GEODISC
THE SEARCH FOR GEOLOGICAL SEQUESTRATION SITES IN AUSTRALIA

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ABSTRACT

The APCRC GEODISC research program has encountered many challenges looking for geological sequestration sites for CO_2 in Australia, but has also found a number of solutions. Challenges already faced have been in searching databases effectively, developing uniform terminology and evaluation methodology, establishing comparative quality assessment of Australia's sequestration sites against each other and against those from overseas, improving understanding of the injection and trapping properties of CO_2 and predicting its effects on reservoirs/seals, and in developing economic and reservoir models.

Pilot research projects at both the regional and site specific levels have been used to address these issues, as well as developing generic models before building site specific models. Each of these processes has enabled methodology to be established and resources to be allocated to undertake the scope of such a broad-based research program.

Preliminary conclusions reached from the regional study of Australia suggest that suitable deep saline formations will be widespread, have the largest sequestration volumes, and are likely to be the most economically attractive option currently available. In the future, some depleted oil and gas fields and enhanced coal-bed methane production sites may also represent local high-volume options. It is considered unlikely that sequestration into voids/cavities or associated with enhanced oil recovery (EOR) will represent large-scale options. Despite these limitations, it is expected that many of Australia's sedimentary basins will have excellent sequestration sites. The GEODISC program will provide an assessment of the critical factors required for success at each site.

Several of the highest-ranking saline formations are currently undergoing site-specific study. Early indications are that the petrophysical data required for models of injection, migration, and trapping is of limited availability. Various methods are required to estimate the distribution and likely variability of these parameters across any site. Issues such as storage efficiency and the use of carbonates as CO_2 sequestration sites remain amongst the challenges for the future. These and other uncertainties in the distribution, quantity and quality of data required for predictive modelling necessitates an innovative and thorough approach to handling both risk and uncertainty. This will also be a challenge to be addressed during the GEODISC program.

From the work to date, it appears that it will be technically feasible to sequester large quantities of CO_2 in geological formations in Australia for long periods of time. What is less clear is whether this can be done at a cost that would not impose an unreasonable economic burden on Australian industry. The future results for GEODISC will be highly relevant to answering this key question.

INTRODUCTION

The GEODISC research program of the Australian Petroleum Co-operative Research Centre (APCRC) commenced in 1999 after extensive discussion with the petroleum industry during 1998. GEODISC is a collaborative program examining the technological, environmental and commercial feasibility of geological sequestration of CO_2 in Australia with particular application to the natural gas and LNG industry. However, the program, which is partly funded by many of Australia's gas production companies, is reviewing all of the Australian sedimentary basins for their geological sequestration options, irrespective of the origin of present or predicted future emissions of CO_2.

Much of the background information regarding Australia's CO_2 emissions, options for the storage of CO_2, specific options for geological sequestration, and the structure of the GEODISC program is addressed in Cook et al (2000).

OBJECTIVES

Specific questions being addressed by the program are as follows;

- Where, in Australia's sedimentary basins do we have suitable geological formations with the right properties that are likely to provide traps for supercritical CO_2?
- What will be the geochemical and geomechanical response of geological barriers (seals) to the introduction of large quantities of CO_2?
- What will be the range of chemical reactions and their products resulting from rock-water/brine-CO_2 interactions and what will be their impact on CO_2 sequestration?
- What are the safety and environmental risks involved in CO_2 injection and how do we ensure that the technique is acceptable to the Australian community?
- How much will it cost to dispose of CO_2 by geological disposal and what is the most cost-effective way to apply the technique?

The various options for geological sequestration of CO_2 are shown in Figure 1. GEODISC is investigating each of these options for every sedimentary basin in Australia.

APPROACH

The GEODISC program is divided into ten specific projects all of which are now in progress and many of which have been operating concurrently since early 2000 (Cook et al, 2000). This paper will briefly address a selection of preliminary results and issues that have arisen from some of these projects including; CO_2 properties in the subsurface (Project 3), regional site analysis (Project 1), geomechanical response to fluid injection (Project 5), site specific analysis (Project 2) and economic modelling (Project 8).

PROJECT 3; CO_2 PROPERTIES and STORAGE DENSITY

An understanding of the physical properties of CO_2/brine mixtures enables some useful generic conclusions to be drawn about CO_2 sequestration. Upon injection into a saline formation, the CO_2 will normally be in a single-phase state, the density of which depends on the assumed conditions for temperature and pressure in the formation.

There is a sharp increase in CO_2 density at depths between 500 and 1000 m, due to the fact that average temperature and (hydrostatic) pressure conditions or those depths are close to the critical point of pure CO_2 (31°C and 7.4 MPa). Below a depth of about 1000m the density becomes fairly constant. For a hydrostatic pressure gradient of 10.5 MPa/km, a mean surface temperature of 15°C and a geothermal gradient of 25°C/km, the density plateau is 720 kg m^{-3}, while for a geothermal gradient of 35°C/km it is about 610 kg m^{-3}. Thus there is no significant advantage in terms of storage density in going to depths much greater than 1000 m; also cooler reservoirs provide more storage. Despite the fact that the most economic solution would usually be to inject supercritical CO_2 as shallow as possible, the geologic setting of reliable and adequate reservoir/seal pairs, for example on the Northwest Shelf of Australia, means that in some circumstances greater depths often need to be considered. The plateau densities are significantly less than the density of water under the same conditions, and as a result of this density difference, the lighter CO_2 tends to rise and occupy the pore space beneath a low permeability layer that constitutes an overlying seal.

CO_2 is slightly soluble in water, and on long enough time scales this will be the dominant form of storage in any formation. For typical subsurface conditions, the solubility of CO_2 in 1 M brine plateaus at about 41–48 kg m^{-3} below 600 m depth. Increasing the salinity to 4 M decreases the maximum solubility to around 24–29 kg m^{-3}. Geochemical reactions between the carbonated water and the rock can increase the solubility on long time scales. In carbonate formations, small amounts of calcite and dolomite will dissolve, increasing the solubility by 2–10% (Gunter, Perkins and McCann, 1993). Formations containing basic silicate minerals offer further possibilities, with the dissolution of feldspars or clays releasing divalent ions, which in turn react with bicarbonate ions to precipitate carbonate minerals. Numerical modelling suggests that the capacity to dissolve CO_2 could increase by more than 20% in the most favourable cases, but the kinetics are slow (10's to 100's of years). Because of this, GEODISC and other researchers are looking closely at the mineral assemblages and timing on CO_2 emplacement occurring in naturally occurring CO_2 accumulations to provide evidence that these changes have occurred (see Stevens et al, this conference).

It is instructive to compare the storage density (in terms of kilograms of CO_2 per cubic meter of formation) in saline formations, with the density of CO_2 adsorbed on coal. The latter is important for sequestering CO_2 in deep unmineable coal seams. Representative data (up to 5 MPa at 30°C) is taken from Stevenson (1997). Figure 2 compares the total storage density as a function of depth for a formation of 15% porosity (and 20% residual water saturation) with adsorption on coal, assuming that coal properties are constant with depth.

Adsorption onto coal clearly provides the greatest storage density at depths less than 600m, and at greater depths it is still competitive with the dense gas phase of saline formation storage, depending on the porosity. The endpoint, when all the CO_2 is dissolved in the water, gives densities that are an order of magnitude less. One of the main obstacles to sequestration in coal is finding coal seams which are too deep to mine but which are still sufficiently permeable to inject effectively.

PROJECT 1; GEOLOGICAL DATABASES

Previous overseas studies on geological sequestration (Hovorka, 1999) have encountered significant problems in obtaining data, in that whilst large volumes of data exist in mature petroleum provinces, either the data was not in an accessible or similar format, or data had not been collected in the intervals of interest. Thus to achieve a systematic regional assessment of the geological sequestration potential of Australia, it was necessary to rely upon a number of Australian Geological Survey Organisation (AGSO) extensively populated petroleum databases.

These databases are integrated through the use of time series searching, allowing different basin elements to be rapidly compared using the same age constraints for the rock units that are part of the site under investigation. This database system has allowed rapid assessment of areas using various cut-off limits relevant to sequestration of CO_2. Some of the data types that limits that have been applied to include; depth (> 800m to keep CO_2 supercritical), porosity and permeability, various coal attributes, temperature and pressure, existence of hydrocarbons in the well, and locations adjacent to significant earthquake epicentres.

PROJECT 1; REGIONAL ANALYSIS

Project 1 within GEODISC has as its two primary tasks; (1) to delineate the most appropriate parameters (‘MAPs’) for geological formations likely to be suitable for large-scale CO_2 injection and (2) to compile regional data to determine formations and potential locations with MAPs for large-scale CO_2 injection.

In the early stages of this project it was realised that many of the problems encountered by other researchers looking at potential sites for geological sequestration of CO_2 around the world (Hovorka, 1999) were also going to be encountered during this project. Most of the factors which make a potential hydrocarbon play attractive to an explorer are similar to those that are favourable for sequestration of CO_2. When sites are considered prospective for hydrocarbons they are eliminated as sites for CO_2 sequestration in GEODISC on the basis that compromising a known or potential resource is not considered to be an option. The converse is that options for sequestration in geological intervals that are non-prospective for hydrocarbons have to be carefully examined as to why they are not favourable. For example, if there were no effective seal for petroleum, would the formation similarly not be suitable for CO_2 sequestration? Where geological intervals have been perceived to be too shallow for hydrocarbon plays or are poorly understood, then often there is little data available for assessing their CO_2 sequestration potential. Water-well databases, which appeared initially to be extensively populated, provided little useable information for GEODISC.

The limitations that the combination of these factors placed upon Project 1 led to a decision to first undertake a short (6-7 week) pilot study. The specific aim of this study was to assess what was available in the AGSO databases that would be of value for GEODISC, and to determine a likely set of products that could be extracted. The results of the pilot study were then utilised in planning the rest of the project and gave realistic timings for delivery of products. The Browse Basin was chosen for the pilot study because it is a tectonically and geologically simple basin, with a well defined but small data set.

Australia has over 300 known sedimentary basins, of which at least 200 are over 1000m thick (Fig. 3). Of these, over 50 could be considered to contain promising sites for preliminary study in terms of location (near CO_2 source; acceptable water depth) and geological characteristics. In order to prioritise the work, Project 1 was divided into three stages:

*Stage 1 Basins – those basins with existing LNG facilities or potential and/or known significant occurrences of CO_2 (21 sites identified)
*Stage 2 Basins – The remaining basins with significant petroleum exploration potential (35 sites identified)
*Stage 3 Basins – The rest of the sedimentary basins in Australia that meet the criteria of being over 1000m thick and are not extensively structured or metamorphosed. Stage 3 basins may have only limited potential, due to either their geologic characteristics or the current poor state of knowledge of the sedimentary sequences in the basins (~ 30 - 40 sites expected to be identified)

TERMINOLOGY, METHODOLOGY AND FURTHER RESEARCH

Because sequestration is a rapidly developing geological science and Project 1 needed to apply it across the vast and diverse geological province of Australia, numerous conceptual issues and problems required resolution. These included;

how to describe suitable sites for study (terminology),

how to compare and contrast each of the sites for the purpose of ranking them (methodology),

how to identify and address critical factors that were uncertain or unknown, and which had the potential to limit the implementation of the findings of GEODISC (future research).

Terminology: Environmentally Sustainable Site For Carbon Dioxide Injection - 'ESSCI'

The existing literature on geological sequestration is inconsistent in its description of the various conceptual options as to what type of site is being described, be it a depleted oil/gas field, saline formation or coal seam (Fig. 1). 'Play', 'prospect', 'reservoir' and 'aquifer' all imply that some type of natural resource exists or is being explored for within a geological sequence. To remove potential confusion that an established resource may be sterilised, a new term was required to describe the wide variety of potential CO_2 injection sites. As such the term ESSCI was developed. This is an acronym for 'Environmentally Sustainable Site for Carbon dioxide Injection' (the play on words with the great Australian 'Esky' as a place to keep your valuables cold –usually beer and prawns –was also thought to be appropriate.) Hence the term ESSCI has been used for grouping the various components of a CO_2 injection site, in the same manner as 'play' or 'prospect' is used for various exploration industries.

Methodology: Ranking.

In order to assess potential ESSCIs occurring in an area the size of Australia at a regional scale, it was necessary to develop a methodology that would allow the capture of detailed analyses for each ESSCI site, in a rigorous and consistent manner in order to allow comparison between ESSCIs. The approach adopted was to modify the 'Play and Prospect' risk assessment approach that has been used in the oil exploration industry following the well-documented principles of White (1987). It has been modified in a manner similar to that documented for Australia in an example which examined both petroleum exploration plays and quarries in the hard rock industry (Bradshaw et al, 1998).

Five factors were chosen to describe an ESSCI (Storage Efficiency, Injectivity Potential, Site Details, Containment, and Existing Natural Resources), each of which have sub-elements that are necessary to consider when assessing the geological risk. Because these ESSCI factors are independent, they can be multiplied together, and then their product multiplied against the estimated storage volume or capacity to provide a risked capacity. This is a valuable tool for comparing different ESSCIs in different basins. The multiplied factors used in Project 1 include;

ESSCI CHANCE = Product of all five individual ESSCI factors
RISKED CAPACITY = ESSCI Chance x total estimated storage capacity of CO_2
ESSCI RATING = ESSCI Chance / radius of 1 Tcf (53.65 x 10^6 T) CO_2 at the site

The *ESSCI Rating* utilises a calculation made for the site based on determining the radius out from the injection site that 1 Tcf (53.65 x 10^6T) of CO_2 could fill, given factors such as the reservoir quality and thickness, depth, pressure and temperature. This is simply an estimate of the theoretical cylinder that the injection bubble could form not the actual shape of the bubble at each site; it is used only for reservoir comparison purposes.

Once Project 1 studies were completed and risk assessments had been made of various ESSCIs around Australia (currently approximately 90 ESSCIs have been examined), generic economic assessments were conducted (Project 8; see later section). These assessments have then also been used as multipliers for the various risk factors and used to high-grade sites suitable for detailed analysis in Project 2.

Further Research: Storage Efficiency

As predicted in the initial planning of GEODISC, many topics surfaced at the beginning of the project that had the potential to influence a successful outcome. One critical topic is that of rates, be it rates of CO_2 injection, migration, or mineralisation. However, at this stage in GEODISC, a particular uncertainty is that of Storage Efficiency and the actual volume of CO_2 that can be injected into any site.

Analysis of the early work on storage efficiency documented major conflicts in the understanding of how storage efficiency will affect saline reservoirs versus depleted oil and gas fields (Holloway et al, 1996). The studies on saline reservoirs on which Holloway et al (1996) was based, suggested very low values (2%) for storage efficiency (van der Meer, 1993 & 1995) whereas for depleted oil and gas fields it was assumed that the volume of CO_2 that could be injected would equal the volume of hydrocarbons that had been extracted allowing for changes in compressibility (Holloway 1996).

In response to the early low values of storage efficiency for saline reservoirs, Holt et al (1995) undertook studies of reservoir simulation associated with Enhanced Oil Recovery (EOR) using CO_2 in a water-flooded reservoir. In contrast to the work of van der Meer (1992, 1995), they obtained storage efficiency rates of 13 – 68% of pore volume (PV). Their simulation examined varying injection rates, permeability and dip of the reservoir (up to 10 degrees). Injection rates of 0.4% PV/year gave storage efficiency values >30%, and at 1.6% PV/year gave 16% storage efficiency. By varying the absolute permeability, the ratio of vertical to horizontal permeability (Kv/Kh) and relative permeabilities, whilst keeping the injection rate constant (1.6% PV/year), they achieved a range of 13 – 26% storage efficiency. These simulations (which have included reservoir conditions where Kv/Kh ranged from 0.01 to 0.1 (Van der Meer 1992 & 1995) and 0.04 – 0.004 (Holt et al, 1995)) concluded that CO_2 would migrate laterally rather than vertically after injection into the reservoir. The properties of Australian reservoirs indicate that these Kv/Kh values previously used in modelling values represent the lower 2% of Australian reservoir conditions. Further discussion on this topic occurs in Bradshaw and Rigg (in press).

Low saline reservoir storage efficiency values have been requoted in many subsequent reviews of CO_2 sequestration potential with no apparent case-specific analysis of the actual reservoirs at any proposed site. This raises the possibility that erroneous assumptions may have been made in some CO_2 injection scenarios. For very large gas fields with high CO_2 contents, such as those containing over 1 Tcf / 53.65 x 106 T of CO_2, it could lead to a conclusion that no single site will be capable of sequestering the CO_2 that the field produces. Such a conclusion would affect the economic viability of an entire project, as multiple injection sites for a single CO_2 source in an offshore setting would make projects cost prohibitive.

GEODISC has concluded that reservoir simulation has to be case specific and no universal number can be used for storage efficiency. Numerous factors including depth, reservoir parameters, supply and injection rate, remaining fluids and pressure regime will influence the result of the simulation. Perhaps more importantly for GEODISC, how do they apply to Australian reservoir examples given the large variance in permeability? The answer will only be derived from the site-specific reservoir modelling that will be undertaken later in the program.

PROJECT 4; POTENTIAL FOR FAULTING INDUCED BY FLUID INJECTION

Fluid injection into the subsurface can create fracture permeability by inducing failure along fractures and faults. Growth of fracture networks forced by fluid injection can for example be demonstrated by recording the location of induced microseismic events in the vicinity of an injection well (eg. Shapiro et al, 1997). Injection-induced faulting during CO_2 injection must be avoided because the formation of connected fracture and fault networks could lead to CO_2 leakage.

Brittle failure in rocks can be induced by high fluid pressures that reduce the shear strength of rocks (eg. Handin et al., 1963). Thus one goal of the GEODISC program is to predict fluid pressures that will not induce brittle failure or fault reactivation during the subsurface injection of CO_2. The stress tensor needs to be known for an accurate determination of fluid pressures that can lead to fault reactivation. Once the stress tensor is determined, as for example, from borehole data (eg. Castillo et al., 1998; Hillis et al., 1998) the likelihood of reactivation of faults with known orientation can be assessed. The geomechanics project within GEODISC will also evaluate whether new fractures can form in intact reservoir rocks or in cap rocks and the likely orientation of such potential new fractures. In some cases, generation of fractures during injection could be beneficial in the same manner as fraccing can be beneficial during hydrocarbon production.

It is noted that in the upper few kilometers of the earth’s crust the state of stress can be close to failure (eg. Scholz, 1990), especially in active tectonic settings. Areas that are close to failure may be identified by the occurrence of creeping faults, current surface deformation, and recent seismicity. In such areas, subsurface fluid injection is more likely to lead to faulting.

In summary, to facilitate safe underground injection of CO_2, critical fluid pressures that can induce brittle failure and fault slip in potential injection sites need to be estimated. To estimate such fluid pressures, the stress tensor, fault orientations, and rock and fault frictional properties need to be determined. In addition, the seismic history and tectonic activity of areas that contain potential injection sites need to be investigated to detect zones of recent deformation where the state of stress may be close to failure.

PROJECT 2; SITE-SPECIFIC ANALYSIS

Project 2 aims to characterise in detail the geology of the ESSCIs at specific sites in Australia, to assess the hydrodynamic regimes and to create 3D geological models for input into engineering simulations of CO_2 injection.

GEOLOGICAL MODEL OF THE PETREL SUB-BASIN

As a result of the ranking scheme outlined in Project 1, the non hydrocarbon-bearing Jurassic-Cretaceous succession in the offshore Petrel Sub-basin, NW Australia, was selected as a pilot site for Project 2, as it ranked highly in all assessment criteria except a location close to a CO_2 source. Once again the purpose of a pilot site was to establish the methodology and approach required to characterise the ESSCIs in more detail, to identify any likely problems, and to allow for any changes in the understanding of what constitutes a good sequestration site for CO_2.

In order to illustrate some of the data availability issues and how these are dealt with, it is useful to examine some of the ESSCI-specific studies from the Petrel Sub-Basin. The Jurassic Plover and Elang Formations in the Petrel Sub-Basin (referred to as the Plover ESSCI) and the Early Cretaceous Sandpiper Sandstone (referred to as the Sandpiper ESSCI) are regionally extensive sandstone units, separated by the Frigate Formation (referred to as the Frigate Inter-ESSCI seal), all regionally sealed by the Bathurst Island Group (Fig. 4). These potential CO_2 sequestration reservoirs were studied on a basin-wide scale, because of the lack of structural closure in the basin centre at this stratigraphic level. The approach taken was to interpret the Jurassic and Early Cretaceous succession within a sequence stratigraphic framework, using an integrated data set encompassing available 2D seismic, wireline logs of 23 wells, biostratigraphy and limited reservoir/seal core data.

The density of data from the non-hydrocarbon producing Mesozoic succession is very limited. For example, pressure data, which is necessary for the assessment of the hydrodynamics, was only available from four wells within the Plover and Sandpiper ESSCI stratigraphic levels. Core through both the reservoir and sealing formations is considered crucial to the assessment of prospective units for CO_2 sequestration, to undertake detailed reservoir characterisation and to test the actual potential seal capacity. Fortunately, in the Petrel Sub-basin, two wells with core through both the reservoirs and the seal were available, due to the far-sighted policies that existed in the 1960's and 70's of collecting core in regular intervals down exploration wells subsidised by the Commonwealth of Australia.

The study has recognised seven unconformity-bounded sequences (Fig. 5). Geometry of the seismic packages strongly suggests that large-scale heterogeneity may exist especially within the inter-ESSCI seal and the lower part of the Sandpiper. This may help retard the vertical and long-term lateral migration of CO_2. The 3D geological model created from the integrated seismic surfaces and sequence stratigraphy incorporated the geometries seen on the seismic, and provides a realistic geological model for the reservoir simulations (Fig. 6).

Reservoir quality studies based on petrology from cores show that the reservoir sandstones of the Plover and Sandpiper ESSCIs are matrix-poor and have fair to good reservoir characteristics. Diagenesis has reduced the porosity and permeability in the deeper, northern part of the basin. The ESSCI reservoirs are mature compositionally, so there is possibly limited scope for CO_2-mineral reactions unless the CO_2 migrates through pore volumes many times its own volume.

Seal analyses based on Mercury Injection Capillary Pressure (MICP) data of the regional seal indicate that the rocks should be capable of holding back an average CO_2 column height of approximately 400m. Heterogeneities within the reservoirs units, such as thin intra-formational siltstones, have the potential to hold back a CO_2 column height of approximately 15m, which suggests that vertical migration of the CO_2 could be hindered thus encouraging the CO_2 to migrate laterally within the ESSCIs.

At seismic-scale resolution, the Mesozoic succession within the Petrel Sub-Basin appears to be structurally simple, with a relatively unfaulted, but weakly developed unclosed three-way structure oriented along the basin axis. The main faults exist only at the basin margins. However, the low number of faults detected does not mean the possibility of fault leakage should be dismissed, as the stress regime will be critical to the potential for fault failure, an aspect addressed later. Salt diapirism in the sub-basin could provide potential containment risks, due to the possibility of associated sub-seismic interlinked fault networks.

Structural mapping indicates that in general, except for anticlinal closures over salt diapirs, there is no structural closure at the ESSCI stratigraphic levels. The hydrodynamics of the sub-basin therefore becomes critical, and the regional analysis has indicated that the likely flow direction is to the SE, up and out of the basin towards the basin margin. The flow velocity is however calculated to be very slow (1cm/year), and therefore, the CO_2 should migrate with the groundwater very slowly towards the basin margin, assuming no fault leakage. A key issue will be the effect of the rate of injection on long-term migration within the groundwater; however, it is expected that the CO_2 migration rate will only be of the order of metres to tens of metres per year. Detailed reservoir simulations will be required to confirm migration rates and directions, and in particular the interaction of injection, hydrodynamic and dissolution processes.

The potential storage space available encompasses the greater part of the basin depocentre. Therefore, volumetric calculations indicate that the Petrel Sub-basin has huge storage capacity.

GEOCHEMICAL MODELLING OF THE PETREL SUB-BASIN

Equilibrium geochemical modelling was carried out on the Plover and Sandpiper ESSCI, to assess the capacity of these formations for mineral trapping of CO_2. The reservoir rock was modelled as being 75 % quartz, 6% K-feldspar, 6% pyrite, 5% kaolinite and 8% illite i.e. a relatively clean sandstone. Based on representative water chemistry data from other parts of the formation, the total dissolved solids were assessed at around 34000 ppm, with small concentrations of Ca^{2+} (18.2 mmol/l) and Mg^{2+} (1.5 mmol/l) - these cations are important for reactions with the carbonated water. The main solid precipitates derived from the modelling were calcite, dolomite and/or siderite, depending on the composition of the illite. However the simulations predict that the amount of CO_2 that would be trapped in a solid mineral phase would be less than 2% of the amount injected. Further simulations will be carried out to assess the effect of coupling the geochemistry to the multiphase flow, since the transport of the CO_2 within the ESSCI may substantially increase the extent of mineral trapping.

GEOMECHANICAL MODELLING IN THE PETREL SUB-BASIN

Geomechanical theory can be applied to the pilot site studied by Project 2, the Petrel sub-basin. Stress gradients (Fig. 7) were determined from drill data. The curve fit for the minimum horizontal stress (S_{hmin}) was based on pressure data from leak-off tests and some formation integrity tests. The gradient for the vertical stress (S_v) was obtained by integrating rock density data from density logs. The maximum horizontal stress could not be constrained due to a lack of appropriate well log information. Based on in situ stress determination in the northern Bonaparte basin (Castillo et al., 1998) it may be inferred that the Petrel Sub-Basin is subject to a normal to strike-slip stress regime. The orientation of the maximum horizontal stress is approximately 55º NE in the entire Bonaparte basin (Mildren and Hillis, 2000).

Major faults occur along the basin margins and have predominantly a SE-strike; some have a S-strike (Colwell and Kennard, 1996). SE–striking faults are favourably oriented to not slip with normal or strike-slip shear sense. The potential for the reactivation of other faults, such as those occurring near salt diapirs at the northern and southern basin margins cannot be assessed without knowing the complete stress tensor and fault frictional properties. No major faults were detected in the southern central part of the basin during project 2 studies of seismic surveys. This is consistent with earlier studies by Colwell and Kennard (1996). The apparent absence of major faults in this part of the basin is advantageous for the subsurface injection of fluids. This is because fault reactivation in many cases occurs at fluid pressures lower than those required for the formation of new fractures.

Without knowledge of the stress difference and the reservoir rock frictional properties, it is not possible to predict the failure mode of new fractures that could be induced by elevated fluid pressures. However, the gradient determined for the minimum horizontal stress (Figure 7) provides a constraint on pore fluid pressures that could induce new or re-open pre-existing fractures in purely extensional mode. This mode of failure would require pore fluid pressures equal to or greater than the prevailing minimum horizontal stress.

PROJECT 8; ECONOMICS OF CO_2 SEQUESTRATION IN AUSTRALIA

A key part of the GEODISC programme was the construction of a computerised economic model to estimate the costs of CO_2 sequestration in Australian sites for any source and any sink. The total costs of sequestration are dependent on the amount of CO_2 produced and injected, the distance between the source of CO_2 and the disposal site, the reservoir conditions at the injection site and the tax circumstances of the overall petroleum production and CO_2 injection project. The main elements of the costs, particularly of offshore CO_2 sequestration are the costs of compression, pipeline transport, drilling injection wells and installing platforms. There are potentially large uncertainties associated with estimating these costs. They relate to uncertainties in measuring the characteristics of the reservoir and predicting its behaviour during the injection process as well as the potential variations in the costs of drilling wells and the cost of manufacturing plant and equipment.

Given the uncertainties mentioned above, coupled with the range of CO_2 sequestration project parameters that might be encountered in Australia, the estimated costs of sequestration vary considerably. For major offshore developments, the initial capital costs might vary between several hundred million to over one billion US dollars with equivalent proportionate variations in operating costs. This is shown in Figure 8, which gives illustrative initial capital costs of different source / sink combinations in Australia. Taking the combined capital and operating costs and their timing over the full life of a CO_2 sequestration project, the present value ('PV') of the overall costs of CO_2 injection might be as high as US$25 per tonne of CO_2 injected before any tax effect is taken into consideration. Conversely costs as low as US$10 or even less may be possible, as have been suggested by some researchers (Wildenborg, 1999). More work is required in order to obtain definitive figures on sequestration costs for specific sites.

CONCLUSIONS

Australia contains many sedimentary basins with suitable geological formations for the long term sequestering of CO_2. GEODISC has identified potential through a process of ranking at a regional scale using a modified petroleum exploration-ranking scheme. Results show that 'saline formation' ESSCIs (thick, regionally extensive sandstone formations devoid of hydrocarbon and usable groundwater resources) are very common in Australian sedimentary basins and have storage capacities far in excess of present and predicted CO_2 emissions. Depleted oil and gas fields appear to be more limited in both their CO_2 storage capacity and their availability and opportunities for coupled CO_2 sequestration and enhanced coal-bed methane production in eastern Australia is likely to be restricted by low production rates and lack of infrastructure.

A pilot study within the Petrel Sub-basin has demonstrated that saline formation ESSCIs have the potential to sequester enormous quantities of CO_2 in formations not considered prospective for hydrocarbons. Reservoir simulation together with chemical and geomechanical modelling is expected to show that there is little risk of CO_2 returning to the atmosphere within hundreds of years from some of the sites being investigated. Work will continue within GEODISC to model a variety of sites in different geological settings to confirm that long-term geological sequestration is both a reality and is verifiable.

Generic economic models show that the cost of geological sequestration varies depending on the location and rates that CO_2 is produced from source areas and injected into the formation, the geological properties of each ESSCI, the location of injection sites and the tax regime. Using the GEODISC economic model, it is able to estimate the magnitude of costs associated with various source-sink combinations, and thus provide a basis for ranking sites against each other. Current indications are that geological sequestration costs are likely to be of the order of U$5 to US$20 per tonne of CO_2.

The GEODISC program is still not half way through, and even though the regional work that acts as a foundation for much of the program is almost completed, much of the detailed study and research remains to be done. The process is iterative with site-specific work to be completed before ground-truthing against the generic economic and simulation models, which are then fine-tuned and repeated. Once finalised, these simulations will form the basis for designing monitoring programs and conducting a comprehensive risk assessment for all of the steps from transportation of the CO_2 from its source to its final destination. One topic, which is also being addressed, is the study of Australia's naturally occurring gas accumulations containing high values of CO_2. Studying these is expected to provide direct evidence of mineral trapping of CO_2 at the same time as providing additional confidence that CO_2 can be safely sequestered in geological formations for very long periods of time.

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GEODISC FIGURES

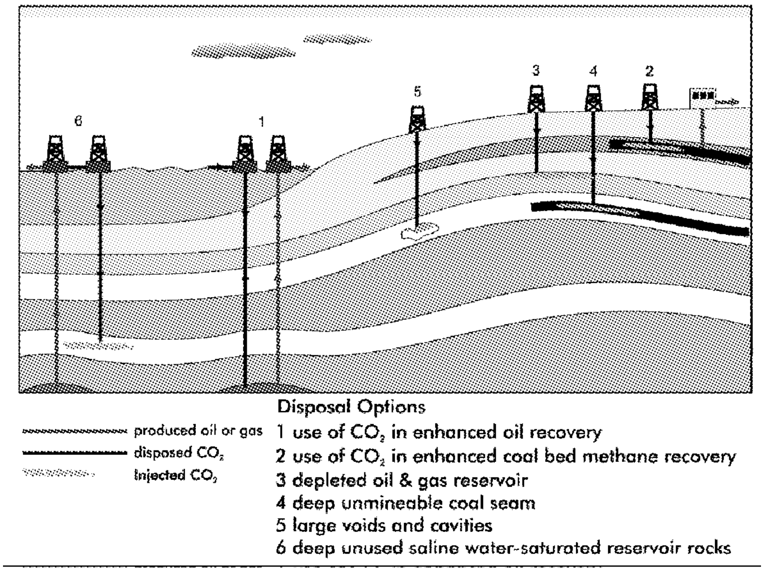

Figure 1. Options for the geological sequestration of CO_2 (Cook 1998)

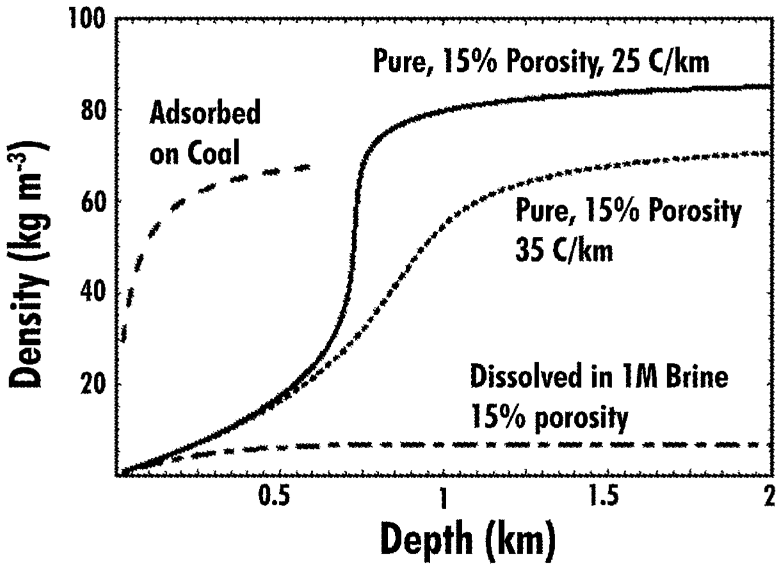

Figure 2: Total storage density (in kg per cubic meter of formation) of carbon dioxide as a function of depth. For the pure carbon dioxide phase and the dissolved phase, the storage density per meter of pore volume has thus been multiplied by the porosity to arrive at the total storage density. The hydrostatic pressure gradient 10.5 MPa/km, the mean surface temperature is 15 C and the geothermal gradient is 25 C/km unless noted.

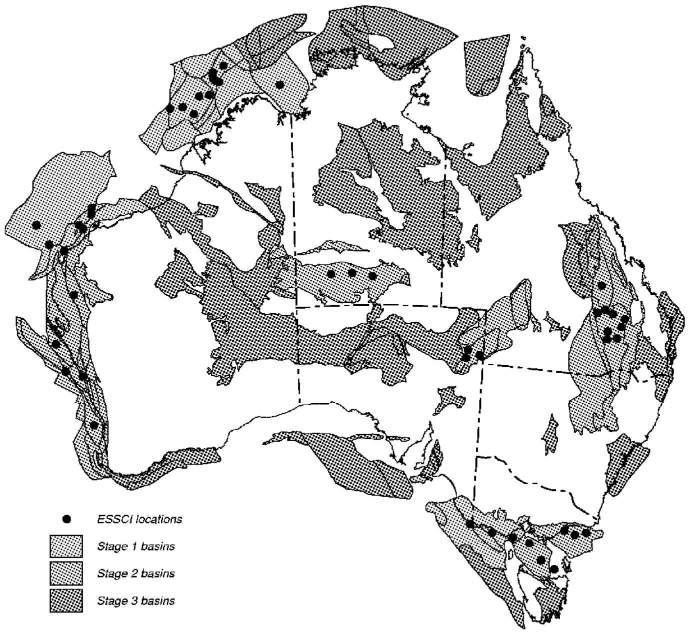

Figure 3. Sedimentary basins map of Australia showing sites that have been examined in Stages 1 and 2 of Project 1, and basins being examined in Stage 3.

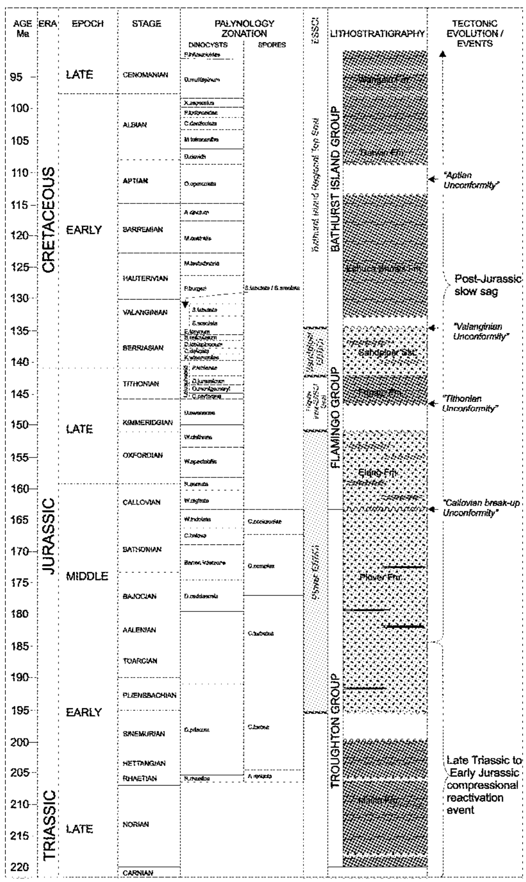

Figure 4. Stratigraphic Column for part of the Mesozoic succession in the Petrel Sub-basin

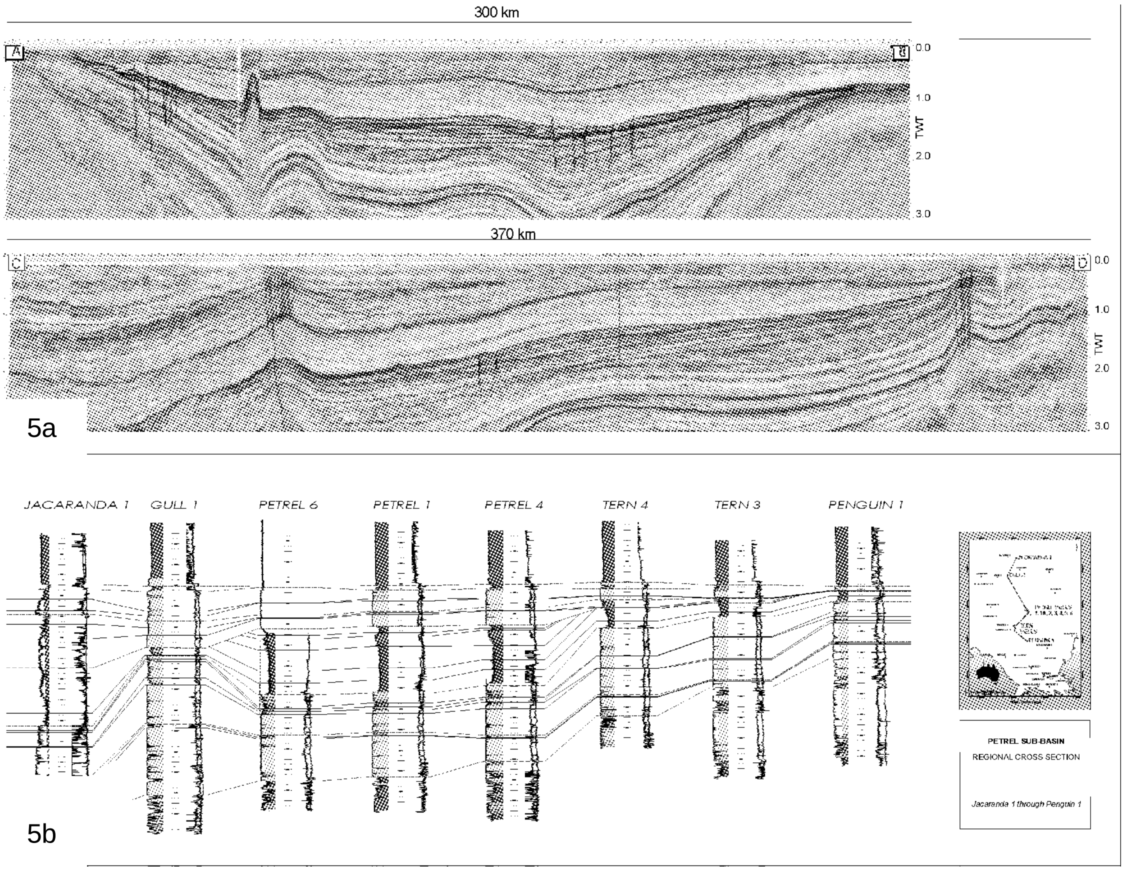

Figure 5a. Interpretation of two regional seismic lines, trending to the NE (A to B, AGSO line 100/03) and to the NW (C to D, AGSO line 100/05). Ten surfaces were correlated across the sub-basin from the top Bathurst Island Group (Late Cretaceous) to the base Plover Formation (Early Jurassic). Major faults are also indicated.

Figure 5b. Regional well correlation panel depicting sequence stratigraphic interpretation for the Petrel Sub-basin. Seven unconformity-bound sequences were identified. Red lines indicate the sequence boundaries and black lines represent transgressive and maximum flooding surfaces. The correlation is flattened on the *M.australis* maximum flooding surface.

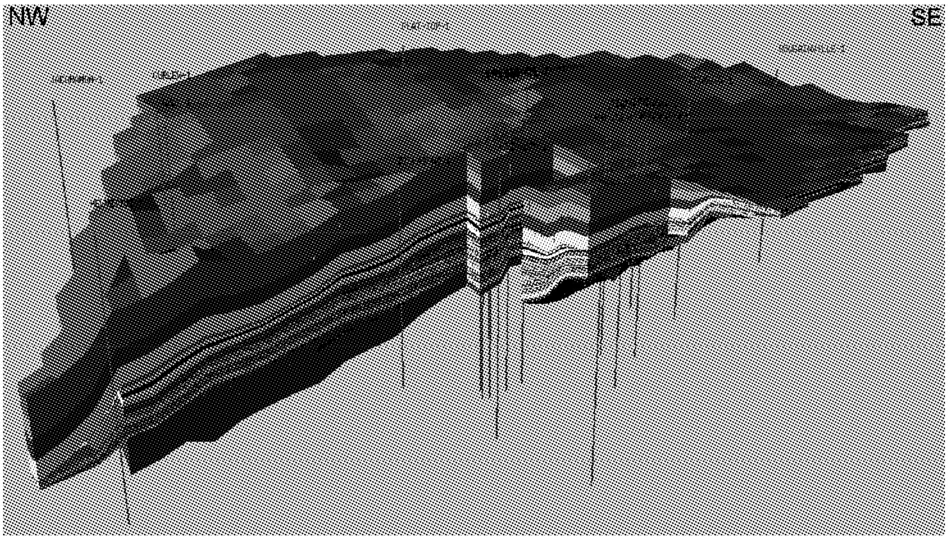

Figure 6. Cut-away section through 3D geological model of the Petrel Sub-basin, showing layer distribution and geometries. Well locations are indicated for reference.

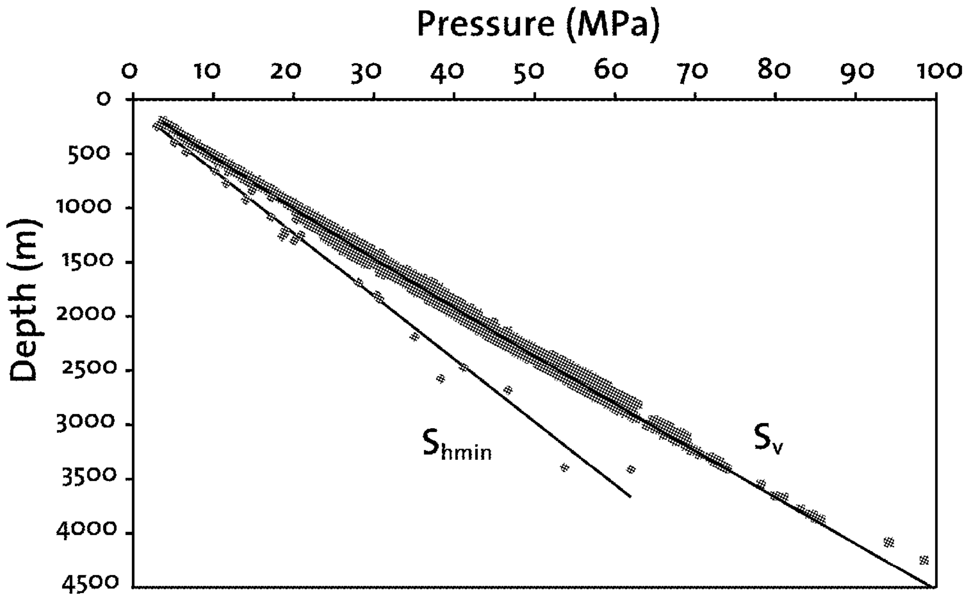

Figure 7. Stress profile based on drill data from the Petrel sub-basin. Estimate of minimum horizontal stress (S_{hmin}) was based on pressure data from leak-off tests and some formation integrity tests (black squares). Estimate of the vertical stress (S_V) was obtained from integrating data from density logs (grey squares).

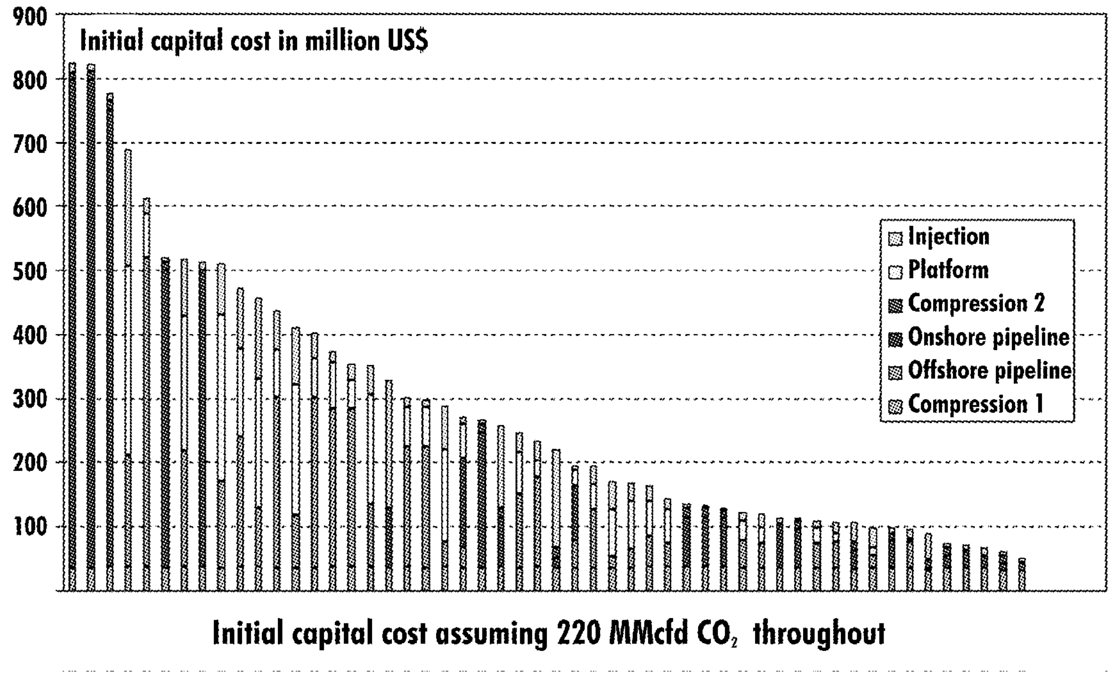

Figure 8. The initial capital costs of different source and sink combinations in Australia.