Deep geological CO2 storage: principles, and prospecting for bio-energy disposal sites

R Stuart Haszeldine, Draft for Paris IEA meeting 24 Sept 04
Professor of Sedimentary Geology,
School of GeoSciences, University of Edinburgh EH9 3JW, Scotland UK s.haszeldine@ed.ac.uk

Summary

The principles of hydrocarbon exploration and production provide well established and tested principles and technologies to investigate storage of fluids in the subsurface. CO2 can be stored in the subsurface using settings of: A) thick permeable coal seams; B) depleted oil and gas fields; C) saline aquifers of regional extent, with an overlying seal. The North Sea Sleipner project shows that CO2 can be injected into the pore space of deep geological aquifers deeper than 800m at 1Mt/yr, using established technology. Suitable sediment sequences of saline aquifers exist in all hydrocarbon-producing areas, are volumetrically much larger than exploited oil and gas fields, and hold the potential to easily store all worldwide CO2 emissions until 2050. Geological principles are established to assess the entire continents for candidate sites of CO2 storage. This shows that opportunity is may be widespread, but need more specific local investigations. Onshore sub-Saharan Africa is considered the most problematic region – but even here there are sediment sequences. No demonstration projects currently exist for CO2 storage using small-scale onshore facilities. A simple estimate, assuming CO2 value of $20 per ton, suggests that single boreholes onshore may be viable over 20 years with supply rates of 100,000 ton CO2 per year. In principle, atmospheric CO2 could be captured by cultivated biomass, and stored deep below ground, in a country distant from the original fossil-fuel CO2 emission site.

Past CO2 levels, spectrum of cycles

The climate of Earth has changed continually during the geological time. Cycles of warming and cooling change are well established, from the longest time scales of tens of millions of years, through a gradual cooling of tens of millions of years, to glacial oscillations of 100,000 year time scales (Jenkins 2001). Also well established, from the sediment record, are decade scale cooling events, and equally rapid warming periods, which may be driven by trans-planet tele-connections. During the past 6,000 years, the earth has been at gradually cooling, and a new glaciation would normally be expected within tens of thousands of years (Fig 1).

Human activity, consequent on industrialization, has used fossil fuels to release fossil carbon, mainly as CO2, into the atmosphere at rates which exceeded natural equilibrium rates by many orders of magnitude. In the geological past, high levels of CO2 have been associated with warm global temperatures, and most scientists consider that the elevation of atmospheric CO2 enforced within the past 300 years will produce consequences of global warming. Global temperature measurements during historical time seem to support this, although local and seasonal variations can still be difficult to disentangle for the complex system. It should be noted that there are many records of past temperature oscillations of similar magnitude on a similar decadal time scales, which have been ascribed to solar flux activity, rather than CO2 fluctuations.

Current predictions are that substantial global warming will occur, possibly by 2.5 degrees centigrade before 2100 (IPCC 2001). Because the global temperature increase, and its effects, appear from ancient data and modelling, to lag behind increases of atmospheric CO2, it is likely that the world is already committed to global temperature increases of six centigrade, or even more, if substantial CO2 emissions from fossil fuel burning continue anywhere in of the world.

Figure 1 here

Burial of organic carbon, generation and migration of oil and gas

An understanding of the deep geological storage of CO_2, is assisted by some basic understanding of natural oil and gas occurrence.

Cycling of carbon at the earth's surface has been extensively studied and the basic sources, sinks, and fluxes are moderately well understood. There is a small crossover from the surface cycle, of about 0.1% per year, into sediments, which eventually become deeply buried, to store biological carbon into the geosphere.

This biological carbon becomes heated as it is buried within natural sediments. Initially degradation is mediated by bacterial action. At temperatures warmer than 70 C, bacterial action decreases rapidly, and thermal cracking of fossil molecules commences. For each kilometre of burial the sediment temperature increases by approximately 35 degrees centigrade. This heating produces transformations of the large organic molecules, fragmenting them into smaller hydrocarbons. This generates oil (liquid hydrocarbon) from marine and aquatic organic debris, through a temperature range of 70- 120 C. At warmer temperatures progressively shorter smaller molecules of hydrocarbon are generated. Natural gas is generated, mainly from terrestrial biological debris, through a temperature range of about 110- 150 C. This is the basis of natural oil and gas generation. At temperatures warmer than 150C, some small quantities of natural carbon dioxide are produced. Deeper burial of organic carbon, to temperatures of 200 C and hotter continues to produce methane gas, until all hydrogen is removed from the fossil organic debris, leaving metamorphic graphite.

The geological factors necessary to form an oilfield are well understood (Fig 2). First of all a source rock is needed, usually a mudrock, containing more than 1-10% of organic debris. This sediment becomes buried, is heated, and the oil generates as liquid hydrocarbons within the pore space of mudrock. Primary migration of the hydrocarbon from the mudrock occurs, on a scale of metres, by fluid-pressure induced fracturing of the mudrock. A much longer process of secondary migration then occurs, by which the oil or gas moves buoyantly through porous and permeable aquifer sediments filled with saline water, deep within a sedimentary basin. Such migration can extend for tens or several hundreds of kilometres laterally, and up to 5 km for vertically. Oil or gas finally accumulates in a porous reservoir, displacing the natural saline water from the reservoir pores. This accumulation requires a seal of less permeable rock, usually a mudrock, immediately above the reservoir aquifer. To ensure that a large quantity of oil or gas accumulates, a geological trap, such as a fold in the sediments, is needed so that buoyant oil and gas "back up" downwards beneath the impermeable seal. The geological timing at which this trap is formed is vital as it must predate, not postdate, the geologically short time span in which oil and gas undergo secondary migration in that particular individual sedimentary basin.

Figure 2 here

The storage of carbon dioxide in the deep subsurface shares many similar features with oil and gas accumulation. At pressures deeper than those occurring at 800 m, carbon dioxide becomes liquid rather than a gas, this liquid has a density of about 0.6 $kg.m^3$, and so is much more buoyant than water, and is comparable to the buoyancy of crude oil. To remove CO_2 from the biosphere for the required time scales of 10,000 years or more, it will be necessary to find locations where buoyant CO_2 can be retained by retained in an aquifer by a less permeable top seal, analogous to an oil field. The reliability of trapping will be enhanced if CO_2 can be injected into a subsurface structure trap, such as a depleted oilfield. Because storage is needed for geologically short time scales, it may also be possible to inject CO_2 into shallow-dipping layers of sedimentary rocks which have no structural trap. The rate of lateral and vertical movement of CO_2 through the permeable sediment aquifer is only a few tens of kilometres in the required time. This is hydrodynamic trapping.

The emplacement of CO_2 by injection into the deep subsurface also calls on oil and gas technology. Investigation of the deep subsurface is routinely undertaken by seismic reflection surveys, which involve the direction of energy from sound waves downwards to reflect of layers of rock. The returning echoes are collected, processed by complex computer programs, and then display cross-sections or three dimensional images of the subsurface. Seismic reflection is the standard technique to evaluate structure traps and the continuity of aquifers and seals in the deep subsurface. Drilling of boreholes is also routine in hydrocarbon exploration and production, such that boreholes can be vertical, can be deviated to become horizontal for tens of kilometres, and can even rise upwards again towards the surface. The injection of gas, or CO_2, into porous and permeable aquifers is well established in oilfield production techniques. Rapid injection of fluids inevitably generates problems with differential rates of movement laterally through the aquifer. Even within one aquifer, there are many different sediment layers and the injected fluids will move much more rapidly through the most permeable of these. This results in "fingering" of fluid fronts, and complex mixing between injected and pre-existing fluids. The relevance for CO_2 injection is that it is difficult to monitor a simple volume of CO_2 in the deep subsurface, and hard to predict exactly how far the injected CO_2 will migrate laterally. It is also important to note that CO_2 cannot be injected into vacant pore space within an aquifer. All pores are filled with oil, gas, or saline water and CO_2 injections must rely on pumping at to exceed the fluid pressure of the deep subsurface and displace the existing pore fluid.

CO_2 storage by adsorption onto coal seams

The possibility of storing CO_2 in coal seams has gained much publicity. Sedimentary basins of earth contain huge resources of coal. These resources could supply world energy needs for hundreds of years to come, but are usually too deep, or too complexly faulted to mine economically. During burial of coal, methane gas is generated naturally. This gas is retained, absorbed onto the surface of coal components. Such methane gas can be extracted by drilling boreholes into the coal, and enabling natural escape of this, or enforced production by de-pressureisation. This coalbed methane industry is current in the onshore United States, where much research has been undertaken. It is apparent that injection of CO_2 into a coal seam, becomes absorbed onto the surfaces of coal components, and displaces the methane. Experimental evidence [Fig 3] shows that approximately two, sometimes up to three, molecules of CO_2 are absorbed for each molecule of methane which is displaced. Adsorbtion of nitrogen is much less efficient, and so coal seams could be used as a naturally occurring separator of nitrogen from CO_2 gas. Additionally hysteresis curves (Orr 2004) show that when CO_2 is absorbed, it is difficult to displace, and so can be considered to be effectively stored. Flow of CO_2 within coal seams occurs primarily along fractures [cleat], and diffuses slowly into the surrounding blocks of matrix coal to displace methane. Pilot studies of CO_2 injection are under way in the Alberta basin of Canada, and in the San Juan Basin of the U.S. A. The San Juan tests have shown that CO_2 injection caused swelling of the coal matrix, resulting in reduced permeability around the injection borehole area. The San Juan coals were originally very high permeability [40 milliDarcy] , and are unusually thick [10 m] (Gale 2003). More typical coal seams around the world may be much thinner, 1 - 5 m, and have much lower permeability , 1 - 5 milliDarcy, and may also be faulted. All those factors would make the seams less feasible as CO_2 storage reservoirs It is possible that the swelling of coal could induce additional faulting, promoting migration pathways and the leakage of CO_2 from the coal seam . Further field tests are planned for Poland (RECOPOL), Australia and Japan. It is apparent that a higher production of methane gas can be achieved, however it is also apparent that each field site has individual characteristics.

Figure 3 here

Benefits of CO_2 injection into coal seams are about huge volumes could be accessed, and that coal seams occur widely beneath countries which produce many historical and future CO_2

emissions, currently Australia, and in future China, India, South Africa. Some seams in these countries are greater than 5m in thickness.

However many problems remained to be solved before this technology can be routinely deployed. A key technical problem is that many coal seams contain methane, yet have poor permeability. This means that CO2 is difficult to inject with a wide geographical spread from one well. Consequently many boreholes will be needed, or relatively more expensive horizontal boreholes will be required. It is also difficult to ensure that all the released methane can be securely captured and utilized at the surface. Techniques for capture may include draining an aquifer above the coal seam, all production from a pairing of wells one for injection and one for production, oriented to exploit the natural fracture [cleat] in the coal permeability. If the methane avoids engineered capture, then this would be released to the earth surface as an even more potent greenhouse gas.

Because of these difficulties, current assessment of CO2 storage capability in the coal seams [Gale 2003] is that only 40 G.t. are available worldwide. This equates to only 2% of world emissions up until 2050, using the IPCC 2001 “business as usual scenario” one.

Consequently, with present understanding, CO2 injection into coal may have local use, but it would require site specific investigation. Coal seams are a much more difficult to demonstrate as a robust storage possibility them disused oil fields, or saline aquifers.

Disused oil fields

Depleted oil and gas reservoirs are attractive as CO2 storage locations because they are known to have trapped and reservoired hydrocarbon fluids for many millions, sometimes hundreds of millions, of years. However it is also important to be aware that many natural hydrocarbon traps are dynamic on a geological time scale. This means that slow rates of gas leakage are balanced by slow rates of gas recharge. Consequently, there remains a small uncertainty as to what the position a national regulator will adopt in such situations, concerning rates of CO2 leakage. It is estimated that the capacity of depleted oil and gas reservoirs worldwide may be 920 G.t. CO2 [Gale 2003] or could range from 740 - 1850 G.t. CO2 [Parson and Keith 1998].

Geological storage of CO2 is not a new technology. CO2 has been injected into oil fields during the past 30 years, to enable increased volumes of oil production. At depths deeper than 800 m the CO2 will be in a supercritical state, ie gas that is the same density as a liquid, which enables an efficient injection method in both pipeline engineering and in filling deep porsespace. It is important to realize that in the deep subsurface there is no vacant space, all pores within sandstones and limestones are filled with water, oil, or gas. Consequently injection of CO2 must be either at increased pressure, or CO2 must dissolve miscibly with remaining oil. The key advantage of depleted oilfields and gas fields is that huge volumes of site specific data are available from the oil industry, to evaluate and affirm reservoir volumes, connections; and the extent and capability of top seals above the reservoir. The longest existing track records are from commercial CO2 injection operations in West Texas, which began in the 1970's and the'80s, by pipelines from Colorado or New Mexico. The motivation for all of these injection projects enhanced oil recovery (EOR) typically an additional 10% of a field's reserves can be produced. The number of EOR projects worldwide, which use CO2, is limited by the availability of injection gas at cheap cost and large volume of continuous supply. In the USA, the availability of substantial CO2 supplies from natural subsurface fields, has encouraged the building of large pipeline networks to transport CO2 (Fig 4). The CO2 pipes reach 900km, and pipelines to transport natural gas liquids can reach 2,500km (Kinder 2004)

Figure 4 here

In all EOR projects one objective has been to maximize the oil production, with minimum C02 injection. In principle it is possible to engineer CO_2 injection in a different league, to enable maximum C02 storage. For example CO_2 may be injected into low porosity zones, or poor permeability zones of the reservoir, or into the transition zone at the oil-water contact. A current, well reported, project currently underway is Weyburn in Canada where, as with all EOR projects, the field Operators are most interested in aspects of increased oil production. By contrast researchers are more interested in the track record of CO_2 storage – which in this case is derived from a coal power station.

Results from previous USA studies suggest that the average volume occupied by injected CO_2 comprises up to 30 percent of the original oil in place. There is also a possibility for CO_2 to dissolve in pore water occupying the reservoir, just as predicted to occur in saline aquifers. Criteria for oil reservoirs which could be used as CO_2 storage occasions are compiled by, Kovscek (2002) and Shaw and Bachu (2002). The detailed engineering of CO_2 injection can be complex, because of the miscibility of CO_2 for effective oil displacement depends on the reservoir pressure, the reservoir temperature, and that the local composition of the oil. Orr [2004] states that estimates of the pressure and temperature conditions required can be extrapolated from comparison with the partial pressure of CO_2. For example a reservoir at 50 C requires a depth of 1,000 m to permit CO_2 to be stored as a fluid. CO_2 is approximately 10 times more soluble in the oil than it is in water. The viscosity of CO_2, is low over a wide range of pressures and temperatures, compared to most oils, and certainly compared to any water in the reservoir. Consequently CO_2 preferentially moves along high permeability beds of the reservoir, in preference to oil. This means that injected CO_2 is re-produced from the field before all the oil has been recovered. In virtually all CO_2 EOR all projects, large volumes of CO_2 are required to be recovered and re-injected.

Permits for EOR projects have been readily obtained during the past 30 years and national regulators in USA and Canada are familiar with the issues and there is already a well-defined structure, which can be adapted to CO_2 storage projects. For offshore EOR projects then the regulatory issues are less well defined. Existing projects [such as Sleipner] use CO_2 derived from offshore production, so are not necessarily a good guide to legal issues of marine disposal conventions, for CO_2 which may originate from onshore. In all cases the additional EOR production of hydrocarbons can offset some of the costs of transporting and storing CO_2. In an offshore setting the engineering facilities required for EOR are very significantly expensive, and to date have negated any additional profits from enhanced production [Espie et al 2003]. In one major case study by BP, for the very large offshore Forties oilfield which had 4.2 Billion barrels oil in place (347 Mtons), and has now produced 59% of that. Key obstacles were identified as: Firstly, the lack of an large, continuous and reliable CO_2 supply at low-cost. Secondly the issue of corrosion management within existing pipeline facilities constructed from carbon steel, with wet CO_2. Replacement with corrosion resistant alloy, or use of corrosion inhibitors [as with the Permian Basin of Texas] could both be satisfactory – but at a large price before the start of production. The high investment at the start of the project will not be repaid until the end of the injection project. In this Forties oilfield, which is connected from offshore UK to the mainland by a 36 inch pipeline, the potential exists to increase oil recovery by up to 200 Million barrels. Oil would be accessed in unswept "attic" parts of the field, poor-quality by-passed reservoirs at channel margins, beneath shales. This is taxed at 70%, but even eliminating this tax does not make the project economic. Injection could be envisaged of 2 - 4 Mt per year CO_2, which would store 40-80 Mt CO_2 over a 20 year lifespan. The competition between CO_2 and water for porespace means that maximizing EOR recovery will not maximize CO_2 storage – neatly illustrating the opposed tension between oil production and CO_2 disposal.

If storage is envisaged for 10,000 years or more, then effects of human induced engineered disturbance must also be evaluated. The first of these is the potential for damage to the natural top seal of the reservoir to have been caused by pressure depletion during production of the oil. This can cause the rock fabric of the reservoir to partially collapse. This may produce fractures, or even faults, which enable leakage pathways for CO_2 to be created through a previously intact seal. Secondly, the reverse effect could occur during the injection of CO2, which needs to be at pressures elevated above that of the natural reservoir. This could inflate the reservoir, and because CO2 has a lower density than that of oil, may also produce a decrease of vertical stress on the cap seal. An increased horizontal stress would result, which can promote fracturing. Thirdly is the issue of borehole integrity. Standard portland cement, which is used to seal a round boreholes, and to block disused boreholes, is known to react with CO2**.** Research is underway to discover cement mixes, which may remain intact for thousands or tens of thousands of years.

Depleted gas reservoirs

Utilizing depleted gas reservoirs is attractive for CO2 storage because the seal to retain the gas has to have been extremely good over a geological timescale. Because CO2 is more viscous than methane, issues of seal quality, to ensure retention of CO2 for geologically long periods are less. In principle storage of CO2 in a gas reservoir could contain all of the CO2 derived from burning of that methane, at the same temperature and pressure. Because CO2 is more dense than methane, then the original natural gas could be replaced by a mixture of CO2 + nitrogen , i.e. full separation of nitrogen from power station flue gases may not be required - which could cheapen the cost of CO2 to supply. It may be possible to design new strategies to inject CO2, with the objectives of reducing or eliminating breakthrough of CO2 along permeable reservoir units, or to inject dense CO2 at the base of gas reservoirs to displace methane gas upwards, or even injecting into well connected aquifers beneath gas reservoirs.

CO2 injection into gas reservoirs has not yet been attempted. The first such project is underway from May 2004 in the Danish offshore, CRUST, operated by GDF Production (Gaz de France). Here CO2 will be separated from produced methane and re-injected at 3,700m subsea, amounting to 22,000 ton CO2/yr (van de Meer et al 2004). This is because recovery from gas fields is often as high as 95% of gas originally present. The scope for CO2 to improve miscibility and enhance recovery is consequently limited. CO2 could be used to maintain pressure, or to mix with condensate, but the high cost of purchasing CO2 means that all of these options have been uneconomic. If a gas field has been fully depleted, then deep basin waters will rise up to fill the pore space previously occupied by methane. Therefore the field is never “empty” and so any CO2 injection into such a "water wet” field would face similar issues to those of saline aquifer storage. Evaluation of gas fields will need to be undertaken on a site specific basis. As with depleted oil fields, huge databases of information on reservoir volume, connection, porosity and permeability exist within the oil companies.

Saline Aquifers

Saline aquifers are by far of the most popular proposal for large-scale CO2 storage. These are water bearing porous layers in the subsurface of sandstone or limestone. At present these are not used for any other purpose. The water salinity renders these unsuitable for use as drinking water or agricultural water, usually being seawater or greater in salinity (32,000 ppm NaCl brine). Because of the requirement that CO2 should be a super-critical liquid, such aquifers need to be greater than 800 m below the surface, to produce the required confining pressures. Consequently all these aquifers, are confined i.e. bounded above and below by less permeable, partly-sealing rock types such as mudstone. Estimates for the global capacity of deep saline aquifers vary from 400-10000 [Gale 2003], to 370-3700 Gt C02 [Parson and Keith 1998]. This range comprises 20-500% of world emissions until 2050. As will be seen later, the range of uncertainty is due partially to uncertainty in technical geological specifications for injection of volumes, and effective feasible volumes are also influenced by the proximity to C02 point sources.

The evaluation of deep saline aquifers requires information identical to that required for evaluation of oil fields, but spread across a much more geographically extensive framework. Critical factors are 1) the thickness lateral extent and continuity of porous sandstone all limestone; 2) the retention capability of a continuous seal above the aquifer; 3) the regional water flow system in the deep sub surfaced; 4) possibilities for leakage induced by natural faulting; 5) the capability of overburden layers above the reservoir seal to delay or diffuse leakage, and 6) the extent of adverse effects at the surface if leakage did occur.

Methods for calculation of the capacity for CO2 storage in deep saline aquifers are usually too simplistic. Initial calculations, for example, have assumed that an aquifer can be represented by a uniform sheet, of constant thickness, and constant porosity of 25%, across an entire sedimentary basin. A simple calculation can be made of the amount of water present, multiplied by the solubility of CO2, producing a theoretical storage figure. This is always incorrect. The true storage capability is much less, and needs to be reduced for factors such as aquifer inhomogeneity, excluded locations near active faults, and especially the realization that CO2 takes hundreds or even tens of thousands of years to dissolve in pore water (Ennis-King + Paterson 2003). Consequently, the potential storage volumes over the decades of human time scales are those for CO2 supercritical fluid, not dissolved CO2. Fluid needs to be injected under pressure, and rely on the compressibility of existing pore water. Van der Meer [2003] estimates that only 2% of the total effective volume is available for CO2 storage. However Holloway et al (1996) make more sophisticated estimates of storage volumes, by assuming that the saline aquifer traps are very large and effectively limit the best and storage capacity due to slow migration rates of the buoyant CO2 fluid through the porous aquifer. These figures are 2% for local confined aquifers, 6% for a fractured aquifers, 6% for horizontal aquifers with overlying mudrock seal, and up to 17% for inclined [dipping] aquifers which can be filled to a structurally defined spillpoint, analogous to oil accumulation in a subsurface structures. This range of figures is used by Bradshaw et al (2002) in their assessment of storage capability in the Australian continent. Site specific studies have been made by the EU-funded GESTCO project for example, and these produce more reliable estimates. Simulations of CO2 mixing and spreading show that during the 30yr lifetime of a disposal site, the CO2 liquid moves laterally away from a single injection borehole for a radius of only 10-30 km.

A key advantage of deep saline aquifers is that they are geographically very widespread around the world. Such aquifers are not limited to prolific hydrocarbon provinces. Matching CO2 source sites to potential storage sites in saline aquifers still requires specific and individual site assessments. Because of the similarity of data required for evaluation of hydrocarbon fields, and saline aquifers, the easiest initial places to search for suitable saline aquifers, are in the sedimentary basins which have had some history of hydrocarbon exploration, even if present-day production is not prolific. In such areas a background suite of geological information exists, such as borehole records, and regional or even specific, surveys of seismic reflection data, which give the best cross-section information for assessment of aquifer existence and continuity. However before any injection program commences it is likely that much-improved information will be needed to delineate aquifer extent, the existence of structural traps, the regional water flow regime, as well as a good understanding of seals, vertical flow barriers, faults, and any other pathways for vertical CO2 migration and of leakage.

Assessing the detailed distribution worldwide of saline aquifers suitable for CO2 disposal is a major task, and beyond the scope of this article. However in sections below, outline information is given which enables large areas of continents to be considered as potential CO2 disposal sites, or alternatively completely excluded. The Australian GEODISC program has extended its assessment work of Australia to a worldwide database (Bradshaw and Dance 2004), and illustrations from this are reproduced.

The first industrial-scale example of CO2 and injection into a saline aquifer is that of the Sleipner oilfield in offshore Norway. This embodies many of the problems and principles facing saline aquifer storage around the world in hydrocarbon-related provinces, and is discussed in more detail below.

Figure 5 here

Sleipner Experiment

In the centre of the North Sea, midway between Norway and the U.K., the Sleipner West oilfield produces condensate hydrocarbon from an upper Jurassic reservoir about 2.5 km below sea bed. This contains about 9% natural CO2, which is separated on the offshore oil rig, and then re-injected into a shallow Utsira sand at about 1 kilometre. This Utsira sand is a major regional saline aquifer, which is only sparsely faulted, and ranges smoothly in depth from 550 - 1500 m. The sand thickness is locally about 300 m, forming a local structural trap, and the regional top seal is a thick mudstone (Fig 5). The Utsira sand is shown by boreholes to have an abrupt top and base, with thin [one metre] layers of discontinuous mudrock within the aquifer, which create local flow barriers. At the top of the Utsira sand, separated by a few meters of mudrock, is an additional 30m sand unit, termed the Sand Wedge.

A deviated borehole extends from the Sleipner production platform, to enable an injection of CO2 fluid into this Utsira sand aquifer. Since 1996 approximately 1 Mt of CO2 have been injected each year, with a final projected target of about 20 Mt. The Sleipner storage operation has been studied by the SACS project, and results of this are reported by Chadwick et al (2003), Torp and Gale (2003), Arts Chadwick and Eiken (2004), Torp and Brown (2004).

A series of seismic reflection surveys have been undertaken across the injection point, with the first of these in 1994 predating any CO2 injection from 1996, and subsequent surveys undertaken in 1999 and 2001and 2002 (Fig 5). These give reflection images of rock layers in the subsurface structure and, because of the large density contrast between fluid CO2 and surrounding pollster, high quality images of CO2 location can be obtained by subtracting different vintages of seismic survey, to provide a picture of CO2 location and migration. Normal resolution of seismic reflection is only tens of metres, however because of the density contrast of CO2 in a pore space, a remarkable resolution of one metre CO2 layers is claimed (Torp and Gale 2003). This can detect CO2 accumulations of only 4000 m^3 (~2800 tonnes) (Arts et al 2004) This has great potential significance in of monitoring and a verification for tax credit purposes in the future. Although such seismic reflection surveys are not cheap, a monitoring borehole is significantly more expensive. The application of conventional time lapse seismic data has shown clearly that the injected CO2 moves by buoyant effects from its injection point deep in the aquifer, and creates a vertical CO2 chimney to accumulate CO2 beneath the thin layers of mudrocks within the aquifer. These thin, laterally impersistent layers could not be well-imaged before injection, and have caused lateral migration of CO2 for several hundreds of metres within the aquifer. This may promote increased rates of CO2 dissolution within the Utsira pore fluid. Calculations suggest that structural trapping at the top of the Utsira sand could accumulate 20 million t of CO2 within a 12 km radius of the injection site, during 20 years.

One unexpected result has been that CO2 has migrated through a 5 metre mud rock to fill the 50m sand wedge overlying the main Utsira formation (Fig 5). However no further vertical migration into the main mudrock seal has been detected. No mineral trapping is expected, and the CO2 is modeled to dissolve by density - driven convection within 10,000 years.

Rock properties of the Utsira aquifer are a largely uncemented, fine grained sandstone, consisting of quartz and feldspar with minor shell fragments. Porosity ranges from core measurement 35-42%, from microscopy 27-31%, and wireline logs 35-40%. The overlying mud rock seal is grey clay and silt or silty clay mix, which is poorly laminated. Quartz content, determined by X-Ray Diffraction, suggests pore throat diameters of 14-40 nanometers, which is empirically converted to predict capillary entry pressures of 2 - 5.5 MPascal, enabling a CO2 column of several hundred meters thickness to be trapped. This is equivalent to a normal (35 API) crude oil column more than 150m thick. By empirical analogy, the mud rock samples suggest an effective seal, with capillary leakage of CO2 unlikely to occur.

Mudrock stratigraphy within the seal has been mapped regionally using seismic reflection stratigraphy. Gas filled sandy lenses occur locally, which may indicate conduits for earlier methane migration. Although the total pore volume of the Utsira sand is 6×10^{11} m ^{3} regionally, the detailed local mapping undertaken indicates that the effective and useable pore volume is just 0.11 percent of the total for the Utsira sand. Thus total storage volume is just 6.6×10^{8} m ^{3} in structural traps. This illustrates again the uncertainty in making generalised estimates of CO2 storage capability and saline aquifers.

COSTS at Sleipner and Weyburn

A dedicated monitoring well is considered to cost 45 million Euro by Statoil (Torp and Gale 2003), and so has not been drilled. Costs of CO2 storage are calculated by Torp and Brown (2004) in 1996 US $. Site characterisation costs were $ 1.9M US, CO2 separator units were 79M $US, drilling the injection well cost $15M US, yearly marginal costs of CO2 separation are $7M US/yr. I calculate by simple arithmetic that over the 20 year field lifetime, this equates to $11.8 per tonne CO2 (using 1996 $, no cash flow discount. This does not consider seismic monitoring costs, and obviously the CO2 is free of charge.

By contrast costs of CO2 disposal at Weyburn (onshore anthropogenic CO2) are about $10.1/tonne CO2 for investment and $9.8 for operation - ie $20US per tonne Torp and Brown (2004). This seems too high to the present author.

Evaluating saline aquifers: Australian continent

To identify candidate sites for CO2 storage in saline and aquifers a geological assessment of suitability need to be undertaken. Because of the enormous range of configurations within sedimentary basins, this is inevitably at a superficial level during the early stages, and becomes progressively more detailed as plausible sites become identified. Thick accumulations of porous rocks occur in sedimentary basins, so that initially entire basins can be assessed, to ascertain if their stratigraphy, rock type, lithologies, and structure are in any way suitable. Although many sedimentary basins and the provinces are known throughout the world, a full systematic approach, on the scale of a whole continent, has only been undertaken in Australia. The results of this work will now be summarized.

Bradshaw et al [2002] worked in the GEODISC program to undertake a regional analysis examining the potential for geological and storage of CO2 in all of the sedimentary basins of Australia. At the start of the survey only geological criteria were used, no information on proximity to CO2 emissions sources was included, this was considered later. 300 sedimentary basins known in Australia were examined from published and pre-existing information. Simple criteria were used to identify important features, including thickness, depth greater than 1,000 m, stratigraphy and lithology, identification of seal and reservoir pairs, and structural complexity. 15 regional examinations were made of selected basins. From this, 65 potential sites for C02 injection were identified, and 22 sites were rejected on the basis that one or more essential criteria were missing, or that the information available was to poor to make a meaningful risk assessment.

Each potential site was then examined in terms of five separate risk factors:
1) Storage capacity: will a reservoir have sufficient volume?
2) Injectivity: is a reservoir suitable for injection of CO2 fluid?

3) Site specifics: is the site possibly economically viable?
4) Containment: how effective for is the trap and seal combination to retain CO_2?
5) Other resources: will CO_2 disposal compromise other viable and natural resources?

Each candidate site was assigned deterministic scores for each of the geological features. This approach enabled comparison between sites, between basins, and ensured a consistent approach. Multiplication of all five factors produced a "Chance" rating (0.01 lowest to 0.9 maximum); multiplication of the Chance rating with estimated storage capacity produced an assessment of "Risked Capacity". A "Final rating" was made by calculating a chance divided by geographic radius of 53 million tons CO_2 at each site (areal footprint).

Figure 6 here

The results of this shows that the best Chance ratings are given to locations, which are positioned predominantly within hydrocarbon basins (Fig 6). Sites which had good geological Chance ratings were not necessarily large in "Risked Capacity". Potential storage sites were also examined in terms of trapping mechanism six different play types were recognized, using an approach which combines a geological factors similar to hydrocarbon exploration.

1) Unconformity
2) Enhanced coal bed methane
3) "dry" structural traps without hydrocarbon
4) Present and future depleted oil and gas fields
5) Stratigraphy traps
6) Hydrodynamic traps relying on slow rates of subsurface fluid flow

The storage capacity of a reservoir was also evaluated using the properties of C02 summarized by Bachu (2001 fig 1). The storage efficiency is influenced by rate of injection, vertical and horizontal permeability, reservoir dip, fluid pressure, fluid temperature, slower injection rates decrease adverse viscous fingering along permeable zones. The criteria of Hollloway et al (1996) were used to estimate injection volumes into saline aquifers. These values remained significantly poorly constrained. The best injection sites for storage efficiency were

A) Large hydrodynamic aquifers with injection a long way distant from the up dip edge of the reservoir.
B) Injection down dip from structures, allowing buoyant migration to fill the structure naturally.

The assessment of Risked Capacity provided a selection of sites which had an average geological Chance of 18%. This equated to 1, 600 years of Australia's total CO_2 emissions in 1998. Enhanced Coal Bed Methane sites comprise 3% of the sites, and much less than 1% of the Risked Capacity for storage; this reflects the geological difficulty of injection and the poor state of ECBM knowledge. Structural traps comprise 43% of the sites analyzed, yet only represent 4% of the total Risked Capacity for storage. Hydrodynamic traps also comprised 43% of the sites analysed, yet provide 94% of the total Risked Capacity for storage.

The final phase was to link CO_2 sources with candidate Risked storage sites. Australian CO_2 emissions in 1998 were 456 million t CO_2/yr [8.5 TCF C02]. About 240million tons CO_2 originate from point sources, which can potentially be sequestered. These comprise fossil fuel power stations (73 %), steel industry (7%), other metals 6%, petroleum industry and oil refinery 7.5%. These represent 39% of the total CO_2 emissions, and approximately 90% of the emissions that can be sequestered. The supply of CO_2 for the next 20 years was estimated from each source, and these were grouped into eight major nodes across the continent. The storage capacity was then divided by the 20 year supply CO_2 volume. This showed that hydrocarbon provinces offshore from west and northwest Australia dominate the storage capability. A further overlay was made of a radial distance from point sources, 100 to 1,000 km, to incorporate the difficulty of pipeline transport. A final overlay was made of a four-tiered cost ranking, based on a net present value. These results show that the South Australian Moomba and Western Australia Burrup areas off the best cost effective option it is. By contrast the large emissions from coalfields in south-east Australia have no possible prospects for geolgical storage in the vicinity.

The cost of CO_2 disposal was estimated using a suite of assumptions relating to CO_2 purity (N_2, CH_4, CO, O_2), assuming all water and sulphur had been removed! The overall cost of CO_2 injection before tax ranged from U.S. $10, to U.S. $25 per ton CO_2.

This type of integrated analysis indicates that CO_2 storage opportunities do not respect national or state boundaries. Similar continent-scale compilations are underway in the USA regional partnerships. It is clear that the largest storage opportunities exist in well-explored hydrocarbon basins, rather than mid-continent basins. Although depleted hydrocarbon fields are most secure, they are small in volume – and hydrodynamic trapping in regional aquifers is safe enough for the timescales involved – provided enough data can be acquired to make an evaluation. The smallest onshore volumes explicitly considered in this assessment were 0.5% of annual CO_2 emissions, ie 2.8Mt. The capital costs of such a disposal operation in Australia range upwards from $13Mill US. The relevance of this for bio-fuels is in judging the minimum size of viable operation: capital costs of drilling and processing divided by CO_2 annual volumes locally. The initial estimate of potential CO_2 storage capacity in Australia was 3.9×10^{12} tonnes (Bradshaw et al 2003). Final volumes, after simple overlays of risking, transport and economics are a more realistic estimate of Australia's CO_2 storage potential, around 25% of our annual emissions or 100 – 115 Mt CO_2 / year.

Evaluation of worldwide sites for CO2 burial

Because of the immaturity of the science for CO_2 storage and the uncertainties in the assessment, there has been a no detailed investigation to identify the locations in which the CO_2 storage potential of the world may be located. The assessment undertaken by Bradshaw et al (2002) in Australia, showed that of the sites most certain to evaluate, and the largest potential volumes for disposal, are located within hydrocarbon basins onshore and offshore of Australia. Using a similar method, of applying several simple screening criteria, combined with detailed assessments from a few locations, and worldwide data sets of hydrocarbon potential, Bradshaw and Dance (2004) have made the first maps to combine worldwide CO_2 point sources with worldwide candidate disposal sites.

Worldwide Data is available free of charge from the United States Geological Survey (USGS 1997), who undertake periodic assessments to prioritize hydrocarbon provinces worldwide. Two areas of Australia were identified by Bradshaw et al (2002) as being of high feasibility for C 02 storage, the North West shelf of Australia, and the Gippsland Basin of southeast Australia. These same two basins were independently identified by the USGS survey as being a high priority for petroleum assessment. The USGS data has been reworked by Bradshaw and Dance (2004), to be interpreted in terms of CO_2 storage potential.

It should be noted that the USGS data is not uniform throughout the world, and is sometimes dated, sometimes generalized, and sometimes overly optimistic in hydrocarbon potential. It is, however, the best compilation accessible outside the few very largest oil companies. Two other factors are relevant, firstly a sedimentary basin may be poorly prospective for hydrocarbons, because of imperfect timing of ancient oil migration, yet be excellent for CO_2 storage, because traps seals and reservoirs co-exist today when they are required. Secondly these compilations take no account of extensive coal deposits, which may be suitable for ECBM storage of CO_2, as such coals seldom occur with significant petroleum accumulations. Note finally that sedimentary basins in active faulting areas can accumulate large oil fields (California, Trinidad, Indonesia), and these need not be immediately eliminated in the search for CO_2 storage sites.

Information on CO_2 point source is has been obtained from the International Energy Agency worldwide data set. This is not always precisely located geographically, but provides good enough information for this high level initial evaluation. Following this world-wide assessment, it is necessary to conduct more detailed investigations at the level of individual countries, or individual sedimentary basins. These first worldwide maps do, however, focus attention on particularly prospective areas.

Initial results (Fig 7) show that some regions have a high CO_2 production without a match to CO_2 candidate disposal sites (China). These may be targets to encourage relocation of CO_2 sources, or to investigate the feasibility of trans-national pipeline networks. Other regions could have potential for CO_2 storage, yet have no indigenous CO_2 production. Such locations could be targets to encourage greater use of local biomass, or could become the storage destinations for transnational pipeline networks. It can also be noted that liquefied CO_2 could, in principle, be transported long distances coast-to-coast by ocean tanker just as occurs for oil and liquefied petroleum gas.

In terms of "Southern" countries which have candidate CO_2 sites within 300 km of CO_2 emissions, the countries with most potential appear to lie in parts of Southeast Asia, followed by parts of North and offshore West Africa, followed in South America by the Llanos and Cordillera basins of Colombia, Santa-Cruz basin of Brazil, Putamayo basin of Peru and Ecuador, and Magdalenas, san Jorge and Neuquen basins of Argentina.

Figure 7 here

Volume problems for bio-energy CO2 disposal

It has been proposed that energy crops should be grown commercially, extensively and rapidly to utilise much of the 'vacant' agricultural land of the world (Read & Lermit 2004). These crops can be utilised for direct or indirect energy generation. Added benefit could be gained if the CO_2 released during the combustion of such crops could be captured and stored below ground

Financing a CO_2 storage development is inevitably a major obstacle. In the successful examples given above of large-scale industrial operations, all have gained access to a reliable supply of large CO_2 volumes, which can be guaranteed at low/no cost for periods of 20 years or more. Injection volumes can be as much as 1Mt per borehole in offshore settings, with investment costs of $10-100M (excluding the offshore platform). When contemplating CO_2 production from biomass, these may be substantial challenges. How will CO_2 be generated and collected? Is it easier to transport the biomass before combustion, or more plausibly, to collect small volumes of CO_2 at dispersed combustion locations, and feed this supply to one "regional" storage borehole?

Gathering sufficient CO_2 to supply an offshore borehole is a very major challenge, especially in less-industrialised countries. However, if an onshore storage setting is envisaged, costs could be very much less, and so the threshold for economic viability is very much lower.

Site investigation costs can be greatly reduced if there has been previous hydrocarbon exploration in the area - and the records of seismic and borehole data have been kept. This can produce a very rapid indication of potential structures with minimal additional costs. The essential geological features are: 1) An aquifer deeper than 800m; 2) A regionally extensive seal overlying the aquifer, which is un-faulted, or can be proven to be intact; 3) An intact structure trap, or a shallow dip of the aquifer, which will enable CO_2 to be retained for a 15 kilometre migration distance. All of these features can be identified using standard techniques of hydrocarbon exploration. If these factors are suitable, an on shore borehole to one kilometre depth could feasibly be drilled and evaluated for 1 - 2 $M US. Costs of CO_2 transport could be very significant onshore, unless the combustion plants are sited close to the storage borehole.

As noted above, hundreds km long pipelines can be constructed, however these entail major costs, and would need decades of use to pay back economically.

The smallest project which could perhaps be envisaged would be, at the present price of oil 40$barrel ($400 $/tonne), where the CO2 had a value of $20 per ton. For a lifetime of 20 years feeding of CO2 to storage, then the 2 $M costs of borehole construction would need at least 5,000 t per year of CO2, but probably 10,000 t per year of CO2 to pay for separation equipment and other evaluation and construction costs. If costed with conventional loan repayments and economic investment of equipment and annual running costs, then 100,000 t/yr CO2 would seem more like a minimum.

Investigations to setup bio-energy agriculture in a less-developed countries must combine the surface assessments of social, land-use and agricultural factors, with exploration for and identification of suitable sites for storage boreholes, to minimize transport costs.

Conclusions

1) Established principles of hydrocarbon exploration have enabled identification of three promising settings for deep geological disposal of CO2: A) injection into thick permeable coal seams; B) injection into depleted oil or gas fields deeper than 800 m; C) injection into regionally extensive saline aquifers, which have an overlying reliable seal, and are deeper than 800 m.
2) The geological protocol has been established to enable continent-wide assessment of likely candidate areas which may host CO2 storage. Initial results show the best areas are usually associated with hydrocarbon basins, although not necessarily. The assessment of storage in coal seams is not well established. When more detailed local assessments are made, combining sites of CO2 generation, transport, and economics with geological candidate sites; then the feasible storage volumes can decline to 25 percent of the initial assessment. However huge storage volumes undoubtedly exist worldwide in saline aquifers onshore and offshore, to accommodate all world CO2 production until 2050.
3) Suitable on shore basins may exist in parts of northwest, Central and southern South America; and Central Africa (with many additional opportunities offshore West Africa); some parts of Indonesia and Malaysia; and some parts of China.
4) On shore projects could be of very much smaller scale than current worldwide demonstration projects, which are geared to multinational oil companies. The minimum annual CO2 production for economic viability could be as little as 100,000 ton per year CO2, assuming a CO2 value of $20 per tonne.

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Figures

Figure 1 Spectrum of temperature change through geological timescales. Change of temperature and CO2 content in the atmosphere has been continuous, although slow. The earth has been much warmer that now in the past, but without extensive human civlisations..

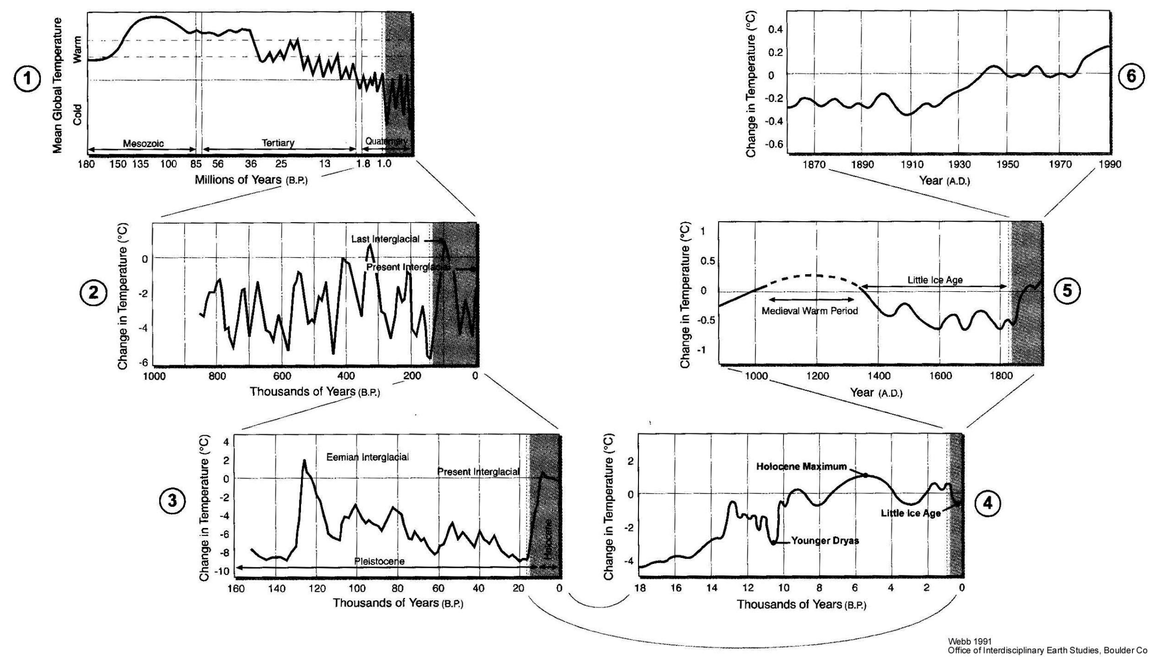
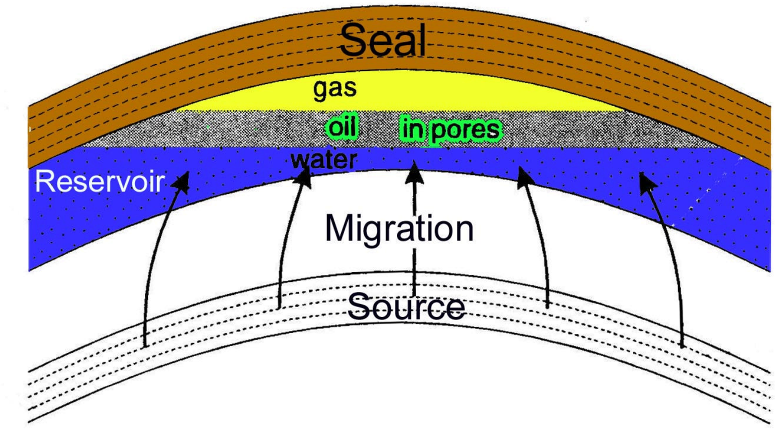
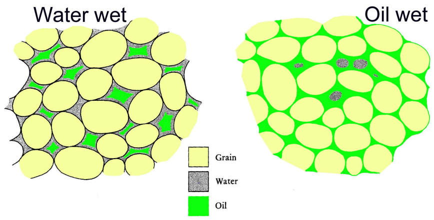
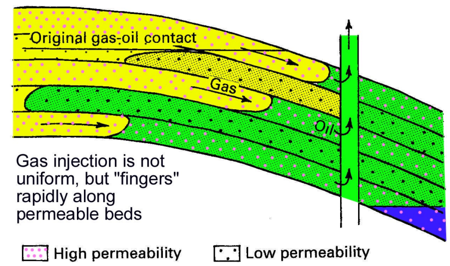


Figure 2
Natural oil and gas are generated by burial of organic material, and migrate buoyantly through saline water, to become trapped in porous sandstones or carbonates, beneath a poorly-permeably seal, usually of mudstone. This system is similar to the CO_2 storage system. A) Migration of oil from source to trap B) Oil resides in pores, where grains may be coated with water (reservoir), or with oil (seal). C) Injection of gas into reservoir aquifers is well established, but at rapid rates viscosity fingering occurs along rock layers which differ in permeability.





Water wet
Oil wet
Grain
Water
Oil



Original gas-oil contact
Gas
Oil
Gas injection is not uniform, but "fingers" rapidly along permeable beds
High permeability
Low permeability

Figure 3
CO2 can be stored in coal thick seams, where one molecule of CO2 displaces two or three molecules of methane. This is the principle of Enhanced Coal Bed Methane, and can be commercially viable for methane production. However it is poorly tested as a means for CO2 disposal. Coals can occur where hydrocarbon aquifers do not – for example in northern India, China, South Africa, or Colombia.

This graph shows that CO2 is more stongly adsorbed onto coal than nitrogen or methane, and does not readily de-sorb

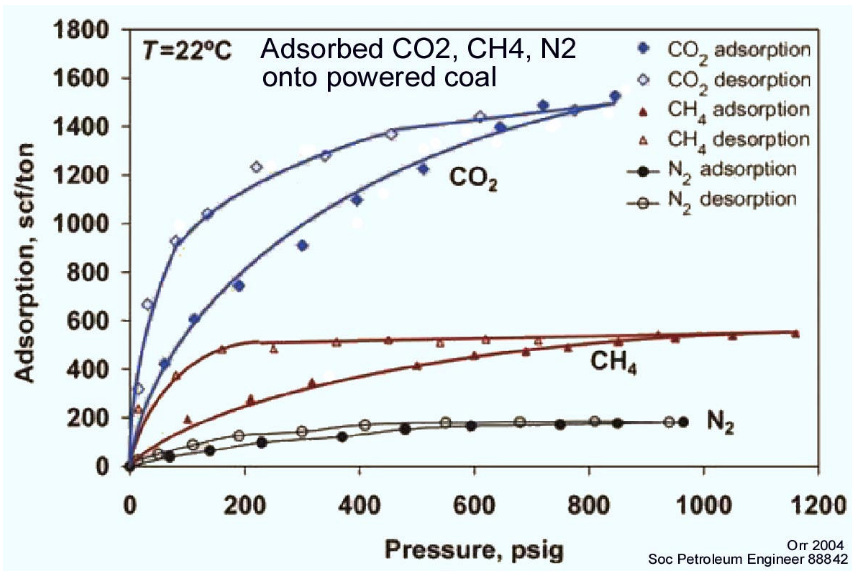
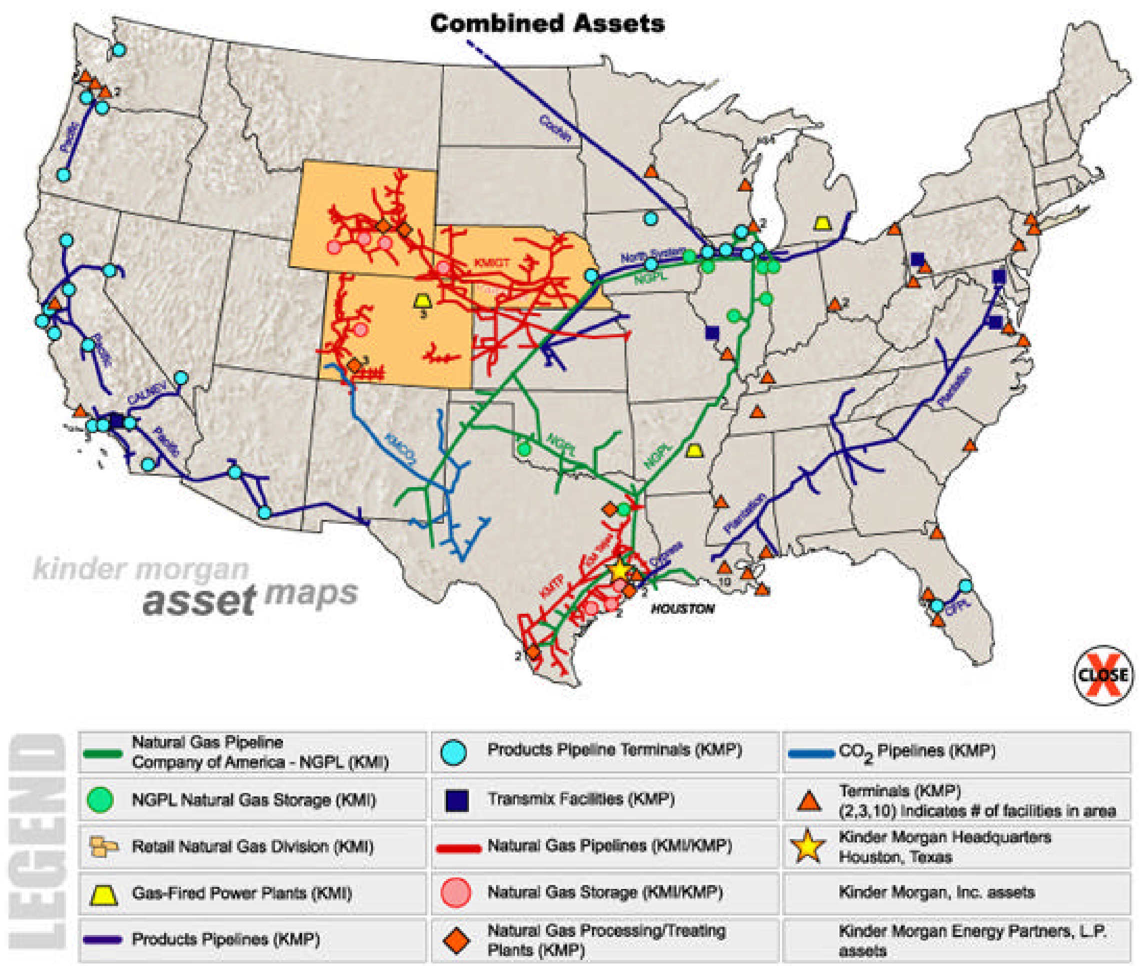


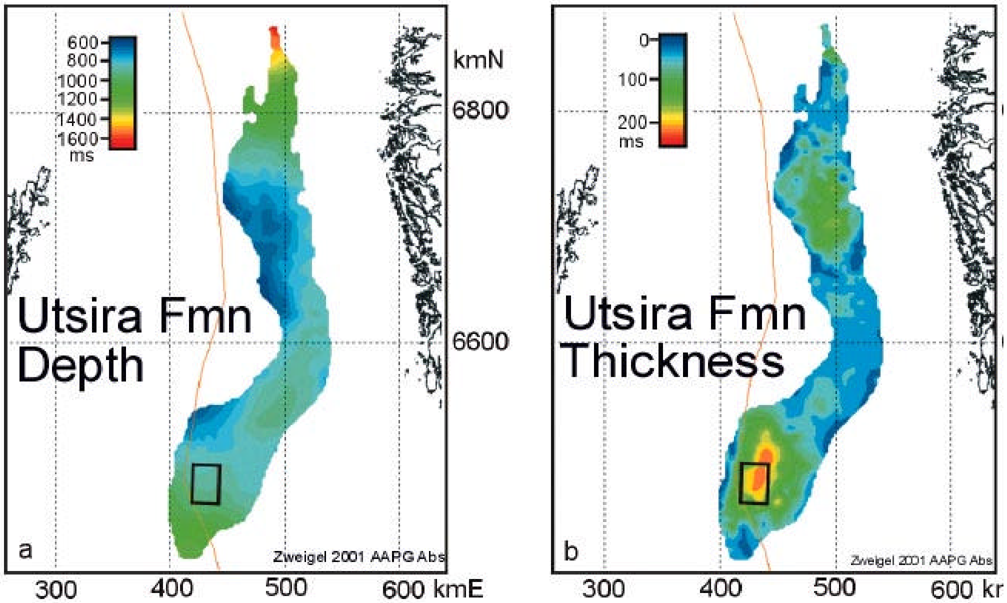
Figure 4

CO2 disposal into depleted oil or gas fields is possible, but currently is only economic in the onshore USA and Canada – where CO2 is used to enhance oil recovery. Natural CO2 is transported through pipelines which are hundreds km long, and 44M m^3/day is typically moved. Similar networks could be engineered for CO2 storage onshore offshore



http://www.kindermorgan.com/asset_map/

Figure 5
Saline aquifers are the largest and most plausible sites fro CO2 disposal on a very large scale. One such operation has been underway since 1996, to re-inject 9% CO2, separated from the West Sleipner condensate field, into the 1000m aquifer of the Utsira Sand.
A) Regional map of Utsira Sand, derived from seismic mapping of the North Sea, midway between Scotland and Norway. The are of injection is boxed, and is a natural dome structure a "dry" trap without hydrocarbon



B)
Seismic reflection survey of Utsira Sand, showing reflectors before CO2 injection in 1994, and same section after 6 years of CO2 injection at about 1Mton/year. The bright reflectors show that buoyant CO2 has migrated to the top of the Utsira Sand, and through a 5 m mudrock at its top, into a local 30m sandstone. However there is no evidence of leakage through the overlying mudrock seal, which is calculated to be capable of retaining an oil column of 150m

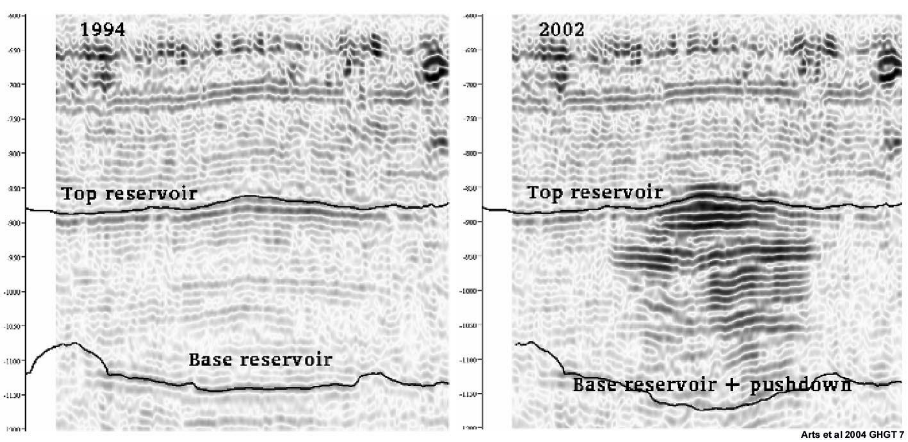


Figure 6

Australia is the first continent to have been assessed for sites of CO_2 storage. All basins were evaluated, and simple five geological criteria were used to numerically score each basin's suitability. This is a similar procedure to that used in oil exploration

A Basins (shaded) with locations of CO_2 sources (factory) and quality of candidate storage site represented by diameter of small circle.

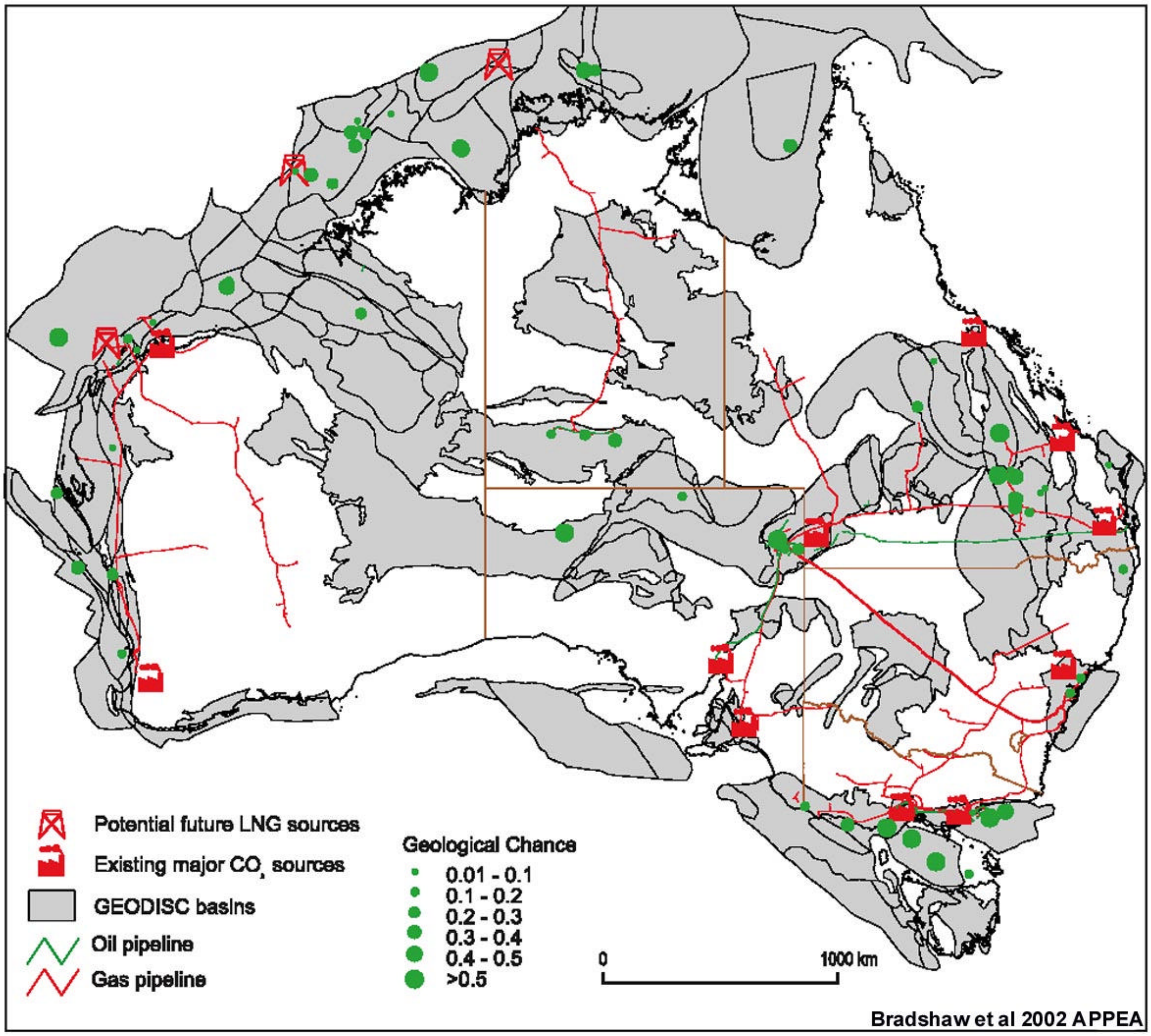
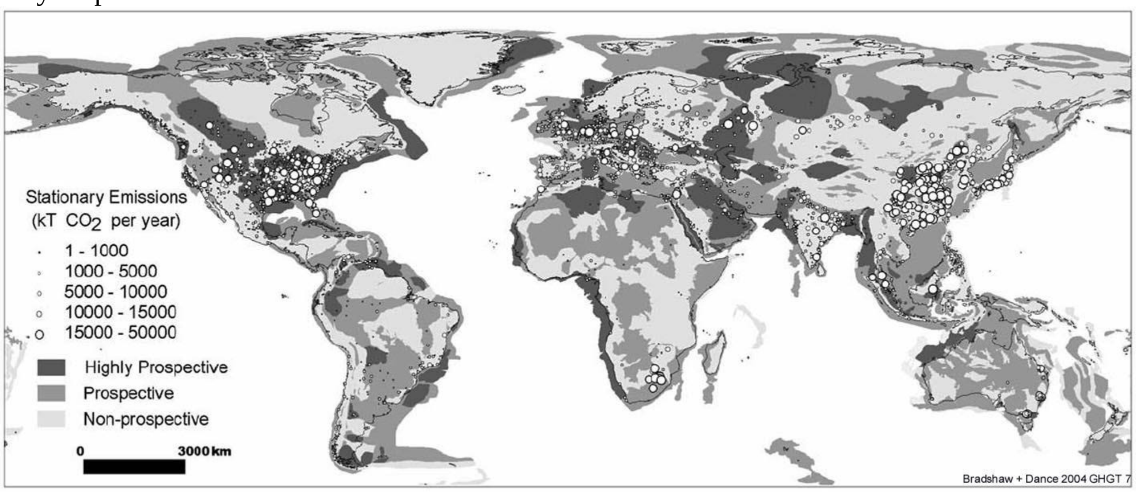
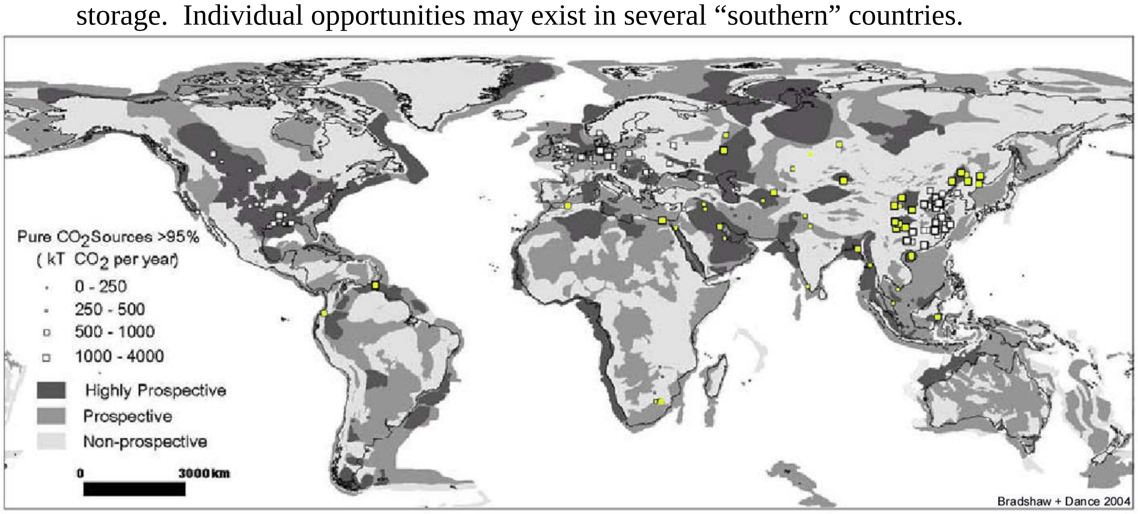


Figure 7
Using a similar methodology to that for Australia, worldwide basins were evaluated for suitability for CO2 storage. This uses United States Geological Survey data intended for application in hydrocarbon exploration. Emission sites taken from IEA data. Suitable basins occur widely around the earth, the best being prolific hydrocarbon provinces. Basins which are (pale grey) less prolific, may still be excellent CO2 stores, and await more detailed assessment.

A Comparison of basins, simply ranked for CO2 storage, with sites of large CO2 emissions. Many candidate basins for storage exist in "southern" countries, but will need re-located CO2 sources, regional pipelines, or ocean tanker transport of CO2 to connect them to the present emission sites. Opportunities exist in "southern" countries to generate CO2 by burning of biomass. Because of the expensive initial investment in boreholes and separators, this needs to be planned to produce enough CO2 (1Mt/yr?) as an economic supply to deep storage boreholes for 20 year periods



B Comparison of basins, simply ranked for CO2 storage, with sites of pure CO2 emissions, which are less volumetric than those shown above, but may be easier to engineer into deep storage. Individual opportunities may exist in several "southern" countries.



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