Carbon Storage Opportunities in the North Sea

24-25 March 2010

The Petroleum Group would like to thank Badley Geoscience and IHS for their support of this event:

BADLEY GEOSCIENCE LIMITED

The Source
for Critical Information and Insight™

Sponsors of the **CO2 Subsurface modelling** sessions

CONTENTS PAGE

PROGRAMME

Wednesday 24 March

09.00	**Registration and Coffee**
	Session One: Creating the Right Investment Environment: Defensible and Accurate Geological Storage Capacity Estimates and Leakage Monitoring Capabilities Part I
09.30	**KEYNOTE: Mike Stephenson** Role of the Geological Survey in CCS
10.00	**Ben Hedley** Regional Characterisation and Assessment of UK North Sea Sub-salt Saline Aquifers for Geological Sequestration of CO_2
10.25	**Bert van der Meer** Subsurface CO_2 Storage Capacity Calculations
10.50	**Coffee and Poster Session**
11.15	**Sveinung Hagen** Exploration for CO_2 Storage Sites in the Norwegian Sector of the North Sea Basin
11.40	**Amy Clarke** Geological Characterisation of the Hewett Field for CO_2 Storage
12.05	**Cliff Lovelock** Assessing Subsurface Risk in Re-Using an Offshore Depleted Hydrocarbon Field for CCS
12.30	**Lunch and Poster Session**
IHS	**Session Two: CO_2 Subsurface Modelling, Long Term Fate and Storage Security in Reservoirs Part I**
13.30	**Graham Yielding** Fault Seal Analysis for CO_2 Storage – An Example From the Troll Area, Norwegian Continental Shelf
13.55	**Joe Cartwright** Quantifying Seal Risk for CCS: The Impact of Seal Bypass Systems
14.20	**Mike Carr** A New Method to Predict and Quantify the Effects of CO_2 Injection Into Subsurface Formations
14.45	**Coffee and Poster Session**
	Session Three: North Sea Opportunity: Government Legal and Regulatory Framework
15.15	**KEYNOTE: Stuart Haszeldine** Carbon Capture and Storage: Geoscience Opportunities for the UK
15.45	**David Rutland** CCS UK Government View
16.10	**Ian Havercroft** Legal Aspects of Carbon Capture and Storage
16.35	**Wine Reception**

Thursday 25 March

09.00	**Registration and Coffee**
	Session Four: Creating the Right Investment Environment: Defensible and Accurate Geological Storage Estimates and Leakage Monitoring Capabilities Part II
09.30	**KEYNOTE: Jaap Breunese** CO_2 Storage in Depleted Gas Fields – The Netherlands Offshore Case
10.00	**Niklas Heinemann** CO_2 Storage Capacity in the Bunter Sandstone Limited by Local Pressure Development, UK Southern North Sea
10.25	**Martyn Quinn** Identification and Characterisation of a Potential CO_2 Storage Site, UK North Sea
10.50	**Coffee and Poster Session**
11.20	**KEYNOTE: Ramon Trevino** Gulf of Mexico Offshore Geosequestration: Status and Future.
11.50	**Stuart Haszeldine** Size-Distribution of CO_2 Storage Units, Limited by Overpressure, in the Pre-Cenozoic of the Central and Northern North Sea.
12.15	**Graham Yielding** Role of Stratigraphic Juxtaposition for Seal Integrity in Proven CO_2 Fault Traps of the Southern North Sea
12.40	**Lunch and Poster Session**
	Session Five: CO_2 Subsurface Modelling, Long Term Fate and Storage Security in Reservoirs
13.40	**Grace Cairns** Geological Factors Influencing Time Lapse Seismic Monitoring of Subsurface CO_2 Storage
14.05	**Gareth Williams** Mapping CO_2 Layer Thickness in a Growing Plume at Sleipner, North Sea, Using Quantitative Seismic Interpretation
14.30	**John Grocott** Application of Structure Validation and Kinematic Modelling in Building a Discrete Fracture Network (DFN) for a Salt-Bounded Dolomitic Limestone Reservoir Unit.
14.55	**Coffee and Posters**
15.25	**Min Jin** Optimisation of CO_2 Storage in the North Sea Aquifer
15.50	**Grant Nicoll** Could CO_2 Storage Site Performance be Compromised by Palaeo-Gas Migration Conduits in the Overburden?
16.15	**Andy Chadwick** Time–lapse Seismic monitoring at Sleipner Provides Insights Into Storage Reservoir Performance
16.40	**Panel Discussion**
17.40	**Conference Ends**

POSTER PROGRAMME
Nicklas Heinemann The Impact of Simulated Mutual Dissolution of CO_2 and Water on the Short Term Pressure Build-Up During CO_2 Injection
Jennifer Roberts To Leak or Not to Leak? Investigating the Plumbing of CO_2 Fluids in Central Italy
John Ove Thorsplass Exploration for CO_2 Storage Sites in the Norwegian Sector of the North Sea Basin
Angus Best Upscaling of Joint Elastic-Electrical Properties of Reservoir Rocks
Michelle Ellis The Potential of Controlled Source Electromagnetic Surveying in CO_2 Storage Monitoring

Oral Presentation Abstracts

(in presentation order)

Wednesday 24 March

Session One: Creating the Right Investment Environment

Part One

KEYNOTE SPEAKER: Carbon Capture and Storage – The Role of the Geological Survey

M. Stephenson, *British Geological Survey, Keyworth, Nottingham, NG12 5GG*

In countries which rely heavily on coal to generate electricity, carbon capture and storage (CCS) could be a vital technology to allow them to continue to grow, but also to cut their CO2 emissions. This is the main reason why CCS has such a high political profile. In Britain the Government predicts that CCS could be an industry the size of present day North Sea oil. According to 2006 figures, rocks under the UK North Sea could store about 22 billion tonnes of CO2 which is 180 years production of CO2 from the UK's 20 largest point sources (e.g. power stations). The British Government also thinks that the CCS business could be huge: estimates suggest a value of £2-4 billion per year by 2030, sustaining between 30,000 and 60,000 jobs. Other circum North Sea countries are also becoming aware of the value of their subsea pore space. Further afield, in the Gulf Coast of the United States where CCS is close to being commercially viable because of the value of CO2 to the enhanced oil recovery business, the Geological Survey is advertising Texas pore space as the 'CO2 sink for the USA'.
However basins with high potential for CCS need to be surveyed and this is a central role of the geological survey being an expansion of their traditional role as inventory maker of subsurface natural resources. In some countries geological surveys are leading, for example the BGS and TNO in the southern North Sea, the Bureau of Economic Geology in the Texas Gulf Coast, and Geoscience Victoria in the Gippsland Basin, Australia.

The role of the survey includes accurate storage estimation in the form of precompetitive exploration to attract company investment and improve general financial investor confidence, as well as developing integrated regional basinwide modelling to handle multiple use of pore space, for example oil and gas production, natural gas storage and water extraction.

A problem that is perhaps not considered enough is public acceptance. The science of CCS needs to be well communicated to the public and to government, and independent scientific organisations like geological surveys and universities have a special role. A broad approach should ensure that the public sees the opportunity of CCS as just that - a way to develop and sustain climate abatement and energy in the national interest.

Regional Characterisation and Assessment of UK North Sea Sub-salt Saline Aquifers for Geological Sequestration of CO_2

B. Hedley[1]; R. J. Davies[1], J.G. Gluyas[1], S. A. Mathias[1], J. Aldersey-Williams[2] & D. Hanstock[3]

[1]*Durham Energy Institute (DEI), Department of Earth Science; University of Durham, Durham DH1 3LE*
[2]*Redfield Consulting Limited, The Clyans, Monymusk, Aberdeenshire, AB51 7HT*
[3]*Progressive Energy Limited, Swan House, Bonds Mill, Stonehouse, Gloucestershire, GL10 3RF*

The United Kingdom Governments aim of cutting CO_2 emissions by 80% before 2050 in conjunction with its declared commitment to Carbon Capture from new and existing coal fired power stations; coupled with subsequent geological storage in the UK North Sea has reinforced the need for greater research into methods and risk of CO_2 trapping mechanisms.

Sub-salt deep saline aquifers represent a potentially large volume, high quality storage medium for deep geological sequestration of carbon dioxide. Examples of laterally extensive aquifers include the lower Permian sandstones with associated Zechstein salt seal, which seem an attractive prospect. However, these areas can have few wells and thus the systems are often perceived to be a greater risk than the more frequently drilled and documented depleted oil fields. Therefore, for these traps to be utilised to their full potential, a method of risk analysis and appraisal must be derived from and ultimately applied to available data.

We focus on the Central Graben, sub-salt, Permian sandstone CO_2 aquifer ‘play’, we look at the generic aspects of this area in terms of structure, reservoir quality, faulting and potential low permeability shear zones that downgrade the CO_2 migration potential across the reservoir. We assess the quality and extent of the salt seal as well as drawing on previous hydrocarbon exploration experience from adjacent producing fields for indications of aquifer extent, porosity, permeability and net to gross ratios; and to quantify regional variance in reservoir thickness. Collation of these data allows us to produce a summary of a large area with respect to the presence of the key features for successful CO_2 sequestration.

We find that the Central Graben sub-salt ‘play’ shows good porosities of approximately 20% - 24% based on sonic logs, and published values of between 9% and 27% based on published values for the aeolian dune and sheetflood facies of the Permian sandstone found in the producing Auk field with permeabilities ranging from 0.2 mD to 125 mD. Previous exploration indicates that the Zechstein represents a thick seal across the area up to its apparent pinch-out to the south-west of the Central Graben in the region of UKCS quads 28 and 36. The base of the Permian Sandstone in these wells is rarely penetrated but there appears to be in excess of 200m in wells to the southwest of the Auk Field. However, the lithology of the base seal in this region is questionable as the Carboniferous coal measures and shales found overlying the Devonian sandstones and limestones within the Mid North Sea High and Southern North Sea Basin are not present under the Auk field. Lack of well penetration into these units therefore cannot prove the northern extent of the carboniferous under the ‘play’ area.

We will use statistical analysis of Monte-Carlo simulations run using a range of physical aquifer properties to determine minimum, maximum and mean cases for storage; as well as running Tough 2 or Eclipse reservoir modelling software to simulate injection and migration across the prospect and identify any reservoir flaw or leakage risk over varied injection pressures.

We anticipate that application of the above method to different sub-salt aquifer systems will provide a rapid prospect appraisal methodology prior to committing to more detailed higher cost investigations.

Subsurface CO_2 Storage Capacity Calculations

B. van der Meer, *TNO Built Environment and Geosciences, Princetonlaan 6, 3508 TA Utrecht, The Netherlands*

Estimation of the capacity of a geological formation to store CO_2 is not a straightforward or simple process. Some scientist have tried to make simplistic estimates at the regional or global level. Bradshaw (Bradshaw et al., 2006) has recently attempted to list various estimations for CO_2 storage capacity for the world and regions of the world. He reports estimations often quoted as “very large” with ranges for the estimates in the order of 100s to 10,000s Gt CO_2. All this work shows clearly the lack of definitions, rules and general practices to calculate storage potentials.

TNO has been involved in earlier studies and feels strongly that at long last we need a more uniform and standard method to calculated the storage potential of any subsurface location, either a partial or empty gas or oil field or aquifer. TNO prefers to consider in any storage capacity calculation the inclusion of a concept of total affect space i.e. all space that has its state or qualities changed by the storage operation over the total storage time. Furthermore, we will have to consider the injectivity of the selected injection location and the pressure and fluid conductivity of the total affected storage space. In addition the intended free CO_2 storage location will need to have enough storage space or enough sealing capacity to contain the CO_2 for at least 10.000 years and prevent it from migrating to the surface. And finally it has to be considered that heavier CO_2 saturated formation water will sink as a result of gravity segregation to deeper parts of the affected space.

TNO has developed a standard method to be used for any storage location to calculate the maximum storage volume based on affected space and maximum pressurization, the storage potential based on injectivity and finally the storage efficiency of the geological trap.

Exploration for CO_2 Storage Sites in the Norwegian Sector of the North Sea Basin

S. Hagen, K. Gro Johanson, R. Maurer, J. Moisan, R. Thorsen, J. Ove Thorsplass, *Statoil - New Energy*

Generally, CO_2-capture projects today aim to reduce CO_2 content in natural gas to meet sale specifications. As a result, these developments are coupled with sites for natural gas development (i.e. Sleipner & Snøhvit). In the future however, more focus will probably be placed on capturing CO_2 from industrial sources, such as power plants that command large, secure and reliable storages. Consequently, exploration and careful selection of sites, that meet strict requirements is a key prerequisite in future carbon-capture and storage (CCS) value chain development.

Various storage options have been evaluated (deep ocean, salt caverns, coal-beds etc.), but generally regarded as the most promising, due to both capacity and safety, is injection of CO_2 as a dense phase into subsurface geological reservoirs such as abandoned hydrocarbon fields, or saline formations.

This paper presents an outline of an exploration initiative, the so-called *CO_2 Storage Mapping Programme* (COSMaP), initiated by Statoil. COSMaP aims to map and mature suitable reservoirs for storage of CO_2 (own or others). Basis is to make storage a future commercially viable business.

In the initial phase of COSMaP, focus will be to establish a common methodology, aligned with international expertise within CCS, that describes the necessary activities involved, and the criteria used to characterise and verify CO_2 storage and capacity estimation. In parallel, all hazards and risks (for example top seal integrity, fault leakage and induced fracturing during injection) involved with CO_2 storage are to be described, assessed and handled satisfactory to assure public and regulatory acceptance.

Exploration for CO_2 storage shares several standard activities with exploration for hydrocarbons. However, some central differences are obvious, and basins that lack hydrocarbon source or migration opportunities, may prove tenable for storing of CO_2.

Geological Characterisation of the Hewett Field for CO_2 Storage

A. Clarke[1], J. Imber[2], R. Davies[2], S. Daniels[2], J. van Hunen[2], S. Mathias[2], A. Heafford[3], G. Yielding[4]

[1]*Centre of Doctoral Training in Energy, Durham University, UK*
[2]*Centre for Research into Earth Energy Systems, Department of Earth Sciences. Durham University, UK*
[3]*IHS Energy, 133 Houndsditch, London. EC3A 7BX. UK*
[4]*Badley Geoscience Ltd. North Beck House, North Beck Lane, Hundleby, Spilsby, Lincolnshire. PE23 5NB. UK*

Coal is a cheap and readily available energy resource, but is very polluting. Carbon Capture and Storage (CCS) has the potential to reduce CO_2 emissions by up to 90 %. The UK is thought to be able to benefit considerably from CCS due to its proximity to the North Sea, once a world class hydrocarbon source, now set to be a world class CO_2 storage area.

The Hewett Unit is located within the Southern North Sea basin, approximately 10 km NE of the Norfolk coastline. The unit is made up of seven gas fields, all with a common NW-SE (Hercynian) trend. The unit is cut by mainly NW-SE trending faults, with major displacements focused along the Dowsing Fault Zone. The Hewett Unit has been producing since 1969, and the fields are depleted or near depletion. This aim of this study is to assess the suitability of the Hewett Unit for CO_2 storage.

The four major gas reservoirs are the Upper and Lower Bunter Sandstones (Triassic), the Rotliegendes Sandstones (Permian) and the Zechstein dolomites (Permian). Production data show that the Upper Bunter Sandstone of the Hewett and Little Dotty fields are in pressure communication across the Dowsing Fault Zone, but the reason for this connectivity is poorly understood.

The main objective of this study is to understand the controls on aquifer connectivity across the Dowsing Fault Zone, and to discuss its implications for CO_2 storage in the Hewett Unit. A structural framework model has been constructed to identify juxtaposition seals, and to assess the potential for hydraulic connectivity along ramps ("fault terraces") between overlapping segments of the Dowsing Fault Zone. Preliminary results suggest that connectivity could be achieved by flow around the lateral tips of a fault situated in the footwall of the main strand of the Dowsing Fault Zone. These regions are characterised by a high density of small-scale faults, but analysis of well by well production data may allow determination of segment size and the transmissibility of intervening features. Hydraulic fracture or reactivation of the Dowsing Fault Zone could also give rise to across-fault leakage. The final objective is to develop a mechanical model to assess whether fault reactivation contributed to pressure communication during depletion, and to predict whether this is likely to occur due to re-pressurisation due to CO_2 injection.

Assessing Subsurface Risk in Re-Using an Offshore Depleted Hydrocarbon Field for CCS

C.E.Lovelock, O.D. Tucker, *Shell International Exploration & Production, B.V., Seafield House, Hill of Rubislaw, Anderson Drive, Aberdeen, AB15 6BL*

Shell announced its participation in Scottish Power's bid to win the UK CCS demonstration project in August 2009. As part of this consortium, we will be providing a suitable storage container (a depleted offshore hydrocarbon field) and offshore transport of the CO_2 to be sequestered. Key to the delivery of a storage solution is the requirement to satisfactorily identify, mitigate and manage the wide range of risks, uncertainties and eventualities inherent in a project of this nature.

Shell has been involved in a number of CCS and CO_2 EOR projects around the world and has used this accumulated experience to develop a methodology to address subsurface issues and risks. This methodology can be uniformly applied across CCS projects – allowing the comparison of "like with like" and the transferring of experience from one project to another. A key differentiator of the Shell approach is the adoption of 'Evidence Based' three-value logic: evidence for, evidence against and unknowns.

In a CCS project, subsurface risks can be assigned to one of four categories: Capacity, Containment, Injectivity and Monitoring. Examples of concerns from each category might include: the size of the available pore volume for CO_2 storage (Capacity); caprock integrity (Containment); well injectivity and operability (Injectivity) and; detection of CO_2 movement/original pore fluid displacement (Monitoring). Following our methodology, we assign a root hypothesis to each concern (e.g., "The primary seal is proven to hold pressures and fluids and this proof is representative of the CO_2 area" for caprock integrity) and divide it into as many sub-hypotheses as necessary to develop an Issue Tree. For each sub-hypothesis, evidence is examined and categorised (including recognition of the gaps in our understanding) to derive an 'Italian Flag' display which clearly indicates the level of confidence in the validity (or otherwise) of this hypothesis and the amount of white space between the green and red bars of the 'flag' showing the level of uncertainty. Parameterising our understanding in this way allows us to apply other graphic approaches to guide our development of work plans to reduce the project's risks (or improve our understanding of those risks).

The structured nature of the methodology means that the technique can be applied at regular intervals though out the project's life-cycle, to monitor progress and identify and focus our work. In the long term, many of these risks will inform the direction and size of the monitoring program, expending most effort and funding on monitoring what remains the greatest risk.

In this paper we explore the methodology and examine how the risks have been assessed in an offshore UK CCS project; how work has been focussed to address those risks as the project moved through the screening funnel; and how the risks could feed into a monitoring programme.

The Source
for Critical Information and Insight™

Sponsors of the **CO2 Subsurface modelling** sessions

Wednesday 24 March

Session Two: CO_2 Subsurface Modelling

Part One

Fault-Seal Analysis for CO_2 Storage – An Example from the Troll Area, Norwegian Continental Shelf.

G. Yielding[1], P. Bretan[1], O. Magne Mathiassen[2], T. Thorsnes[2]

[1]Badley Geoscience Ltd, North Beck House, North Beck Lane, Hundleby, Spilsby, Lincolnshire PE23 5NB, U.K.
[2]Norwegian Petroleum Directorate, Professor Olav Hanssens vei 10, 4003 Stavanger, Norway.

Fault seal plays a critical part in many hydrocarbon traps, and the same will be true for CO_2 storage. The standard workflows for prediction of capillary seal of hydrocarbons by fault rock can be readily adapted to prediction of CO_2 seal since the fluid properties of CO_2 at reservoir temperatures and pressures are within the range shown by hydrocarbons. We illustrate this modified workflow with a feasibility study into proposed CO_2 storage in the Johansen Formation underlying the Sognefjord/Fensfjord reservoirs of the Troll Field. An important concern here is the possibility of leakage of injected CO_2 across faults into the stratigraphically shallower producing oil and gas reservoirs.

A comprehensive fault-seal analysis was conducted on a depth model of the Troll area using TrapTester software. Computation of Shale Gouge Ratio (SGR) over the fault surfaces, in combination with juxtaposition diagrams, was used to estimate the sealing potential of faults cutting the Johansen Sand. SGR values were converted to potential CO_2 column heights that might be trapped at each fault on a northward migration path. Trappable column heights are generally <100m at each fault, allowing a cross-fault migration route which proceeds from the Johansen Sand via the Statfjord Formation, Cook Formation and Brent Group, ultimately reaching the Fensfjord Formation of the Troll West Oil Province. Flow simulation will be required to define the timescale needed for this migration.

Analysis of in situ stresses suggests that the faults in the Troll field are not close to failure and therefore up-dip leakage is unlikely. Extremely large CO_2 columns would be required to change this stress stability, and across-fault capillary leakage would occur first.

Quantifying Seal Risk for CCS: The Impact of Seal Bypass Systems

J. Cartwright, *3DLab, School of Earth and Ocean Sciences, Cardiff University, Main Building, Park Place, Cardiff CF10 3YE, Wales, UK*

A conceptual model for the analysis of the sealing potential of caprock sequences for sites targeted for carbon capture and storage (CCS) is summarised here based on the recognition that many high quality seals are breached episodically or semi-permanently by a range of geological structures that act as seal by-pass systems (SBS). We formally define SBS as seismically resolvable geological features embedded within sealing sequences that promote cross-stratal fluid migration and allow fluids to bypass the pore network. We advance the concept that if such bypass systems exist within a given sealing sequence sequence, then predictions of sealing capacity based exclusively on rock physical properties such as capillary entry pressure/hydraulic conductivity will be largely negated by the capacity of the bypass system to breach the grain and pore network. This model is based largely on observations of sealing sequences using 3D seismic data, in which there is direct evidence of highly focused vertical or sub-vertical fluid flow from subsurface reservoirs up through the sealing sequence with leakage internally at higher levels or to the surface as seeps or pockmarks.

We classify SBS into three main classes based on seismic interpretational criteria: (1) fault related, (2) intrusion-related, and (3) pipe-related. Examples are presented of each class of SBS in a relevant context of a particular sealing sequence that might be considered a legitimate target for CCS, and where seismic evidence of hydrocarbon leakage allows the role of the bypass features to be evaluated. These include mud volcano conduits, sandstone intrusions, normal and thrust faults, blowout pipes and igneous intrusions. We show how each class exhibits different modes of behaviour with potential for different scaling relationships between flux and dimensions, and different short and long-term impacts on seal behaviour. We conclude with an analysis of SBS and their relative impacts on potential CO_2 storage in Cenozoic sequences in the North Sea Basin, to show how this model can be employed to reduce risk and aid prediction in a range of reservoir contexts, as a prelude to more quantitative seal risk analysis.

A New Method to Predict and Quantify the Effects of CO2 Injection into Subsurface Storage Formations - A Case Study from the Sleipner CCS Project

T. Graf[1], M. Meadows[2]

[1]*Fugro Consult GmbH, Berlin, Germany*
[2]*Fugro Seismic Imaging, Houston, TX USA*

CCS is a critical option in the portfolio of solutions available to combat climate change, because it allows for significant reductions in CO2 emissions from fossil-based systems, enabling it to be used as a bridge to a sustainable energy future. Much recent activity has focused on ways to reduce, eliminate, or sequester CO2 in order to minimize its impact on the environment. Miscible CO2 floods, in addition to their primary role in EOR (Enhanced Oil Recovery) as a means to recover residual or bypassed oil, have become an increasingly effective mechanism for long-term storage of CO2. Clearly, an understanding of the effects of CO2 on rock-fluid systems, together with an ability to accurately map CO2 fronts during injection, are crucial for improving recovery rates, optimizing well patterns, locating bypassed oil, and minimizing the cost of injected CO2.

The Sleipner CO2 project in the North Sea is one of only three large-scale CO2 storage projects worldwide. The oldest in operation, Sleipner has been injecting about 1 million metric tons of captured CO2 each year. Sleipner captures CO2 separated from the natural gas production stream and injects it back into the Utsira Formation. This sub-seabed saline aquifer is a thick, extensive sand-dominated package above the Sleipner gas deposits and was chosen as the CO2 storage reservoir.

A new method to predict and quantify the effects of CO2 injection in porous saline and oil/brine reservoirs using time-lapse seismic data was developed on field data from the Sleipner project. This new inverson method uses CO2 fluid properties from time-lapse seismic data and takes into account the complicated behavior of CO2 mixtures as well as effects such as seismic thin-bed tuning.

The technical approach consists of three steps: modeling CO2 petrophysics under reservoir conditions; using these petrophysical properties to model synthetic seismic data over a range of reservoir properties; and making quantitative estimates of changes in reservoir properties, such as pore pressure and CO2 saturation, using the synthetic modeled data in a multiparameter inversion of the time-lapse seismic field data.

The new inversion approach has been demonstrated by estimating the amount of CO2 injected into the Sleipner reservoir using time-lapse seismic attributes. Time-lapse changes in traveltime and amplitude were measured at the top of the Utsira reservoir at Sleipner, and then inverted to yield a CO2 thickness map and its standard deviation for the sand wedge layer. As a result, the total amount of CO2 that penetrated the sand wedge within a five-year period was estimated. In principle, this procedure could be repeated for each layer of the reservoir, so that the total estimated amount of injected CO2 could be compared to known values.

Wednesday 24 March

Session Three: North Sea Opportunity

KEYNOTE SPEAKER: Carbon Capture and Storage: Geoscience Opportunities for the UK

R.S. Haszeldine, *School of GeoSciences, Scottish Centre for Carbon Storage, The University of Edinburgh, Grant Institute, West Mains Road, Edinburgh, UK, EH9 3JW*

To achieve UK objectives in reducing CO_2 emissions by 80% relative to 1990, power plants burning coal or gas are some of the early targets for CO_2 capture, transport, and storage (CCS). The Committee on Climate Change recommends that electricity generation is mostly decarbonised by 2030. To undertake this, means building pilot capture plant to test the CCS chain through to geological storage, followed by reference plant to demonstrate this in commercial operation. These cycles of learning need to be complete by 2020, or very soon thereafter, so that routine fitting of CCS can occur. This is a very rapid timescale. The UK is a leading nation in enabling the legal framework for CCS, and is poised to be amongst the earliest developers piloting CCS. However the government commitment to build up and establish a full CCS industry is less clear. If CCS an be rapidly and commercially developed, then a UK share in the design and build of worldwide projects could be worth £ 3-5Bn/year by 2030. If the extremely large storage assets owned offshore deep beneath the North Sea can be commercially exploited, that could yield an additional £5 Bn/year in commercial rents, with extended employment and skills development for offshore industries transferable worldwide. The abundant information gathered during 10,000 boreholes, with 40 years of seismic surveying fluid production and injection, make the UK offshore a world-leading target for CO_2 storage. Many of the skills and technologies established offshore can be adapted for re-use. Conceptually, CO_2 will be captured at a power plant by one of three methods, pressurised to become fluid, and transported by pipe, to be injected into long-term storage below 800m. Several assessments of CO_2 storage beneath and around the UK have been undertaken, these show that sites beneath onshore locations are small and geologically complex. By contrast, storage offshore appears extremely promising, with mid-range storage resource estimates of 60Gt CO_2 comparing well to annual UK power plant production of 200Mt CO_2. Offshore Norway may have similar storage resources. Three types of storage are possible: depleted oilfields, depleted gasfields, and more than 95% capacity in saline water-filled formations. Determining the efficiency of use for each of these types is currently not validated by any large sale project, and efficiency estimates range from 40% of porespace in individual structures, to less than 0.2% in closed deep geopressured aquifers. This presentation will review the regulatory landscape; the state of leading CCS projects in the UK and worldwide; the geoscience and commercial opportunities and difficulties faced in exploration and exploitation of storage; and provide some visions of what CCS may mean for provision and price of electricity in the UK, and opportunities across the EU.

CCS UK Government View

D. Rutland

This talk will cover general government policy on CCS. The talk will consider the policy drivers for government intervention and what we have done to enable CCS, to promote demonstration at commercial scale and to facilitate wider deployment. The information will provide some context for the specialised discussion on storage that will form the main part of the programme.

Legal aspects of Carbon Capture and Storage

I. Havercroft, Carbon *Capture Legal Programme, Faculty of Laws, University College London*

The increasing emphasis placed by governments upon Carbon Capture and Storage (CCS) as a key mitigation option for climate change and as a mainstay of energy policy, has resulted in various novel regulatory developments worldwide. Government and industry have ensured that Europe remains at the forefront of this regulatory growth, with many of the early legal developments championed by its Member States. Nowhere is this more evident than in the amendments made to the international marine agreements, the London Protocol and the OSPAR Convention, and the more recent design of an EU Directive for carbon dioxide storage.

This presentation will examine the emerging regulatory regime for CCS activities in the marine environment, including the North-East Atlantic, as well as the EU's framework Directive for geological storage.

Thursday 25 March

Session Four: Creating the Right Investment Environment

Part Two

KEYNOTE SPEAKER: CO_2 Storage in Depleted Gas Fields – The Netherlands Offshore Case

J.N. Breunese, *TNO Built Environment and Geosciences, Utrecht, The Netherlands*

The Netherlands has been blessed with a wealth of natural gas fields. The portfolio of these fields is nearing depletion, creating empty pore space for alternative use such as CO_2 storage.

In a joint study undertaken in 2008 / 2009 by the Dutch Ministry of Economic Affairs (MEA) and the oil and gas industry (NOGEPA), the potential for large scale CO_2 transport and storage on the Netherlands part of the North Sea has been assessed. In the assessment, the CSLF concept of matched capacity has been applied.

The theoretical capacity amounts to 1,6 Gt. Taking into account geological and engineering constraints, in particular small field size and low permeability, the effective capacity amounts to 1,0 Gt. Finally, taking remote isolated fields apart, which probably will not justify the long distance infrastructure, the practical capacity amounts to 0,9 Gt. For the largest part this potential is concentrated in the central part of the Dutch Continental shelf, with the remainder in the southern near shore part, close to the Rotterdam and Amsterdam industrial areas.

Ultimately, a technical, legal and commercial match between demand for and availability of transport and storage capacity will dictate the true storage capacity. Given to day's large uncertainties in the demand profile for CO_2 storage, and given the large value of extending the gas production, a strategy has to be devised that aims at keeping all options open against reasonable costs. An example scenario will be presented to illustrate the various considerations. The strategy itself now is under development by the Dutch government and her agencies, under the title 'National Masterplan for Transport and Storage of CO_2'.

Finally, matched capacity only can be achieved by realizing an adequate and timely sequence of demonstration projects and upscaling towards large scale CCS. The situation in the Netherlands will be explained, also highlighting the public acceptance issue.

CO_2 Storage Capacity in the Bunter Sandstone Limited by Local Pressure Development, UK Southern North Sea

N. Heinemann[1], M. Wilkinson[1], G. Pickup[2], R. S. Haszeldine[1]

[1]School of GeoSciences, The University of Edinburgh, The King's Buildings, West Mains Road, Edinburgh, EH9 3JW,
[2]Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh, EH14 4AS

Local pressure-build-up during CO_2 injection into a reservoir could cause fracturing or faulting which would compromise storage. If multiple well are used for large-scale injection of CO_2 into an aquifer, the pressure around the wells will mutually interfere; the separation between the injection wells becomes a crucial injection design parameter. We present a generic technique for estimating the well separation using the ECLIPSE compositional simulation package. The Bunter Sandstone Formation, UK southern North Sea is used as a test case, and storage capacity estimated. It is assumed that during the injection period, pressure cannot dissipate horizontally due to adjacent injection wells; and that vertical pressure migration is unlikely since the Bunter Sandstone is sealed above and below by low permeability rocks. Assuming an injection rate of 1 Mt of CO_2 per year per well, approximately 7.8 Gt of CO_2 could be stored in the formation. This storage capacity estimate is smaller than a previous estimate by a factor of c. 0.5 and shows that capacity calculations which are not based on pressure development may produce overestimates of storage capacity.

Identification and Characterisation of a Potential CO_2 Storage Site, UK North Sea

M. Akhurst, **M. Quinn**, M. Smith, *BGS Edinburgh*

Identification of CO_2 storage sites followed by mapping and characterisation of selected saline aquifer stores has been undertaken by source-to-sink consortia of academic, industry and Scottish Government members through two successive studies. Firstly, the Scottish Carbon Capture & Storage Joint Study identified CO_2 sources onshore Scotland and NE England, identified and assessed the CO_2 storage potential offshore Scotland in the Northern and Central North Sea, investigated the various transport options and proposed a range of possible economic models for CCS. It showed that offshore Scotland has the potential to store a large proportion of CO_2 emissions from the UK and mainland Europe within depleted hydrocarbon fields and mostly saline aquifer formations which are less well known.

Secondly, the ongoing Scottish Carbon Capture Transport Storage Development Study has focussed on a saline aquifer selected from those identified in the first study as having good potential for CO_2 storage. Mapping and characterisation of this aquifer refines our understanding and increases our knowledge of North Sea aquifer stores and decreases current uncertainty in their storage capacity. Benefiting from extensive available hydrocarbon field information and using released well data tied to a large 2D seismic dataset, detailed mapping of this selected potential CO_2 storage site has been carried out enabling a range of static storage capacities to be calculated. A 3D geological model has been constructed that will be utilised in the dynamic modelling of this potential CO_2 store.

This presentation briefly charts the selection process and the methodology employed that led to the delineation of this site before going on to describe its geological characteristics and assesses its potential as a CO_2 store. Accurate mapping of CO_2 storage sites is essential to ensure that enough is known about the potential store to satisfy regulators and the general public of its effectiveness and safety.

KEYNOTE SPEAKER: Offshore Geosequestration Potential in the Gulf of Mexico

R. Treviño, *The University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center*

The Gulf of Mexico Basin (GOM) contains the greatest capacity for carbon Geosequestration in North America. Although, some of the basin extends onshore, most resides offshore. To date, almost all Geosequestration research in North America has been focused on intra-cratonic basins or onshore portions of the continental margins. The Gulf Coast Carbon Center recently secured support from the U.S. Department of Energy and the Texas General Land Office to study the near shore waters of the State of Texas (a.k.a., State Submerged Lands) and the immediately adjacent Federal Waters. Due to the concentration of anthropogenic point sources of CO_2 along the upper Texas coast (i.e., Houston to Beaumont), the study will focus on the Submerged Lands of the upper coast. The study area has several advantages. 1) In contrast with onshore, there is only one owner of the pore space (i.e., either the State of Texas or the U.S. Federal Government), and Texas' Submerged Lands are more extensive than other states 'offshore waters. 2) There is a greatly reduced (near zero?) chance of negatively impacting groundwater resources. 3) Decades of oil and gas operations have resulted in abundant available data for characterizing reservoirs, seals, faults, and possible leakage pathways. 4) Current processes (e.g., natural gas seeps, near surface faults, etc.) are in some cases more easily and economically detectable with available technologies (e.g., shallow geophysical methods, deep seismic) in an offshore setting than onshore.

We consider current capacity estimates to be inadequate because they do not take into account sand body connectivity, which is a key control on rate of pressure increase. The effects of fluid release on capacity may also require consideration. As a young basin, the GOM is still actively expelling fluids. Features such as gas chimneys, carbonate concretions and surface pock marks, which are indicative of fluid release can be readily identified. Older basins may contain features that could leak, but if they are now stable, such features may not indicate their propensity to leak. Therefore, research on how fluids from compaction and hydrocarbon generation are expelled in the GOM could help us select secure sites for GOM storage and help us identify leaks in other basins.

Assessment of risk will be part of the study and includes elements conducted by Environmental Defense Fund looking especially at ecosystem risks (intended as a link to international research). Another risk element will be conduced by Los Alamos National Laboratory to prepare guidance on key elements to be considered in risk assessment for use by future commercial operations.

Size-Distribution of CO2 Storage Units, Limited by Overpressure, In the Pre-Cenozoic of the Central and Northern North Sea

R.S. Haszeldine[1], M. Wilkinson[1], A. Hosa[1], R. J. Stewart[1], S. Holloway[2], M. Bentham[2], M. Quinn[3], K. Smith[3], R. Swarbrick[4], S. Jenkins[4], J. Gluyas[5], E. Balbinski[6], E. Mackay[7], G. Smith[8], S. Daniels[9], D. Anderson[8]

[1]*School of GeoSciences, The University of Edinburgh, Grant Institute, West Mains Road, Edinburgh, UK, EH9 3JW*
[2]*British Geological Survey, Kingsley Dunham Centre, Keyworth, Nottingham, UK, NG12 5GG*
[3]*British Geological Survey, Murchison House, West Mains Road, Edinburgh, UK, EH9 3LA*
[4]*GeoPressure Technology, Mountjoy Research Centre, Stockton Road, Durham, UK, DH1 3UZ*
[5]*Department of Earth Sciences, Durham University, Science Labs, Durham, UK, DH1 3LE*
[6]*RPS Energy, Winfrith Technology Centre - A31, Dorchester, Dorset DT2 8DH*
[7]*Institute of Petroleum Engineering, Heriot-Watt University, Riccarton Campus, Edinburgh, UK, EH14 4AS*
[8]*Senergy Alternative Energy Limited, 15 Bon Accord Crescent, Aberdeen AB11 6DE*
[9]*Geospatial Research Ltd., Department of Earth Sciences, University of Durham, Durham, UK, DH1 3LE*

Within the North Sea, the potential for CO2 storage in saline aquifers greatly exceeds that of depleted oil and gas fields (SCCS, 2009), but is less well constrained. The UK Storage Appraisal Project, funded by the Energy Technologies Institute, has the remit to produce an auditable, probabilistic assessment of the storage potential of saline aquifers and other formations within the UKCS. This will be the most comprehensive CO2 storage exercise ever undertaken on the UKCS. An initial step is the sub-division of the area into units of assessment, the storage capacity of each of which will be assessed individually, prior to summation to provide a storage total for the offshore UK. This paper is concerned with the former task as applied to the Pre-Cenozoic strata of the Central and Northern North Sea.

One of the innovations in this assessment is to anticipate that pressure build-up during injection will be the limiting factor for CO2 injection in many units, so that the working definition of an assessment unit is: *"a volume of reservoir which acts as a single pressure compartment, such that the pressure build up around an injection well can potentially dissipate within the unit, but not beyond it"*. There is no implication that the storage potential of the entire assessment unit can be accessed from a single borehole or injection site. In all cases, the smallest stratigraphic units (formations and members) defined by the British Geological Survey (BGS) are used for vertical division of the stratigraphy. These are always regarded as assessment units separate to underlying and overlying units despite the possibility of pressure connection from unit to unit.

Above the BCU (base Cretaceous unconformity) the stratigraphy is relatively unfaulted, except within structurally reactivated areas, so that potential reservoir units are regarded as single assessment units. Below the BCU, faulting is known (from the distribution of overpressure) to divide reservoir units into lateral pressure cells. Although pressure maps were only available for the Upper Jurassic (GeoPressure Technology North Sea Central Graben and North Sea Viking Pressure Studies), the assumption was made that the cell boundaries are faults and are hence effectively vertical. The faults are assumed to extend from the BCU to basement i.e. sub-Devonian.

Assessment units were created in a GIS system using the geographical extent of formations / members divided using pressure compartments at Jurassic level. This resulted in 1215 units of assessment, substantially more than was anticipated initially. A 50 Mt storage capacity filter has hence been applied to the units, to eliminate small ones so that resources can be concentrated on units that have significant storage potential, and to remove a small number of artefacts where the boundaries of the area maps and the pressure cells are close but not exactly coincident. The thickness, net:gross and porosity of stratigraphic units was taken from the literature, and a first-pass, maximum likely, storage capacity calculated using a CO_2 density of 700 kg / m^3 and a storage efficiency of 0.02. Units below 50 Mt were found to be numerous (802) but to have a combined storage potential of only 5 % of the total. The distribution of volume of the assessment units approximately follows a log normal distribution, as has been reported for hydrocarbon fields.

SCCS (2009) Opportunities for CO2 storage around Scotland – an integrated strategic research study. Scottish Centre for Carbon Storage,

http://www.geos.ed.ac.uk/sccs/regionalstudy/CO2-JointStudy-Full.pdf

Role of Statigraphic Juxtaposition for Seal Integrity in Proven CO_2 Fault Traps of the Southern North Sea

G. Yielding[1], N. Lykakis[2], J. R. Underhill[2]

[1]*Badley Geoscience Ltd, Lincolnshire, UK*
[2]*Grant Institute of Earth Sciences, School of Geosciences, the University of Edinburgh, UK*

Exploration well 50/26b-6 in the UK Southern North Sea discovered a gas-bearing Rotliegend Group (Leman Sandstone Formation) trap which was a major surprise in that the gas was approximately 50% CO_2 (with 9% N_2 and the remainder methane). Christened the 'Fizzy Discovery', the accumulation was appraised by well 50/26b-8. Subsequently, another CO_2-rich discovery (Oak) was made along-strike in nearby block 54/1b. Column heights are of the order of a few tens of metres. The study area is covered by a high fidelity PSTM 3D seismic dataset acquired by WesternGeco in 1995. Seismic interpretation of this dataset has been constrained by 33 exploration wells allowing fault geometries and stratigraphic offsets to be determined with confidence. The robust *in situ* calibration of proven accumulations confirms that fault-bound traps in the Rotliegend Group of the SNS are likely to be excellent sites for carbon storage. In the instance of the NW-SE-striking Fizzy Horst, there is net normal fault offset on the SW-dipping boundary, despite this fault showing clear evidence of late-stage (Late Cretaceous) structural inversion. Whilst the fault's contractional reactivation must therefore have reduced the existing normal offsets at Permian and Triassic levels, the net fault offset is sufficient in both the Fizzy and Oak discoveries to breach the Zechstein super-seal, and the CO_2-bearing Rotliegend Group in the footwall is now juxtaposed against hangingwall sediments of the lower Triassic (Bacton Group, Bunter Shale Formation). Hence, it is conjectured that the Bunter Shale Formation can act as a robust side-seal for the carbon dioxide or that halite from the faulted Zechstein may contribute to a 'salt smear' on the fault surface. Either way, these accumulations are noteworthy in providing a natural demonstration of top seal and fault seal for carbon dioxide in a subsurface reservoir, intact over a geological time-scale in what is otherwise a prolific methane-rich reservoir play fairway.

The Source
for Critical Information and Insight™

Sponsors of the **CO2 Subsurface modelling** sessions

Thursday 25 March

Session Two: CO_2 Subsurface Modelling

Part Two

Geological Factors Influencing Time-lapse Seismic Monitoring of Subsurface CO2 Storage.

G. Cairns, H. Jakubowicz, L. Lonergan, A. Muggeridge *Department of Earth Science and Engineering, Imperial College London, South Kensington Campus, London SW7 1AZ*

Seismic surveillance will be an essential part of any carbon storage project in order to monitor the long term integrity of the reservoir and detect leakage. Ideally surveillance should locate the CO2, quantify its saturation distribution and detect the dominant trapping phase both during and after injection. Post injection surveillance, probably via time lapse seismic surveys, will need to continue over many hundreds of years to monitor the integrity of the storage site.

The accuracy of seismic monitoring will be influenced by the properties of both the reservoir rocks and the rocks overlying the reservoir in which the CO2 is stored. A rock physics model was used to predict the seismic response from supercritical CO2 injection into a sandstone reservoir with properties typical of the Sherwood formation. The influence of reservoir depth and the properties of the overburden and reservoir were investigated. The results shown in Figure 1 demonstrate that CO2 plume extent could be found at all depths examined (up to 2500m) due to the significant drop in *Vp* caused by small CO2 saturations. However quantifying the saturation would be more difficult. Low saturations up to 40% may be discernable, but higher saturations can be seen to be indistinguishable. These results depend on the nature of the fluid distribution within the pore space. The detectability of the CO2 trapping phases was examined by modelling the dissolution of CO2 in brine. Dissolution resulted in a very small and possibly undetectable *Vp* increase.

These results indicate that the location and to a certain extent the saturation of CO2 can be found using conventional seismic techniques, however ascertaining the trapping phase may be more challenging.

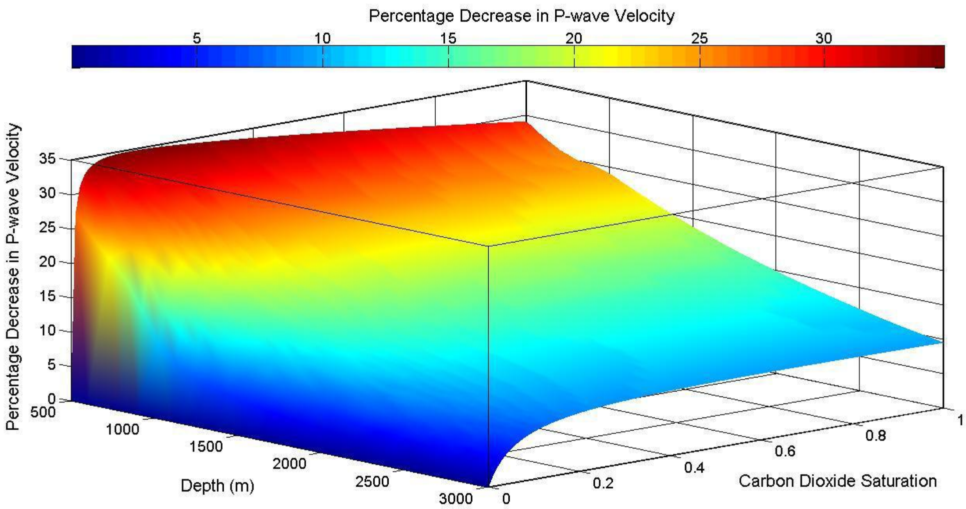

Figure 1 Percentage decrease in P-wave velocity (*Vp*) resulting from the injection of different saturations of CO2 into sandstone reservoirs found between 500 and 3000m depth. The significant drop in *Vp* caused by small CO2 saturations indicate that CO2 location could be detected at all depths. In addition inferring saturation from *Vp* may be possible for saturations up to 40%, but higher saturations appear to be indistinguishable.

Mapping CO_2 Layer Thickness in a Growing Plume at Sleipner, North Sea Using Quantitative Seismic Interpretation

G. A. Williams, R. A. Chadwick, *British Geological Survey*

CO_2 produced at the Sleipner gas field is being injected into the Utsira Sand, a regional saline aquifer. Time-lapse seismic surveys have been acquired in 1994, (baseline), 2001 (4.26 Mt CO_2 injected), 2004 (6.84 Mt CO_2 injected), 2006 (8.4 Mt CO_2 injected) and recently in 2008 in order to monitor the growth of the plume. The plume is imaged as a sequence of high amplitude sub-horizontal reflectors within the aquifer; the reflections are thought to represent the tuned response from thin layers of CO_2 trapped beneath intra-reservoir mudstone baffles. An additional high resolution 2D survey was acquired in 2006 over key sectors of the plume to better image these thin CO_2 layers. The successive time-lapse surveys show that the upper layers continue to spread laterally and generally increase in amplitude, whereas the lower layers have stabilised in size and are growing progressively dimmer, probably due to signal attenuation (Figure 1).

Quantifying the total volume of CO_2 in the plume becomes increasingly difficult as the lower layers get attenuated with time. Consequently, this contribution describes the results of recent work focused on the topmost CO_2 layer. The thickness and volume of this layer can be quantified most accurately and its growth essentially measures the total upward flux of CO_2 through the reservoir and how this changes over time. A number of quantitative seismic techniques have been applied to determine the layers thickness including amplitude-thickness modeling, topographic analysis of the reservoir seal and spectral decomposition.

Spectral decomposition of seismic data can be used to map temporal bed thickness across a 3D seismic survey. Conventional techniques employ the Short Time Fourier Transform using an appropriate window function to localise the frequency spectrum of the seismic trace. The resulting power spectrum represents a combination of the seismic wavelet and local thin bed effects. Time-frequency decomposition using the Short Time Fourier Transform suffers from resolution problems: a wide analysis window gives good frequency resolution, but poor time localisation, while a narrow window localises the spectrum in time but provides poor frequency resolution.

In order to overcome these limitations this study investigates the potential of the Wigner-Ville Distribution to map thin layers of CO_2 at Sleipner. Preliminary analysis of the Sleipner datasets using this technique shows strong frequency tuning effects and indicates that quantitative temporal-thickness mapping is practicable. Correlating temporal-thicknesses with depth-thicknesses derived by other methods provides additional constraints on layer velocities.

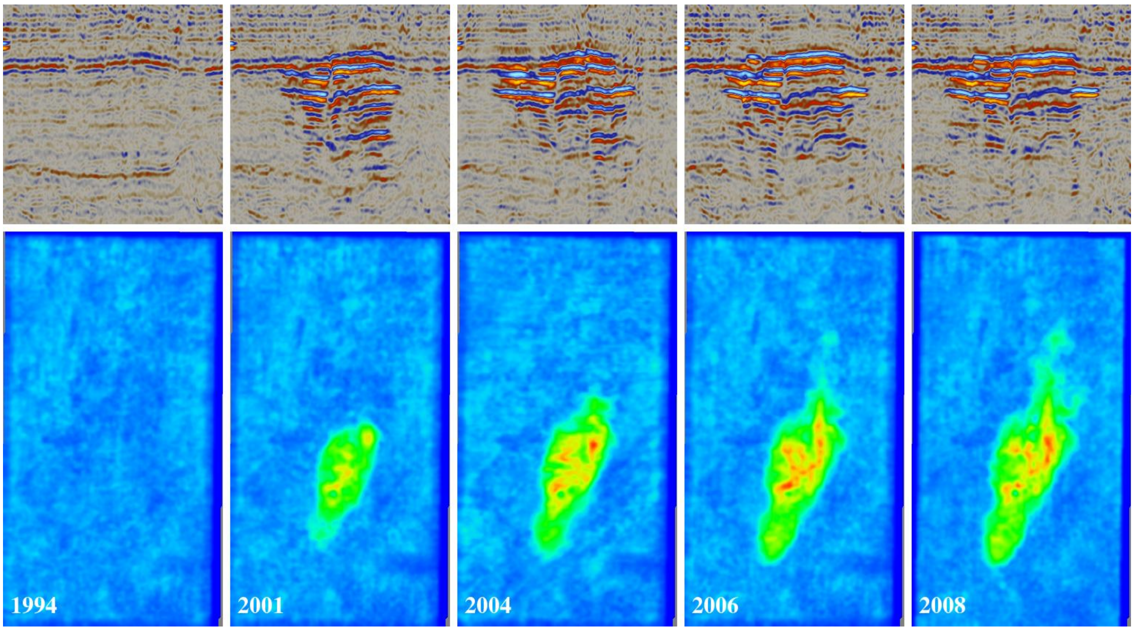

Figure 1. Time lapse response of a growing CO_2 plume at Sleipner, North Sea.

Application of Structure Validation and Kinematic Modelling in Building a Discrete Fracture Network (DFN) for a Salt-Bounded Dolomitic Limestone Reservoir Unit.

J. Grocott, C. Bond, A. Gibbs, *Midland Valley Exploration, 144 West George Street, Glasgow G2 2HG, UK*

Examination of the integrity of the structural model is a primary requirement in identifying and working with uncertainty surrounding carbon storage in depleted oil and natural gas reservoirs. If understanding of reservoir characteristics and behaviour is based on an invalid or unvalidated structure this increases the risk significantly of surprises emerging during the (re-)injection phase. In the extraction of oil and gas, the industry needs the best structural model to be available at the end of production as the fluids will progressively “see” the fractures and compartmentalisation with declining pressure and saturation. In storage, on the other hand, accuracy is required at the beginning of the injection processes to predict the interaction of fluids with the structural framework during increasing pressure and saturation. Static structural models – either cross sections or 3d models – remain “artist’s impressions” of the geology until they have been assessed (validated) for their geometric and kinematic integrity. At one level such models can be validated geometrically by area and line length balancing. However, kinematic modelling (forward and reverse modelling through time) offers far greater scope to analyise and understand structural evolution and provides a basis for advanced structural modelling leading to the development of fracture models and calculation of their properties (e.g. connectivity, permeability and porosity tensors) to determine the full fluid flow characteristics of the reservoir.

A typical kinematic modelling workflow relevant to carbon storage in the North Sea involves seven stages – data import and integration; model validation and conditioning; analysis of structural history and deformation style; identification and sensitivity testing of various structural variables; 3d restoration and backstripping of selected scenarios; strain analysis in the reservoir horizon to predict potential sites of strong sub-seismic scale fracturing and fracture modelling. Our case study is a salt-bounded dolomitic limestone reservoir unit. We first apply backstripping techniques to determine the displacement history on the fault framework and the timing of salt emplacement and withdrawal. Backstripping of cross sections allows the structural history to be determined quickly and identifies the sequence of events to be used in 3D kinematic modelling (restoration and forward modelling). Fracture modelling is then carried out based on a “recipe” determined by the structural evolution of the valid model. For each step (increment) of the structural evolution a structural concept is invoked which predicts, in a general way, the expected relationship between fracturation and each stage of the structural development. In our case study, the main fracturing events are related to 1) extensional/transtensional deformation during the main rifting phase; 2) inversion during subsequent Alpine contraction. In detail, fracture orientation and intensity may be modelled using either static attributes (e.g. curvature, dip) or dynamic attributes (e.g. incremental strain calculated by forward modelling). The Discrete Fracture Network (DFN) constructed in this way can be tested against fracture data measured in wells and connectivity analysis can be used to predict comparmentalisation of the reservoir. Connectivity analysis can be compared with measured flow rates in wells and if necessary, the model can be (re-)scaled to match the known flow rate behavior. Properties of the model calculated by the software are available for output to reservoir modelling software.

Optimisation of CO2 Storage in a North Sea Aquifer

M. Jin[1], K. Yawa[1], E. Mackay[1], G. Pickup[1], M. Quinn[2]

[1]*Heriot-Watt University*
[2]*British Geological Survey*

A recent study has identified a number of large saline aquifers in the North Sea as potential CO2 storage sites. One of these sites, the Tay Aquifer, has been investigated in detail including study of various scenarios for optimising CO2 storage. The Tay Aquifer is comprised of sequences of submarine fans, which are Eocene in age. The aquifer extends over an area of 2484 square km, with a thickness of 400-500 m, and has a high net to gross ratio.

Using a geological model derived from existing data, with tops/base/thickness from released well data gridded and contoured to produce surfaces, and also published data, a reservoir simulation model was constructed. A number of simulations of CO2 injection were performed, varying the number of wells, their locations and the well type (vertical, horizontal or deviated). In each case the total amount of CO2 injected was 375 Mt over a period of 25 years. Simulations were continued for a further 8000 years to identify extent of CO2 migration within the aquifer system. Buoyancy effects and the dissolution of CO2 in brine were considered, as were the assumptions made about pressure dissipation at the boundaries of the geological structure.

In the first set of numerical tests, only vertical wells were considered. The criterion for selecting the optimum number of wells was a compromise between a high build-up of pressure when few wells are used, and an increase in cost of using more wells. A scenario with three wells was chosen to investigate additional sensitivities. In this scenario, where the formation is relatively thick (400 – 500 metres), there was no significant advantage in using horizontal or deviated wells, which would increase the cost with no significant benefit in terms of improved injectivity.

Also considered were schemes where brine is produced to lower the formation pressure and increase the CO2 storage capacity, and alternatively, where water is simultaneously injected with the CO2 to increase the dissolution of CO2 in brine. However, while injecting water increases the amount of CO2 dissolution, it also lowers the injectivity through as increase in system pressure. In general, the extra injection schemes were not found to be viable in this case, due to the cost of the additional infrastructure.

Could CO_2 Storage Site Performance be Compromised by Palaeo-Gas Migration Conduits in the Overburden?

G. D. Nicoll[1], M. Naylor[1], A. J. Cavanagh[2], S. Geiger[3], R. S. Haszeldine[1]

[1]*The University of Edinburgh,*
[2]*Permedia Research Group, Ottawa, Canada,*
[3]*Institute of Petroleum Engineering, Heriot-Watt University*

Saline aquifers and depleted hydrocarbon fields situated beneath the North Sea are frequently suggested as prime storage locations for anthropogenic CO_2 captured from point source emitters in the UK and mainland Europe. Two sites are already operating successfully offshore Norway; Utsira, since 1996 and Snøhvit, since 2007, collectively storing several million tonnes of CO_2/year. Despite the success of these current projects, one of the major public and scientific concerns is the ability of storage sites to retain CO_2 on the millennial timescales required.

Whilst CO_2 is still a discrete fluid, it is in a mobile, buoyant state and may come into contact with existing features that could affect seal integrity in the long-term, such as geological heterogeneities (e.g. fractures, faults, joints, lithological variations) and palaeo-migration pathways. Some areas of the North Sea are known to contain palaeo-gas seepage pathways within overburden sediments overlying hydrocarbon reservoirs (e.g. Witch Ground Graben). These areas either need to be avoided for CO_2 storage or rigorously assessed in terms of leakage risk.

From interpretation and detailed mapping of 3D seismic (acquired before CO_2 injection operations commenced in 1996), we have identified several palaeo-migration pathways and high-amplitude seismic anomalies within the Nordland Group overburden sediments deposited in the vicinity of the Utsira CO_2 storage site. We attribute these features to thermogenic or biogenic gas migration and accumulation over geological time. These relict pathways may be encountered by the top layer of the CO_2 plume as it ascends and migrates laterally beneath the caprock.

In this paper we assess whether it is possible for migrating supercritical and gaseous CO_2 to re-use these palaeo-migration pathways as preferential bypass routes through the caprock and overburden using our Utsira model as a case study. We evaluate the critical column height required for entry into a palaeo-migration pathway under a range of storage conditions for a CH_4/CO_2/brine system, under the premise that these pathways currently contain methane gas. Risking scenarios are based on phase saturations and pressure, temperature, density, viscosity, interfacial tension and wettability conditions likely to be encountered at depths commensurate with those of the caprock at Utsira.

We conclude that given certain conditions at the caprock, CO_2 can leak more easily into palaeo-migration pathways than CH_4 (i.e. at a lower entry pressure and therefore smaller column height); this assumes that brine densities and, most importantly, pore radii have not changed significantly over geological time (i.e. no cementation or dissolution has taken place). Hence a critical CO_2 column height needs to be established for caprocks deemed to be at risk. Areas containing migration pathways in the overburden should be appropriately risked for CO_2 storage, particularly where seepage is still active. Mitigation strategies may include defining whether the critical CO_2 column height is within an acceptable safety margin for prevailing storage conditions or intervention to pre-emptively seal migration conduits. Although much work has already been done on two-phase CO_2/brine systems and CH_4/brine systems, more experimental work is required to assess the impact of three-phase saturations, wettability and IFT for CO_2/CH_4/brine systems (with and without impurities) for a range of typical storage conditions.

Time-Lapse Seismic Monitoring at Sleipner Provides Insights into Storage Reservoir Performance

A. Chadwick, *British Geological Survey*

Since 1996, the Sleipner CO_2 storage operation in the Norwegian North Sea has injected more than 11 million tonnes of CO_2 into the Utsira Sand, a major saline aquifer. Time-lapse seismic monitoring datasets provide unique images of a developing CO_2 plume in a sandstone reservoir of relatively simple structure. The plume is imaged as a tiered feature, comprising a number of subhorizontal layers of CO_2 each trapped beneath a thin intra-reservoir mudstone. The topmost layer is accumulating beneath the reservoir caprock with its lateral spread closely controlled by buoyancy-driven flow beneath the topseal topography.

The flow properties of the intra-reservoir mudstones exert a major influence on reservoir storage performance, but the mode of transport through these features remains uncertain. Overall rates of flow through the reservoir can be simulated by Darcy flow through semi-permeable mudstones, but this is inconsistent with lateral flow beneath the caprock which appears to behave as a ‘hard’ flow barrier. This is supported by laboratory flow testing of core samples which indicates that the caprock will behave as a capillary seal under reservoir conditions. Detailed assessment of CO_2 distributions in the plume suggest that upward flow through the reservoir is via a limited number of discrete conduits. These may correspond to some form of induced pathway, but pre-existing heterogeneities such as small faults, soft-sediment structures and erosional features are preferred. Intermediate wetting behaviour in the CO_2 – water – rock system could reduce capillary trapping capacity. This is currently being investigated in terms of CO_2 layer geometries in the reservoir and potential flow rates within the seals.

Poster Presentation Abstracts

The Impact of Simulated Mutual Dissolution of CO_2 and Water on the Short Term Pressure Build-Up during CO_2 Injection

N. Heinemann[1], G. Pickup[2], M. Wilkinson[1], R. S. Haszeldine[1]

[1]School of GeoSciences, The University of Edinburgh, The King's Buildings
West Mains Road, Edinburgh, EH9 3JW
[2]Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh, EH14 4AS

The injection of CO_2 into a saline aquifer leads to a rapid fluid pressure increase that derives from the instantaneous displacement of in situ brine in the vicinity of the well. There is a growing concern that pressures may reach levels at which fractures may open or that shear movement may occur on fault planes. Although the rock failure would probably occur in the reservoir rock, it is likely that the seal would also be affected considering that reservoir and cap rocks are not isolated systems.

There has been little work carried out on the simulation of pressure build-up in the vicinity of a CO_2 injection well, even though accurate simulation of this is crucial as the increase of pressure can be greatest there. Mutual dissolution of CO_2 and water, which is usually simulated as an instantaneous reaction, probably compromises the results of the simulation of the pressure development. Although CO_2 dissolves relatively quickly, especially along the CO_2-front, the idea that CO_2 gas rich phase and the water phase are always in equilibrium, is rather unrealistic. Therefore, the simulation of the early stages of CO_2 injection into a saline aquifer leads to a temporary increase in CO_2 dissolution.

This study is an evaluation of the impact of mutual CO_2 dissolution on short term pressure simulation in the vicinity of the injection well. Numerical simulations were conducted to investigate processes that influence the simulated pressure development during an injection of 200.000 sm^3 CO_2 (~ 374 t) per day into a 1 km deep saline aquifer. A radial model with a radius of 742 m and a thickness of 100 m was chosen. CO_2 injection was modelled using the ECLIPSE Compositional simulation package (E300) (Schlumberger 2008). The add-on CO2STORE was applied because it is capable of computing the mutual solubility of CO_2 and saline water.

One key finding of our research is that the temporary increase in CO_2 dissolution may occur due to numerical dispersion which also artificially reduces the pressure. This emphasizes the importance of being aware of the limitations of numerical simulations, and the need to select parameters appropriate to the scale of the simulation grid.

To Leak or not to Leak? Investigating the Plumbing of CO_2 fluids in Central Italy

J. J. Roberts, R. A.Wood, R. S. Haszeldine, S. V. Gilfillan, P. Cowie, *Scottish Centre for Carbon Storage, The University of Edinburgh*

Italy is a region of anomalously high natural CO_2 degassing; it is estimated that 5.3 Mt/yr of CO_2 is released through the crust from CO_2 seeps. Travertine (continental carbonate) formation is also widespread in Italy and is related to high pCO_2 waters. Interestingly, CO_2 flux is much reduced in the most seismically active belt in the Apennines where unusual seismic sequences have been attributed to the presence of trapped CO_2 fluids at depth. In addition, hydrocarbon exploration drilling in Central Italy frequently encounters CO_2 accumulations, some of which are geographically related to CO_2 seeps implying breaching of the reservoir seal, analogous to leakage scenarios from engineered CO_2 storage sites.

Gas seep, exploration and tectonic data have been collated to identify:

a) Patterns in the distribution and characteristics of CO_2 seeps which can elicit the local and regional controls on concentration and/or flow of CO_2 fluids.

b) Case studies of similar CO_2-bearing structures which either leak or retain CO_2. A detailed study on the structural and geochemical relationships between deep CO_2 reservoirs, surface CO_2 seep sites and travertine deposits will describe the internal "plumbing" within the crust in this region.

This research will improve our scientific understanding of processes that generate seismicity in Central Italy, and will also be important for understanding and preventing CO_2 leakage from carbon storage sites.

Exploration for CO_2 Storage Sites in the Norwegian Sector of the North Sea Basin

S. Hagen, K. Gro Johanson, R. Maurer, J. Moisan, R. Thorsen, J. Ove Thorsplass, *Statoil - New Energy*

Statoil has a dedicated sub-surface group working on a programme to screen and mature CO2 storage reservoirs in the Norwegian part of the North Sea basin.

This poster will highlight the background for this work, the activities involved, the methodology applied and the current status of the programme.

Upscaling of Joint Elastic-Electrical Properties of Reservoir Rocks

A. Best[1], L. North[1], T. Han[1], C. McCann[1], J. Sothcott[1], L. MacGregor[2]

[1]*National Oceanography Centre, Southampton*
[2]*Offshore Hydrocarbon Mapping Ltd., Aberdeen*

Controlled source electromagnetic (CSEM) and co-located seismic surveying offers improved imaging and inversion of reservoir pore fluid and rock properties for reservoir characterisation and monitoring. The method is equally applicable to hydrocarbon and CO_2 reservoirs. The main challenge facing inversion of joint seismic-CSEM data is the lack of detailed rock physics knowledge on joint properties. Issues such as electrical current frequency become important when comparing CSEM resistivity values at < 10 Hz to those obtained from well logging tools at 50 kHz. Together with known elastic wave frequency dependent velocity and attenuation between seismic (< 100 Hz), sonic (2 – 20 kHz) and ultrasonic frequency ranges (> 100 kHz), the proper comparison of results from different measurements methods is a complex problem. To gain insight into the scaling laws affecting both elastic wave and electrical properties, we are conducting laboratory experiments to determine the range of joint elastic-electrical behaviour of typical reservoir sandstones and carbonates. The techniques involve: i) an ultrasonic pulse-echo system (giving P- and S-wave velocity and attenuation at 400 – 1000 kHz) combined with a circumferential electrode array for resistivity (4 – 50 kHz) on 5 cm diameter, 2 cm long core samples inside a pressure cell rated to 70 MPa; ii) a sonic resonant bar method for 2 cm diameter, 30 cm long samples inside a pressure cell also rated to 70 MPa giving P- and S-wave velocity and attenuation in the range 3 – 50 kHz; iii) a resistivity system for use on the sonic resonant bar samples (4 – 50 kHz). Initial results for brine saturated sandstones show systematic pressure and frequency effects on elastic and electrical properties moderated by lithological correlations with reservoir rock porosity, permeability and clay content. The results will guide the development of rock physics models for improved joint inversion of seismic-CSEM datasets.

The Potential of Controlled Source Electromagnetic Surveying in CO_2 Storage Monitoring

M. Ellis, M. Sinha, *National Oceanography Centre, Southampton UK*

Controlled Source Electro-Magnetic (CSEM) surveying is a powerful geophysical tool for mapping electrical resistivity in geological structures beneath the sea floor. It is increasingly being used to investigate regions of potential economic or industrial interest. CSEM imaging exploits the variation in resistivity between brine saturated sediments and gas/oil/hydrate saturated sediments to give a better understanding of the pore fluid and water saturation. Therefore EM methods may be ideally suited to the study of CO_2 storage. Geophysical methods used to monitor the migration and leakage of CO_2 at current Carbon Capture and Storage (CCS) sites include seismic, gravity and borehole monitoring. Although CSEM is not currently used, it has potential advantages over other geophysical survey methods. In particular, CSEM offers the possibility of detecting and quantifying relatively low levels of CO_2, information that is needed for early warning of CO_2 leakage and long term site management. Unlike seismic velocity, formation resistivity is known to be sensitive to brine saturation (S_w) over a wide range of S_w. The high resistivity of immiscible CO_2 (whether in its gaseous, liquid or critical states) means that low concentrations should be detectable; while the sensitivity of CSEM responses to formation resistivity should enable quantitative estimates of CO_2 saturation.

This study uses 1d forward modelling to determine the change in CSEM response at possible storage sites when CO2 is injected. The background resistivities for the models are based on the active Sleipner storage site and the proposed storage site in the Miller oil and gas field. The modelling shows that the changes in resistivity caused by the presence of CO2 (determined using Archie’s equation) are detectable by CSEM in some scenarios. However the vertical distribution of the CO2 does play a major role in determining the amount of change in the CSEM response.

Burlington House
Fire Safety Information

If you hear the Alarm

Alarm Bells are situated throughout the building and will ring continuously for an evacuation. Do not stop to collect your personal belongings.
Leave the building via the nearest and safest exit or the exit that you are advised to by the Fire Marshall on that floor.

Fire Exits from the Geological Society Conference Rooms

Lower Library:
Exit via Piccadilly entrance or main reception entrance.
Lecture Theatre
Exit at front of theatre (by screen) onto Courtyard or via side door out to Piccadilly entrance or via the doors that link to the Lower Library and to the main reception entrance.
Piccadilly Entrance
Straight out door and walk around to the Courtyard or via the main reception entrance.

Close the doors when leaving a room. **DO NOT SWITCH OFF THE LIGHTS**.

Assemble in the Courtyard in front of the Royal Academy, outside the Royal Astronomical Society.

Please do not re-enter the building except when you are advised that it is safe to do so by the Fire Brigade.

First Aid

All accidents should be reported to Reception and First Aid assistance will be provided if necessary.

Facilities

The ladies toilets are situated in the basement at the bottom of the staircase outside the Lecture Theatre.

The Gents toilets are situated on the ground floor in the corridor leading to the Arthur Holmes Room.

The cloakroom is located along the corridor to the Arthur Holmes Room.

Ground Floor Plan of the Geological Society, Burlington House, Piccadilly