenario exhibited the most desirable qualities for dense phase pipeline transport.
- Only one case (i.e. adsorption with high N_2 content) showed significantly higher compression energy requirement than the other scenarios, being 7% more than the base case.
- For dense phase transport, the worst-case scenarios (i.e. adsorption with high N_2 content and oxyfuel combustion with high O_2 content) would lead to an increase in pipeline sizes compared to the base case, which would raise their capital cost.
- Temperature has a more pronounced effect on density than pressure, meaning that in order to increase the pipeline's capacity the inlet temperature should be as low as possible.
- Saturation pressure of CO_2 is a critical variable for fracture control. Especially H_2 has a strong elevating effect on saturation pressure. High levels of O_2 and N_2 also lead to an increase.
- The water specification for some scenarios (i.e. adsorption with high N_2 content and oxyfuel combustion with high O_2 content) will require careful consideration, due to the influence of impurities on water solubility, which in turn can affect corrosion and stress corrosion cracking. CO and H_2S may also increase the risk of stress corrosion cracking.
- Ship transport under most investigated scenarios would be uneconomical, as it requires high pressures and very low, i.e. cryogenic, temperatures. Thus, it might only be economically viable in case of very high CO_2 purity. The general arrangement and design parameters would likely be similar to a Type C ship for liquefied natural gas (LNG) but need to consider the significant variation in density of different impurity scenarios.

Background to the Study

The impurities present in CO_2 streams are important for CO_2 pipeline and ship transportation affecting various aspects, such as the range of operation, safety considerations, fracture control, cracking, corrosion control, dispersion in the event of a release, fluid density, operating pressure, temperature and the quantity of CO_2 that can be transported. The range and levels of potential impurities emitted from CO_2 capture facilities will differ between different power plant and industrial sources and also between the capture technologies installed at the source. However, the potential CO_2 specifications that could enter the transport and storage systems, particularly from industrial sources, remain relatively under-researched. Therefore, it is essential to improve the understanding of the effect of these potential impurities on CO_2 compression, liquefaction and transportation under relevant conditions.

IEAGHG has identified the need to investigate these effects and commissioned a study to a consortium led by Newcastle University and including the University of Edinburgh.

Scope of Work

The main objectives of the report are to:

- Review the CO_2 impurities that could be present from different CO_2 capture technologies and develop twelve CO_2 impurity scenario compositions for further analysis;
- Evaluate these impurity scenarios for CO_2 physical and transport properties. The properties that are investigated are the dew point, bubble point, melting point, density, Joule-Thomson coefficients, speed of sound, viscosity and thermal conductivity.
- Evaluate the effects of the impurities on CO_2 compression and liquefaction in terms of performance and energy requirements;
- Identify the effects of the impurities on the operating conditions for both pipeline and ship based transportation;
- Evaluate the effect of the impurities on the selection of materials for pipeline and ship transportation.
- Table 1 summarises the twelve CO_2 impurity scenarios developed at the beginning of this study.

Scenario Number	Scenario Name	Component (all values % by volume)							
		CO_2	O_2	N_2	Ar	H_2	CO	H_2S	CH_4
1	REF	100							
2	CO_2 MEM1	93		7					
3	CO_2 MEM2	97	3						
4	ADS1	90	1	9					
5	ADS2	95		5					
6	Ca LOOP	95	1	2	2				
7	OXY1	90	6	3	1				
8	OXY2	96.5	0.5	2.5	0.5				
9	PRE	98				2			
10	H_2 MEM	96		1		1	0.5	1.5	
11	CH_4-RICH	98							2
12	TGR-BF	96		0.5			3.5		

Acronyms: ADS - adsorption; Ca LOOP - Calcium looping; CO_2 MEM - CO_2 membrane; H_2 MEM - H_2 membrane; OXY - oxyfuel; PRE - pre-combustion; REF – reference; TGR-BF – Blast furnace with top gas recycling

Findings of the Study

Impact of impurities on CO_2 physical properties

This section investigates the effect of the addition of the components identified in the scenarios developed on the physical properties of CO_2, i.e. regarding location of the phase boundaries, density, speed of sound, Joule-Thomson coefficient, viscosity and thermal conductivity relative to pure CO_2. The twelve scenarios identified represent a plausible range of 'worst case' scenarios for steady-state operation. The pressures and temperature ranges to cover the physical properties were selected to be representative of dense phase pipeline operation, a pressure of 15MPa was chosen and a temperature range of 0 to 50°C.

Details regarding the reference equations and assumptions used are laid out in the main report. Since not all experimental work covers the regions of interest in this paper, the thermodynamic and physical properties of the mixtures are modelled. Furthermore, there is limited experimental data available for the properties of potential captured CO_2 streams. In addition,

for some impurity combinations, due to the lack of experimental data, the equations of state are operating in regions where they are less robust.

The qualitative effect of an impurity can be inferred from the binary behaviour but its behaviour in more complicated mixtures cannot be quantified by looking at the binary behaviour. The physical properties of the scenarios are compared with pure CO_2 in order that the worst case scenarios can be selected.

Figure 1 to Figure 3 show exemplary physical and transportation properties for all scenarios, i.e. bubble point curves, densities and dew point curves. Optimum dense phase transport requires low bubble point curves and high densities, whereas optimum gas phase transport needs high dew point curves. The dense phase Scenarios 4 (ADS1), 7 (OXY1) and 2 (CO_2MEM) tend to produce the least desirable qualities for pipeline transportation. These CO_2 streams have the lowest proportions of CO_2 and have the highest bubble point curves, compressibility, Joule-Thomson coefficient and the lowest densities, speed of sound and thermal conductivities. However, it is worth noting that these scenarios have the lowest viscosities.

Apart from pure CO_2, Scenario 11 (CH_4-RICH) has the most desirable qualities for dense phase pipeline transportation with the lowest dew point curve, Joule-Thomson coefficients and compressibility and the greatest density and speed of sound. This is balanced with the fact that it has the lowest thermal conductivity and the highest viscosities. It should also be noted that, even though it has a high CO_2 purity (98%), Scenario 9 has shown relatively undesirable dense phase pipeline transportation characteristics because H_2 has large effects in small quantities. For these reasons, Scenarios 4, 7 and 2 are selected for the worst cases for dense phase pipeline transportation.

Due to their relatively high compressibility, Scenarios 4, 7 and 2 show the highest compression power requirements for compression to dense phase.

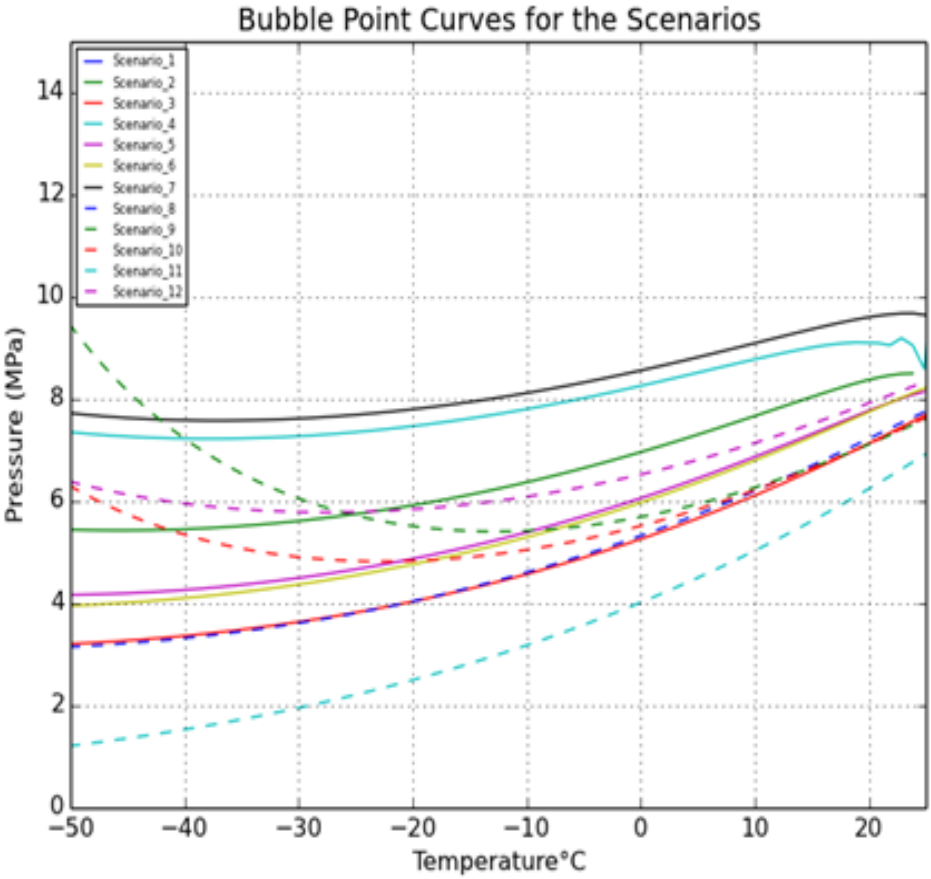


Figure 1: Bubble point curves for all scenarios

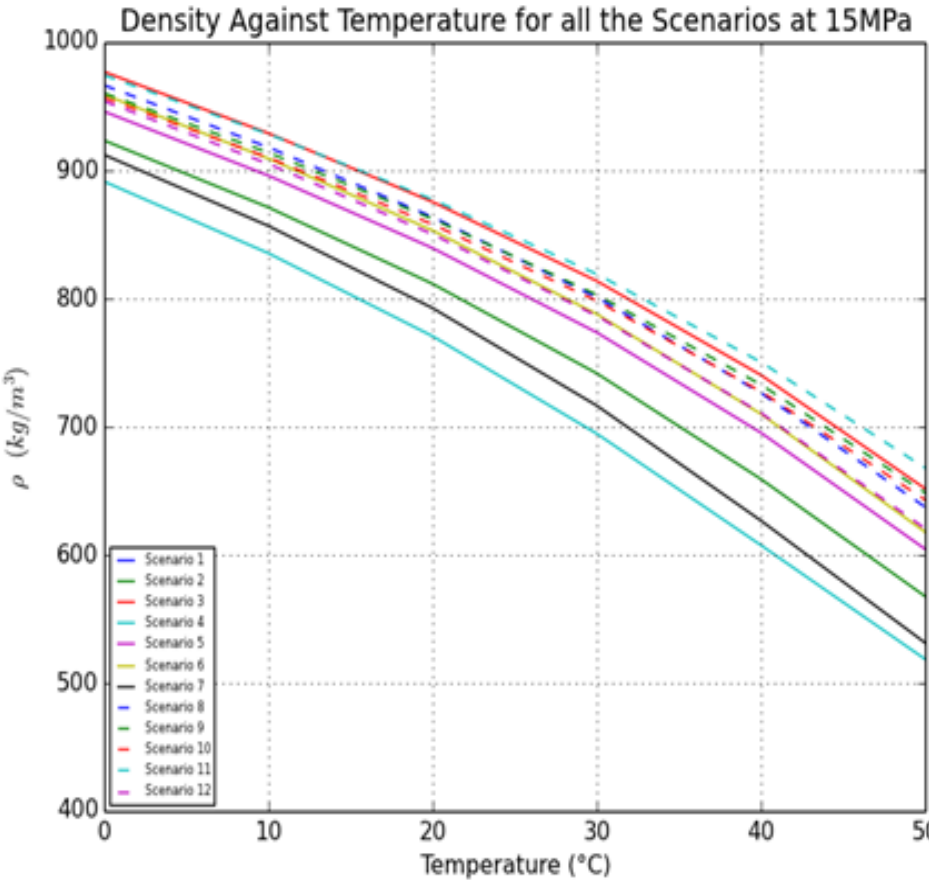


Figure 2: Densities for all scenarios

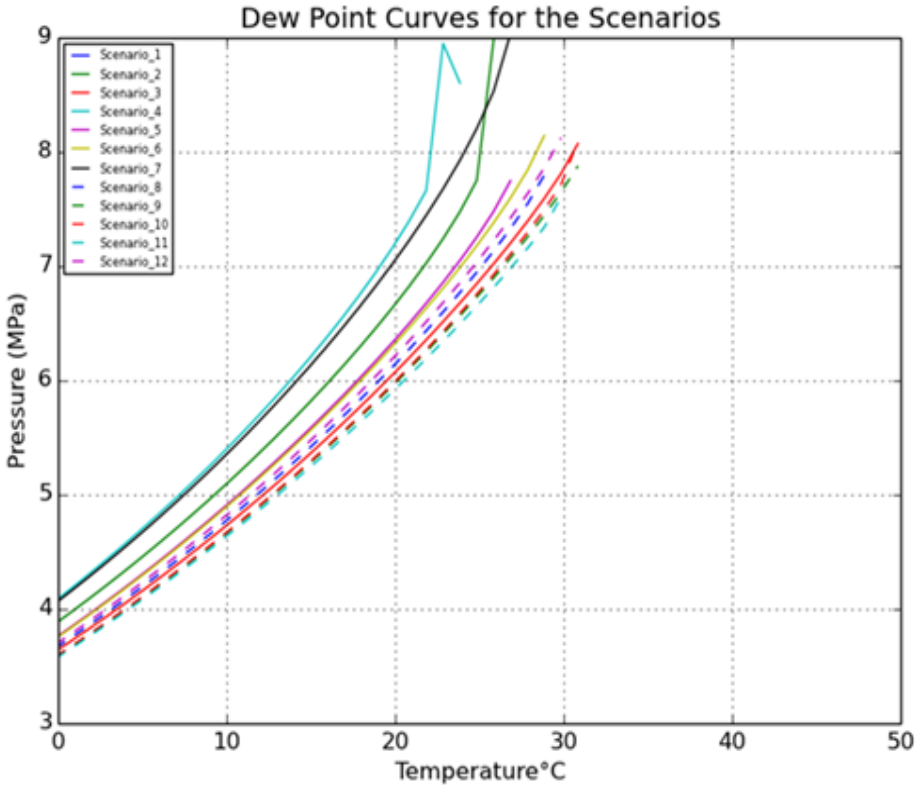


Figure 3: Dew point curves for all scenarios

Impact of impurities on CO_2 compression

Using commercially available pipeline simulation software, the energy requirement for a set of compressors for each scenario relative to a base case of pure CO_2 was evaluated and compared.

The choice of base case sets the number of compression stages and the compression ratio at each stage. It should be noted, however, that the number of compression stages is process-specific and different project developers may adapt the number of compression stages used to better integrate the CO_2 capture and compression processes.

The inlet pressure and temperature were selected to be 1.6bara and 38°C respectively. These initial conditions are broadly representative of current

recognized capture technologies and allow comparisons to be made between the scenarios. It should be noted that for specific CO_2 capture options actual compressor entry conditions should be used since these can have a noticeable impact on CO_2 compressor power requirements and costs. A constant mass flow rate of 700,000 kg/h is assumed to entering the compressor. For the analysis of dense phase streams, it is assumed that that the CO_2 flow delivered to the pipeline in the dense phase has a pressure of 110bara and temperature of 30°C. Table 2 in the next section summarises these and further assumptions for the analysis. For simplicity, this study has assumes a constant composition throughout the CO_2 compression process.

To draw clearer conclusions, the total power requirements of the anthropogenic CO_2 streams were normalized against the total power requirement of the REF case and the results are demonstrated in Figure 5 (page 211). These are the data obtained with an efficiency of 85%.

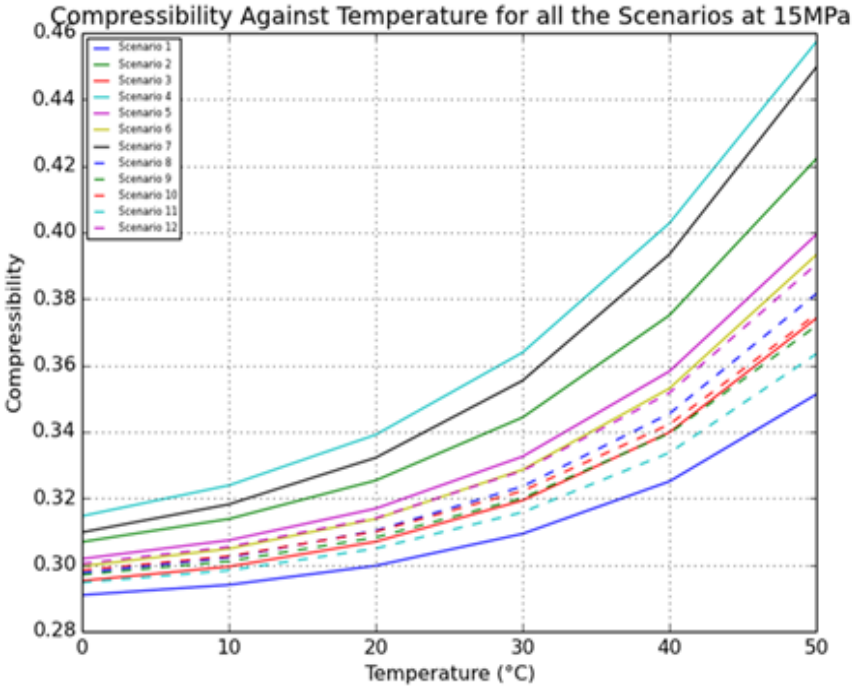


Figure 4: Compressibilities for all scenarios

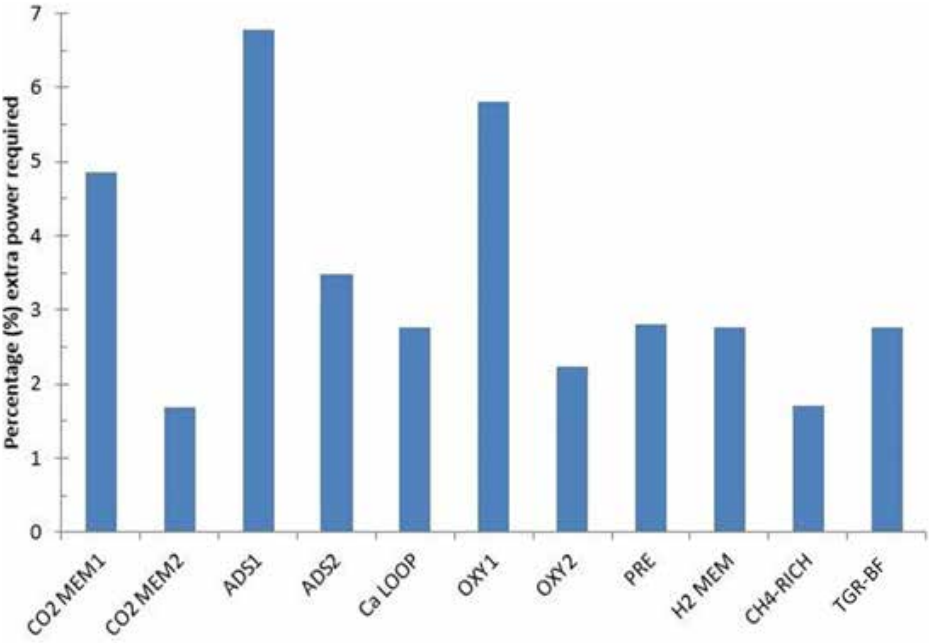


Figure 5: Extra power requirement of the impurity scenarios relative to the REF case

ADS1 is the worst-case scenario of all, with slightly below 7% extra energy requirements. Sorting the energy requirement of the anthropogenic scenarios, if only the composition varies (i.e. given that inlet conditions are assumed constant), then scenarios that also cause significant changes to compression power requirements are OXY1 and CO_2MEM1. This is in agreement with the compressibilities calculated and shown in Figure 4 (page 210). Optimum compression processes require low compressibilities.

Impact of impurities on pipeline transport

Specifications

As demonstrated earlier, the impurities influence a wide range of thermodynamic properties, including the density of the stream, the specific pressure drop and the critical point. As a consequence, the pipeline design parameters such as diameter, wall thickness, inlet pressure, minimum allowable operational pressure (MAOP) and the distance between booster

stations are potentially subject to change. This will also have a great impact on the cost of whole CCS chain. CO_2 is generally transported in the dense phase at temperature and pressure ranges between 12°C and 44°C and 85bara and 200bara. The lower pressure limit is set by the phase behaviour of CO_2 and should be sufficient to maintain single conditions while the upper pressure limit is mostly due to economic and material concerns. Regarding the temperatures, the upper temperature limit is determined by the compressor station discharge temperature and the temperature limits of the external pipeline coating material, while the lower limit is determined by the winter ground temperature of the surrounding soil.

To study the impact of the impurities on transportation, a set of assumptions have been assumed as listed in Table 3. The scope of this task is designing pipelines that transport the CO_2 stream from the capture site, where the CO_2 stream enters the pipeline at 110bar and 30°C and is transported to an onshore storage site or a terminal a distance of 150 km. This is a single point to point pipeline on a flat terrain.

PARAMETER	VALUE	UNIT
Horizontal Distance	150	km
Elevation Difference	0	m
Roughness	0.0457	mm
Ambient Temperature	5	°C
Inlet Pressure dense phase	110	bara
Inlet Pressure gas phase	40	bara
Mass flow rate	700	ton/hr
Inlet Temperature	30	°C
Burial depth	1.1	m
Pipe steel yield stress	450	MPa
Steel Heat Transfer Coefficient	60.55	$W/m^2/K$
Soil Heat Transfer Coefficient	2.595	$W/m^2/K$

Table 2: Initial condition considered for CO_2 transport

Hydraulics

Using the parameters in Table 2, the pipeline geometry requirements for dense phase transportation of the worst-case scenarios and of pure CO_2 case were calculated and are summarised in Table 3. Data for gas phase transport is available in Table 4.

Dense phase	Calculated Pipe Parameters (mm)			P_{inlet}	T_{inlet}	P_{outlet}	T_{outlet}	Hoop Stress	%SMYS
	ID	wt	OD	bara	°C	bara	°C	MPa	
REF	490.4	8.8	508	110	30	84.87	15.39	317.5	71
ADS1	588	11	610	110	30	96.80	17.51	305.0	68
OXY1	588	11	610	110	30	97.20	17.53	305.0	68
PRE	490.4	8.8	508	110	30	83.3	15.78	317.5	71

Table 3: Comparison of pipeline dimensions, pressure and temperature losses for dense phase transportation

Gas Phase	Calculated Pipe Parameters (mm)			P_{inlet}	T_{inlet}	P_{outlet}	T_{outlet}
	ID	wt	OD	bara	°C	bara	°C
REF	851.4	6.3	864	40	30	25.5	8.6
CH_4-RICH	851.4	6.3	864	40	30	25.0	8.7
OXY2	851.4	6.3	864	40	30	24.9	8.7
PRE	851.4	6.3	864	40	30	24.8	8.5

Table 4: Comparison of pipeline dimensions, pressure and temperature losses for gas phase transportation

In order to transport 700Ton/hr (194.44kg/s) of pure CO_2 in dense phase, a pipeline of 508mm outside diameter would be required. The minimum thickness for this pipeline to comply with the maximum allowable tangential stress is 8.8mm. The maximum allowable tangential stress calculated as 324MPa and the designed stress limit is 317.5MPa. The choice of optimum wall thickness also keeps the pipeline weight to a minimum. This setup results in a 25.13bar pressure drop along the length of the pipeline which is equivalent to 16.75kpa/km and in agreement with allowable pressure drops limits in pipeline engineering. The delivery pressure is such that two phase flow in

the pipeline is prevented. There is almost a 15°C drop in the temperature of the fluid, which makes the fluid slightly denser at the delivery point. This, in turn, causes a slight reduction in the erosional velocity. The erosional velocity ratio (flow mean velocity to erosional velocity) is around 0.3. The same design considerations as REF case have been applied in pipeline design for the worst case scenarios. The cases ADS1 and OXY1 require pipelines OD sizes of 610mm with wall thicknesses of 11mm. This keeps the hoop stress down to below 305MPa. Figure 6 shows the data for wall thickness and OD for the dense phase calculations of the worst case scenarios normalised to the REF case.

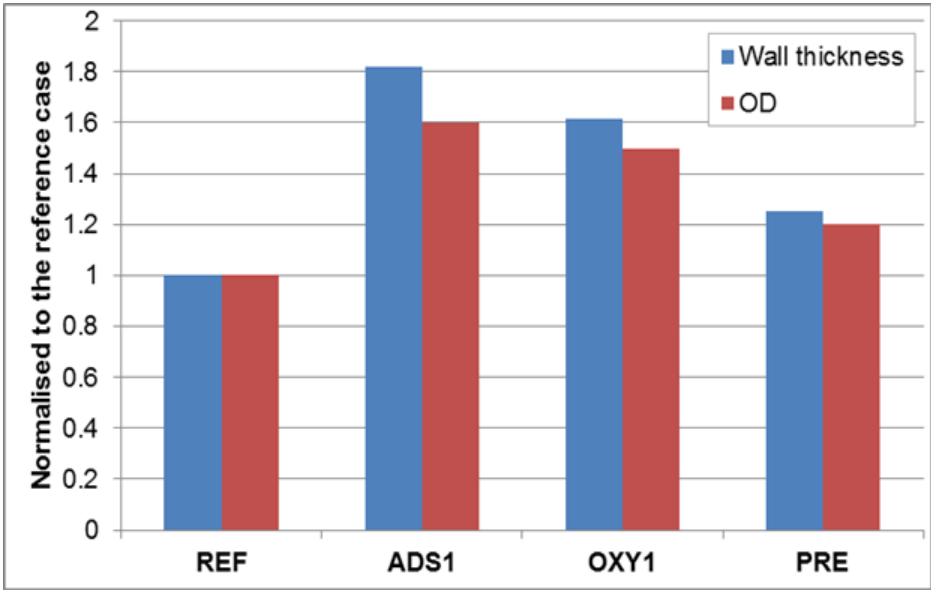


Figure 6: Effect of impurities on pipeline dimensions

Materials selection

It is highlighted that there is little published work on the types and levels of trace elements that could be present in the final captured CO_2. It could be considered that any components which could be present in the various waste streams of the plant could also be carried through to the exported CO_2 stream at very low levels. The types and levels of these trace elements therefore becomes very hard to quantify as coal and biomass can contain

many different types of elements at low levels and some capture options might also add trace elements due to the nature of the process. Consequently, the approach in this work considers the effect that the trace elements could have on the various aspects of pipeline transportation and the levels required for these conditions to occur.

In order to identify a worst case composition from the developed scenarios, the saturation pressures have been calculated for each composition based on decompression from the pipeline operating conditions of 150bara and 30°C. The results are presented in Table 5. From this analysis, it can be seen that the OXY1 composition is the most troublesome composition to transport in terms of fracture control and will require careful consideration when designing the pipeline to ensure fracture arrest.

Scenario Number	Scenario Name	Component (all values % by volume)								Saturation pressure
		CO_2	O_2	N_2	Ar	H_2	CO	H_2S	CH_4	bar
1	REF	100								
2	CO_2 MEM1	93		7						82.0
3	CO_2 MEM2	97	3							69.5
4	ADS1	90	1	9						82.2
5	ADS2	95		5						75.5
6	Ca LOOP	95	1	2	2					79.8
7	OXY1	90	6	3	1					86.7
8	OXY2	96.5	0.5	2.5	0.5					77.2
9	PRE	98				2				62.3
10	H_2 MEM	96		1		1	0.5	1.5		77.1
11	CH_4-RICH	98							2	59.0
12	TGR-BF	96		0.5			3.5			82.5

The specification of water in currently operating pipelines ranges between 640ppmv and 20ppmv to avoid the formation of free water in the pipeline at the operating conditions. However, whilst it is known that the presence of impurities will affect the solubility of water in CO_2, there has been little research into the absolute effects of these impurities and the published data is limited. The CO_2-H_2O-CH_4 system has been studied and the experimental

results and thermodynamic models indicate that the addition of CH_4 requires a more stringent water content, as the solubility of water decreases with increasing CH_4 content. Similar results have been observed in the CO_2-H_2O-N_2 system where at a temperature of 40°C, an addition of 10% N_2 can lower the solubility of water in CO_2 by up to 26%. It is highlighted that this composition is similar to the ADS1 composition. Conversely, in the CO_2-H_2O-H_2S system, the solubility of water would increase with the addition of H_2S. Although these ternary systems provide useful information on the potential effects of individual components, the data on representative CO_2 streams as presented in the scenarios in this paper is extremely limited. In systems of CO_2 and 5.05% N_2 -3.07% O_2, 2.05% Ar at a pressure of 150bar, the addition of these impurities reduced the solubility of water by 20% compared to pure CO_2. This composition is similar to the OXY1 scenario considered in this paper and therefore water content for this scenario would have to be very carefully specified at the pipeline operating conditions to avoid associated degradation mechanisms.

Impact of impurities on ship transport

In order for the product to be kept in liquid phase, liquid carbon dioxide (LCD) will need to be transported in Type C tanks. Currently, Type C tanks have typical application for smaller liquefied natural gas (LNG) ships which are usually suitable for coastal trade for areas which lack conventional gas pipelines. For example, 1000m^3 capacity ships currently operate in remote coastal areas of Norway. However, larger vessels are currently being developed with Type C tanks. TGE Marine are currently constructing two 30,000m^3 carriers, with class approval in principle, and already operate a 7,500m^3 vessel. An advantage of Type C is the minimisation of the boil-off-gas (BOG). Some ships do not carry any BOG re-processing facility.

To enable containment of CO_2 mixtures in liquid form, the containment system must keep the product (above the triple point pressure) at pressures and temperatures that are above the bubble and melting point lines. This zone varies for different impurity scenarios. Some of the impurity scenarios can be transported in the liquid phase at around -57°C and 1 to 1.5MPa, with the others requiring higher pressures. The melting points are fairly invariant for the feasible containment pressures and range from -57°C to -73°C. Increasing

the tank pressure further will move more scenarios further into the liquid phase. This improves the capabilities of the containment system for different impurity scenarios but some scenarios require unfeasible storage pressures.

Care must be taken to avoid formation of solids (dry ice) in the storage tank and when loading/unloading. This may indicate that higher tank pressures would be required. The suggested containment pressures/temperatures are similar to previously reported values.

It is feasible to transport certain impurities of CO_2 by ship. An equivalence to Type C LNG ships shows that the operating pressures and temperatures are within existing ship design scope. A suitable pressure/temperature combination for high purity CO_2 scenarios is 0.6MPa and -57°C. Increasing the tank pressure moves less pure scenarios into the liquid phase and improves the capabilities of the containment system for different impurity scenarios, although the majority of the worst case scenarios will require storage at unfeasible pressures. The general arrangement and fundamental design parameters of an LCD ship would likely be similar to a Type C LNG ship. The density of different impurity scenarios varies significantly. This would need to be considered for stability and sea-keeping during the ship design. It will also affect the payload capacity of the ship and would therefore impact on transportation costs.

Impact of impurities on buffer storage and liquefaction

Intermediate buffer storage could be placed in saline aquifers along the route of a pipeline or in a CO_2 terminal at the shore. However, these options could run into difficulties with health and safety bodies as well as public acceptance of onshore CO_2 storage. For CO_2 mixtures to be in the liquid state they must be stored at pressures and temperatures on the liquid side of the bubble point and melting point curves. Additional impurities in a pure CO_2 stream cause a two phase region to open up. Large quantities of these impurities tend to increase the size of the envelope, especially if they are very different to CO_2, and the envelope opens out away from critical point, i.e. at lower temperatures the bubble and dew point curves are further apart. Wider envelopes also have the dew and bubble point lines further apart and will require higher pressures to reach the liquid phase. There has been very little work done on low temperature CO_2 mixtures near the solid phase and

impurities will affect the melting line, although there has been work done on the equation of state for solid CO_2 and the impurities in their pure form.

The lack of data on the melting point line for CO_2 mixtures leads to uncertainties in the liquid storage region. In order for mixtures with large amounts of impurities to be on the liquid side of the bubble point curve at low temperatures, large pressures are required. Therefore buffer storage of these types of mixtures is unlikely. For mixtures with a small amount of impurity, the properties of the mixtures will be near identical to pure CO_2 and therefore the storage conditions and tank properties will be the same to those of pure CO_2.

The liquefaction states of CO_2 transport by ships that were investigated in this study are (i) 50°C, 7bara and (ii) -130°C and 7bara. A closer look at the condition (ii) reveals that all of the streams would be at their solid state for this condition; while in condition (i), many of the scenarios are either in the two phase region or in the gaseous phase (see Figure 1). Therefore it can be concluded that the decision on the conditions under which anthropogenic streams should be transported depends on the phase envelope of each stream.

Expert Review Comments

Nine reviewers were invited to provide feedback on the report, of which four submitted comments. In general, the majority of reviewers found that the report was well-written, provided a wealth of information underpinned by simulation data and presented a valuable contribution to the area. The contractors addressed several comments that asked for more clarification or references. However, there have also been some comments that were not addressed as they were considered out of the scope of this study and/or were not raised by a number of reviewers, e.g. regarding investigation of transient states, consideration of higher H_2S content, quantification of impurities' cost implications, impact on equipment, injection characteristics and leakage during transportation. Some of these topics might be a subject for further studies, as mentioned in the "Recommendations" section at the end. One reviewer did not agree with the chosen impurities levels for the scenarios. However, no changes were made here because other reviewers and IEAGHG regarded the numbers as appropriate.

Conclusions

It is has been possible to identify twelve worst case but plausible scenarios in this work which are representative of the main capture processes. In the dense phase, the ADS1, OXY1 and CO2MEM1 scenarios tend to produce the least desirable qualities for pipeline transportation. These CO_2 streams have the lowest proportions of CO_2 and have the highest bubble point curves, compressibility, Joule-Thomson coefficient and the lowest densities, speed of sound and thermal conductivities. However, it should be noted that these scenarios have the lowest viscosities. Apart from pure CO_2, the CH4-RICH scenario has the most desirable qualities for dense phase pipeline transportation with the lowest dew point curve, Joule-Thomson coefficients and compressibility and the greatest density and speed of sound. That is balanced with the fact that it has the lowest thermal conductivity and the highest viscosities.

ADS1 show the highest compression energy requirements amongst all of the scenarios studied and this was 7% more than the base scenario. It is highlighted that this extra energy requirement is only at the compressor stages and does not represent the overall energy requirement for the whole process unit. In terms of dense phase transport, the worst case scenarios (ADS1 and OXY1) require increased pipeline sizes over the reference case of pure CO_2 for the design conditions considered. This will affect the capital cost of these pipelines. Temperature has a more significant effect on density than pressure for both pure CO_2 and CO_2 containing impurities. To increase the density and therefore capacity of the pipeline, the inlet temperature should be as low as possible.

For fracture control, the saturation pressure of the CO_2 stream is a critical variable that will determine the required pipeline dimensions and toughness to prevent a long-running ductile fracture. H_2 in particular has the most potent effect in raising the saturation pressure. The OXY1 scenario was the most difficult scenario composition to transport due to the high levels of oxygen and nitrogen which also raise the saturation pressure. Corrosion and stress corrosion cracking of plain carbon steel will not occur without the presence of water. The effect of impurities on water solubility is therefore critical. There is little information on water solubility available in the literature, but it has

been shown that water specification for the ADS1 and OXY1 scenarios would require careful specification.

In order to liquefy the scenario compositions studied in this paper high pressure and low temperature conditions are required to maintain the fluid in its liquid phase. This renders these compositions uneconomical for transportation in the cryogenic liquid phase. It is feasible to transport high purity CO_2 streams by ship. The general arrangement and fundamental design parameters of an LCD ship would likely be similar to a Type C LNG ship but there are significant design and approval consequences if Type C vessels are applied for LCD in large volumes.

Recommendations

The authors of the study and the reviewers have identified the following areas for further work:

- Investigate more challenging CO_2 specifications for CO_2 transport systems in non-steady state conditions and particularly in upset conditions.
- A more detailed analysis with variations in CO_2 composition during compression, as composition is likely to have a significant impact on CO_2 compression requirements. A tailored, optimized compression route could be designed for each scenario based on the impurities existing in the CO_2 stream.
- Identify the best approach to setting pressure and temperature at the exit of the CO_2 capture plant, given the implications this will have for CO_2 transport, compression and/or liquefaction.
- Determine the cost implications of impurities on CO_2 transport and storage and recommend technically and economically reasonable ranges of impurities for CCS chain operation.
- For CO_2 capture from industrial sources, it may be valuable to review plant permits (rather than more generic best available technology documents) to improve understanding of the flows entering CO_2 capture, transport and storage systems.
- Consider a broader range of scenarios with different intercooling temperatures (e.g. depending on available cooling source) and a variety

of heat exchanger options.

- IEAGHG recommends investigating at least some of the points above in a future follow-up study.

2016-04 OPERATIONAL FLEXIBILITY OF CO_2 TRANSPORT AND STORAGE

Key Messages

- Large point sources of CO_2 can deliver relatively pure 99.7% CO_2 after capture and dehydration. However, it is important to recognise that many large-scale industrial processes that generate CO_2 emissions are cyclical and intermittent, therefore, to ensure a consistent and reliable CO_2 supply integrated pipeline networks will be essential.
- Experience from the United States clearly demonstrates that CO_2 with a high level of purity can be effectively and safely delivered using integrated pipeline networks.
- Networks can be a useful means to control flow in a pipeline and can also act as a buffer by supplying CO_2 from several sources to a number of different sinks. Multiple sources also mean that there is less reliance on a single source and intermittent supply from different sources can be accommodated. CO_2 can also be temporarily compressed or 'packed' into pipelines as a short term measure.
- This study has shown that most North American CO_2 pipelines are overdesigned for their current application. They are designed for higher flow rates and operating pressures through the use of thicker walls and larger diameters. Future pipeline networks can take advantage of this experience if there is an intention for increased capacity in the future.
- Impurities particularly H_2O and O_2, can have negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. The density and viscosity of fluids can also be affected. Non-condensables like N2, O_2, Ar, CH_4 and H_2 should be separately limited to <4% because their presence increases the amount of compression work. Compression and transport of CO_2 for CO_2-EOR use in the United States has shown that impurities are not likely to cause transport problems provided CO_2 stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).

- The most significant effect on transport and injection of CO_2 is the water content. The Kinder Morgan specification for pipeline transport of CO_2 is a 600 ppm by weight for H_2O and 10 ppm by weight for O_2. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of chemical dryers such as monoethylene glycol.
- Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects. Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.
- CO_2 storage in deep saline formations can be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry.
- CO_2-EOR relies on controlling pressure and flow rate conditions to optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions the precipitation of minerals or asphaltenes (high molecular weight compounds such as bitumen) or changes in formation fluid saturation properties can occur. Reservoir permeability can be reduced as a result. This study has found that experienced operators can plan for intermittency in both the supply of CO_2 and in CO_2-EOR operations.

Background to the study

The optimisation of CCS projects in terms of cost and efficiency requires one or more large scale point sources of captured CO_2 which can be transported via a pressurized CO_2 pipeline to reservoirs with suitable storage properties such as high permeability and known capacity. In many countries where CCS projects are under evaluation, CO_2 will be captured from fossil-fuel power stations. Over the last 20 years there has been a trend towards deregulation of the electricity supply market, and an expanding contribution from

intermittent renewable forms of electricity production. Both these factors have led to a greater demand for flexible operation of power plant, and often at a short notice, to maximise the revenue and to meet regulatory requirements. Cyclical and intermittent operation of power plants will increase plant operation and increase plant operating costs. Consequently, the rate of captured CO_2 supply for transportation will also be affected, although the magnitude of this effect will depend on the extent of any interconnected pipeline network, multiple sources of captured CO_2 and rates of supply from different sources.

CO_2 transportation pipelines will need to be connected to CO_2 capture plants at power stations or other point sources (such has heavy industries) that will link them to potential CO_2 storage reservoirs. The ability of CO_2 pipelines to operate flexibly at higher pressures to maintain CO_2 in supercritical phase, and the technical implications of this mode of operation, need to be understood. The time duration to reach the complete supercritical phase in CO_2 pipeline will depend on the temperature and other parameters including the presence of impurities particularly the presence of water. In a supercritical phase, and at maximum operational pressure, line packing may be an operational option but constrained to a comparatively short period of a few hours before the system reverts to a standby mode which might include venting of CO_2 to atmosphere.

In addition to pipeline operation the composition of CO_2 from a variety of different sources has been reviewed to explore the potential impact on variable composition and impurities. CO_2 can be captured from various industrial processes and emission sources such as power generation, oil refining, iron and steel, cement etc. This will affect the type and concentration of impurities in captured CO_2. The presence of various impurities within the captured CO_2 needs to be taken into account because of the effects on Pressure Vapour Temperature (PVT) conditions. The fluctuations in supply from different industrial sources and power generation may also have an impact on transport and storage. The magnitude and the ability to manage injection programmes also needs to be understood. Diurnal swings in CO_2 output may be frequent; consequently system stability, including PVT balance, needs to be controlled to ensure that optimum transmission and injection conditions can be maintained and instability avoided.

There is also potential for hydrate formation in the immediate proximity of the wellbore due to the presence of formation water. The PVT conditions that could arise from flexible operation, and the presence of impurities have formed part of this investigation.

This study has reviewed how flexible CO_2 supplies might have an impact on both CO_2-EOR operations and permanent storage in depleted oil and gas fields and deep saline formations. CO_2 injection programmes for large scale geological storage and CO_2-EOR will have different objectives. Historically, the driver for using CO_2 for CO_2-EOR has been economic rather than environmental. The CO_2 injection rate needs to be optimized to enhance production without causing early breakthrough. The initial stages of injection will require much more CO_2 than in the later stages of recovery, as the reservoir is saturated and the CO_2 produced with the oil is recycled back into the reservoir. Therefore, the timing of the availability of the CO_2 is crucial. There is extensive experience of the use of CO_2 for CO_2-EOR, mainly in the United States, which has provided relevant detailed background.

In contrast, large scale CO_2 storage in depleted oil fields, and large saline aquifers, needs to maximize reservoir capacity with potentially long term injection over several years, and at higher pressure, compared with CO_2-EOR. The reservoir pressure needs to be controlled to avoid damage to the caprock or cause instability in faults. In both cases careful planning is required to ensure that the pressure/ temperature conditions of the CO_2 are compatible with the reservoir.

Scope of work

This study has reviewed different transport and storage scenarios to reflect the range of full-scale commercial operations. In addition to a wide ranging literature review a survey of industrial, utility, pipeline and CO_2-EOR operators was also conducted to obtain their insights of CO_2 transport and storage. Owing to the sensitivity of these commercial operations it has not been possible to attribute background information to either individuals or their companies. Anonymity has not prevented the inclusion of real world data on exhaust gas composition from different sources including power generation (coal and natural gas), oil refining, gas processing, cement, hydrogen production, and ethanol production. It also includes background

information on actual CO_2 pipeline operation, including network hubs, and CO_2-EOR experience in the United States. Experience from different industrial scale injection projects such as Sleipner, Snøhvit and In Salah, has been included. The study has investigated how flexible operation affects CO_2 storage and the measures adopted to accommodate intermittent supply.

There are a series of prioritized recommendations based on the gaps in knowledge.

Findings of the Study

Five full-scale commercial transport-storage examples including Sleipner, Snøhvit, In Salah, Weyburn and Decatur were reviewed. All these projects experienced mass flow variability or interruptions in flow. Mitigation strategies implemented at these sites have accommodated the effects of intermittent flow.

Different industrial processes produce CO_2 streams with different compositions. The different CO_2 capture method can also affect the composition of the flue stream.

Approximately 28% of global CO_2 emissions come from coal-fired power plants. After scrubbing and dehydration relatively pure 99.7% CO_2 can be achieved. The amount of CO_2 produced by a power plant depends on the electricity demand. Research conducted as part of this study revealed that CO_2 emissions from a power plant can be fairly constant for 8-12 hours with only minimal change. At other times the load change fluctuate higher or lower by a rate of 1-2% a minute. This rate of change can shift in the same direction for as long as 30-45 minutes. Electricity generation is governed by market demand which means that plant operators are not able to predict the load on an hourly basis. However, operators who responded to this study commented that the CO_2 concentrations in the flue gas are fairly constant across the load range, varying from 10% to 12%.

In contrast the flue composition of cement plants, based on investigations by this study, varies widely with CO_2 forming between 14% - 33%. Capture technology and scrubbing can deliver comparatively pure CO_2 but cement plants operate intermittently depending on demand for the product consequently their integration into a CO_2 supply network would be

challenging, particularly as they can be periodically shut down for months. Petroleum refineries can individually produce substantial volumes of CO_2, but from several different processes. CO_2 purities of 95% to 99% are feasible. There are two examples of refineries, the Pernis refinery in Rotterdam and Valero's refinery in Port Arthur Texas, that have CO_2 capture facilities from hydrogen production unit syngas streams. CO_2 is delivered to pipeline networks in both cases.

Modelling results have indicated that the presence of certain impurities in the CO_2 stream may cause problems with the maintenance of single-phase flow within a CO_2 pipeline, particularly the presence of water which can form corrosive carbonic acid and hydrates that can obstruct pipelines. Impurities change the physical and therefore the transport properties of CO_2. Changes in stream hydraulics changes the number of compressors and therefore the power demand to pump CO_2.

Depending on the type and concentration of impurities there can be negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. However, compression and transport of CO_2 for CO_2-EOR use in the United States has shown that impurities are not likely to cause transport problems provided CO_2 stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).

The economics of CO_2 transport favour movement in a supercritical phase as opposed to a vapour phase which would require a considerably larger diameter pipeline.

Impurities can have a significant effect on temperature and pressure conditions but also on density and viscosity of fluids. Some combinations can cause higher pressure and temperature drops for a given length of pipeline. Sudden temperature drops can cause embrittlement and/or hydrate formation both of which can damage pipelines. Some contaminants, or combinations, have specific effects relative to a CO_2 stream and its transport or end use. Examples include:

- N_2, CH_4 and H_2 all have lower critical temperatures than CO_2 which would lead to increased pipe strength to minimise ductile potential.

- Noncondensables like N_2, O_2, Ar, CH_4 and H_2 should be limited to <4% because their presence increases the amount of compression work.
- The concentration of O_2 in CO_2 should be limited to eliminate the potential for exothermic reactions with hydrocarbons in CO_2-EOR operations. N_2, H_2 and CH_4 increase the miscibility pressure during CO_2-EOR activities and should be limited.

The most significant effect on transport and injection of CO_2 is the water content. The formation of carbonic acid can corrode a pipeline at a rate of 1-2mm within 2 weeks. Supercritical CO_2 can store several hundred Parts per million (ppm) of water depending on its temperature which can lead to the formation of hydrates that can cause obstructive plugs. Pressure and temperature conditions within a pipe caused by variable flow conditions can have a substantial effect on corrosion and hydrate formation. However, pressure control systems are designed and operated to ensure operating conditions avoid deleterious effects. The topographic variability over the course of a pipeline route can lead to low spots where two-phase flow can occur leading to the pooling of the supercritical phase. Two-phase flow seems more likely to occur when the pipe is oversized relative to the amount of CO_2 that is transported. Another condition that should be avoided is rapid pressure oscillations which can lead to cavitation (the formation of vapour cavities or voids in a liquid caused by rapid pressure changes where the pressure is relatively low. When voids are then subjected to higher pressure, they can implode and cause intense shockwaves).

Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.

CO_2 pipeline design needs to take account of the source and sink or destination of the CO_2. This investigation has revealed that most CO_2 pipelines currently in existence in North America are overdesigned for their current application. They are designed for higher flow rates and operating pressures through the use of thicker walls and larger diameters. For example, the Denbury Greencore Pipeline began operation with a capacity of 0.96 M tonnes / year but was designed to carry up to 13.9 M tonnes /year. The additional pipeline

dimension enables the company to expand its network's carrying capacity.

CO_2 pipeline networks and hubs can be controlled so that the supply and demand of CO_2 can be regulated. Temporary storage can be achieved by increasing the gas pressure and loading more gas into a pipeline a process known as pipeline packing. This procedure is more effective at lower pressure. For example, the capacity of supercritical CO_2 packed into a 320 km 600mm diameter pipeline could be increased by almost 8,300 tonnes if the pressure was raised from 8.4 MPa to 10.4 MPa. Increasing the pressure from 16.0 MPa to 18.8MPa would only increase capacity by 2,900 tonnes. The other advantage of a network system is that several sources can be accessed so that reliance does not depend on a single or limited supply option.

The largest CO_2 hub in the world is the Denver City hub in eastern Texas. It distributes CO_2 from the 808 km Cortez Pipeline which has a capacity of 30.4 Mm^3/d and a planned expansion to 56 Mm3/d (61.125 ktonnes day). Other hubs are established in Texas (McCarney) and Rotterdam in the Netherlands. The UK is planning to develop a Central North Sea CCS hub to transport CO_2 from large power plants and other industrial point sources in the Yorkshire and Humber regions of the country. A government-industry partnership in Western Australia is also planning a network, the Collie-South West CO_2 Geosequestration Hub.

Networks can be a useful means to control flow in a pipeline. They can also act as a buffer by supplying CO_2 from several sources to a number of different sinks. Multiple sources also mean that there is less reliance on a single source and intermittent supply can be accommodated. Viable pressure and flow conditions in pipelines can be controlled by remote terminal units (RTUs) that communicate with sensors and actuators as well as Supervisory Control and Data Acquisition (SCADA) systems. SCADA systems co-ordinate responses to variable flow conditions by transmitting command signals to RTUs. This form of control can also estimate the physical state of a fluid and therefore minimise pressure drops. SCADAs are used to estimate the volume of CO_2 that can be accepted or delivered before the pressure limits are exceed. Leaks, ruptures or other losses can also be detected.

The impact of intermittent flow on storage related to CO_2-EOR, depleted oil and gas reservoirs and deep saline formations was also investigated. CO_2-

EOR relies on controlling pressure and flow rate conditions that optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions attendant drops in oil production could occur and in some circumstances the precipitation of minerals or asphaltenes or changes in formation fluid saturation properties could also occur. The reservoir permeability could be reduced as a result. This investigation found that experienced operators can plan for intermittency and use strategies such as water injection and pipeline packing to manage impacts. CO_2-EOR projects are designed with a safety margin on both pressure and capacity that is significantly above operation pressure. These schemes are also designed for additional CO_2 capacity and include recycled CO_2. Intermittency can be mitigated with the use of recycled CO_2. However, if wells are shut in the value of lost oil production can range from tens of thousands to millions of dollars a day in lost production depending on the size of the field.

Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects. The Joule-Thomson effects caused by pressure-drop can also lead to freeze-up of valves and joints. The use of standard oil and gas industry protocols can limit the impact of intermittent operation.

CO_2 storage into deep saline formations can also be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry. Potential deleterious impacts such as fatigue and corrosion are most likely to be caused by mixed gas streams such as CO_2 and H_2S. The presence of acidic gases can lead to the reduction in pH of formation fluids causing dissolution of minerals. Although acification and dissolution might increase prorosity, secondary precipitation of minerals can also reduce porosity and permeability. Sudden pressure drops can lead to extreme freeze-up causing values to cease up. Standard reservoir mangement and contingency plans should avoid such complications. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of monoethylene glycol.

Expert Review Comments

- The report provides a good reference source for existing projects such as Sleipner. It has useful references and gives excellent details of industrial process variability. It also provides notable insights and identifies gaps in knowledge and challenges.
- The origin of some data is unclear. The authors have had to comply real-world data without revealing either specific sources or companies because of commercially sensitive information. This is particularly evident when the well-known large-scale demonstration projects are compared to the widespread CO_2-EOR operations in the United States.
- Much of the anecdotal information is concentrated on experience in the United States especially pipeline operation and CO_2-EOR. This is because the vast majority of CO_2-EOR operations take place there.
- There may be limits to onshore CO_2-EOR operations that can be transferred offshore. The authors did summarise the lessons learned from offshore projects. Some of the experience of onshore CO_2 pipeline operation can be transferred offshore.
- None of the five named projects is an example of anthropogenic CO_2 and therefore these are not exemplars of variable flow used in a storage operation. There is a lack of real-world data directly linking an anthropogenic source to a sink. However, the report comments on trends that have been inferred from variable power generation.
- Experiences related to a depleted gas field do not apply to deep saline formations. This assertion was disputed by the authors who highlighted the broad spectrum of studies that support the relevance of and applicability of CO_2 storage into both types of reservoir.
- Updated information on the UK's proposed Yorkshire and Humber network has been included.
- More detail has been provided on how intermittency is treated during CO_2-EOR operations.

Conclusions

- Approximately 28% of global CO_2 emissions come from coal-fired power plants. After scrubbing and dehydration relatively pure 99.7% CO_2 can be achieved. Investigations carried out by this study revealed that CO_2 concentrations in the flue gas were fairly constant across the load range varying from 10% to 12%.
- Capture technology can produce comparatively pure CO_2 from cement plants but they are often operate intermittently consequently their integration into a CO_2 supply network would be challenging.
- Petroleum refineries can individually produce substantial volumes of CO_2, but from several different processes. CO_2 purities of 95% to 99% are feasible. Two refineries, the Pernis refinery in Rotterdam and Valero's refinery in Port Arthur Texas, have CO_2 capture facilities from hydrogen production unit syngas streams that delivered CO_2 to pipeline networks.
- Impurities can have negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. However, compression and transport of CO_2 for CO_2-EOR use in the United States has shown that impurities are not likely to cause transport problems provided CO_2 stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).
- Impurities can have a significant effect on temperature and pressure conditions and also on the density and viscosity of fluids. Sudden temperature drops can cause embrittlement and/or hydrate formation both of which can damage pipelines. However, pressure control systems are designed and operated to ensure operating conditions avoid deleterious effects.
- The most significant effect on transport and injection of CO_2 is the water content. The formation of carbonic acid can corrode a pipeline at a rate of 1-2mm within 2 weeks. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of monoethylene glycol.

- Sudden pressure drops can also lead to extreme freeze-up causing values to cease up. Standard reservoir mangement and contingency plans should avoid such complications.
- Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.
- CO_2-EOR relies on controlling pressure and flow rate conditions to optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions attendant drops in oil production could occur and in some circumstances the precipitation of minerals or asphaltenes or changes in formation fluid saturation properties could occur. Reservoir permeability can be reduced as a result. This investigation found that experienced operators can plan for intermittency and use strategies such as water injection and pipeline packing to manage impacts.
- Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects.
- CO_2 storage into deep saline formations can be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry.

Knowledge Gaps

The following gaps in knowledge and proposed topics for future research and development were identified by this study. The topics are arranged in order of priority.

- Experimental research is needed to validate model predictions, particularly the behaviour of CO_2 containing impurities during transport. More experience is required to understand the nature of the CO_2 flow, the range of slug speeds and induced stresses on pipelines.
- A better understanding of the fundamental properties of CO_2 mixtures with impurities and their impact on operation and costs is required for

pipeline transport, injection and storage.

- Improve the accuracy of predicted thermodynamic and transport properties over a range of compositions and conditions of fluid transported in pipelines.
- There is a need for a recommended practice or guideline on transmission of supercritical CO_2 that incorporates all of the industry guidelines and standards. The aim of this initiative is to ensure that all pipelines will meet safety standards.
- Models need to be accurate over a wide range of CO_2 compositions pertinent to CCS. Equally accurate experimental data will be necessary to validate property models.
- The response of intermittent flow to different types of reservoir needs to be understood.
- There is a need for an improved understanding of heat-transfer characteristics of CO_2 pipelines in different media such as sea water, gravel, clay and when ice-covered.
- There is a need for accurate prediction of:
    - Multiphase properties as well as of solid CO_2 and hydrate formation.
    - Improved modelling of captured CO_2 fluid wave-propagation, flow-regime and component-tracking between phases.
    - Noise generation and atmospheric dispersion prediction.
    - Metal crack propagation behaviour.
- Experimental validation of custom and commercial software-based depressurization models (such as OLGA) would enable their application to real-world scenarios with confidence.
- Publically accessible accurate capital and operating cost information especially for CO_2 from variable anthropogenic sources.

Recommendations

- IEAGHG could consider undertaking study of the fundamental properties of CO_2 mixtures with impurities and their impact on operation particularly costs for pipeline transport, injection and storage, if no other study or reference sources exists.

- IEAGHG could consider co-ordinating a workshop, to define the experimental research and model validation that is needed to predict the behaviour of CO_2 containing variable concentrations of impurities during transport.
- IEAGHG could consider a future study to review to collate operational experience of CO_2 flow in pipelines over a range of slug speeds and induced stresses.

2016-05 CAN CO_2 CAPTURE AND STORAGE UNLOCK 'UNBURNABLE CARBON'?

Key Messages

- The global 'carbon budget' in emission scenarios for climate change mitigation implies that a certain amount of fossil fuel reserves should not be used and their resulting greenhouse gases emitted to atmosphere. This concept is often referred to as 'unburnable carbon'.
- As CCS is a technology that prevents or reduces the emissions of CO_2 to the atmosphere, it has the potential to enable use of fossil fuels in carbon-constrained scenarios.
- In order to evaluate the potentially unburnable carbon of fossil fuel reserves, it is necessary to estimate the overall remaining fossil fuel reserves and compare them with the global carbon budget.
- Integrated assessment models (IAMs) are a good means to evaluate carbon budgets as they have a large coverage of technologies, geographical scope, economics and climate data. These models are widely used in publications of the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA) and academia, and most of them cannot achieve a 2°C or lower scenario without CCS. This report selects and investigates a subset of models that focus on technology options and include CCS.
- This study does not aim to assess or provide evidence of the 'unburnable carbon' concept but rather to look at the role of CCS technologies in this regard. It will assess the assumptions, methodologies, any contentious subjects and differences related to this topic.
- This study found that the impact of CCS on unburnable carbon appears to be material up to 2050 and further increases up to 2100. This applies especially to coal but also to gas to some extent.
- Model assumptions and cost data availability do generally not limit uptake of CCS in IAMs. However, other reasons seem to limit CCS uptake in models, and the authors of this report hypothesise it could be that residual emissions from CCS, for which CO_2 capture rates of 85-90% are

usually assumed, are the reason. It is recommended to investigate this further and to give consideration in R,D&D to increasing capture rates.

- Uncertainties in IAMs and fossil reserve estimates can influence the total amount of carbon considered as unburnable.
- The authors review estimates of global CO_2 geological storage capacity, and find that estimates obtained from volumetric approaches are large and well above the extent of the CO_2 emissions related to fossil fuel reserves.
- Storage capacity estimates from dynamic approaches are likely to be lower, and hence further work on improving dynamic storage efficiency, such as pressure management by brine extraction, is required.
- The related additional costs for pressure and brine management should be considered in IAMs.

Background to the Study

'Unburnable carbon' refers to fossil fuel reserves that cannot be used and the resulting greenhouse gases emitted if the world has a limited carbon budget i.e. they would become 'stranded assets'.

This situation leads to the question: what role does technology have in addressing these concepts and concerns? This study does not aim to assess or provide evidence of the 'unburnable carbon' concept but rather to look at the role of CCS technologies in such concepts. This report will also not evaluate other approaches to reduce CO_2 emissions from fossil fuel use besides CCS, such as high efficiency low emission (HELE).

Organisations such as Carbon Tracker Initiative (CTI), the Smith School Stranded Assets Programme (Oxford University) and University College London (UCL) have recently produced papers on these topics. These include assessments of the role of CCS that suggest CCS will have an insignificant impact on the amount of the world's fossil fuel resources that can be utilised in a 2°C climate scenario. Some of these reports view CCS from a resource-limited perspective, for example taking conservative views of the amount of CO_2 storage capacity available and on availability of CCS before 2050.

The International Energy Agency (IEA) has been mentioning the role for CCS

in this concept for a couple of years: "CCS therefore promises to preserve the economic value of fossil fuel reserves and the associated infrastructure in a world undertaking the strong actions necessary to mitigate climate change." In addition, the recent 5th Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC) mentions that the availability of CCS would reduce the adverse effects of mitigation policies on the value of fossil fuel assets.

Scope of Work

This study has undertaken an initial assessment on the relevance of CCS in terms of the unburnable carbon issues. This consisted of the following tasks:

1. Undertake a comprehensive literature review to identify and assess those studies done to date which are relevant to, include or comment upon the role of CCS in the issues of unburnable carbon.
2. Assess the assumptions, methodologies, any contentious subjects, and understand differences in these studies.
3. Identify and assess sources of information on the global potential for CCS deployment, including storage potential.
4. Potential issues that would contribute to better understanding and assessment of this topic (which are of a technical nature and thus IEAGHG could address), will be identified and recommendations made for further work, including whether any work is necessary relating to global storage capacity and CCS global potential.

Unburnable Carbon and CCS

Global greenhouse gas (GHG) budgets and fossil fuel reserves

Several studies have estimated global carbon and greenhouse gas (GHG) budgets, such as by the Potsdam Institute for Climate Impact Research, the University of Oxford and the IPCC. Each study also gives the probability of exceeding a global temperature increase of 2°C. Some studies consider CO_2 only, whereas others include the full range of GHGs under the Kyoto Protocol (i.e. CO_2, CH_4, N_2O, HFCs, PFCs, SF6). The timeframe is usually 2000 to 2050 but one study reports the carbon budget for the period 1750 to 2500. Carbon budgets usually include fossil sources as well as land use change. Figure 1 summarises the results.

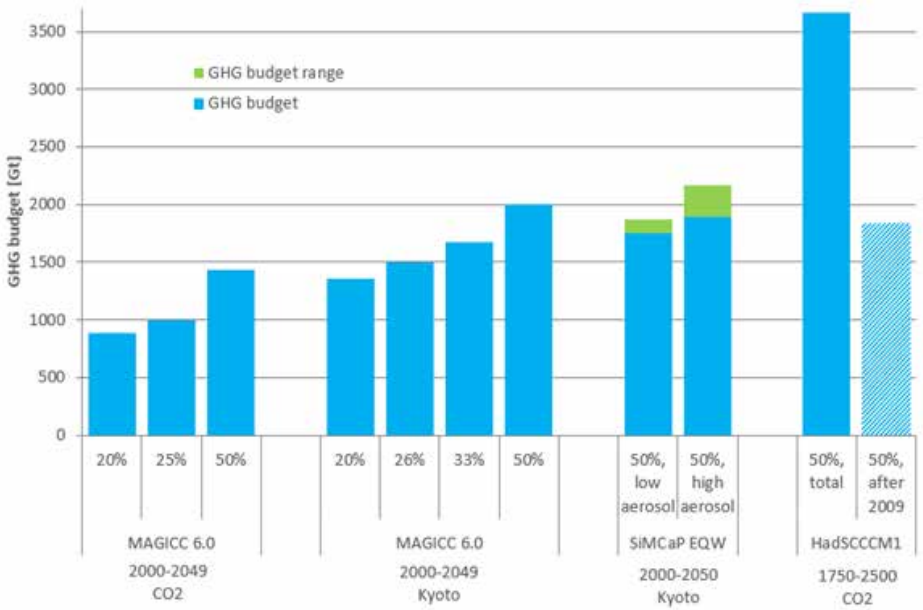


Figure 1. Global emissions budgets from different models for 2000-2050 timeframe for either CO_2 or all Kyoto gases. HadSCCCM1 timeframe is 1750-2500. % = chance of exceeding 2°C scenario.

The study using MAGICC 6.0 by Meinshausen et al. 2009 further estimates that non-CO_2 GHGs contribute up to 33% to overall emissions. Allen et al. calculated a total carbon budget between 1750 and 2500 of 3670 $GtCO_2$. It is important to note that we have already used up around half of this budget from 1750 to 2009, leaving less than 1800 $GtCO_2$ for the future. The IPCC and CTI both assessed available literature and data on carbon budgets and arrive at a best estimate of around 960-975 $GtCO_2$ until 2100 (with a 68-80% probability).

The results from those studies on carbon budgets of course contain several sources of uncertainty, such as the level of climate sensitivity, carbon cycle feedbacks, aerosol emissions and unmodelled processes. IPCC and CTI also point out that the remaining carbon budget after 2050 will be only in the region of 7-10% of the total budget. The future global carbon budget erodes quickly at currently approximately 40 $GtCO_2$/yr, underlining the importance of timely action on climate change mitigation.

In order to evaluate the potentially unburnable carbon of fossil fuel reserves, it is necessary to estimate the overall remaining fossil fuel reserves and compare them with the global carbon budget. However, determining global fossil fuel reserves is a function of price that is subject to significant volatility and different methods exist. Thus, the resulting estimates can vary and contain different levels of uncertainty. This will also be influenced by whether reporting standards and best practices are used, e.g. coal reserves are often reported under the Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves (JORC Code). Figure 2 contains data on overall reserves as well as burnable and unburnable carbon. Most of the selected studies agree on fossil fuel reserves of around 2800 $GtCO_2$ leading up to 2050, with the most recent study reporting a significantly higher amount of 3613 $GtCO_2$. However, they report different shares of unburnable carbon, ranging from 49-80%, translating into a range of 1360-2565 $GtCO_2$. IEA assessments on global carbon reserves further reveal that usually coal contributes around 63%, oil 22% and gas 15% to these carbon reserves.

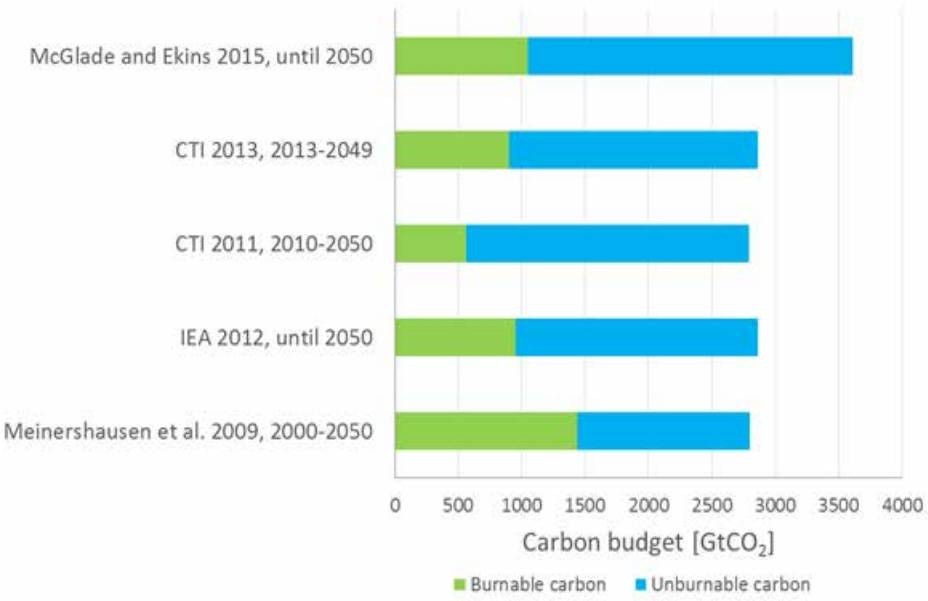


Figure 2 Burnable and unburnable carbon of fossil fuel reserve estimates

Recent assessments on CCS' effect on unburnable carbon

As CCS is a technology that prevents or reduces the emissions of CO_2 to the atmosphere, it has the potential to enable continued use of fossil fuels in carbon-constrained scenarios. Many studies have analysed the role of CCS in future energy scenarios, however only a small number in the context of unburnable carbon. Sources that have explicitly included this issue are:

- CTI
- Institute for Sustainable Resources (UCL)
- IPCC

CTI concludes that CCS would increase the percentage of burnable fossil fuel reserves in the power sector. Their most recent analysis estimates fossil fuel reserves to be 2860 $GtCO_2$ and that almost 70% of these reserves are unburnable. Applying CCS as in IEA's 2°C scenario could extend the carbon budget by around 14%, i.e. 125 $GtCO_2$ but would require nearly 3800 CCS projects operating by 2050 and full investment in the technology.

A study by McGlade and Ekins (UCL) found CCS had the largest effect of any technology on cumulative fossil fuel production levels. However, overall the effect is modest, allowing for an increase in oil use by 1%, in gas use by 3% and in coal use by 7% until 2050. According to the authors, reasons for the limitation of the amount of burnable carbon that CCS can unlock are maximum rate of construction, delayed implementation and costs.

Current projections of biomass in combination with CCS (Bio-CCS or BECCS) estimate a potential of this negative emissions technology (NET) of up to 10 GtCO2/yr by 2050. This would translate to an extension of the carbon budget of ~1%. Potential of Bio-CCS in the longer term could be more significant but its estimation is subject to high uncertainties at present.

Integrated Assessment Models (IAMs)

IAMs are a good means to analyse unburnable carbon, as they have a large coverage of technology options and geographical scope, as well as economic and climate data. To understand the role CCS plays in the context of unburnable carbon better it is important to determine the factors that potentially limit its rollout in IAMs. Several studies in the literature have

reported the following limitations so far:

- Costs
- Energy penalty
- Locations
- Storage capacity
- Water availability
- Regulatory environment
- Project development timeframes across the CCS chain

As some studies named limitations related to storage capacity as potential major challenges, this work will undertake a further investigation of this topic in the next chapter.

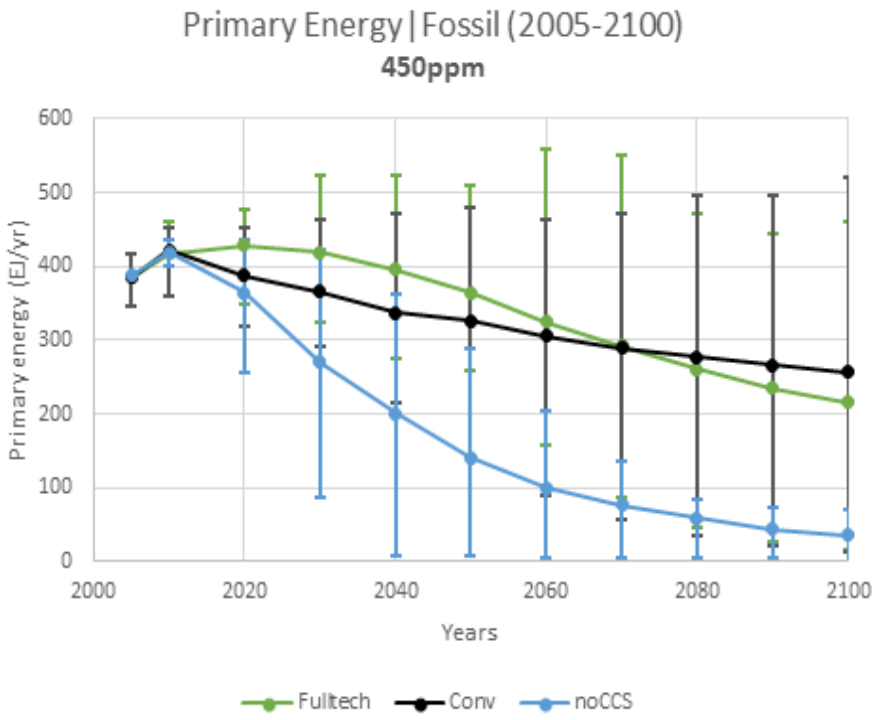
Case study: Energy Modelling Forum (EMF27)

The scenario database of IPCC's AR5 includes 31 different models and a total of 1184 scenarios, which all have to meet certain criteria (i.e. peer-reviewed publication, minimum set of variables, full energy representation and at least a 2030 time horizon). Several model inter-comparison exercises exist, one of which is the Energy Modelling Forum (EMF) at Stanford University. EMF27 compares 18 different IAMs, covering different equilibrium concepts, solution dynamics, time horizons, land use sector representations and GHGs. EMF27 was chosen over other modelling comparison exercises due to its focus on technology and representation of CCS in the models. In addition, EMF27 figures prominently in the IPCC's 5th Assessment Report. The assessment of the role of CCS uses the following three technology scenarios:

- Fulltech: Full portfolio of technologies available and future scale-up possible
- Conv: Solar and wind limited to 20%, biomass limited to 100 EJ/yr and non-traditional biomass
- noCCS: CCS excluded from technology portfolio in all sectors

More information about the models, scenarios and assumptions is available in the main report and the cited literature.

The climate mitigation scenarios are either a 450 or 550 ppm target for atmospheric CO_2 concentration and the analysis focusses on the models that can produce a 2100 timeframe. Many models do not include a limitation of storage rate and/or capacity. Almost all model scenarios with full technology availability deploy CCS at significant scale and only four models could achieve a 450 ppm target without CCS. This highlights the importance of CCS in adhering to the 2°C scenario by providing flexibility and the scope for negative emissions through bio-CCS. However, it is important to note that not all models were able to give an output for specific scenarios, likely due to a lack of either technical or economic feasibility. Kriegler et al. 2014 provide a detailed review of the EMF27, including technical and economic uncertainties/feasibilities of the models.



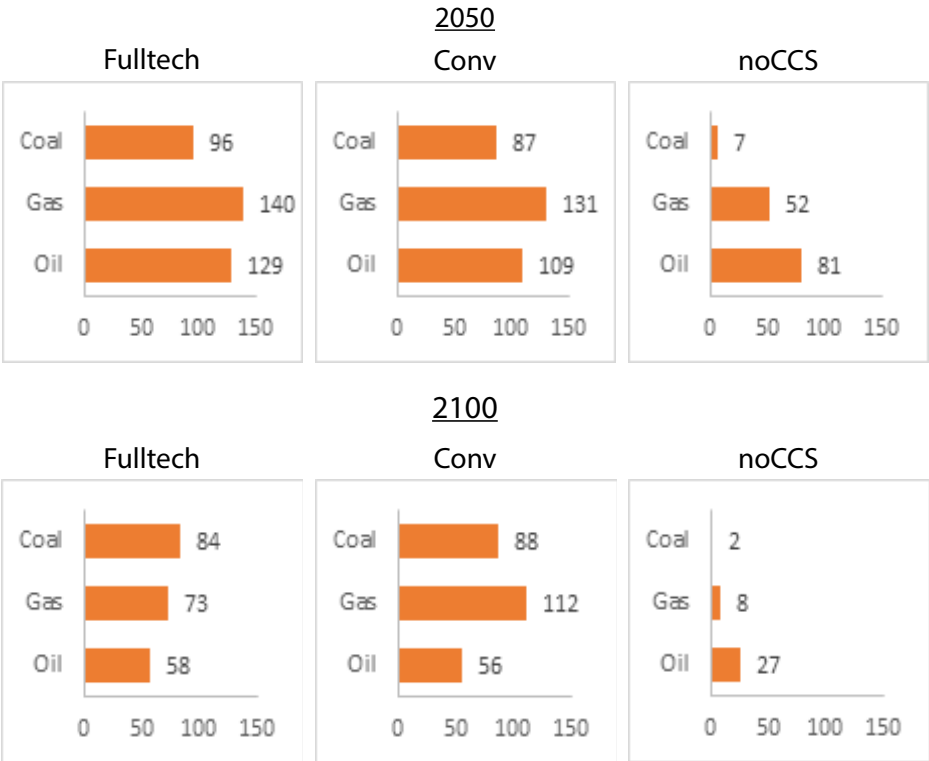


Figure 3 Primary energy from fossil fuels and fuel type shares in 2050 and 2100

Figure 3 shows the fossil fuel usage for the three scenarios for a 450 ppm target and presents the shares for each fossil fuel in 2050 and 2100. A key message is that the utilisation of fossil fuels decreases in all scenarios over time. From 2030, the availability of CCS has significant impact on the continued use of fossil fuels, especially for coal but also for gas to some extent. However, it is important to note that the range of outcomes from the different models is large (see error bars in Figure 3).

Koelbl et al. 2014 reviewed the EMF27 exercise as well and pointed out the main reasons for variations in the model results with respect to CCS:

- Fuel prices
- Baseline emissions
- Model type
- Representation of technology change
- Representation of CCS

The authors suggest further research into this area, as they could not clearly associate a specific model assumption with the amount of CO_2 captured. They did not cite any limits on uptake of technologies and further personal communications of the contractor with the relevant modellers confirmed that any such limits were likely to be non-binding, particularly in later model years. Thus, this report hypothesises that the constraint on CCS is not cost or supply chain related. One possibility is that the residual emissions from CCS could make it an unfavourable option in climate change mitigation scenarios. Even such low levels of emissions could be sufficiently high to conflict with extremely constrained global carbon budgets. Testing of this hypothesis is outside the scope of this report but could be investigated in future work.

Figure 4 (next page) summarises the role CCS can play in unlocking unburnable carbon for the timeframes from 2005 to 2050 and 2100. Especially in the longer term, CCS could enable access to significant amount of fossil fuels, i.e. under a 2°C scenario 65% of reserves could be consumed, compared to only 33% without CCS technologies.

Status of CO_2 storage potential

Global potential

Current efforts assessing CO_2 storage resources use evaluation methods that fall into two general categories, i.e. static or dynamic. Static techniques use a product of the total pore volume available in a given storage site, region, etc. with an efficiency that can take into account a number of variables, and form the basis for most national storage assessment. More recently, static estimates incorporating impacts of pressure build-up have become available. Dynamic methods encompass those techniques that model the

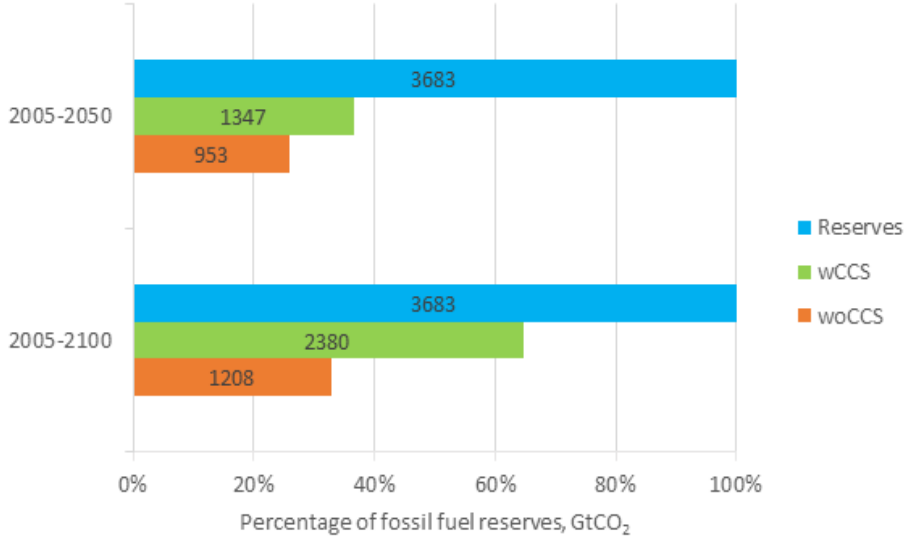


Figure 4 Cumulative fossil fuel consumption in a 2°C scenario with and without CCS. Reserves estimates from McCollum et al. 2014.

time-transient movement of CO_2 injected into a storage site. They provide time-varying resource estimates, accounting for the limitations that pressure build-up and dissipation in the reservoir will place on allowable injection rates. They also provide the most realistic estimates of a true storage capacity, while demanding more information about the storage site than is generally required by the volumetric evaluations. Unlike the static techniques, there is no standard procedure for producing a dynamic estimate. In general, static estimates incorporating pressure constraints are systematically lower than volumetric estimates ignoring limitations imposed by pressure build-up. Former IEAGHG work also estimates that static pressure limited estimates are at least an order of magnitude lower than volumetric capacity estimates. This suggests that useful capacity estimates cannot readily be derived from volumetric estimates, i.e. volumetric estimates cannot be appropriately corrected for pressurization effects. In general, it appears that dynamic simulation, whether using reservoir simulation or a simpler model, even at the regional scale, should be applied for a realistic assessment of the storage resource availability on the decadal timescale. Engineering strategies for

pressure management, and particularly the production of brine from the reservoir, are effective at mitigating the impact of local and regional pressurization. A pressure management strategy using brine production wells will have a noteworthy impact on the overall cost of CO_2 storage. Costs will include further reservoir characterization needed to choose the placement of wells, the construction of the wells, and the management of the produced water. The technology for pressure management and handling produced water is mature and information for producing cost estimates for use in techno-economic models of CCS, or IAMs that use CCS should be readily available. The extent to which pressure management will be required to reach near term storage injection targets, however, will not be clear until more national and regional scale assessments of storage capacity using dynamic modelling are performed.

Geographical distribution

Studies covering international regions using a consistent assessment methodology have thus far employed volumetric estimates of capacity, and have only been performed for North America and OECD Europe. The global resource availability estimate ranges from 5,000 to 33,000 $GtCO_2$. Figure 5 summarises the regional breakdown from these compilations. For oil and gas fields, capacity ranges 1-2 orders of magnitude lower than the total storage capacity, i.e. between 400 and 1000 $GtCO_2$. In some regions, particularly in the Middle East, capacity in oil and gas fields is a majority of the total capacity, as the regional breakdown in Figure 6 shows.

Limitations to CCS deployment

The previous section implies that sufficient storage capacity is available for CCS. There will likely be no significant storage capacity limits for the first generation of CCS deployment, as oil and gas fields could meet all demand. However, the estimates are mostly volumetric, and thus the extent to which pressure and brine management strategies are necessary is the major uncertainty in this context. In conclusion, IAMs should consider the additional costs for such methods.

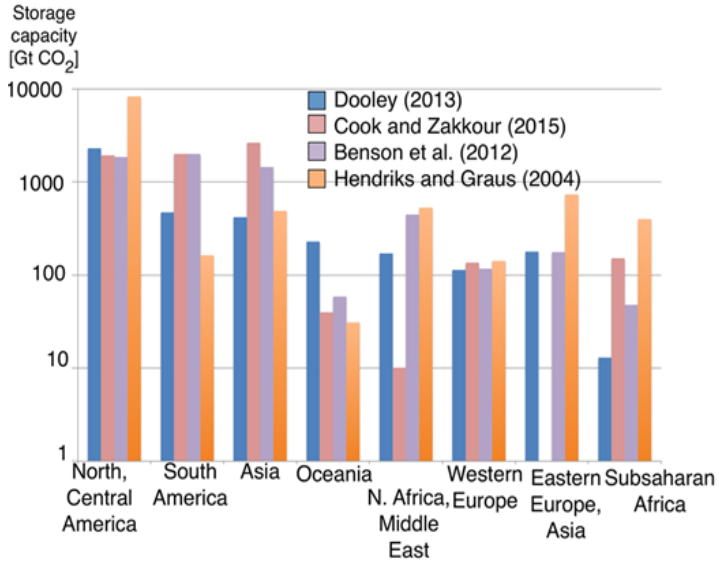


Figure 5 Regional CO_2 storage capacity estimates

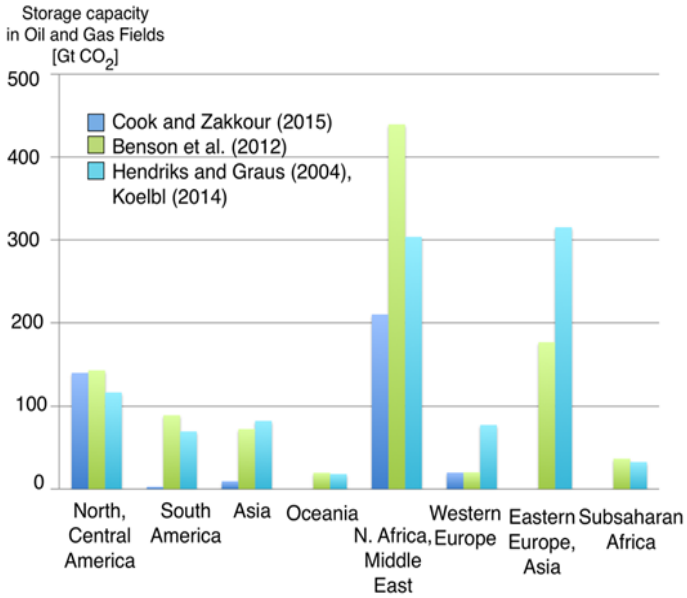


Figure 6 Regional CO_2 storage capacity estimates in oil and gas fields

Expert Review Comments

Seven experts from different backgrounds (academia, industry and NGOs) reviewed the report. Most reviewers commented the report was well written, timely and would be a useful resource. Some of the more specific comments, which the authors addressed in the final version, included a better comparability/consistency of number in EJ and $GtCO_2$, improvement of the graphical presentation of the results and making the conclusions clearer and more accessible. Requests for testing the hypothesis of residual emissions and for resolving the debate around fossil fuel reserves and resources estimates are outside the scope of this work and have not been addressed. A few reviewers disagreed with the numbers presented for CO_2 storage and Bio-CCS potential. However, the authors and IEAGHG consider them reasonable and sufficiently backed up by literature.

Conclusions

A number of recent studies have reviewed the unburnable carbon topic. These have broadly reached the same conclusion: that some portion of fossil fuel reserves is unburnable in scenarios where global temperature rise must be less than 2°C. A few studies explicitly considered the impact of CCS on unburnable carbon and found a modest impact of CCS on the amount of reserves that are burnable. However, none of these studies focused on the potential of CCS, or questioned why results indicated a less prominent role for the technology than might otherwise be expected.

In order to fill this gap, this study undertook an EMF27 multi-model comparison, which produced a set of scenarios of energy system change to mitigate climate change. Analysis of results confirms that CCS availability has a large impact on the extent of fossil fuel consumption in climate-constrained scenarios, as scenarios with CCS lead to a fossil fuel use that is ~200EJ/yr higher. A key difference between this study and previous efforts is that the dynamics of CCS uptake were considered herein, with the observation that CCS adoption is still ramping up at 2050 (previous studies limited the time horizon of consideration to 2050).

Based on the evidence available from EMF27 models, there are few limiting assumptions made on the availability of CCS. Almost all models reviewed

had no capacity or uptake-rate limits for the transport and storage phases of CCS. While less evidence was available for the capture phase, it is unlikely that such constraints are preventing uptake substantially, particularly later in the time horizon (i.e. 2040 onwards).

In addition, the cost of CCS technology in the models does not appear to be a significant barrier. Therefore, if CCS is available (and not unfavourable for other reasons) further adoption should be observed in the models. One explanation that such adoption does not occur is that there are other factors in the models preventing uptake, e.g. the residual emissions from CCS installations. Though small, they could be significant enough to prevent further technology deployment. However, testing this hypothesis is outside the scope of this work.

CO_2 geological storage capacity is large from a volumetric standpoint, i.e. the pore space available is sufficient to accommodate CO_2 from all fossil fuel reserves in virtually any scenario. However, reservoir pressurisation and uncertainties in volumetric estimates could significantly limit storage capacity. Pressure and brine management strategies would be necessary to alleviate this issue and the impact on costs and deployment requires further assessment and inclusions in IAMs. This constraint is probably not binding in the short to medium term, as adequate storage capacity is available in depleted oil and gas fields, and in higher quality saline aquifers.

IEAGHG is aware of the different opinions that exist on the concepts around unburnable carbon. This study did not attempt to provide a full analysis of these concepts. The report started out with the assumption that the unburnable carbon hypothesis does exist and subsequently evaluated the role CCS could have in enabling continued access to fossil fuel reserves under different climate change mitigation scenarios. Other means of reducing CO_2 emissions from the use of fossil fuels, e.g. HELE for coal-fired power plants, were not part of this study.

Recommendations

Recommendations for future work on the topic include:

- Testing of the hypothesis that residual emissions from CO_2 capture can limit uptake of CCS in IAMs, and if so then increased R,D&D on improving capture rates is necessary.
- More work on dynamic estimates of global CO_2 storage capacity.
- Work on improving dynamic storage efficiency through pressure management and other techniques.
- Inclusion of pressure and brine management strategies and their costs in IAMs.

A forthcoming SGI White Paper will looked at some of the issues identified in this study in more detail.

evaluate technology options to mitigate greenhouse gas emissions

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