AQUIFER STORAGE - DEVELOPMENT ISSUES

Technical Study

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CO2CRC, Canberra, AUSTRALIA

With assistance from:

CSIRO, The University of Adelaide, and Schlumberger

The principal researchers were:

- K. Michael
- G. Allinson
- M. Arnot
- P. Cook
- A. Golab
- J. Ennis-King
- R. Funnell
- J. Kaldi
- D. Kirste
- L. Paterson
- S. Sharma
- V. Shulakova

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The IEA GHG manager for this report: Toby Aiken

The expert reviewers for this report:

- Stefan Bachu, ARC, Canada
- Malcolm Wilson, University of Regina, Canada
- John Litynski, US DOE, USA
- Ed Steadman, EERC, USA
- Ziqiu Xue, Kyoto University, Japan

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Further information or copies of the report can be obtained by contacting the IEA Greenhouse Gas R&D Programme at:

IEA Greenhouse Gas R&D Programme, Orchard Business Centre, Stoke Orchard, Cheltenham, Glos., GL52 7RZ, UK
Tel: +44 1242 680753 Fax: +44 1242 680758
E-mail: mail@ieaghg.org
www.ieagreen.org.uk

OVERVIEW

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) commissioned CO2CRC of Australia to undertake a study of the current status of CO_2 storage in deep saline aquifers[1].

Earlier studies by IEA GHG had shown that of the main geological storage reservoirs available globally for CO_2 storage, deep saline aquifers have the highest storage potential and substantial cuts in CO_2 emissions may therefore require utilisation of deep saline aquifers as storage reservoirs. However, the storage capacity of deep saline aquifers from various estimates show wide bounds: from 1,000 to over 10,000 $GtCO_2$ globally. Many of the deep saline aquifers being considered for storage are 'virgin' formations and structures in which little or no geological characterisation has taken place, in contrast to many oil and gas fields. Therefore, considerable exploratory work will be required before such structures can be considered as "fit for purpose" for CO_2 storage. Selection of safe and secure geological reservoirs must be accompanied by confidence in the associated CO_2 storage capacities.

The aim of this study was to bring together and review the research that has been undertaken in Europe, North America, Japan and Australia, to develop an understanding of how knowledge on deep saline aquifers has developed in recent years, in particular since the 2005 IPCC Special Report on CO_2 Capture and Storage (IPCC SRCCS). Emphasis was placed on the identification of knowledge gaps and priority areas for R&D activities.

Scope of Study

The reference point for the study was the conclusions and knowledge gaps outlined and identified in the IPCC SRCCS. The study aimed to review all practical research activities carried out since that publication, and summarise progress made towards addressing those knowledge gaps.

Individual tasks were outlined for the study:

1. The starting point of the study was to develop a database of all projects and research currently underway. This database was compiled in close consultation with the assigned IEA GHG project manager. The database aimed to pull together all new information relating to the knowledge gaps identified in the IPCC SRCCS.
2. Utilising the database, the study determined the current state of knowledge relating to each knowledge gap identified in the IPCC SRCCS, including:

    - Definition of the current state of knowledge on global capacity estimates for deep saline aquifers and the methodologies used to determine these, including recent work carried out by CSLF and others.
    - Definition of the current status of regional capacity mapping and estimation of storage potential, with reference to global capacity assessments.

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[1] The term deep saline aquifers in this overview is used to maintain consistency with the main report, and refers to aquifers containing only saline water with no links to potable water supplies and of no value as an underground source of drinking water (USDW).

- Definition of the current status of storage science, in particular trapping mechanisms, and specifically the kinetics of geochemical trapping and the long term impact of CO_2 on both the reservoir rocks and fluids.
- Commentary on the current state of knowledge on risk assessment related to deep saline aquifers and any particular issues that could arise as a result of brine displacement. The contractor was able to draw upon the results obtained from the IEA GHG international research network on risk assessment.
- Provide a summary of monitoring activities in deep saline aquifer storage projects, with consideration of whether monitoring needs for deep saline aquifers are different from other storage reservoir types.
- Definition of the current status of model simulations and their contribution to understanding of the transport and fate of injected CO_2 in deep saline aquifers; in particular definition of the current development of coupled models and their application.
- Review new cost information available from pilot and demonstration projects for injection into deep saline aquifers, with commentary on implications for future projects.
- Review Best Practise guidelines and related experience on deep saline aquifers and comment site characterisation requirements, again with narrative on differences from other storage reservoir types.

3. The study also aimed to create a comprehensive summary of reservoir properties and injectivity data based on pilot and demonstration activities, both underway and planned. The study aimed to comment on the range of reservoir properties encountered and whether these may be representative of global storage conditions, or if particular reservoirs or regions that should be preferred for future pilot studies or demonstration projects.

4. Finally, the study sought to establish knowledge targets necessary to achieve a level of confidence needed, to confirm deep saline aquifers as suitable, secure and safe options for CCS activities.

The study involved primarily desk-based activities but industry and regulatory perspective was sought on certain issues.

Results and Discussion

The starting point for the study was the knowledge gaps identified by the IPCC SRCCS, which were summarised in the study report as the following ten key points:

1. Current storage capacity is imperfectly known due to inconsistency in assessment methodologies, lack of data and gaps in global, regional and local estimates, particularly data from Africa, South America and large parts of Asia, although there are also many data gaps in OECD countries too.
2. Kinetics of trapping mechanisms and their long term impact on reservoir characteristics, particularly geochemical trapping need further investigation.
3. Improved coupled hydrogeological-geochemical-geomechanical numerical models would help to better predict the long-term fate of injected CO_2 in the subsurface and quantify potential leakage[2] rates.

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[2] Within this overview, leakage is defined as the movement of CO_2 outside of the targeted storage formation.

4. Risks of CO_2 leakage from abandoned wells due to casing and cement degradation and the temporal variability and spatial distribution of leaks should be better assessed.
5. Quantitative methods to assess the risk of CO_2 leakage to human health and the environment are needed.
6. Improved monitoring technologies would be useful, such as a) better geophysical techniques for the quantification and resolution of CO_2 plumes in the subsurface, b) improved remote sensing and other cost-effective methods for temporally variable leak detection, c) methods for fault and fracture detection and characterisation of their leakage potential, and d) development of suitable long-term monitoring strategies.
7. Options for mitigation and remediation technologies for potentially leaking CO_2 need to be developed.
8. There is insufficient information on potential costs of CO_2 storage in aquifers, including regulatory compliance costs and monitoring requirements.
9. The regulatory and liability framework for CO_2 storage in aquifers is unclear or needs to be established, particularly with respect to decommissioning requirements and long-term liability.
10. Standardised approaches for verification and accounting of CO_2 storage are lacking.

The study successfully developed a database of relevant scientific literature for the period 2005 to 2008, which has been provided by the contractor as a separate database and spreadsheet. The review of this information, including that reported from various pilot, demonstration and commercial injection projects, has enabled a comprehensive review of progress made in addressing the key knowledge gaps in the intervening period since the publication of the IPCC SRCCS.

Storage Capacity Estimation

Detailed work on methods for storage capacity estimation has been undertaken by both the CSLF and US DOE in recent years. Estimates of regional storage capacity should always be supported by clear statements defining the methodologies and nature of assumptions employed. This allows quoted capacities to be placed in the context of techno-economic resource classification schemes – for example, the CSLF 'pyramid'. Such an approach facilitates comparison of results from different regional studies.

Aquifer storage typically accounts for 90% or more of regional or global geological storage capacity according to many studies – so the underlying assumptions used for aquifer calculations have a fundamental effect on estimates of total capacity. Two factors were highlighted which can cause major discrepancy between different approaches:

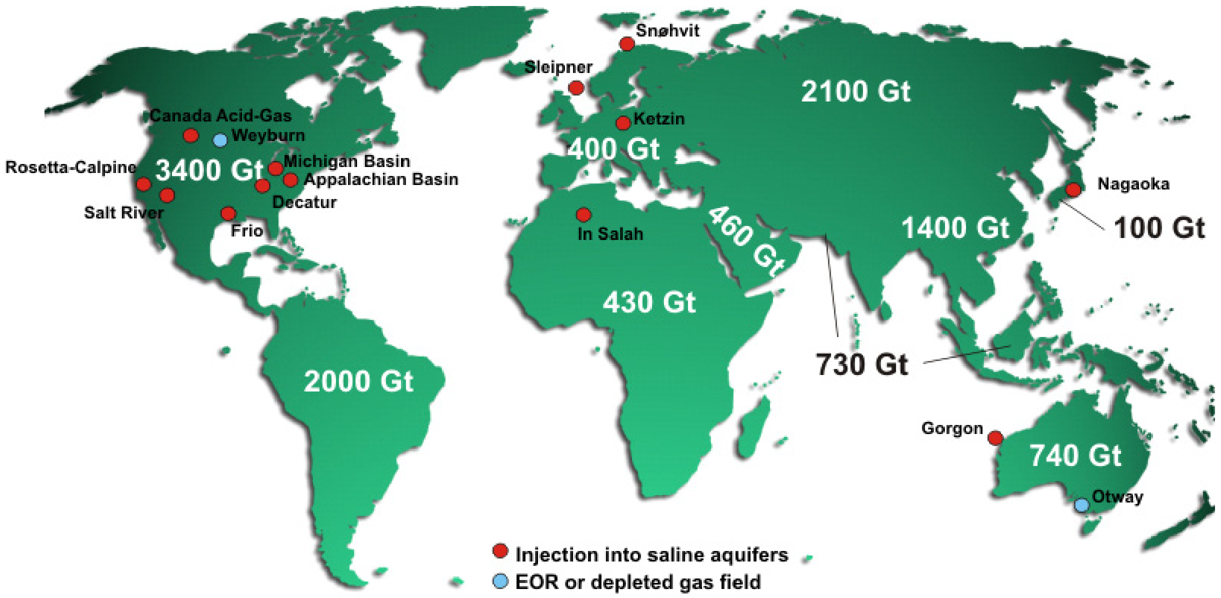
- Whether to limit capacity estimates in aquifers to structural traps (favoured by CSLF) or consider entire formations (favoured by US DoE), and
- How capacity is considered in terms of storage as free-phase or dissolved-phase CO_2. The CSLF methodology includes calculation of dissolved-phase capacity, whilst the US DoE methodology recognises the long term significance of dissolution but without any method for calculation.

Key remaining knowledge gaps were identified as:

- Consistent global approach to methodology for capacity estimation and storage coefficients
- Improved regional estimates for Africa, Latin America and Asia (excluding China and Japan)

The report included an updated world map, Figure 1 below, with storage capacities relating to theoretical resources at the base level of the CSLF pyramid:

Figure 1: ***Map showing projects injecting or having injected CO_2 into deep saline aquifers. Also shown are projects in an advanced planning stage (see text for details) as well as the Weyburn and Otway pilot projects. The first-order theoretical storage capacity estimates are based on the map by (Dooley et al., 2006) and updated with values for North America (DOE, 2007a), Japan (Li et al., 2005), Brazil (Ketzer et al., 2007), and China (Li, 2007).***



Geochemistry and Trapping

The rates at which geochemical trapping mechanisms such as solubility, ionic and mineral trapping occur are dependent on thermodynamics, kinetics and physical properties of the storage formation. Predicting the potential timescales over which these geochemical processes take effect, is crucial to understanding the relative importance of geochemical trapping in relation to the security and viability of any given storage site. Where predictive modelling of storage fails to account for geochemical trapping mechanisms, the effect will be to overestimate the amount of CO_2 stored as an immiscible phase and therefore, also overestimate the potential risks associated with leakage.

The report describes recent advances in understanding the geochemistry of CO_2 storage, which have been achieved through experimental studies at both field and laboratory scales, natural analogue studies and modelling. The ability to simulate CO_2 dissolution into formation water has been demonstrated to match experimental data, although the report identifies a need for more data at pressure and temperature conditions analogous to storage scenarios. Similarly, modelling codes have been developed to allow calculation of saturation indices for complex solutions and mineral phases. However, more experimental and field data for both single and multi-mineral phase systems is required to verify models are representative of natural systems. Continued modelling of various experimental, field and analogue data allows further progress in incorporating kinetics of reactions into modelling codes.

The report also identifies some specific knowledge gaps that still remain:

- Conceptual models of the geochemical system need to be provided in detail. Choices of reactant and product phases are often the product of the numerical model rather than constrained by experimental and observational data.

- More thermodynamic and empirical data especially for Pitzer equation formulation is required for saline solutions.

- Thermodynamic properties of mixed mineral phases (solid solutions) and poorly defined mineral phases like clays are not well constrained.

- Surface processes like adsorption and exchange can act as a significant buffer to pH changes and can be a store of cations that may be involved in mineral trapping. Many modeling codes include the ability to simulate adsorption and ion exchange making sensitivity analysis possible. More experimental data is required.

- Kinetic rate parameters still need to be refined for some mineral phases especially mixed mineral phases and poorly defined mineral phases like clays. Dawsonite precipitation kinetics need to be investigated as this is one of the most common product phases of numerical simulations and yet is not a common phase observed in natural analogues or experiments.

- Reactive surface area – determination, calculation, estimation. The most common difficulty described in the recent literature is the selection of a value for the reactive surface area to include in rate equations.

- Surface reaction mechanisms and how they influence the rates of reaction is poorly understood and difficult to model.

- Precipitation nucleation and degree of supersaturation required for precipitation for many important phases is not well known.

- Upscaling of reaction kinetics from the mineral surface to the continuum scale of reactive transport modeling is poorly constrained.

- Integration of experimental and natural analogue observations with geochemical reaction path and reactive transport modeling is receiving considerable attention and has promising outputs for helping constrain predictive models. More extensive datasets need to be gathered to populate model systems.

- Experiments addressing specific aspects of the mechanisms of geochemical trapping need to be undertaken – dissolution/precipitation kinetics, multiphase systems, mineral surface processes. All require more attention.

Predictive Modelling

Current numerical modelling codes, many being based on standard modelling and simulation tools from the petroleum industry, can incorporate hydrodynamic, geomechanical and geochemical processes. The effects of heterogeneity, relative permeability hysteresis, convective mixing and brine co-injection have all been the subject of recent research. Similarly leakage scenarios have been investigated, including assessment of self-enhancing and self-limiting geochemical and geomechanical processes. The report provides an informative overview of all significant factors affecting the current state of the art in CO_2 storage modelling.

There has been a marked increase in recent years, both of simulation software and the number of worldwide research groups engaged in the modelling of CO_2 storage. The need for cross-checking exercises for code comparison is therefore of considerable importance; the University of Stuttgart is in the process of completing such a study. IEA GHG is planning to hold a workshop on CO_2 storage modelling in February 2009 with a view to establishing a research network on the subject, to help facilitate the sharing of knowledge and experience in this rapidly developing area of expertise.

Trapping mechanisms for CO_2 storage in saline aquifers are understood in theory. Injected CO_2 can be stored as: a gas phase, either beneath a seal or in residual form within the pore space; dissolved in formation water; or precipitated in a mineral phase. The fate of injected CO_2 and the relative importance of these trapping mechanisms will have a major bearing on the optimal injection strategies for sites, and modelling processes should be sufficiently robust to inform these strategies. Adequate characterisation of the storage formation is also important. For example, the presence of shale barriers in a storage formation can reduce vertical permeability, thus increasing the tortuosity of migration pathways and enhancing residual and dissolution trapping mechanisms.

Leakage scenarios investigated by various authors include migration upwards through high-permeability conduits such as faults, and gradual accumulation in shallow formations prior to leakage to surface via tipping of ‘spill points’. A number of challenges are presented by leakage to shallow depths, particularly in terms of migration through the unsaturated zone to surface water or the atmosphere.

Identified knowledge gaps remain, including:

- Code comparisons need to be extended to more detailed examinations of coupled geochemical and geomechanical models.

- Improved flow modeling of CO_2 liquid/gas transitions in shallow reservoirs or near-surface leakage, possibly including hydrate formation.

- Better simulations of tracer effects in CO_2, especially density effects due to accumulation of relatively insoluble tracers at the front.

- Inclusion of fluid density changes in reactive transport simulations, for coupling to fluid convection.

- Upscaling of CO_2 simulations e.g. upscaling of solubility, residual gas trapping, convective mixing or vertical migration of CO_2.

- Improved quantification of potential leakage rates of CO_2 and CO_2/gas mixtures to the surface, especially through faults and fractures, with coupling to geomechanics.

- Simulation of CO_2 leakage rates through wellbore cement, including coupling to CO_2-cement reactions, to arrive at a better assessment of the overall risk of well leakage.

- Simulation of surface leakage of CO_2, including screening of scenarios for sudden releases, and coupling with the atmosphere (onshore) and the sea (offshore).

- Simulation of coupling CO_2 injection to hydrogeology, including assessment of effects on CO_2 migration and adjacent aquifer units.

- Data sets to test models for convection of dissolved carbon dioxide and coupled reactions on large time scales (beyond what is possible in demonstration projects, so would need to be from natural systems).

- Data sets to test geomechanical models for fault reactivation (if faults are to be deliberately reactivated to test models this would involve water rather than carbon dioxide).

- Data sets to test leakage models, perhaps using natural systems.

- Data sets to test and calibrate tracer/CO_2 behaviour in laboratory and field, including partitioning coefficients between a dense CO_2 phase and water.

- The knowledge gaps identified above for predictive and geochemical modeling, will form part of the basis for discussions at the forthcoming IEA GHG workshop on geological storage of CO_2 storage, scheduled for February 2009 in Orleans, France.

Risks Associated with Wellbores

The 2008 aquifer study describes the issue of potential leakage through abandoned wells as significant, particularly at onshore locations with high concentrations of wells. Wellbore leakage raises the potential problem of CO_2 interactions with standard Portland cement and this topic has been the subject of much research effort, as reported by the IEA GHG international research network on well integrity.

Research effort is also being focussed on the coupling of migration through cement and reactions within the matrix. A key factor here is the characterisation (width and permeability) of pre-existing fractures through cement, since diffusive transport of CO_2 through cement is considered to be too slow to affect integrity. A further challenge is then for reactive transport modelling simulations to match laboratory experiments and even field data. The lack of field data to characterize leakage pathways through wellbore cement is considered to be a key knowledge gap.

The work of the IEA GHG Wellbore Integrity Network continues to provide an international forum for experts to discuss these issues.

Site Characterisation

Site characterisation can be regarded as the collection and analysis of geological information to confidently predict the safe and effective injection of CO_2 into an accurately constrained storage capacity. Key relevant documents issued in recent years are the 2007 Best Practice Manual from the SACS/CO2STORE project, and the 2008 CO2CRC report on storage capacity estimation, site selection and characterisation.

Site characterisation can be regarded as the most costly and time-consuming part of the site selection process. CO2CRC report that the key steps involved in characterisation are: structural and stratigraphic interpretation based on subsurface data; construction of geological models with realistic representation of heterogeneity; geochemical, geomechanical and hydrogeological modelling; and numerical modelling to predict CO_2 plume migration.

The report recommends that development of best practice manuals include reference to a broad range of case studies from around the world.

IEA GHG is co-funding a study on site characterisation by DNV that aims to develop qualitative 'best practice' procedures, whilst a second proposed study will consider quantitative criteria.

Risk Assessment

Established risk assessment (RA) methodologies for various environmental or industrial scenarios are described as factors of likelihood and consequence, with risks proportional to impact severity and probability. Risks can be assessed using qualitative, deterministic or probabilistic methods.

To date, no consistent RA methodology for CCS projects and CO_2 storage exists. The IEA GHG risk assessment network has facilitated much debate and sharing of experience on the application of risk assessment techniques to CO_2 storage. The third workshop of this network in 2007 concluded that, whilst a fully quantitative RA process for CCS may be desirable, current limitations and uncertainties in CO_2 storage modelling and impact assessment restrict meaningful RA techniques to qualitative or semi-quantitative methods.

Monitoring Technologies

The study reported a summary of monitoring undertaken at injection sites. At Sleipner, 4D seismic has been successfully deployed but this technique is relatively expensive; 4D gravity has also been shown as a useful tool for qualitative assessment. At the Frio and Nagaoka injection sites, 4D vertical seismic profiling and cross-well electromagnetics allowed quantitative tracking of the CO_2 plume.

Monitoring technologies for shallow groundwater, soil and atmosphere have been researched and developed, but still require successful demonstration.

Knowledge gaps were identified as:

- Improvement of cost-effective monitoring strategies, including new techniques;
- Additional monitoring and verification data from injection projects.

In addition, natural analogues provide important opportunities for ongoing testing of near-surface CO_2 leakage. The work of the IEA GHG monitoring network continues to focus on the development of CO_2 storage monitoring technologies.

Potential Costs of Storage

Normalisation of available cost data to create a predictive cost model for aquifer storage is problematic at present due to a number of factors. Available cost data is sparse, quoted in different currencies from different years, and based on widely differing storage scenarios and methods. The current widespread absence of regulatory regimes also means that the requirements for the major cost elements of site characterisation, monitoring, abandonment and remediation are all uncertain.

The report's conclusion on the difficulty of estimating storage project costs reflects the IEA GHG position; a proposed study of CO_2 storage costs has been delayed, pending completion of studies on site characterization, injectivity and efficient use of storage capacity, and further development of regulatory regimes. IEA GHG proposes to consider such a study in 2009/10, when other relevant studies listed above can be used to better inform projection of storage costs.

Regulatory and Liability Framework

Key issues that need to be addressed by various regulatory regimes currently under development are:

- Long term liability and stewardship of storage sites,
- Definition of monitoring and verification requirements,
- Emission trading scheme implications.

These issues are being addressed rapidly in several regions of the world, and the IEA regulators network is providing an important contribution.

Roadmap

The report also presents a roadmap towards commercialisation of storage in saline aquifers. This highlights the knowledge gaps described throughout the preceding sections of the report, again emphasising that these knowledge gaps should not be regarded as barriers to implementation of storage in saline aquifers. Indeed, data from additional injection projects is required to address many of these issues.

The most significant barrier to widespread commercial implementation remains the absence of regulatory frameworks. To enable broad uptake of CCS by 2020, it is considered essential that regulatory frameworks are developed in nations and regions with significant CCS potential.

Overall Conclusions of the Study – Knowledge Gaps

Table 2 below provides a summary of overall progress, key issues and knowledge gaps for storage of CO_2 in deep saline aquifers. The report also states that four priority scientific research areas can be considered as:

- Better understanding of long term geochemical processes
- Coupled simulation modelling for long term predictions
- Quantification of leakage scenarios
- Potential wellbore leakage due to cement degradation

Table 2. Geological storage of CO_2 in saline aquifers – issues, progress and remaining knowledge gaps

	Issue	2008 Progress	Remaining gaps	Comments	Importance for commercial implementation
Storage Capacity	Uncertainty in capacity estimates	US DOE Atlas Japan (Europe, Australia*)	Africa, Asia, Latin America (Europe, Australia*)	*Work in progress, but not yet published	🟩
	Inconsistent methodology	US DOE Atlas CSLF Report CO2CRC Report	Universal document	Should be consistently applied	🟩
Storage Science	Geochemistry	Advances in *solution composition* and *surface processes*	Use of reactive surface area in models; experiments addressing specific aspects of geochemical trapping	Field-relevant experimental data is needed.	🟧
	(Coupled) numerical models	Modelling of experimental and natural analogue data; well leakage	Data for calibration; up-scaling of processes	Need more demonstration projects	🟨
Storage Engineering	Local-scale capacity		Portfolio of storage environments		🟨
	Injectivity				
Monitoring	Need for testing and improvement of technologies?	Results from Frio & Nagaoka	Long-term monitoring and verification data		🟨
	Detection of leaks	-	Cost-effective monitoring techniques	Need more demo projects.	🟧
	Verification of storage	-			🟧
Regulations	Lack of proper regulatory framework	Draft legislations in Australia, US, Europe (WY?)	Final legislation and trading schemes		🟥
Economics	Cost for storage projects not well known		Comparability of different cost estimates	Economics depend significantly on location and legislation	🟥
Risk/Operation safety	Lack of quantitative methods				🟧
	Need for protocols for storage duration and safety	Best Practice Manual(s)			🟧

red = significant road block; orange = substantial research gaps, but not crucial for commercial application; yellow = some research needed, but depends largely on new data from large-scale injection projects for verification; green = sufficient knowledge, might need minor improvements & consistency.

Expert Review Comments

The draft report was sent to a panel of expert reviewers, and feedback received was complimentary. In particular there was an agreement amongst the reviewers that the report provides a timely overview of the current status of CO_2 storage in saline aquifers. Most of the comments received addressed typographic errors or minor discrepancies in factual information.

Some of the more significant comments centred on estimation of storage capacity, in particular the alternative approaches of evaluating entire saline formations or only structural traps. Other comments included:

- Storage formation heterogeneity can improve trapping, but can also have a negative effect by allowing bypass of potential storage zones and slowing of contact with unsaturated formation water,
- Scalability of monitoring technologies needs to be considered, given the difference in size between pilot and commercial projects,
- Selection of monitoring technologies should be partly dependent on site-specific circumstances; and many cost-effective technologies can already be employed for particular scenarios e.g. pressure monitoring. Furthermore, expensive techniques (e.g. 3D seismic) may not always provide useful data and this needs to be borne in mind when regulations are drafted,
- Capillary entry pressure may be an important factor for consideration in terms of caprock integrity,
- Generic indicators of storage site suitability should not be confused with ‘cut off’ criteria; for example, several storage targets in the Williston Basin of the USA are relatively low-permeability formations.

Conclusions

The study has demonstrated that considerable progress has been made in addressing the knowledge gaps pertaining to CO_2 storage in saline aquifers, as identified in the 2004 IPCC SRCCS. However, some of these knowledge gaps still require further research.

Nevertheless, the identified knowledge gaps are not considered barriers to injection projects; indeed, more widespread injection projects are required to demonstrate aquifer storage and allow calibration of predictive models. Further development of ‘Best Practice’ manuals for aquifer storage needs to focus on an increasing number of case study injection sites across different geographic regions.

The report concludes that geological storage of CO_2 in saline aquifers can be regarded as a proven technological option due to the success of large scale injection projects at Sleipner and In-Salah; the most significant barriers to wider commercial uptake of aquifer storage are the absence of regulatory frameworks and economic drivers. However this is a gap that is being addressed in Europe, Canada, USA and Australia.

Recommendation and IEA GHG Activities

Future research into storage of CO_2 in saline aquifers, including IEA GHG studies and research network activities, should be guided by the knowledge gaps identified by the study. Current IEA GHG activities are addressing these gaps in a number of areas:

- A study on the use of setting and use of coefficients to refine regional storage capacity estimates has been commenced in September 2008. This study will draw on modelling and field experience from around the world and build on the output and findings of the CO2CRC report,
- Wellbore integrity issues are being addressed through a study being undertaken by TNO on behalf of IEA GHG, in addition to the ongoing work of the research network,
- Leakage scenarios will continued to be considered by the risk assessment network,
- Knowledge gaps in storage science, concerning the need for improved understanding of geochemical processes and application of coupled predictive models, will be key topics for discussion at the forthcoming IEA GHG modelling workshop,
- IEA GHG is co-funding a study on site characterisation by DNV that aims to develop qualitative 'best practice' procedures, whilst a second proposed study will consider quantitative criteria,
- The IEA regulators network is providing an important contribution to the rapid development of regulation in various parts of the world,
- During the GHGT9 conference in Washington, over-pressurisation of aquifers and brine displacement were highlighted as two linked, key issues that could affect the total capacity available for storage in saline aquifers. These issues will be addressed during the forthcoming IEA GHG modelling workshop in Orleans, France in February 2009.

Aquifer Storage – Development Issues

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**K. Michael[1], G. Allinson[2], M. Arnot[3], P. Cook[4], A. Golab[4], J. Ennis-King[1],
R. Funnell[3], J. Kaldi[5], D. Kirste[6], L. Paterson[1], S. Sharma[7], V. Shulakova[1]**

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[1]CSIRO Petroleum; [2]University of New South Wales; [3]Geological and Nuclear Sciences, NZ; [4]CO2CRC, Canberra, [5]University of Adelaide; [6]Simon Fraser University; [7]Schlumberger

Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)
GPO Box 463, CANBERRA ACT 2601, AUSTRALIA
Ground Floor, NFF House
14-16 Brisbane Avenue
Barton, ACT 2601
Phone: +61 2 6120 1601
Fax: +61 2 6273 7181
Email: pjcook@co2crc.com.au
Web: www.co2crc.com.au

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Executive Summary

Injecting carbon dioxide (CO_2) into deep saline aquifers is one of three main options for the geological storage of CO_2 in order to reduce anthropogenic greenhouse gas emissions into the atmosphere. Previous studies have shown that, compared to the other two options (storage in depleted hydrocarbon reservoirs and in deep, un-minable coal seams), deep saline aquifers have the highest potential capacity globally for CO_2 storage. However, at the same time, there are many uncertainties regarding the extent to which potential capacity can be turned into useable storage capacity. The current report reviews the recent advancements in the science related to aquifer storage of CO_2, summarizes the knowledge gained from existing CO_2 injection operations, and addresses the need for future research towards achieving the commercialization of CO_2 geological storage in deep saline formations.

The starting points for this study were the conclusions and knowledge gaps identified in the Intergovernmental Panel of Climate Change Special Report on Carbon Capture and Storage (IPCC SRCCS) from 2005. The CO2CRC project team reviewed all key research and demonstration activities carried out since the compilation of the report in 2004 and summarized the progress that has been made towards filling these knowledge gaps. In particular, it reviewed the lessons learnt and compiled in a database relevant data from pilot, demonstration and commercial storage projects.

Numerous research results have been published on the science of CO_2 storage in aquifers since the IPCC SRCCS. The main knowledge gaps remain associated with the understanding of long-term geochemical processes of CO_2 in the subsurface, the use of coupled simulation models to make long-term predictions, the quantification of leakage rates from storage sites, and the risks of wellbore leakage due to cement degradation from CO_2 (Table 1).

In regard to geochemistry, advances have been made with respect to the modelling of experimental and natural analogue data and in understanding effects of solution composition and surface processes on reaction kinetics. However, certain aspects like "reactive surface area" and the role of adsorption and ion exchange have not yet been incorporated in published models.

Current numerical codes can model a wide range of hydrodynamic, geomechanical, and geochemical processes. Advances have been made in investigating the effects of heterogeneity, relative permeability hysteresis, convective mixing and brine co-injection on CO_2 trapping. Gravity currents have been used as an analogue for CO_2 plume migration, and coupled geomechanical models have been used to improve predictions of fault slip. Still, there is a lack of data from CCS pilot or demonstration projects that could be used for the calibration of numerical modelling efforts. Specific issues that still remain to be further investigated include code comparisons on coupled models, coupling of density effects in reactive transport simulations, the simulation of tracer effects in CO_2, coupling with hydrogeology, and the upscaling of simulating various processes (i.e., solubility, residual gas trapping, convective mixing, vertical CO_2 migration).

Leakage scenarios for storage scenarios have been investigated, and so far no cases have been found which allow for sudden large releases to surface, since there are self-limiting as well as self-enhancing effects that come into play. A leaking well completed in a natural CO_2 bearing aquifer in Utah did not result in concentrations with substantial risks to health or environment and may be regarded as an analogue for a worst-case scenario. Coupling from near-surface leakage to the atmosphere has been examined in field trials. Caprock leakage has been studied for the balance between self-limiting geochemical processes and self-enhancing geomechanical effects due to pressure increase. CO_2-cement interactions have been tested in laboratory experiments and field data has been obtained. Further work is needed to quantify potential leakage rates, especially from faults and fractures, and for this analogue or field data is required. Simulation of near-surface leakage or shallow aquifers requires better models of CO_2 gas/liquid transitions and hydrate formation. Quantification of wellbore leakage requires better characterization of leakage pathways through wellbore cement, and simulation of the coupling between flow along these pathways and CO_2-cement reactions.

It should be emphasized that the currently remaining knowledge gaps in the storage science and modelling should not be considered as barriers to the implementation of large-scale CO_2 storage projects in aquifers. On the contrary, more CO_2 storage operations are needed to provide realistic data for model calibration and substantiation of time frames for various trapping mechanisms.

Table 1. Geological storage of CO_2 in saline aquifers – issues, progress and remaining knowledge gaps.

	Issue	2008 Progress	Remaining gaps	Comments	Importance for commercial implementation
Storage Capacity	Uncertainty in capacity estimates	US DOE Atlas Japan (Europe, Australia*)	Africa, Asia, Latin America (Europe, Australia*)	*Work in progress, but not yet published	🟩
	Inconsistent methodology	US DOE Atlas CSLF Report CO2CRC Report	Universal document	Should be consistently applied	🟩
Storage Science	Geochemistry	Advances in *solution composition* and *surface processes*	Use of reactive surface area in models; experiments addressing specific aspects of geochemical trapping	Field-relevant experimental data is needed	🟧
	(Coupled) numerical models	Modelling of experimental and natural analogue data; well leakage	Data for calibration; up-scaling of processes	Need more demonstration projects	🟨
Storage Engineering	Local-scale capacity		Portfolio of storage environments		🟨
	Injectivity				
Monitoring	Need for testing and improvement	Results from Frio, Nagaoka & Sleipner	Long-term monitoring and verification data		🟨
	Detection of leaks	-	Cost-effective monitoring strategies		🟧
	Verification of storage	-			🟧
Regulations	Lack of proper regulatory framework	Draft legislations in Australia, US, Europe	Final legislation and trading schemes		🟥
Economics	Cost for storage projects not well known		Comparability of different cost estimates	Economics depend significantly on location and legislation	🟥
Risk/Operation safety	Lack of quantitative methods				🟧
	Need for protocols for storage duration and safety	Best Practice Manual(s)			🟧

red = significant road block; orange = substantial research gaps, but not crucial for commercial application; yellow = some research needed, but depends largely on new data from large-scale injection projects for verification; green = sufficient knowledge, might need minor improvements & consistency.

The experience from CO_2 injection at pilot projects (Frio, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) (Figure 1) shows that CO_2 geological storage in saline aquifers is technologically feasible. By the end of 2007, approximately 15 Mt of CO_2 had been successfully injected into saline aquifers by these operations. Particularly, Sleipner, In Salah, and Snøhvit demonstrate that, given the right geological and reservoir conditions, injecting industrial-scale volumes on the order of 1 Mt/year CO_2 into saline aquifers is achievable. However, these projects are not necessarily representative for conditions encountered globally. For example, aquifer permeability at Sleipner is probably unusually high compared to what could be expected for other sites. In Salah operates 3 injection wells in a low-permeability aquifer, but there is limited monitoring information. Nagaoka and Frio have comprehensive M&V programs, but injection rates/volumes are very low. The various acid-gas injection operations in Western Canada cover a wide range of reservoir properties, but again injection rates are relatively low and very limited subsurface monitoring is done. Hence, there remains the need for a more comprehensive portfolio of aquifer storage projects that covers the range of variability of different subsurface environments (e.g., on-/offshore, low/high permeability, sandstone/carbonate/basalt, pressure, temperature, salinity) as well as different monitoring strategies, regulation requirements and economics.

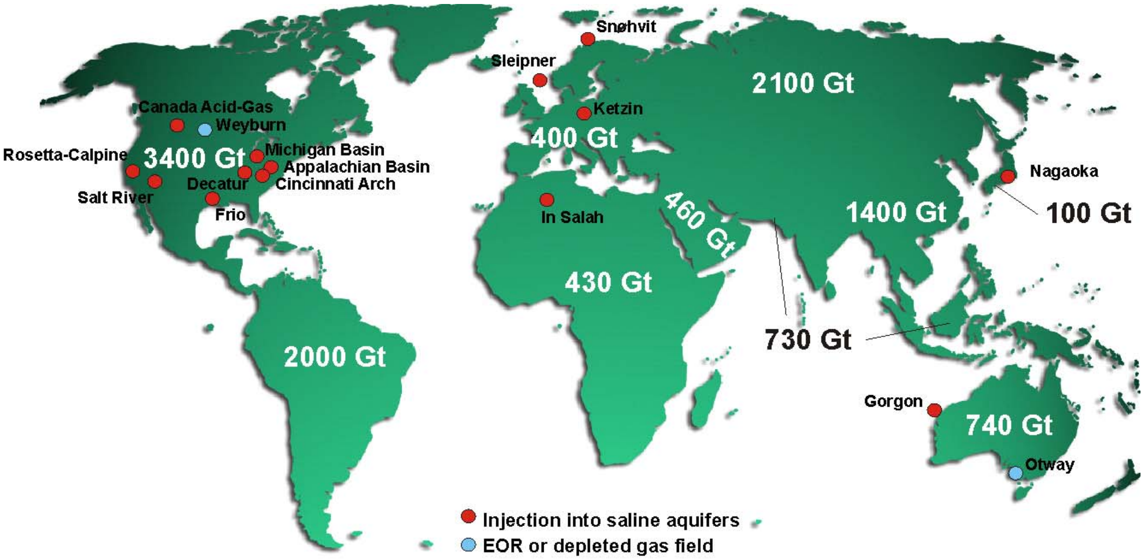


Figure 1. Map showing projects injecting or having injected CO_2 into deep saline aquifers. Also shown are projects in an advanced planning stage (see text for details) as well as the Weyburn and Otway pilot projects. The first-order theoretical storage capacity estimates are based on the map by Dooley et al. (2006) and updated with values for North America (DOE, 2007a), Japan (Li et al., 2005), Brazil (Ketzer et al., 2007), and China (Li, 2007).

With respect to monitoring and verification of CO_2 storage reservoirs, 4D seismic proved to be very successful at Sleipner, but has the disadvantage of being relatively expensive and might prove challenging for onshore storage sites related to repeatability problems due to changing weather, soil humidity and contact conditions. Also, successfully implemented at Sleipner was 4D gravity, which has lower costs and works well for qualitatively assessment of CO_2 saturation in the subsurface, but requires a detailed, well-characterized geological model. Promising geophysical methods that worked well at Frio and Nagaoka for quantitative tracking of the CO_2 plume were 4D vertical seismic profiling (VSP), which allows for a good source signal control, and cross-well seismic and electro-magnetics. However, these two methods require a monitoring well in addition to the injector and the transmission distance between injection and monitoring well might get too big in the case of commercial projects with large CO_2 plume sizes, resulting in a loss of resolution. Monitoring technologies for the shallow groundwater, soil and atmosphere have been developed, however they have not yet been successfully demonstrated to detect potential CO_2 leaks from the reservoir unit due to relatively high natural CO_2 fluctuations in these environments. Requisite monitoring plans in future regulations for CO_2 storage projects should carefully weigh the necessary requirements for ensuring storage verification and safety against cost and suitability of the various monitoring techniques for specific storage environments and geological conditions.

Comparing the costs for operations storing CO_2 in saline aquifer is difficult for a variety of reasons: a) cost data are scattered and patchy; b) costs are quoted for different years, c) costs are quoted in different currencies, d) quoted costs are based on different methodologies, and e) costs for fuel, steel, labour, and construction vary globally and regionally. As a result, considerable analysis would be required to normalize the cost data and construct predictive analytical tools for future projects. Alternatively, but not mutually exclusive, computerized costing models and equations could be created, based on vendor quotes that reflect current economic circumstances.

The existing expertise in CO_2 injection technology currently resides mainly with the petroleum industry. Other industries have to be introduced and, maybe more importantly, become more comfortable with the concept of geological storage.

The publication of the Carbon Sequestration Atlas of the United States and Canada (DOE, 2007a) and the Phase 2 report on the Estimation of CO_2 Storage Capacity in Geological Media by the CSLF (2007) represent significant progress towards developing consistent methodologies for the classification and determination of CO_2 storage capacity in saline aquifers. CO2CRC (2008) in Australia proposes to adopt a combination of the US DOE methodology of capacity calculation with the CSLF classification scheme of storage estimates, and to expand the latter by incorporating the SPE Petroleum Resources Classification framework (SPE et al., 2007). The main cause for the large discrepancy between and range in existing global and regional CO_2 storage capacity estimates is the use of a combination of two fundamentally different concepts: 1) considering the entire aquifer versus considering only structural traps for CO_2 storage, and 2) assuming CO_2 storage in solution versus storage as free-phase fluid. However, the example of the US DOE Atlas shows that, by knowing the underlying assumption in each regional partnership's estimation methodology, the results obtained by different methods can be easily converted into comparable capacity estimates. In addition, when presenting regional or global storage capacity values, they should be clearly classified within the CSLF Techno-Economic Resource-Reserve pyramid.

Since the publication of the IPCC SRCCS, new storage capacity estimates have been produced by the US Regional Partnership program, individual studies in Japan, China and Europe, and regional, basin-scale studies in Australia. In addition, there are active projects like GEOCAPACITY in Europe and CARBMAP in Brazil that anticipate to present regional capacity estimates for their respective regions within the next year or two. However, except for the initiation of CCS research programs almost no progress has been made in obtaining reliable CO_2 storage estimates for Latin America, Africa, and large parts of Asia.

With respect to the site specific assessment of prospective CO_2 storage site, the SACS/CO2STORE Best Practice Manual represents significant progress towards comprehensive guidelines regarding site selection, site characterization, risk assessment and monitoring and remediation plans. The document relies heavily on the experience gained from CCS operations and research in Europe, particularly from the Sleipner project. The Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects (CO2CRC, 2008) provides an additional Australian prospective to these topics in a single document. It is recommended that future best practice development should focus on expanding the range of case studies referenced in the current Best Practice Manual, and incorporating examples from other geographic locations (e.g. USA, Canada, Australia) to broaden the range of geological, political and economic environments. The combination of Best Practice and Site Characterisation manuals with regulatory requirements should not only be attempted for deep saline aquifer sites, but also with reference to depleted petroleum reservoirs, EOR/EGR and coal studies.

In conclusion, CO_2 geological storage in saline aquifers is a technology that can be successfully and safely applied today as shown by the experience from active commercial storage projects at Sleipner, In Salah, Snøhvit, and acid-gas injection sites in Canada. Research at pilot storage operations at Frio, Nagaoka and Otway have significantly advanced the science and numerical modelling of CO_2 geological storage, tested various monitoring technologies and resulted in Best Practice recommendations for the sighting and characterization of CO_2 storage sites. For further progress, a larger portfolio of large-scale storage operations (demonstration/commercial) is needed to provide data for verification and calibration of numerical models, and to better constrain geomechanical as well as geochemical processes. The most significant barriers for the wider commercial implementation of CO_2 storage in saline aquifers is that a proper regulatory framework is still lacking in many jurisdictions. Many countries expect to have regulations for CO_2 storage in place within the next 1 or 2 years, which will reduce the current uncertainty associated with the economics of CO_2 storage and hopefully will accelerate the deployment of CCS technology.

Introduction

Injecting carbon dioxide (CO_2) into deep saline aquifers is one of three main options for the geological storage of CO_2 in order to reduce anthropogenic greenhouse gas emissions into the atmosphere. Previous studies have shown that, compared to the other two options (storage in depleted hydrocarbon reservoirs and in deep, un-minable coal seams), deep saline aquifers have the highest potential capacity globally for CO_2 storage (IPCC, 2005). However, at the same time, there are many uncertainties regarding the extent to which potential capacity can be turned into useable storage capacity. The current report reviews the recent advancements in the science related to aquifer storage of CO_2 since the review in 2004 by IPCC, summarizes the knowledge gained from existing CO_2 injection operations, and addresses the need for future research towards achieving the commercialization of CO_2 geological storage in deep saline formations.

Report Structure

This report is subdivided into four main sections. The first section introduces the scope, background and objectives of the project, and presents the definition of “aquifer storage” as used in this report. In the second section, the recent literature of the general science relating to CO_2 aquifer storage (capacity estimation, trapping mechanisms, coupled numerical modelling, risk assessment and site characterization) is reviewed, from which the current state of knowledge is defined. The third section, describes the results obtained and the experiences gained from existing commercial or pilot CO_2 injection operations, particularly with regard to the costs, regulations and monitoring operations associated with these projects. The review of injection operations is based on a comprehensive database containing reservoir characteristics and operational parameters, specifically compiled for this project. The current state of scientific research and experience gained from storage projects reviewed in the second and third sections are used in the fourth section to identify specific knowledge targets that are necessary to achieve a level of confidence suitable for the secure and safe implementation of CO_2 aquifer storage as part of carbon capture and storage operations. Based on these targets, a road mapping exercise was conducted to develop a plan towards tentative commercialization by 2020. This roadmap may form the basis for a new research network on the subject of CO_2 storage in deep saline aquifers. A bibliography of the recent scientific literature (2005-2008) reviewed in this study accompanies the report as a separate Endnote database and in an Excel spreadsheet.

Project Scope and Objectives

The IPCC Special Report on CO_2 Capture and Storage (IPCC SRCCS), completed in late 2005, identified various knowledge gaps related to aquifer storage of CO_2, many of which may need to be addressed before there is widespread commercial implementation of the technology (IPCC, 2005). The knowledge gaps can be summarised as follows:

1. Current storage capacity is imperfectly known due to inconsistency in assessment methodologies, lack of data and gaps in global, regional and local estimates. This is particularly the case in Africa, South America and large parts of Asia, although there are also many data gaps in OECD countries.

2. Kinetics of trapping mechanisms and their long-term impact on reservoir characteristics, particularly geochemical trapping need further investigation.

3. Improved coupled hydrogeological-geochemical-geomechanical numerical models would help to better predict the long-term fate of injected CO_2 in the subsurface and quantify potential leakage pathways, events and rates.

4. Risks of CO_2 leakage from abandoned wells due to casing and cement degradation and the temporal variability and spatial distribution of leaks should be better assessed.

5. Quantitative methods to assess the risk of CO_2 leakage to human health and the environment are needed. It is critical that these methods are relevant to geological storage of CO_2 and the relatively nonhazardous nature of CO_2.

6. Improved monitoring technologies would be useful, such as a) better geophysical techniques for the quantification and resolution of the location of CO_2 plumes in the subsurface, b) improved remote sensing and other cost-effective surface methods for temporally variable leak detection, c) methods for fault and fracture detection and characterisation of their leakage potential, and d) development of suitable, cost-effective long-term monitoring strategies.

7. Options for mitigation and remediation technologies for potentially leaking CO_2 need to be further developed.

8. There is insufficient information on potential costs of CO_2 storage in aquifers, including regulatory compliance costs and monitoring requirements.

9. The regulatory and liability framework for CO_2 storage in aquifers is unclear or needs to be established, particularly with respect to decommissioning requirements and long-term liability.

10. Standardised approaches for verification and accounting of CO_2 storage are lacking.

Progress has been made towards addressing some of these knowledge or technology gaps through research activities and experience gained from pilot and commercial CCS projects. The principal objective of this report is to provide a comprehensive review of the progress in international research and understanding with respect to the storage of CO_2 in deep, saline aquifers particularly in the last 4-5 years, including the evaluation of results from pilot, demonstration and commercial storage projects around the world.

Methodology

The starting points for this study were the conclusions and knowledge gaps identified in the IPCC SRCCS (IPCC, 2005). The CO2CRC project team reviewed all key research and demonstration activities carried out since the compilation of the report in 2004 and summarized the progress that has been made towards filling these knowledge gaps. In particular, it reviewed the lessons learnt from pilot, demonstration and commercial storage projects. Following is a list of tasks performed for this study:

1. New results from technical work and storage projects were compiled by the CO2CRC researchers and collaborators.

2. The members of the project team reviewed and defined the current state of knowledge regarding geological storage of CO_2 in saline aquifers with respect to:

    a) Estimates of storage capacity for deep saline aquifers and the methodologies available for the determination of these;

    b) Regional capacity mapping, estimates of storage potential and impact of local conditions and comparison to global capacity estimates and determination methods;

    c) Trapping mechanisms, including structural, stratigraphic, hydrodynamic, solubility, capillary, and geochemical trapping, and their long-term impact on aquifer characteristics such as porosity, permeability and fluid chemistry;

d) Risk assessment associated with CO_2 storage in aquifers and brine displacement issues;

e) Experience from monitoring activities at existing aquifer storage sites;

f) Contribution of coupled-flow modelling (multiphase fluid flow-geochemical-geomechanical models) to understanding the movement and distribution of injected CO_2 in deep, saline aquifers;

g) Information and experience from pilot, demonstration and commercial CO_2 storage projects where aquifers are the injection target;

h) The work on Best Practice manuals, characterization requirements and methodology for aquifer storage site selection, including comparison of storage site selection in depleted hydrocarbon reservoirs, EOR projects and coal systems;

i) Comparison of the CSLF, DOE (Regional Partnerships) and other schemes used for characterization and assessment.

3. A detailed examination of data from existing saline aquifer storage sites and pilot projects; provision of a database of available reservoir properties (e.g., lithology, porosity, permeability, injectivity, brine chemistry) to help establish whether current storage operations cover a representative range of reservoir characteristic and/or if specific aquifer types should be targeted with future pilot sites or demonstration projects.

4. An assessment and compilation of the various regulatory regimes under which the current projects operate, to the extent to which this is possible.

5. After compiling the current state of scientific research and experience gained from storage projects from the work described above, specific knowledge targets were identified that are necessary to achieve a level of confidence suitable for the secure and safe implementation of CO_2 aquifer storage as part of carbon capture and storage operations. Based on these targets, a road mapping exercise was conducted to develop a plan towards tentative commercialization by 2020. This roadmap may form the basis for a new research network on the subject of CO_2 storage in deep saline aquifers.

Aquifer Storage – Definitions

For the purpose of this report and following Bachu et al. (2007), an aquifer is defined as a layer, formation, or group of formations of permeable rocks, saturated with water and with a degree of permeability that allows water withdrawal through wells. Aquitards are porous layers or beds from which water cannot be produced through wells, but where the vertical flow is significant enough over large areas to feed adjacent aquifers, and aquicludes are layers or beds that have generally extremely low, if any, permeability. Aquifers, regardless of their lithology (siliciclastics or carbonates), are defined in terms of their hydraulic properties and are separated by intervening aquitards (e.g. shales, evaporites). With respect to CO_2 geological storage, it is understood that only deep saline aquifers are considered, which implies that they contain water with salinity greater than that of protected groundwater. Depending on the jurisdiction, protected groundwater includes water suitable for human consumption (< 3000-4000 mg/l) or water with salinity of up to 10,000 mg/l fit for irrigation or consumption by live stock. The term *saline formation* is used alternatively in the literature. Although the term *reservoir* generally is defined by the same lithological and hydraulic properties as an aquifer, it usually implies that a top seal (aquitard, aquiclude) and lateral boundaries delineate a structural or stratigraphic trap and that the pore space is saturated, at least partly, with a different fluid than water (i.e., oil, gas). Most often, hydrocarbon reservoirs are located within and are in hydraulic communication with an aquifer, the latter acting as a conduit for migrating hydrocarbons.

Consequently, the terminology can become somewhat vague in cases where CO_2 is injected into an aquifer that underlies a reservoir (i.e., In-Salah) or where injection occurs into a depleted reservoir and CO_2 either dissolves into the underlying water leg or spreads beyond the spill point. For every injection scenario or regional assessment of CO_2 capacity it is therefore important to consider the spatial and hydraulic relationships between *aquifers* and *reservoirs*.

If an aquifer allows water withdrawal, then it will also allow injection of fluids. The most common fluid currently injected into aquifers is waste water, but acid gas for disposal, natural gas for temporary (seasonal) storage, and CO_2 for permanent storage are also injected.

Recent Advancements in the Science of CO_2 Storage in Aquifers

The main knowledge gaps with respect to the actual science of CO_2 storage in aquifers identified in the IPCC SRCCS refer to the geochemical processes in the subsurface environment and to the numerical modelling of coupled processes. The review of the current literature related to these two scientific topics will be the main focus at the beginning of this section. The section concludes with a review of new developments and methodologies with respect to Storage Capacity Estimations, Best Practice of Site Characterisation and Risk Assessment related to the geological storage of CO_2 in saline aquifers.

Geochemistry

In the IPCC SRCCS, the need for a greater understanding of the kinetics of geochemical trapping and the long term effects on aquifer rocks and fluids of CO_2 sequestration is identified as a knowledge gap. The extent to which the solubility, ionic and mineral trapping will occur is dependent upon the temperature, pressure, fluid composition and mineralogy as well as the flow of the injected CO_2 and formation water. However, the rate at which they occur, which is of primary interest in assessing the security and viability of a storage site, is dependent on the thermodynamics, kinetics and the physical properties of the rock. Advances in the ability to numerically simulate geologic storage come through a combination of detailed experimental studies at laboratory and field scales, natural analogue studies and geochemical modelling.

This section describes the recent advances in knowledge of geochemical trapping in terms of published works since the release of the IPCC SRCCS. Flow and transport will be discussed in the modelling portion of this report.

CO_2 Solubility

The amount of CO_2 that will dissolve in water is dependent on the pressure and temperature of the system and on the composition of the water. A number of different thermodynamic models have been formulated to calculate CO_2 solubility and there exists a moderate experimental dataset to evaluate the models (Hu et al., 2007). Substantial reviews of CO_2-H_2O and CO_2-H_2O-NaCl mixtures including their thermodynamic and empirical derivation were published in 2007 (Hu et al., 2007; Marini, 2007). Spycher and Pruess (2005) extended their computational approach for the mutual solubilities of CO_2 and H_2O (Spycher et al., 2003) to incorporate the role of NaCl and $CaCl_2$ at 12 – 100°C and up to 600 bar. Activity coefficients for aqueous CO_2 are based on Pitzer equations (Rumpf et al., 1994; Duan and Sun, 2003). This method is particularly valuable as the iterative methods of Duan and Sun (2003) are not easily incorporated into numerical models. A more efficient, non-iterative equation describing CO_2 solubility in aqueous solutions containing Na-K-Ca-Mg-Cl-SO4 than the model by Duan and Sun (2003) was developed by Duan et al. (2006). This model is a better fit to lower T data than the Duan and Sun (2003) model but requires the selection of 1 of 6 P-T conditions to carry out the calculations.

Fundamental to the calibration and verification of the numerical methods for determining CO_2 solubility are experimental datasets. Although numerous data exist, there remains a limited number that fit specifically within the P-T-x conditions of CO_2 sequestration (Hu et al., 2007). In recent experiments by Portier and Rochelle (2005), CO_2 solubility was measured in synthetic brine with a composition approximating that found in the Utsira formation in the proximity of Sleipner. Their experiments were carried out at temperatures of 18–80°C and pressures of 20–200 bar. Koschel et al. (2006) measured the enthalpy of mixing for the dissolution of CO_2 in water and NaCl solutions at 50–100°C and 20–200 bar pressure using an isothermal differential heat flux calorimeter.

Ionic and Mineral Trapping

Once the CO_2 is dissolved in the water the potential exists for some proportion of that CO_2 to form ionic species. The primary mechanism for that process is the consumption of hydrogen ions through mineral dissolution reactions, adsorption on mineral surfaces and ion exchange. The ability to predict the extent of dissociation of carbonic acid is achieved by geochemical modelling. Marini (2007) provides a review of aqueous electrolyte solution modelling theory and application. The majority of available codes utilize the extended Debye-Hückel equation, the Davies equation, the Truesdell-Jones equation or the B-dot deviation function to determine activity coefficients. There are ionic strength limitations for the validity of the various formulations and considerable error can be introduced if those limitations are exceeded (Langmuir, 1997). For concentrated aqueous solutions, virial expansions through the semi-empirical Pitzer equations are recommended but are currently not incorporated into many codes nor are the data well constrained for elevated temperatures and pressures. Another cautionary note is the limited Pitzer equation data for Al and Si making calculations involving silicate or alumino-silicate minerals non-trivial. Recent data from Li and Duan (2007) for the Pitzer formulation of the H_2O-CO_2-NaCl system at temperatures of 0–250°C and pressures of 0–1000 bar and NaCl concentrations of 0–5 M allows speciation of CO_2 and more accurate calculation of dissociation constants of carbonic acid at elevated T, P and salinity.

Fundamental to any geochemical model is the composition and quality of the thermodynamic database. Most databases contain thermodynamic data of basis species, aqueous complexes and minerals with additional data on redox species, ion exchange and surface complexes if these types of reactions are incorporated into the code. Most of the codes come with thermodynamic databases that cover a range of temperatures although temperature ranges for which the databases are valid can vary. The effect of temperature and pressure on the equilibrium constants for simulations at P, T conditions other than those for which the thermodynamic databases are compiled may need to be accounted for (Allen et al., 2005). Many codes do not account explicitly for pressure and in the elevated pressure regime of CO_2 sequestration uncertainty can be introduced although the pressure effect tends to be small relative to the temperature effect (Langmuir, 1997). Thermodynamic databases can be recalculated for specific pressures, if required, using codes like SUPCRT92. Internal consistency of the thermodynamic data can be a problem if data is obtained from different sources. Care must be executed when new thermodynamic data is added to any dataset.

Marini (2007) provides an extensive review of mineral reactant and product phases that are applicable to CO_2 sequestration geochemical modelling. Although the author focuses on carbonates and provides an in depth discussion of dawsonite stability, other phases include silicate minerals with an emphasis on clay minerals. The author points out that mixed mineral phases and non-stoichiometric mineral phases like many of the clay minerals have a highly variable chemical composition and therefore have poorly constrained thermodynamic properties. Mixed mineral phases like solid solutions are commonly dealt with in geochemical modelling by using the mole fraction of the end member minerals and treating the solid solution as separate end member phases (e.g., Gaus et al., 2005a; Xu et al., 2005; Audigane et al., 2007). This can introduce problems if there is a large difference in the solubility or kinetic rates between the phases during dissolution (Carroll and Knauss, 2005). While it is possible to calculate the thermodynamic data for a solid solution if the composition is known, the kinetic data may be poorly constrained. Furthermore, it is common in natural systems for the selective leaching of the more soluble end member of some mineral phases to take place, thus careful consideration must be given in how to incorporate these minerals. It is generally very difficult to predict the composition of a product phase that is a solid solution so the end member approach must be applied for precipitation. Similarly, non-stoichiometric phases are difficult to characterize and currently the clay minerals like smectite are modelled through ideal end member compositions like beidellites and fixed composition smectites.

The ability to model geochemical reactions through time involves the incorporation of kinetics based reaction path modelling. Marini (2007) summarizes kinetic theory, data acquisition methods and details the rate data of most mineral phases considered in CO_2 sequestration scenarios. Also recently published were several reviews of kinetic theory and mechanisms in geochemical reactions (Brantley et al., 2008). The dissolution and precipitation of minerals occurs by either a transport controlled mechanism that involves the transport of dissolved species from the solution to the surface, a surface reaction controlled mechanism or a combination of the two. In general, minerals with relatively high solubility are transport controlled and minerals of low solubility are surface controlled. The dissolution process can be described by the following steps: diffusion of species in solution to the mineral surface; adsorption to the surface; breaking and forming of chemical bonds; desorption from the surface, and; diffusion into the aqueous solution. The rate of the surface reaction controlled mechanism is limited by the slowest step of the dissolution or precipitation process and the number of steps varies depending on the complexity of the structure of the crystal. Precipitation is further complicated because nucleation must occur. Nucleation can either be in the bulk solution or on a surface and is a related to the degree of oversaturation. However, there is only a limited data on the kinetics of precipitation because the experimental difficulties associated with precipitation under controlled conditions.

The most common rate law used in geochemical modelling is a rate law based on transition state theory for dissolution-precipitation reactions. A substantial compilation of rate parameters under acid, neutral and basic conditions was provided by Palandri and Kharaka (2004). Marini (2007) discusses an alternative rate law (Oelkers, 2001) that is based on a multi-oxide dissolution model which incorporates surface reactions through the solute activity ratio of the hydrogen ion to the exchangeable metal of mineral surface complexes. Although not commonly used in geochemical codes, the rate law is easily adapted and a short compilation of suitable rate data is provided by Marini (2007).

Since the publication of the IPCC SRCCS, a number of studies investigated processes at the solid-fluid interface with direct implications to dissolution kinetics showing the importance of surface features in controlling rates (Toulhoat et al., 2005; Beig and Lüttge, 2006; Sorai et al., 2007). However, results from other experimental studies indicate that this is not always the case and the concept of reactive surface area needs to be further investigated (Marini, 2007). The question of surface area for reaction and surface versus solution control on rates is fundamental to dissolution kinetics (Marini, 2007; Brantley et al., 2008). Surface area can be determined using the BET method or calculated using a geometric model based on the grain shape. Most kinetic rates are normalized to the BET surface area but geometric methods are commonly used to parameterise geochemical models (Gunter et al., 2000; Johnson et al., 2001; Xu et al., 2004; Brosse et al., 2005). Even when there exist well constrained experimental data, weathered mineral grains generally have lower dissolution rates than the fresh grains used in most laboratory experiments (White and Brantley, 2003; Beig and Lüttge, 2006; Zhu et al., 2006). The difference is attributed to variability in the available reactive surface area.

Currently there is no unified approach to the determination or calculation of reactive surface area in consolidated material. The difficulty lies in translating rate data which is from crushed single phase samples under specific conditions to consolidated multiphase rocks. In consolidated material not all of the surface of a grain is exposed to the solution and thus is not available for reaction. One approach for estimating reactive surface area of consolidated materials is discussed by Kieffer et al. (1999) and Colón et al. (2004). Reactive surface area was calculated through geometric models and it was found that there was a reasonable correlation for granular material by applying simple grain packing geometry. This method underlies the majority of recent geochemical simulations although the application varies considerably. Mineral grains with non-spherical geometry like mica and clay minerals can either be described by assigning plate-like shapes that account for the increased edge surface area or by using the BET determined surface area (e.g., Gaus et al., 2005; Xu et al., 2005), although growing evidence suggests the BET overestimates reactive surface area (Metz et al., 2005; Rozalén et al., 2008). Hodson (2006) studied the application of different surface area normalization methods to dissolution rates and found BET determined surface area for experimentally derived rates was the most consistent but field rates showed the least variability when using grain shape appropriate geometric surface area calculations. Even if the reactive surface area for each mineral phase present could be estimated or measured, the need to establish effective upscaling methods to translate kinetic rate data from the experimentally determined rates on well characterized single phase systems to multiphase consolidated porous media is needed (Li et al., 2006a). In their study, the role of pore scale heterogeneity, if not taken into account, was found to introduce significant error when experimentally determined rates are used at a continuum scale at high pCO_2. In a companion study, Li et al. (2008) determined that differences in laboratory and field measured reaction rates were unlikely to be the result of pore scale concentration gradients in low flow rate natural conditions.

The kinetics of dissolution are measured in the laboratory under controlled conditions to identify the effect of specific parameters on rates. Temperature, pressure, ionic strength, pH, and catalyzing and inhibiting species have been shown to influence rates and are subject to experimental studies. There continues to be significant research in understanding reaction rates and mechanisms (see Marini, 2007; Brantley, 2008). Recent articles addressing the impact of CO_2 on dissolution rates include experimental studies of carbonates, and a number of silicate minerals. The solubility of calcite in Na-Ca-Mg-Cl brines was investigated by Gledhill and Morse (2006a) through application of the Pitzer theory. In this study it was found that the data were in good agreement with literature data at TDS<100,000 mg/l but for highly concentrated brines resulted in calculated saturation states that were too high. Such an error has implications for kinetic models that rely on proximity to equilibrium in their formulation. In a companion publication (Gledhill and Morse, 2006b), the authors determined the rate constant for calcite dissolution in Na-Ca-Mg-Cl brines is a function of T, pCO_2, ionic strength and Ca and Mg activity. It was also determined that sulphate at elevated concentrations inhibits the dissolution rate. The kinetics of dissolution of calcite, dolomite and magnesite at variable pCO_2 were studied experimentally by Pokrovsky et al. (2005). The dissolution rates were found to be only weakly dependent on pCO_2 and that a surface complexation model for dissolution was effective in describing dolomite and magnesite dissolution rates but calcite dissolution at low pH was controlled by transport. Bénézeth et al. (2007) evaluated dawsonite solubility, refining the thermodynamic data. Difficulty in precipitating synthetic dawsonite except at high pH was interpreted to indicate that dawsonite formation may be subject to nucleation and other kinetic inhibitions as well as requiring alkaline conditions. Dawsonite dissolution rates as a function of pH at 80°C were determined experimentally by Hellevang et al. (2005). The rate is much lower (3 orders of magnitude) than that provided in the summary of Palandri and Kharaka (2004) which comes from an estimated rate by Johnson et al. (2001) based on calcite and magnesite rate data.

Giammar et al. (2005) experimentally determined the effect of variable pCO_2 on forsterite dissolution and magnesite precipitation. Dissolution extent was higher as pCO_2 increased and they interpret the lower pH as the primary condition whereas magnesite precipitation was limited by nucleation and the degree of supersaturation. The effect on dissolution kinetics of forsterite by CO_2 at 90-150°C, pH 2-12.5 and pCO_2 0, 15, 180 bar was studied by Hänchen et al. (2008). In the presence of CO_2 at pH<5 rates were higher but at pH>5 the presence of CO_2 resulted in lower rates. Carroll and Knauss (2005) and Golubev et al. (2005) determined the effect of dissolved CO_2 on the dissolution rates of several silicate minerals (labradorite, diopside, forsterite, wollastonite and hornblende). They found pH to be the primary factor and the role of CO_2 was weak to negligible. Carroll and Knauss (2005) used the model of Oelkers et al. (1994) for surface reaction controlled rates to determine the stoichiometric exchange coefficient used in the rate law formulation at different temperatures and parameterize the rate expression. It was also observed that the dissolution of labradorite was incongruent at and below 60°C with Ca being released at 3 times the rate of Si.

Geochemical modelling of CO_2-water-rock interactions linked to experiments is an important component of understanding CO_2 sequestration. Various authors provide reviews of simulations coupled with experimental work (Czernichowski-Lauriol et al., 2006; Gunter et al., 2004; Marini, 2007; Rochelle et al., 2004). The value of these studies lies in the use of multiphase materials as opposed to the single phase rate mechanism and parameter studies although the purpose is to observe and measure mineral and fluid chemical changes not to measure rates. A flexible cell hydrothermal apparatus was used by Kaszuba et al. (2005) to study CO_2-water-rock reactions in an aquifer (synthetic arkose) and a caprock (argillaceous shale) at elevated P (200 bar), T (200°C) and salinity (5.5 molal NaCl) with and without CO_2. Changes in fluid included a drop in pH, a decrease in Na and an increase in Si. Mineral compositional changes included magnesite and siderite precipitation and clay mineral precipitation at elevated pCO_2. However, it was observed that analcime precipitated in both the high pCO_2 experiment and the control. Speciation-solubility modelling to determine saturation states was carried out using Geochemists Workbench and revealed limitations in the results due to system complexity and uncertainty in calculations for the high salinity water although the SI results were determined to be useful for understanding relative stability. In similar static experiments, Rosenbauer et al. (2005) showed the role of mineralogy and initial brine composition in controlling the extent and type of reaction as well as the effect on CO_2 solubility of a limestone and an arkosic sandstone at 25°C and 120°C and 100-600 bar. Changes in the Ca, Mg, K and Na content after CO_2 injection were interpreted to be the result of carbonate dissolution/precipitation, anhydrite precipitation and feldspar dissolution in the case of the arkoses. Equilibrium reaction path modelling using the geochemical code CHILLER/SOLVEQ was carried out for the arkoses and the limestone and experimental results were used to calculate saturation indices using SOLMINEQ88. Model results were consistent with reactions interpreted from the chemical evolution of the solution. Bertier et al. (2006) studied the effect of CO_2-water-rock interactions of three sandstone aquifers in NE-Belgium by measuring changes in solution and mineral composition in a batch reactor. The experiments were conducted at 80°C and 150 bars for 200 days with monthly sampling of the brine. Early dissolution and later precipitation of carbonates was observed as well as precipitation of K-rich clays at the expense of feldspars and mica. Using dawsonite dissolution rates determined experimentally, Hellevang et al. (2005) conducted 1D reactive transport modelling using PHREEQC to calculate dawsonite stability in subsurface CO_2 sequestration conditions. The model results were interpreted to indicate dawsonite stability was only maintained at high pCO_2 with significant dissolution occurring as the partial pressure dropped towards typical background values in sedimentary basins.

Flows through experiments are used to evaluate how minerals and aqueous solution evolve through time by pumping a known composition aqueous fluid through solid material. The column flow through experiments of Bateman et al. (2005) were carried out at 70°C and a pCO_2 of 100 bar using a synthetic mineral composition and brine. Over a period of 7.5 months, fluid samples were collected regularly throughout the run and the column was segmented and analysed petrologically after completion. Elevated HCO_3, Ca and Mg in the fluid corresponded to carbonate dissolution while silicate dissolution, indicated by increased Si content in the fluid, could not be confirmed by SEM. The experiment was simulated using a reactive transport modelling code PRECIP. The model simulation tended to overestimate the amount of reaction and predict precipitation of dawsonite but no dawsonite was observed. The authors felt that the quality of the thermodynamic and kinetic data contributed to differences between the simulated results and the experiment. Brosse et al. (2005) conducted plug flow experiments on limestone at 25°C and 1 bar pCO_2 to determine the role of reaction surface area on reaction transport modelling simulations. Modelling was conducted using the code DIAPHORE with the best fit to experimental data achieved by assigning 2 separate grain sizes to account for micritic and crinoidal grains. The geometric surface area, reduced by a coefficient (0.1-1) to account for grain surface unavailable for reaction was used to fit the model to observations in the case of surface controlled dissolution. When modelled to evaluate transport vs. surface control of the dissolution reaction for calcite and limestone it was determined to be a mixed transport and surface mechanism at the pH and flow rate of the experiments. Izgec et al. (2008a, b) conducted flow through experiments on carbonate core plugs at 18–50°C with varying concentration NaBr solutions and different injection rates. The procedure also investigated the roles of changed orientation of heterogeneities in porosity and permeability using computerized tomography and found preferential flow paths dominated. Porosity and permeability changes were found to be dependent on pore distribution, brine composition and T. Numerical modelling was carried out using the STARS code and sufficiently matched experimental results for the porosity and permeability changes.

Reaction path modelling simulates reactions in a system stepwise towards an equilibrium state. Although mass and energy transfer is possible and temporal data can be included there is no spatial component. This simplifies the model but provides crucial information on system behaviour. Ultimately a well constructed kinetic reaction path model is the geochemical component of coupled reactive mass transport simulations. It is thus critical for these types of models to be constructed and tested against real systems whether experimental, from field or natural analogue sites. The output gives the most clear indication of the response of the system to elevated CO_2, establishing the reactivity of the aquifer and determination of the relative importance of the geochemical trapping mechanisms over time. Because these models relate dissolution and precipitation with time, prediction of porosity change potential is enabled providing information on the role of water-rock interactions on injectivity and storage security. Marini (2007) demonstrates reaction path modelling of CO_2 sequestration using the EQ3/EQ6 codes on serpintinitic rock under varying salinity conditions, tholeiitic flood basalt and basaltic glass. Detailed model setup and input data are provided while output is discussed in terms of product phases, aqueous solution composition, porosity changes and amount of CO_2 sequestered. The report by Zwingmann et al. (2005) describes kinetics based reaction path modelling of the Haizume Formation in Nagaoka, Japan. Reservoir rock mineralogy and formation water composition were determined and, using EQ3/EQ6, were modelled under elevated pCO_2 conditions. Simulation results show changes in water and rock composition through time, the amount of CO_2 stored in the aqueous phase as well as mineral storage. Zerai et al. (2006) discuss equilibrium and kinetics based reaction path modelling of the potential CO_2 sequestration target, the Rose Run Sandstone in Ohio, USA. The Geochemists Workbench React code was used to simulate CO_2-water-rock interactions on the dolomite, sandstone and mixed dolomite-sandstone assemblages at varying T, P, fluid composition and fluid/rock ratios. The Rose Run Sandstone was determined to be suitable for CO_2 sequestration with a significant potential for mineral trapping. Parry et al. (2007) investigated the potential of the Navajo Sandstone, Utah for geochemical storage of CO_2. The Geochemists Workbench modelling indicated there is low mineral reactivity in the Navajo Sandstone and the geochemical CO_2 storage would be limited to solubility trapping.

CO_2 sequestration demonstration project and sites are the source of data for comparing models to real systems at short time scales. The geochemical monitoring results of Weyburn and three experimental sites for CO_2 sequestration have been released (Emberley et al., 2005; Kharaka et al., 2006a; Kharaka et al., 2006b; Matter et al., 2007; Mito et al., 2008). Emberley et al. (2005) report the results of baseline and post injection fluid sampling carried out at the Weyburn, Canada EOR site. The post injection samples had lower pH, higher alkalinity and Ca content and were enriched in ^{13}C interpreted to reflect CO_2-water-rock interactions in the carbonate reservoir. Changes in the silica content of the formation water suggests silicate reactions may be taking place but must be evaluated as more data becomes available. Speciation-solubility modelling using Solmineq88 highlights the difficulty in measuring an accurate pH for wellhead samples that can degas and thus alter the calcite saturation index. Kharaka et al. (2006a, b) discuss the results of the Frio project water and gas chemistry. Changes in pH, alkalinity and Fe as well as gas composition are the main focus. Dissolution of calcite and iron oxyhydroxides dominated the CO_2-water-rock interactions and oxygen isotopic exchange between the water and CO_2 took place allowing for brine to supercritical CO_2 volume ratios to be estimated. A single well push-pull test into basaltic rocks of the Newark Basin, USA was conducted to determine CO_2-water-rock reactions and dissolution rates of Ca-Mg silicates (Matter et al., 2007). The test showed rapid pH buffering and the release of Ca, Mg and Na confirming mineral dissolution reactions were taking place although field rates were much lower than the laboratory determined values. The difference in the rates was partially attributed to unconstrained reactive surface area estimations for the field test. Mito et al. (2008) discuss the results of an experimental and field study of CO_2-water-rock interactions for a sandstone reservoir in Nagaoka, Japan. In this study batch experiments with crushed reservoir rock and formation fluid were carried out at 50°C and 100 bar pCO_2 and separately with N_2 as a reference. Calcite and gypsum dissolution was observed to occur with concomitant increases in the Ca and SO_4 (pH and HCO_3 were not reported) as well as Mg, Fe and Mn. The field study involved injection of 10,400 tonnes of CO_2 over a 1.5 year period. Formation water collected from an observation well 633 days after breakthrough showed increases in HCO_3, Ca, Mg, Fe and Si corresponding to chlorite, plagioclase and calcite dissolution.

Reactive Transport Modelling

Reactive transport modelling enables prediction of the short-term and long-term spatial changes in mineral and fluid chemistry. The distribution of CO_2 into the various trapping mechanisms allows evaluation of risk of leakage, insight into monitoring strategies and is a benchmark for verification of the sequestration site. It has been shown that most mineral trapping is slow, on the order of hundreds to hundreds of thousands of years. However, solubility trapping and ionic trapping can be significant in a much shorter time frame. In reactive transport simulations, not just the trapping mechanisms but also the changes in porosity are predicted and with that implications of reservoir and seal integrity.

Knauss et al. (2005) carried out reactive transport simulations to determine the impact of CO_2 and H_2S or SO_2 on carbon sequestration in the Frio Formation, Texas. The code CRUNCH was used to conduct 1D reaction transport simulations at 64°C and 100 bar in a CO_2 +/- co-contaminant gas fully saturated aqueous fluid with kinetically based mineral precipitation and dissolution reactions. The simulations show that the CO_2 sequestration potential is high with calcite, dawsonite and magnesite as the mineral trapping phases at the expense of labradorite and chlorite. The H_2S injection resulted in little effect on the injectivity or CO_2 sequestration while co-injection of SO_2 would have a serious impact because of the formation of sulphuric acid. The authors question the kinetic data of dawsonite and express a need for precipitation data in the acid to neutral conditions of CO_2 sequestration.

White et al. (2005) using the code ChemTOUGH produced a 2D reactive transport simulation of CO_2 injection into an aquifer system on the Colorado Plateau, Utah. The modelling exercise tested four different rock formations for CO_2 sequestration potential and through this identified the White Rim Sandstone as displaying characteristics most suitable for CO_2 sequestration. Incorporating mineral reactions in the simulation of the White Rim Sandstone resulted in an increase in gas phase sequestration as well as an increase in dissolved CO_2 and mineral trapping and a decrease in leakage to the surface relative to simulations not including mineral reactions. Calcite and dawsonite were the mineral trapping phases generated from the dissolution of Na-smectite, albite and anorthite.

Lagneau et al. (2005) studied the benefits and limitations of using reactive transport simulation for predicting CO_2 sequestration of the carbonate Dogger Formation of the Paris basin and the Bunter Sandstone in the North Sea. A 2D model using the code Hytec was generated and populated with physical and chemical data from the two aquifers. Limitations of the code, in particular, the inability to model multi-phase flow impaired the simulation. The carbonate aquifer was interpreted to be dominated by solubility trapping. The sandstone aquifer simulation illustrated the importance of mineral reaction in buffering pH and sequestering CO_2 but the lack of reaction kinetics in the model reduced the effectiveness for understanding CO_2 sequestration.

The reactive transport program TOUGHREACT was used by Audigane et al. (2007) to generate reaction path and 2D reactive transport models of sand and shale assemblages of the Utsira Formation. The simulation investigated changes in structural, dissolution and mineral trapping in a heterogeneous sand-shale system. Model outputs showed a low mineral reactivity of the sand assemblages and solubility trapping as the dominant long-term CO_2 sequestration mechanism. The physical and chemical heterogeneity of the sand-shale system was interpreted to strongly influence the geochemical evolution of the system.

Gaus et al. (2005a) conducted equilibrium and kinetic reaction path and 1D reactive transport modelling using PHREEQC to simulate the diffusion of CO_2 into the caprock and the subsequent CO_2-water-rock reactions at Sleipner. Initial carbonate dissolution is followed by feldspar dissolution and carbonate precipitation. The diffusion process was determined to be very slow and porosity loss was limited to the first few meters of shale. Problems encountered were with predicting of reactive surface area and with minerals that occur as solid solution being modelled as end member phases when their individual solubilities and reaction rates created unrealistic dissolution rates.

Xu et al. (2005) performed reactive transport (TOUGHREACT) of a sand-shale system (aquifer-caprock) using rock properties and mineralogy based on typical Gulf Coast sedimentary rocks. The aqueous phase was modelled as 1 M NaCl solution in equilibrium with the mineral phases at T, P and pCO_2 of 0.01 bars. Diffusion of CO_2 into the shale and Fe and Ca out of the shale dominates the transport mechanisms of the sandstone. Ankerite and siderite precipitation as well as dawsonite precipitation occur mostly in the sandstone. Reactant phases are chlorite, oligoclase and hematite. Sensitivity analysis of the dawsonite surface area was carried out showing the controlling mechanism was alumino-silicate dissolution rate rather than the dawsonite precipitation rate.

Numerical modelling of reactive transport to determine the effect of CO_2-water-rock interactions on a carbonate rich caprock was carried out by Gherardi et al. (2007). TOUGHREACT was used to simulate diffusion and mixed advection and diffusion. It was found that models predicted extensive dissolution when the CO_2-rich fluids advect into the caprock whereas diffusion in the aqueous phase reduces the porosity through precipitation. Mineral reactions were dominated by calcite dissolution with minor clay mineral reactions to generate dawsonite, siderite and ankerite. The authors expressed concern over several model simplifications that influence the simulation results including hydraulic conditions for the reservoir and caprock, the wettability, relative permeability and capillary entry pressure of the caprock, addressing chemical heterogeneity in the aqueous and mineral system, and incorporating diffusion coefficients representative of different aqueous species.

Natural Analogues

Natural accumulations of CO_2 provide an opportunity to evaluate the predictive capabilities of geochemical models by enabling comparison of model results with real systems. The role of natural analogues as a tool for enhancing the predictive capabilities of CO_2 storage models is discussed by Pearce (2006). Mechanisms and examples from published literature are reviewed including overviews of CO_2-water-rock interactions and leakage. Brennan et al. (2005) define CO_2 systems and methods to evaluate natural analogues to make them useful for comparison to laboratory studies, predictive modelling and storage projects. Leakage from natural CO_2 accumulations and gas storage sites is reviewed by Lewicki et al. (2007a). Observations from those sites are used to provide a framework for risk assessment associated with CO_2 sequestration. Haszeldine et al. (2005) describe a number of locations in the UK and the USA that are potential sites for studies for long-term simulations.

One of the difficulties encountered in the use of natural analogues as a tool for comparison with modelling results is that the age of the CO_2 accumulations is often poorly constrained. Stevens et al. (2005) used the age of local igneous intrusions to estimate the timing of CO_2 flux from outgassing to reservoirs containing CO_2 accumulations in 3 locations in the USA. The age of the intrusions, at 70 ma, suggests the relatively high quality of the reservoir seal. Changes in the fluid composition at the Montmiral, France natural analogue site were used to evaluate CO_2-water-rock interactions (Pauwels et al., 2007). Mineral reactions and isotopic equilibration with the CO_2 phase were shown to influence the chemical and isotopic composition of the fluids illustrating the value of fluid monitoring at storage sites. Two natural analogue sites were studied by Gaus et al. (2005b) to determine the long term effects of CO_2-water-rock interactions. Detailed petrographic characterization and fluid chemistry were used to model geochemical reactions and the role of elevated T at the Montmiral site in France was interpreted to be a significant factor in controlling the extent of reaction. The Messokampos site in Greece shows little effect of the CO_2. Worden (2006) discussed the origin of dawsonite in the Triassic Lam Formation in Yemen. Dawsonite occurrence was attributed to albite dissolution at elevated pCO_2. Moore et al. (2005) investigated a natural analogue site in Arizona to establish the geochemical processes that occurred in the reservoir. Elevated pCO_2 contents were interpreted to promote feldspar dissolution and dawsonite and kaolinite precipitation. Geochemical modelling of the system indicated the stability of dawsonite occurred at elevated pCO_2 and as the pCO_2 decreased kaolinite stability was reached.

Progress in Geochemistry and Remaining Knowledge Gaps

Since the completion of the IPCC SRCCS there has been a considerable increase in the number of publications addressing aspects of the geochemistry of CO_2 sequestration. The ability to simulate the dissolution of CO_2 into variable salinity NaCl dominated formation water is demonstrated to match experimental data although there is a need for more experimental data in the P-T-x space typical of CO_2 sequestration conditions. Geochemical modelling codes are sufficiently well developed to enable speciation and saturation index calculation for complex aqueous solution composition and many mineral phases. More experimental and field data for single- and multi-mineral phase-aqueous solution systems are required to ensure reaction path models are representative of natural systems. Incorporation of kinetics of reactions introduces significant uncertainty because of the number of variables required to adequately represent the controls on rates and the reaction mechanisms. However, the geochemical modelling of experimental, field and natural analogue data is being carried out and the uncertainty is recognized and can be addressed. Even with this uncertainty, numerical simulations of aquifers and reservoirs that do not incorporate geochemical interactions will always overestimate the amount of CO_2 that is sequestered as an immiscible phase and thereby elevate the predicted risk of leakage. To develop a comprehensive understanding of the fate of CO_2 over time in terms of the distribution between immiscible phase trapping, solubility trapping and mineral trapping geochemical models have to be coupled with transport models in 3D. The ability to predict system behaviour thus hinges on the capability of the flow models to simulate CO_2 transport from which the geochemical models can simulate CO_2 dissolution and gas-water-rock interactions. The process of mineral trapping can be slow (100's to 10,000's of years) for a substantial impact on the total CO_2 to be thus stored. However, minerals acting as pH buffers driving the solubility and ionic trapping mechanisms do play a significant role in the short, medium and long term storage of carbon.

1. Conceptual models of the geochemical system need to be provided in detail. Choices of reactant and product phases are often the product of the numerical model rather than constrained by experimental and observational data.

2. More thermodynamic and empirical data especially for Pitzer equation formulation is required for saline solutions.

3. Thermodynamic properties of mixed mineral phases (solid solutions) and poorly defined mineral phases like clays are not well constrained.

4. Surface processes like adsorption and exchange can act as a significant buffer to pH changes and can be a store of cations that may be involved in mineral trapping. Many modelling codes include the ability to simulate adsorption and ion exchange making sensitivity analysis possible. More experimental data is required.

5. Kinetic rate parameters still need to be refined for some mineral phases especially mixed mineral phases and poorly defined mineral phases like clays. Dawsonite precipitation kinetics need to be investigated as this is one of the most common product phases of numerical simulations and yet is not a common phase observed in natural analogues or experiments.

6. Reactive surface area – determination, calculation, estimation. The most common difficulty described in the recent literature is the selection of a value for the reactive surface area to include in rate equations.

7. Surface reaction mechanisms and how they influence the rates of reaction is poorly understood and difficult to model.

8. Precipitation nucleation and degree of supersaturation required for precipitation for many important phases is not well known.

9. Upscaling of reaction kinetics from the mineral surface to the continuum scale of reactive transport modelling is poorly constrained.

10. Integration of experimental and natural analogue observations with geochemical reaction path and reactive transport modelling is receiving considerable attention and has promising outputs for helping constrain predictive models. More extensive datasets need to be gathered to populate model systems.

11. Experiments addressing specific aspects of the mechanisms of geochemical trapping need to be undertaken – dissolution/precipitation kinetics, multiphase systems, mineral surface processes. All require more attention.

Numerical Modelling

In the last decade, the numerical modelling of geological storage in saline aquifers has progressed from the examination of completely generic models - usually homogeneous and with simple geometry - to generic models with more realistic heterogeneity (Basbug et al., 2007; Doughty and Pruess, 2005; Flett et al., 2007; Ghanbari et al., 2006) and the simulation of more complex geological models for hypothetical sites (Ennis-King et al., 2005; Gupta et al., 2005; Imaseki et al., 2005; Kreft et al., 2007; White et al., 2005a) or actual field projects (Hovorka et al., 2006; Hovorka et al., 2005). In part this progress has been achieved by taking standard modelling and simulation tools from the petroleum industry, and applying them to CO_2 storage. However, there are new aspects to consider which are specific to long-term storage of CO_2, and these will be the focus of this section of the review.

Theoretical results have important applications for two common types of saline aquifer storage sites. The first is a large laterally unconfined aquifer without a structural trap, for which the intention is that a combination of trapping mechanisms will limit the ultimate migration distance. Good estimates of this distance in particular sites are likely to be needed to define leases for CO_2 storage, analogous to petroleum leases. The discussions below on heterogeneity, relative permeability hysteresis, brine injection and convective mixing all have a bearing on the extent to which the various trapping mechanisms contribute, and ways in which trapping can be maximized. The results on gravity currents help to define the extent to which CO_2 spreads both in the gas phase, and also as when dissolved in the formation water.

The second type of storage site is a thick permeable sequence with an overlying lithological seal, which may or may not have a structural trap (thus overlapping with the first type). Here the injection strategy of injecting deep and letting the CO_2 rise is discussed below. Heterogeneity and its effect on vertical permeability will determine the time it takes the injected CO_2 to reach the caprock, and this may be important for storage security and even for possible interference with hydrocarbon or water resources in shallower formations. Upscaling of these properties for field scale simulations then becomes a key technical issue.

Quantification of leakage rates was one of the knowledge gaps previously identified in the IPCC SRCCS. The discussion below briefly surveys the progress on understanding of wellbore leakage (one of the key pathways). There have also been investigations into whether sudden large releases of CO_2 could occur from underground storage sites and the coupling to the surface level. Leakage through the caprock is another pathway, and geochemical effects need to be included. Lastly, the pressure increases due to injection carries a risk of fault reactivation and leakage, and this is discussed in the section on geomechanical modelling.

Simulation Approaches

The challenges of CO_2 simulation have led to continuing improvements to existing software, as well as the development of new software e.g. (Sasaki et al., 2008). Most of codes used for modelling CO_2 have been based on traditional finite difference methods, but streamline-based reservoir simulation is a complementary alternative. Streamline-based simulation has been used by (Obi and Blunt, 2006) to model CO_2 injected into a deep North Sea aquifer using a one million cell model.

The proliferation both of simulation software and of the number of groups engaged in simulation does raise the need for some cross-checking of results on well-defined problems. The code comparison study (Pruess et al., 2004) run in 2000-2002 helped to increase the level of proficiency of simulation users, as well as testing out codes, and remains as a useful set of test problems for those entering the field. A second code comparison study is nearing completion, run from the University of Stuttgart, and it provides more challenging 3D problems, including well leakage (Ebigbo et al., 2007) (with an option to study near-critical effects of CO_2), enhanced gas recovery, and a 3D saline aquifer problem (with an option to examine effects of relative permeability hysteresis).

Carbon Dioxide Properties in Simulation

One of the early challenges in simulation was a sufficiently detailed representation of properties of CO_2/brine mixtures. In the first code comparison study (Pruess et al., 2004); one of the sources of difference between results came from the accuracy of representation of fluid properties. For example, when considering the solubility of CO_2 in brine, a Henry's law relation will significantly overestimate solubility at high pressure. In this area, the literature data on solubility has been thoroughly analysed (Spycher and Pruess, 2005; Duan et al., 2006; Hu et al., 2007;), and new experimental data has also been obtained e.g. (Portier and Rochelle, 2005). Similarly, the densities of CO_2/brine mixtures have also been re-examined (Duan et al., 2008).

There are two ways in which these representations can be employed. If a commercial black-oil simulation code is used, then fluid properties must typically be provided as tables, and some guidelines have been given for how to do this (Mo and Akervoll, 2005; Hassanzadeh et al., 2008;). The other way to use representations is to build them into the code itself, and this is often necessary for more subtle effects. For example, specialised equation of state modules have been developed for the TOUGH2 software, incorporating detailed CO_2/brine representations that are accurate for the ranges of temperature and pressure used in geological storage (Talman et al., 2004; Pruess and Spycher, 2007).

A particularly challenging situation for simulation is where the CO_2 gas/liquid phase boundary is reached, since there can be two CO_2 phases present, as well as an aqueous phase. This is relevant in shallow storage settings, or in leakage to near-surface conditions (Pruess, 2004, 2005, 2008). Thermal effects are particularly important here, and careful attention has to be given to the flash calculations (Fuller et al., 2006). The most recent code comparison exercise contains a problem variant that entails such phase transitions.

Injection Strategies and Heterogeneity

The trapping mechanisms for CO_2 in a saline aquifer are now well-known. The CO_2 will end up either as a gas phase beneath a top seal, or as a residual gas in the pore space, or dissolved in the formation brine, or precipitated in a mineral phase. The question then arises as to which injection strategies can maximize the amount stored, or minimize the time to achieve such storage and how the CO2 will be distributed between these states over time.

If the target formation for injection is sufficiently thick (at least 50-100 m), then injection into the deeper part of the saline aquifer has been studied as a strategy to maximize trapping, since the buoyancy of CO_2 relative to the formation brine will cause it to rise within the formation. Residual trapping along the migration path will then immobilize a good part of the injected CO_2 (van der Meer and van Wees, 2006). The buoyant plume is intrinsically unstable, which might be expected to lead to fingering, but fine-scale simulations indicate that the CO_2 follows preferential flow paths determined by geological heterogeneity (Bryant et al., 2006a, b).

In oil production, heterogeneity and residual trapping are often problematic since they can reduce the expected recovery. For saline aquifer storage, however, when injection is done to trap the CO_2, both of these phenomena can be turned to advantages, if sufficient storage capacity is available. When Sleipner was the sole example of CO_2 storage, it was tempting to conclude that the best storage sites would be of high permeability and relatively homogenous. However, higher permeability also increase migration rates as well as increasing injectivity. With the development of fields such as In Salah in Algeria (Riddiford et al., 2005), attention has now turned to the possibilities of low-quality heterogeneous saline formations as possible storage sites (Flett et al., 2005; 2007).

Greater heterogeneity in the form of shale barriers reduces vertical permeability by increasing the tortuosity of migration pathways, and thus lateral movement is favoured over vertical migration (Flett et al., 2007). Proper upscaling of the permeability distribution then becomes important for field-scale simulation. For deep injection scenarios, the arrival time of the injected CO_2 at the top of the formation can be an important determinant of the suitability of the site. In the case of the Kingfish field, in the offshore Gippsland Basin in

SE Australia, a study was conducted of deep injection of CO_2 several hundred metres beneath a major oil field. The key challenge was to quantify the risk of CO_2 arrival at the oil field before the end of production (Gibson-Poole et al., 2006).

The interaction of gravity, residual trapping and heterogeneity has also been studied by comparing simulations with different ratios of gravity forces to viscous forces (Ide et al., 2006, 2007) (although dissolution of the CO_2 in brine was not included). It was found that when gravity dominates, residual trapping is small but occurs relatively quickly, whereas for situations where viscous forces dominate the amount of residual trapping is much greater, but it occurs relatively slowly. In practice, one way to increase the amount of residual trapping is to increase the injection rate, subject to constraints on the fracture pressure.

Co-Injection of Brine

An alternative strategy for increasing trapping is to inject brine either during or after the CO_2 injection (Kumar et al., 2004; Keith et al., 2005; Juanes et al., 2006; Leonenko et al., 2006; Ide et al., 2007; Leonenko and Keith, 2008). This affects both amount of residual gas trapping (Ide et al., 2007) and the rate of dissolution of CO_2 in the brine (Leonenko et al., 2006). Reducing the amount of mobile CO_2 will reduce the overall risk of leakage, and could expand the range of sites which are suitable for geological storage in saline aquifers. “Ex-situ” dissolution (i.e. the CO_2 is dissolved in brine at the surface before injection) is possible, but would require very large volumes of brine to be produced and injected, since the solubility of CO_2 in brine even at reservoir pressure is only a few percent by weight, depending on the salinity. Another option is alternating CO_2 injection and brine injection through the same well (referred to as WAG in petroleum contexts). This breaks up large CO_2 plumes and increases trapping, although it clearly decreases the overall rate of CO_2 injection through that well and it also leads to higher bottom hole pressures at injection wells (Juanes et al., 2006). Finally, brine injection through a separate well can be used in several ways: “steering” the CO_2 plume post-injection through creating a pressure gradient, or as a remediation technique in case of unexpected migration, or purely to increase trapping. In the latter case, the best results are obtained when the brine contacts regions of high gas saturation e.g. by using horizontal wells near the top of the formation (Ide et al., 2007). Greater efficiency is also obtained when the horizontal spread of the CO_2 is reduced by the structural trapping in anticline (Leonenko and Keith, 2008). A direct comparison of co-injection (brine and CO_2 together) with sequential injection (brine inject after CO_2 injection has finished) suggested that the latter strategy leads to more residual trapping and greater dissolution of the CO_2 (Kumar et al., 2004). The strategy of increasing the CO_2 migration distance fits well with dipping formations that lack a structural closure. Here the aim is to use dissolution and residual gas trapping to contain the injected CO_2. Especially in cases where gravity is the dominant effect, even dip angle of a degree or two can significantly increase the rate of trapping, due to the accelerated migration (Hesse et al., 2006; Ide et al., 2007).

Coupling with Hydrogeology

Injection of CO_2 into open saline aquifer systems will result in changes to the natural hydrodynamic flow regime. This could result in saline formation water being displaced into adjacent formations, possibly changing overlying aquifer levels (Nicot, 2008), and even changing the level of the ground surface (which involves geomechanical coupling). Standard flow simulation tools are being used to investigate these effects, although some lack the capability to implement the kind of boundary conditions common in groundwater applications. There will also be some long-term effects on CO_2 migration from the natural flow regime, which will only become relevant when the pressure effects from CO_2 injection have dissipated. Simple analytical calculations suggest that changes in migration direction would only be likely when the structural gradient (e.g. the slope of the caprock) is small (below about one degree) and the hydrodynamic gradient is strong. However this needs to be investigated with numerical simulations, both in generic and in field models. As in the petroleum domain, one could also have a tilting of the CO_2-water contact in a structural trap due to a hydrodynamic gradient.

Analytical Analysis Based on Gravity Currents

When gravity effects dominate, CO_2 injection in a saline aquifer with a flat top seal produces a characteristic plume shape that spreads out beneath the caprock. This is analogous to gravity currents in porous media, where theory and experiments show for that denser fluid released at a constant rate, the radial extent of the plume increases with the square root of time (Bickle et al., 2007). A similar analytic result is obtained during the injection of CO_2 into a two dimensional system when relative permeability effects are included (Hesse et al., 2006).

In the post-injection phase, the spreading of CO_2 is now driven only by buoyancy effects. In two dimensions (e.g. along a vertical cross-section through a horizontal well), there is a transition to a regime of slower spreading, where the lateral extent of the plume only increases as time to the power of one third (Hesse et al., 2006; 2007). This agrees with the result for gravity currents in a two dimensional system. In a radial geometry (e.g. migration away from a vertical well), the radial spreading should scale as time to the power of one quarter (Lyle et al., 2005).

These results for plume spreading have been applied to the lateral extent of CO_2 plumes detected at Sleipner by seismic techniques (Bickle et al., 2007). However the fitting process gives permeabilities that are much lower than those measured, and this may be due to neglect of relative permeability effects in the theory.

The theory of gravity currents can also be applied to the spreading of dissolved CO_2 from an injection plume, although the process is much slower. However the usual assumption that the density difference between the plume and the formation water remains constant no longer seems to be valid everywhere, so theoretical developments are needed to match simulation results.

There is also a need for results in heterogeneous media, and experimental and theoretical work is currently underway on gravity currents in layered media. This is relevant to the situation in which a poorer quality reservoir unit overlies a good quality reservoir unit, where CO_2 injected in the lower unit can migrate into the upper unit, where its lateral mobility is then restricted.

Relative Permeability Hysteresis

Early simulation work on CO_2 storage tended to ignore hysteresis effects in relative permeability. However it is well-known that after a drainage phase, in which CO_2 invades a section of the porous medium and water drains out, the relative permeability to gas during the imbibition phase (when water re-enters and CO_2 drains out) does not follow the path it took during the drainage phase. Instead the gas mobility falls until the saturation of the gas phase reaches the residual gas saturation value. Evidence for this can be seen in the numerous water-CO_2 relative permeability curves that have now been measured for different rock types (Bennion and Bachu, 2005; 2006; Bennion and Bachu, 2007). Gas-water relative permeabilities measured with other gases, which are widely available in the petroleum literature, should also be applicable, since CO_2 should be the non-wetting phase.

A number of researchers have examined the consequences of including hysteretic relative permeability curves in modelling CO_2 storage in saline aquifers (Doughty, 2007; Flett et al., 2004; Juanes et al., 2006; Kumar et al., 2004; Kumar et al., 2005; Spiteri et al., 2005). The first observation is that trapping only occurs during the imbibition phase. For example, in a “deep injection” scenario, trapping of residual gas occurs as the trailing edge of the CO_2 plume rises, after injection has ceased. This is obviously an important phenomenon for saline aquifer storage, especially when there is a long migration path for the CO_2.

A non-hysteric formulation for relative permeability can mimic some of effects of hysteresis by using a value of residual gas saturation that is between that of draining and imbibition. However this makes the migrating plume too compact, since in a hysteric formulation the leading edge of the plume is more mobile, and the trailing edge is less mobile. Moreover, in the hysteretic formulation, the residual gas saturation at a particular location in the reservoir depends on the maximum gas saturation that is encountered there. In a heterogeneous formation, both draining and imbibition can occur during the injection phase, making the use of non-hysteric models more problematic (Doughty, 2007).

Convective Mixing

One of the subtle phenomena in underground storage simulations is that under typical storage conditions, dissolved CO_2 slightly increases the density of the formation brine. The density increase is only around 1 %, depending on salinity (which reduces CO_2 density) and temperature (which affects the partial molar volume of dissolved CO_2) (Ennis-King and Paterson, 2003b). During injection and migration, this is a small effect compared to other driving forces, but on long time scales it needs to be considered. In a typical saline aquifer, gravity effects will cause some of the injected CO_2 to rise and form a thin layer beneath the caprock. Even as this spreads out through continued migration, residual gas trapping will cause a significant amount of CO_2 to remain in that layer. As this saturates the surrounding formation water with dissolved CO_2, a density instability is created. Initially, downward transport of dissolved CO_2 is by diffusion, but eventually there will be a transition to a regime where convective transport dominates, and then the net dissolution of CO_2 is significantly accelerated (Lindeberg and Wessel-Berg, 1997; Ennis-King and Paterson, 2003b, 2005). This process is important because the reduction in the amount of CO_2 in the gas phase contributes to reducing the leakage risks through caprock or seal.

The important time scales to determine are the onset of convection, and the time for complete dissolution of the layer of gas-phase CO_2. (Rees et al., 2008) survey the results of a number of authors for this problem (both in the CO_2 context e.g. (Ennis-King and Paterson, 2005; Ennis-King et al., 2005; Hassanzadeh et al., 2005; 2006; Riaz et al., 2006; Xu et al., 2006; Farajzadeh et al., 2007) and also in a more general context e.g. (Selim and Rees, 2007a, b). Depending on techniques and the criteria for instability, estimates vary by more than a factor of two. However the key fact is that the critical time for the onset of convection depends inversely on the square of the permeability, and so can vary from less than a year to thousands of years as the reservoir permeability varies from darcies to millidarcies.

At the onset of convection, small “fingers” of CO_2-saturated brine begin to appear within the diffusion layer. A theoretical estimate of the length scale of these fingers is important for understanding how to simulate this phenomenon directly. The wavelength of these fingers at the onset of convection can vary from centimetres to tens of metres as the permeability varies from darcies to millidarcies. This is a particular challenge to field scale simulation, since it is not possible to resolve such small features as the fingers of dissolved CO_2. Convection does occur on coarser grids, but the time of onset can be delayed due to the suppression of the smaller wavelengths. Thus there is a need for a suitable upscaling technique to allow convection to be properly accounted for on a field scale.

The delineation of the time of onset of convection is less important than the rate of change in the amount of dissolved CO_2 when convection does begin. Once past the linear regime of finger development, complicated non-linear dynamics then ensue, as fingers merge and coarsen (Ennis-King and Paterson, 2005; Hassanzadeh et al., 2007; Riaz et al., 2006). However the key observation is that the amount of dissolved CO_2 increases linearly with time once convection begins, until the time that the plumes of dissolved CO_2 encounter the bottom of the reservoir unit (Ennis-King and Paterson, 2005; Hassanzadeh et al., 2007; Riaz et al., 2006). If the reservoir unit is not thick enough for the entire gas layer to dissolve by this stage, then further dissolution will depend on the transport of dissolved CO_2 away from the injection region by gravity currents.

The theoretical analysis so far has been highly idealised, and the question arises as to how robust the results are if some of the assumptions are relaxed. The influence of anisotropy of the permeability on convection has been studied (Ennis-King and Paterson, 2003a; Ennis-King et al., 2005; Xu et al., 2006). A reduction in vertical permeability (the most common situation geologically) increases the time of onset of convection, and increases the wavelength of fingers at the onset of convection.

The theoretical analysis of the onset of convection is valid in three dimensions, but most of the direct numerical simulations to date have only been two-dimensional vertical cross-sections due to the large number of grid blocks required for fine-scale simulations in 3-D models. However, the dynamics of plume evolution, and hence the effective rate of CO_2 dissolution in the convective regime, will not be the same in three dimensions as compared to two, and there has not been any theoretical analysis of the lateral distribution of plumes.

The idealised problem also ignores any flows that might occur in the aquifer. The migration of CO_2 itself will introduce heterogeneities in the lateral distribution of gas, due to both the permeability variation and the changes in saturation and plume thickness away from the injector, and these heterogeneities could interact with the initiation of convection. Also, the presence of hydrodynamic gradients in the aquifer system will affect convection, once the injection-induced pressure gradients have dissipated. The deliberate injection of brine either during or after CO_2 injection, as discussed above, will also affect convection; preliminary indications are that it speed up the onset of convection by spreading a plume of dissolved CO_2 (Leonenko and Keith, 2008).

Convection is in many cases a slow physical process, and it is therefore important to see how it might interact with other slow processes that affect CO_2. Reactions of the dissolved CO_2 with the rock obviously depend firstly on plume location, but the reactions could consume CO_2, or could change the local permeability through net precipitation or net dissolution. Even if CO_2 is consumed in reactions, the solution density could still increase due to other dissolved species. Some initial simulations have been done on a field scale for a generic saline aquifer system (Ohkuma et al., 2005). Preliminary theoretical analysis in the limit of reactions being faster than convection (the local equilibrium assumption) suggests that convection would be slowed due to the consumption of CO_2, since it would take longer for the critical layer thickness to be achieved (Ennis-King and Paterson, 2007). A direct numerical simulation, including kinetics, indicates that in some cases the increase in plume density due to reactions could significantly accelerate convection. The feedback effect of changes in permeability on plume evolution appears to be weak for the cases tested (Ennis-King and Paterson, 2007).

The theory of convective mixing is a long way ahead of field observations. It will always be difficult to obtain useful measurements from demonstration and commercial projects due the long time scale required for convection to occur. Careful analysis of natural analogues may provide evidence of historic convection, and this could be used to verify simulation models. At present this remains a significant gap.

Wellbore Leakage

One of the important questions for underground storage is the likelihood of CO_2 leaks from the target formations, and the consequences of such leaks. For a large-scale injection project (of at least a million tonnes per year), the plume could easily spread out over tens of square kilometres. This raises the chances of the plume intersecting a permeable or fractured zone in the caprock, a pre-existing fault, or an abandoned and poorly completed well, any of which could provide a leakage path out of the reservoir unit. The pressure increase due to the injection could also create new fractures, or reactivate old ones, and geochemical changes might in some cases affect seal integrity.

Friedmann et al., (2006) describe the case of an improperly completed and plugged well in Utah that episodically discharges natural CO_2 from an aquifer every 4-24 hours. Maximum concentrations of CO_2 reached less than 12,500 ppm and the results of atmospheric plume simulations suggest that the rate and risks associated with long-term catastrophic failure of a single well are low (Friedmann et al., 2006).

The rate of leakage is largely dependent on the specific characteristics of the leakage path e.g. the fault permeability, width and continuity, the properties of overlying reservoir units etc. Some insight on fault leakage pathways can be deduced from the study of analogues (Shipton et al., 2004; 2005). Abandoned wellbores are also thought to be a significant leakage risk, particularly in onshore areas where well densities are high. For example in the benchmark problem on leakage from a reservoir unit through an old wellbore (assigned a permeability of 10^{-12} m^2), the maximum leakage rate is found to about 0.22 % of the total CO_2 injection rate (Ebigbo et al., 2007), and this is close to the approximate semi-analytical solution for the same problem (Celia et al., 2005; Nordbotten et al., 2005).

However wellbore leakage raises the much more complex question of CO_2 interactions with the wellbore cement. It is known that ordinary Portland cement, commonly used in cementing operations, is not stable in the presence of dissolved CO_2, and laboratory experiments have been conducted to examine these reactions (Duguid et al., 2005; Duguid et al., 2006; Jacquemet et al., 2005; Jacquemet et al., 2007; Kutchko et al., 2007). There has also been research into new cement formulations which may be more resistant to CO_2 (Barlet-Gouédard et al., 2006, 2007). Retrieval of cement samples from wells with significant exposure to CO_2 has also been important for understanding the alterations that can occur (Carey et al., 2006a, b). Most of the modelling effort so far has concentrated on developing reactive transport models that can match the laboratory or field data (Carey and Lichtner, 2006; Carey et al., 2006b; Huet et al., 2006), where the transport is only in one spatial dimension (by diffusion through the cement).

A more complete answer to questions on wellbore integrity depends on the coupling between migration through the cement and the reactions with the matrix. Current research indicates that one of the key questions is the characterization of pre-existing leakage paths through the cemented zone. Diffusive transport of CO_2 alone is too slow to have a major impact on wellbore integrity, and so the key parameters are the width and permeability of existing fractures or micro-annuli in the cement. The challenge for reactive transport simulations is to match the laboratory experiments, but also then to model the exchange between a thin fracture of high permeability, and a reactive matrix of low permeability.

Leakage to the Surface

Studies of natural analogues also provide indications of possible processes that might create CO_2 leaks (Birkholzer et al., 2006; Lewicki et al., 2007a). Although many natural leaks are slow and pose low risks, one issue is the possibility of sudden large releases at the surface, which would be hazardous due to high concentrations of CO_2 in the air. In geological storage, leaking CO_2 will expand as it rises. In some cases there will be a gas-liquid transition and a significant expansion of the CO_2. As already observed, such simulations require good thermodynamic representations of the properties of the phases and must be able to handle the thermal effects and the coexistence of three phases (two CO_2 phases and an aqueous phase).

Simulations of leakage up a high permeability conduit (in radial symmetry) show complex effects (Pruess, 2004). The boiling of liquid CO_2 at the phase boundary results in strong cooling effects. Even in the absence of a phase change, cooling effects due to expansion are still important. Under some conditions it is predicted that the cooling will eventually lead to the formation of CO_2 hydrates in the near-surface region. Modelling of this situation (along with the three other phases) is beyond the current capabilities of simulation codes. Also, the creation of three-phase zone reduces CO_2 mobility due to phase interference effects, causing the migrating CO_2 to spread out laterally around the leakage path. More realistic simulations are needed here to examine the effects of multiple barriers along the leakage path. There is also a need for experimental measurements of three phase relative permeabilities with the two CO_2 phases and water, since no data is yet available in the literature.

Leakage to the surface up a fault zone provides greater thermal contact of the CO_2 with the surrounding rock mass. The result is a quasi-periodic oscillating surface leakage rate (Pruess, 2005). As a three phase zone is formed and mobilities there fall, the CO_2 spreads out laterally to migrate around this zone. Thermal conduction from the walls of the fault then causes boiling of the liquid CO_2, reducing the three-phase zone and increasing the leakage rate again. Compared to an isothermal simulation, there is a marked reduction in the surface leakage rate due to these self-limiting effects.

Another possible leakage scenario is the slow accumulation of leaking CO_2 in a shallow formation, followed by migration past a spill-point to the surface. The slow leakage reduces the magnitude of thermal effects during the accumulation phase. Simulations of this scenario that there is an enhancement of the peak surface leakage beyond the rate of supply, due to the effects of CO_2 expansion (Pruess, 2008). Larger supply rates lead to a greater enhancement of the surface leakage rate (the largest supply rate gave an enhancement factor of more than 3), but at larger rates the formation of hydrates due to cooling again challenges the capacities of simulation codes. Lower fault permeability on the leakage path to the surface allows a greater build-up of pressure, which delays the surface leakage, but enhances the peak rate. None of these simulations indicate a catastrophic run-away leak, since there are self-limiting effects as well as self-enhancing ones in CO_2 leakage. However further exploration is needed both of possible leakage scenarios and of natural analogues to see if such catastrophic leaks can be ruled out.

As leaking CO_2 enters the near-surface, there are a number of modelling challenges. Work has been done on CO_2 in the unsaturated zone and its coupling to the atmosphere (Oldenburg and Unger, 2004; 2005; Oldenburg and Lewicki, 2005), or the coupling to migration in surface water (Oldenburg and Lewicki, 2006). Most recently, field trials have been carried out on shallow leakage from a horizontal well placed just below the water table (Lewicki et al., 2007b). Simulations in 2D were able to predict the key features of the field observations.

Caprock leakage

The leakage scenarios so far considered only simulate flow. However there may be coupling between CO_2 and geochemical reactions that could be self-enhancing (with permeability increases due to dissolution) or self-limiting (with permeability decreases due to precipitation). The pressure increases due to injection and CO_2 migration may also couple to geomechanical effects which could be self-enhancing. Although this applies to all the scenarios, an important case that has been studied is migration through micro-fractures in the caprock (Johnson et al., 2005a, b; Gherardi et al., 2007). Here there are both self-limiting and self-enhancing effects in competition.

In the case studied by Johnson et al. (2005), using a simulation code that couples geomechanics and geochemistry with flow, the magnitude of the pressure increases at the caprock depended on the permeability, the location of the injector, and whether the system was open or confined. The pressure increase widened the microfractures during the injection phase, although there was some relaxation post-injection. This was opposed by geochemical changes: the clay-containing shales in the simulation led to net precipitation, particularly of magnesite, tending to decrease the width of the microfractures. A conceptual framework was then proposed for the counterbalance of the geochemical and geomechanical effects, with the diffusion distance and the reaction progress determining the degree to which precipitation would close the fractures.

Another study on caprock leakage concentrated on carbonate-rich shales (Gherardi et al., 2007), but without geomechanical effects being considered. Here it was found that the net effect of CO_2 invasion of the caprock depending on the means of transport. Diffusion in the aqueous phase tended to net precipitation of calcite, with reductions in porosity and permeability. On the other hand gas advection (e.g. through fractures) induced enhancements in porosity and permeability.

The effect of CO_2 on caprocks is clearly important for risk assessment of leakage. There is a need for further theoretical studies to elucidate the net geochemical effects for different types of caprocks, and the balance with geomechanical effects. There's also a strong need for both field and laboratory data so that these theoretical concepts can be checked and refined.

Impurities in CO_2 Stream

Depending on cost and the capture technology, a mixture may be injected rather than pure CO_2 (Ho et al., 2005; Knauss et al., 2005). The nature of the impurities depends on the process stream from which the CO_2 is separated. Separation from natural gas is likely to leave CH_4 impurities, whereas separation from coal-fired power stations might leave SO_x, NO_x, H_2S and N_2.

All impurities have an impact on the properties of the fluid phase that modify injectivity. For example, small amounts of methane can give a disproportionate reduction in the density of the fluid compared to pure CO_2. There is also of course the simple reduction in the amount of CO_2 being stored for the amount of gas being injected. Although there are clearly economic implications, considering only the flow processes, the gas mixture nevertheless behaves similarly to pure CO_2 in the subsurface, with buoyancy being a key driving force. The difference in solubility between the injected components will have an effect at a migrating front, with less soluble components (such as methane) being enriched relative to CO_2, and more soluble components being depleted (Ozah et al., 2005). In this respect impurities behave rather like tracers.

However impurities such as SO_x, NO_x and H_2S have effects not just on the flow but also on geochemical reactions. The presence of SO_x and NO_x impurities will increase the acidity of the formation water, and speed up mineral dissolution, but does not significantly change the ultimate extent of alterations to the mineralogy (Bryant and Lake, 2005); Ozah et al., 2005). The net change in mineral volume is likely to be small, since any mineral that precipitates appreciably must use cations from the dissolution of existing minerals. However if conditions allow sulphur to be oxidised, then SO_2 impurities could lead to very low pH, and there is potential for anhydrite to form and reduce the porosity (Knauss et al., 2005). A more recent study confirms the strong effects possible with SO_2 injection, and the significant porosity changes that can occur (Xu et al., 2007).

A good deal of field data is available for acid-gas injection projects, where the gas contains CO_2, H_2S and minor traces of hydrocarbons (Bachu and Gunter, 2005; Bachu et al., 2005). Thus there has been progress on good representations for the density, viscosity and phase behaviour of such gas mixtures (Bachu and Carroll, 2005). Numerical modelling of injection has been carried out for some sites, and is a useful analogue for CO_2 storage (Bachu et al., 2005; Michael and Buschkuehle, 2006). Experimental and theoretical geochemical work on aquifers in Canada used for acid gas operations indicates that with high H_2S content, iron-containing minerals will react rapidly to form iron sulphides, with the amount of mineral trapping limited by the availability of such minerals (Buschkuehle and Perkins, 2005; Gunter et al., 2005).

Upscaling

In typical field-scale reservoir simulations, the lateral dimensions of the gridblocks are often tens of metres, if not hundreds of metres for migration in a large unconfined saline aquifer. On the other hand the rock properties - porosity, permeability, mineralogy - and the rock-fluid interactions - relative permeability, capillary pressure, geochemical reactions - are measured on core samples (on a centimetre scale) or derived from well-logs (on a decimetre scale). The technical challenge of upscaling is to find appropriate methods to convert measured values and properties in fine-scale geocellular models to the scale of the reservoir simulation gridblock.

Since the upscaling issue is common to all reservoir simulation in petroleum recovery, there are good review articles (Christie, 2001; Farmer, 2002). It is also a topic of active research (for example Zhang et al. 2008)

Nevertheless, there are some upscaling challenges that are particularly relevant to CO_2 injection. Deep injection is often considered for saline aquifer storage, to minimise the effect on the caprock, and maximise residual gas trapping and dissolution along the upward migration path. In some cases, there may also be a risk of CO_2 coming into contact with an overlying resource, such as a hydrocarbon field or water resource. Then the quantity of most interest is the vertical permeability. This is again familiar territory for petroleum reservoir simulation, where techniques have been developed for estimating upscaled vertical permeability. In the case of CO_2 injection, when relying on low vertical permeability to retard vertical migration one also needs to know the variability of vertical permeability (e.g., the risk of a “fast path” that allows CO_2 to migrate upwards more quickly) and work is underway in this area.

Geochemical modelling depends on reaction rates measured in the laboratory, and these need to be upscaled to effective reaction rates suitable for larger gridblocks (Kechagia et al., 2002; Brosse et al., 2005; Li et al., 2006a), since the distribution of reactive minerals is likely to be heterogeneous. Likewise, methods need to be developed for upscaling CO_2 dissolution, residual gas trapping and convective mixing.

Tracer Simulation

Tracers have been used in the petroleum domain and also in groundwater studies for several decades. One purpose is simply to label a particular fluid, so that when it appears elsewhere in sampling, then the origin is clear. In the petroleum context, tracer injection has been used to identify communication between injection and production wells in complex reservoirs. In groundwater studies, tracers can be used to identify migration rates and directions. In the context of subsurface contaminant by non-aqueous phase liquids (NAPL), a partitioning inter-well tracer test used several tracers with different solubilities to help characterise the residual saturation and distribution of the NAPL. The principle is that more soluble tracers have their breakthrough retarded because they partition more into the NAPL.

In some field trials of CO_2 injection, tracers have been added to the CO_2 to monitor breakthrough or possible leakage, and also to deduce some information about the subsurface environment (Freifeld et al., 2005; Saripalli et al., 2006; Wells et al., 2007). Natural noble gas tracers have also been studied in natural CO_2 accumulations (Gilfillan et al., 2008).

Many simulation codes have the capacity to add tracers, although this has not yet been widely used for CO_2 injection modelling. It is typically assumed that the tracer is present in such small concentrations that its effect on the other phase can be neglected. The solubility of the tracer is often represented by a Henry's law formulation. However there are conditions where these assumptions are questionable. Most of the tracers being considered are less soluble than CO_2, and this implies that as the front of CO_2 advances, the tracer concentrations will increase at the front due to the greater dissolution of CO_2. Thus the tracer could come to have a non-negligible concentration at the front, changing the properties of the gas phase. For example, SF_6, a common tracer of low solubility in water, will increase the density of the gas phase. Most of the partitioning data for tracers is based on low pressures and partitioning between a dilute gas phase and water. Little laboratory data exists on partitioning between a dense, high-pressure CO_2 phase and water. When such data become available, the tracer partitioning models used in simulators may need some revision.

Coupled Geomechanics

Coupled geomechanics can be considered in two contexts. One context is where permeability and the flow response depend on stress; hence close coupling of flow and geomechanics through the time-stepping of simulations is required. The other context is where the porous medium can be considered to be effectively rigid, but where a geomechanical response such as fault reactivation may occur at some stage. In this latter context the coupling between flow and geomechanics can be weaker, with the effective stresses being determined when required. This may be only at the end of a simulation stage. Naturally weak coupling is much easier to implement in practice.

Developments in coupled geomechanics have been driven by the wider petroleum industry, so the literature specific to CO_2 forms only part of the overall picture of what is relevant to CO_2 storage. Various approaches to the coupling of flow and geomechanics have been investigated (Minkoff et al., 2003; Tran et al., 2004; Dean et al., 2006), and applications have been made to field examples (Cappa et al., 2006; Samier et al., 2006).

There have been a number of applications of these developments to saline aquifer storage. Most of the software development has been done by coupling flow simulators externally to specialised geomechanics packages (Johnson et al., 2005b; Le Gallo et al., 2006; Rutqvist et al., 2006) or to simpler geomechanical models (Li et al., 2006b). In some cases the coupling is only from flow to geomechanics (i.e., the effect of stress changes on porosity and permeability is neglected) (Johnson et al., 2005), but more closely coupled approaches have also been used (Rutqvist et al., 2006).

One of the concerns with CO_2 injection is that the pressure increases might lead to reactivation of existing faults, and so there is a need to estimate the maximum sustainable injection pressure for a storage site. Analytical techniques have been used to estimate the risk of fault reactivation in various CO_2 injection sites (Streit and Hillis, 2004; Lucier et al., 2006; van Ruth et al., 2006). Comparison with a coupled numerical model shows that the simplified analytical techniques may either underestimate or overestimate the maximum injection pressure (Rutqvist et al., 2007). A coupled numerical model is able to evaluate the spatial evolution of fluid pressure and stress during injection, and incorporate poro-elastic effects, and thus produce more accurate estimates of the maximum injection pressure. Semi-analytical models for fault reactivation are also being developed (Soltanzadeh, 2008).

Another concern is that fracturing induced by injection, or the opening of existing fractures, could allow CO_2 to migrate upwards out of the target reservoir unit. A case of interest is where the injection zone is situated below a multilayer sequence of caprock and aquifer zones that are intersected by a vertical fault. The potential for fault reactivation depends largely on the initial stress regime. Under a compressive stress regime, failure would preferentially occur along shallowly dipping fractures, but would be unlikely propagate all the way through the multilayer sequence, so the CO_2 would still be contained. On the other hand, in an extensional stress regime, failure would be more likely to occur along steeply dipping fractures, and might propagate through the overburden (Rutqvist et al., 2008). Pressure-induced changes in permeability along faults are likely to be only moderate, and thus CO_2 leakage along this pathway is likely to be relatively small (Rutqvist et al., 2006).

The application of coupled geomechanical simulations to CO_2 storage is still at an early stage. As in other areas of numerical simulation, modelling capabilities have advanced ahead of data that can be used to test the models. In the case of geomechanics, parameters such as stress measurements, elastic moduli and Poisson's ratios are usually in short supply, let alone cohesion and friction coefficients for the faults. Code comparison studies for coupled geomechanical-flow simulations remains more immature than other forms of code comparison, and this also represents a gap.

Progress in Numerical Simulation and Remaining Knowledge Gaps

A number of the knowledge gaps identified in Section 5.10 of the IPCC SRCCS relate to numerical modelling. One was the development of "Reliable coupled hydrogeological-geochemical-geomechanical simulation models to predict long-term storage performance accurately". As seen above, the simulation software for coupled models is well-developed, particularly for reactive transport models, although the coupled geomechanical codes are still at a more preliminary stage. Code comparisons are important to developing greater confidence in these modelling tools, and another one is currently underway for flow simulations. However the use of such coupled models to probe scenarios for CO_2 storage is still in an early phase of development, since there is a very wide spectrum of possibilities e.g. the range of mineralogies in reactive transport simulations. In many domains, the capabilities of the coupled models are well ahead of laboratory or field data that could constrain or verify their predictions, and this need is detailed in the current knowledge gaps listed below.

Another IPCC knowledge gap was the "Quantification of potential leakage rates from more storage sites". Progress has been made here on exploring a variety of scenarios for leakage to surface, including the possibilities of sudden large releases. Both self-limiting and self-enhancing effects are present, but no risk of catastrophic release has yet been identified. Caprock integrity is also germane to leakage rates, and the competition between self-sealing and self-enhancing processes in caprock leakage has also been investigated. Relevant here too is the IPCC knowledge gap on "Risks of leakage from abandoned wells caused by material and cement degradation". Progress has been made on laboratory studies on CO_2-cement interactions and analysis of some field samples. Leakage is most likely to occur along pre-existing flow paths in the cement, and the key issue is how to characterize the properties of these paths.

The current knowledge gaps can be divided into three categories. The first is technical simulation issues, such as processes that are not adequately modelled in current software. The second is theoretical issues, where simulation tools are being used to explore and optimize scenarios for CO_2 storage. The third is data issues, where laboratory, field or analogue data is needed to check and improve the existing numerical models.

1. Code comparisons need to be extended to more detailed examinations of coupled geochemical and geomechanical models.

2. Improved flow modelling of CO_2 liquid/gas transitions in shallow reservoirs or near-surface leakage, possibly including hydrate formation.

3. Better simulations of tracer effects in CO_2, especially density effects due to accumulation of relatively insoluble tracers at the front.

4. Inclusion of fluid density changes in reactive transport simulations, for coupling to fluid convection.

5. Upscaling of CO_2 simulations e.g. upscaling of solubility, residual gas trapping, convective mixing or vertical migration of CO_2.

6. Improved quantification of potential leakage rates of CO_2 and CO_2/gas mixtures to the surface, especially through faults and fractures, with coupling to geomechanics.

7. Simulation of CO_2 leakage rates through wellbore cement, including coupling to CO_2-cement reactions, to arrive at a better assessment of the overall risk of well leakage.

8. Simulation of surface leakage of CO_2, including screening of scenarios for sudden releases, and coupling with the atmosphere (onshore) and the sea (offshore).

9. Simulation of coupling CO_2 injection to hydrogeology, including assessment of effects on CO2 migration and adjacent aquifer units.

10. Data sets to test models for convection of dissolved CO_2 and coupled reactions on large time scales (beyond what is possible in demonstration projects, so would need to be from natural systems).

11. Data sets to test geomechanical models for fault reactivation (if faults are to be deliberately reactivated to test models this would involve water rather than CO_2).

12. Data sets to test leakage models, perhaps using natural systems.

13. Data sets to test and calibrate tracer/CO_2 behaviour in laboratory and field, including partitioning coefficients between a dense CO_2 phase and water.

14. Field data sets to characterize leakage pathways through wellbore cement

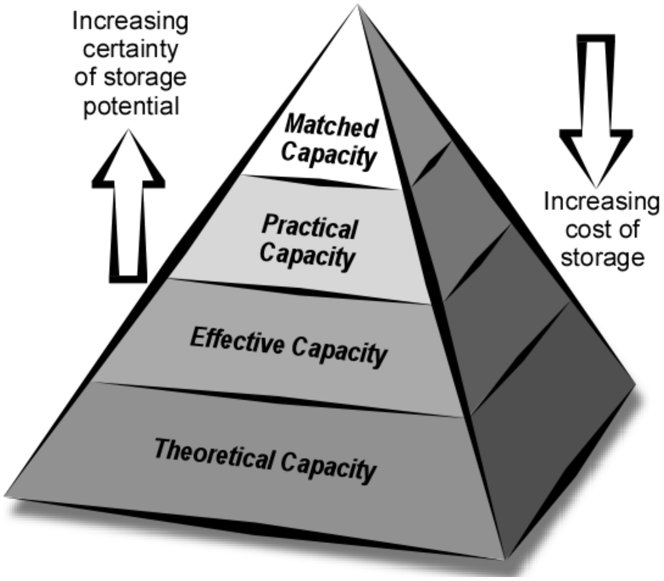
Capacity Estimation of CO_2 in Saline Aquifers

Due to inconsistency in assessment methodologies and gaps in regional and local estimates, particularly data from Africa, South America and large parts of Asia, global storage estimates of CO2 are largely speculative (IPCC, 2005; Bradshaw et al., 2007). Two major works outlining methodologies for the estimation of CO_2 storage capacity in geological formations have been published since the IPCC Special Report in 2005. In December 2006, the Capacity and Fairways Subgroup, under the direction of the U.S. DOE NETL Regional Carbon Sequestration Partnership Program, completed the "Methodology for Development of Carbon Sequestration Capacity Estimates." This was followed in April 2007 with the "Estimation of CO2 Storage Capacity in Geological Media–Phase II" prepared by the Task Force on CO_2 Storage Capacity Estimation for the Technical Group of the Carbon Sequestration Leadership Forum (CSLF), (CSLF, 2007). The results and summary of the CSLF study were published subsequently by Bachu et al. (2007). Also, the two methodologies were compared in Phase III of the CSLF work (CSLF, 2008) and the US DOE methodology is adopted as part of the Australian CO2CRC document 'Storage Capacity Estimation, Site Selection and Characterisation for CO2 Storage Projects' (CO2CRC, 2008).

This section will begin with a review of two storage capacity classifications based on the works by the CSLF (2007), Bradshaw et al. (2007) and CO2CRC (2008). Subsequently, global capacity estimations will be reviewed, before discussing the recently published methodologies for capacity estimation in saline aquifers. Details of the various methodologies and recent examples of country- and regional efforts of capacity assessments in various parts of the world are compiled in Appendix 1.

Storage Capacity Classifications

The CO_2 storage capacity of a saline aquifer is defined by CSLF (2007) as a geological resource, whose availability can be expressed in the same manner as resources and reserves are classified in other commodities (e.g. oil and gas, gold, uranium, iron, coal, etc.). Based on earlier concepts of Masters (1979) and McCabe (1998), the 2007 study by CSLF provides a Techno-Economic Resource-Reserve Pyramid for CO_2 storage capacity, whereby the degree of geological and economic uncertainty associated with a capacity estimate is represented by its place on the pyramid (Figure 2). For this reason, it is essential that, when an estimate of storage capacity is calculated, the type of estimate and its position in the resource pyramid are specified.



Theoretical Storage Capacity	Physical limit of what the geological system can accept. It assumes that the system's entire capacity to store CO_2 in pore space, or dissolved at maximum saturation in formation fluids is accessible and utilized to its full capacity.
Effective Storage Capacity	Subset of the theoretical capacity that is obtained by considering that part of the theoretical storage capacity which can be physically accessed and which meets a range of geological and engineering criteria. This corresponds to the term "resources".
Practical Storage Capacity	Subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructural and general economic barriers to CO_2 geological storage. Corresponds to the term 'reserves' used in the energy and mining industries.
Matched Storage Capacity	Subset of the practical capacity that is obtained by detailed matching of large stationary CO_2 sources with geological storage sites that are adequate in terms of capacity, injectivity and supply rate to contain CO_2 streams sent for storage from that source or sources. Corresponds to the term 'proved marketable reserves' used by the mining industry.

Figure 2. Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region (CSLF, 2007). The pyramid shows the relationship between Theoretical, Effective, Practical and Matched capacities.

Following the suggestions of Frailey et al. (2006), the classification system by CO2CRC (2008) adopts the scheme developed by the SPE Petroleum Resources Management System, putting emphasis on the pore space in which it is economically and technically feasible to store CO_2 either under current or anticipated future conditions (Figure 3).

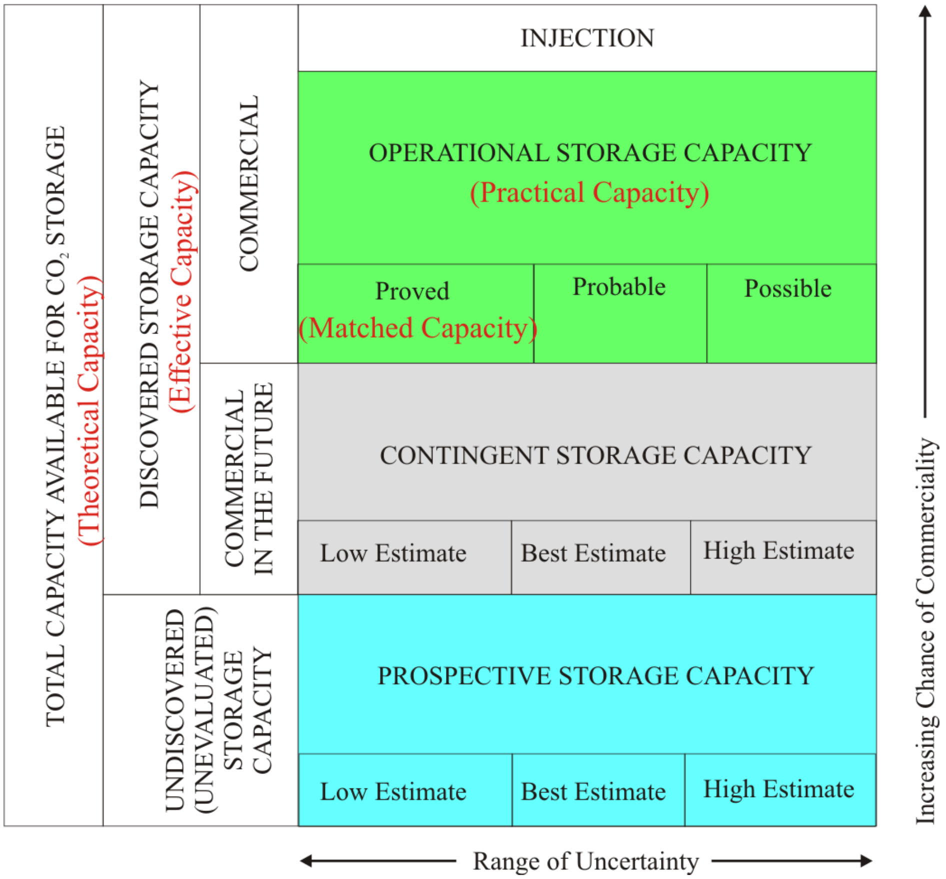


Figure 3. CO_2 storage capacity classification system based on (SPE et al., 2007) and modified from CO2CRC (2008). The equivalent CSLF storage classification is shown in red for comparison.

Total Storage Capacity: upper limit of storage capacity available for optimal CO_2 storage in separate-phase, dissolved phase or mineral phase, which in practice is an unrealistic number because physical, technical, regulatory and economic restrictions will always limit the full utilization of the total available pore space

Discovered Storage: storage capacity limited to known (i.e. well characterised) storage settings; may be further subdivided into commercial and future-commercial categories,

Undiscovered or Prospective Storage Capacity: storage capacity which is yet to be discovered, but is estimated to be available for storage at some future date “after discovery”. The estimated Undiscovered Storage Capacity is classified as Prospective Storage Capacity, which is that quantity of pore space into which it is estimated, on a given date, that CO_2 will be technically and economically feasible for injection.

Operational Storage Capacity: storage capacity which will be technically and commercially available for injecting CO_2 at known storage sites from a given date forward. **Proved Operational Storage Capacity** is that volume, which by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially accessible by injection, from under defined economic conditions, operating methods and government regulations. In contrast **Probable and Possible Operational Storage Capacity** may be based on anticipated future techno-economic conditions. In general, pore space should not be classified as Operational Storage Capacity unless there is an expectation that the storage site will be developed and used to store CO_2 within a reasonable timeframe. The definitions of “commercial” and “technically feasible” for a storage site will vary according to local conditions and circumstances and is left to the discretion of the operator or jurisdictional (country/state) authority concerned.

Contingent Storage Capacity: storage capacity estimated, on a given date, to be potentially technically and economically feasible for CO_2 injection into known storage sites based on anticipated future techno-economic conditions, but which is not currently considered to be commercially viable.

Prospective and Contingent Storage Capacity as defined by CO2CRC (2008) do not have explicit definitions in the CSLF (2007) classification scheme, but would correlate approximately to Theoretical minus Effective Storage Capacity and Effective minus Practical Storage Capacity, respectively.

Methodologies for Capacity Estimations in Saline Aquifers

The two methodologies for the estimation of storage capacity of CO_2 in saline aquifers that appear to show the most promise of being consistently applied were published by DOE (2007a) and CSLF (2007). While the DOE-proposed methodology has been used to produce capacity estimates for the *Carbon Sequestration Atlas of the United States and Canada* (DOE, 2007a), mainly European countries are in the process of applying the CSLF-proposed methodology. Detailed comparisons of the two methodologies were performed by CSLF (2008) and CO2CRC (2008). Alternative methodologies, proposed for example by Hendriks et al. (2004) or Li et al. (2005) represent simplifications of or derivations from the DOE and CSLF methods and were used for storage capacity estimations globally or in China and Japan, respectively. Details on the various calculations methods are compiled in Appendix 1.

There are several analogies and differences between methodologies proposed by the CSLF (2007) and the DOE (2007a), most of which where identified by CSLF (2008):

1. Only volumetric (static) storage of CO_2 in free phase is considered and discussed by the USDOE Capacity and Fairways Subgroup (no CO_2 in solution); however the need is identified for a method converting E for free-phase CO_2 to the equivalent E for dissolved CO_2.

2. Unlike the CSLF Task Force, the US DOE Capacity and Fairways Subgroup does not limit the volumetric trapping in deep saline aquifers to stratigraphic and structural traps; rather the entire aquifer is considered.

3. Both methodologies have introduced storage efficiency coefficients; however only DOE provides actual values derived from Monte Carlo simulations ranging between 1 and 4 % for the 15 – 85 % confidence interval.

4. The effect of irreducible water saturation is not taken into account explicitly the equation proposed by the US DOE Capacity and Fairways Subgroup, but is included in the efficiency factor E through the pore-scale displacement efficiency.

5. The two methodologies are computationally equivalent if $E = C_c \times (1 - S_{wirr})$ and if an average CO_2 density at in-situ conditions is used in the DOE equation rather than minimum and maximum values.

6. The DOE proposed to use a confidence indicator from 1 (low) to 9 (high) based on the amount, coverage and quality of the data used in the capacity estimation and on the degree of variability in the geological environment.

Given the equivalency of both methodologies for the conditions mentioned above, it follows that the CSLF methodology does not have to be restricted to defined traps but could be applied also to the entire regional aquifer geometry. Both proposed methodologies are useful in estimating the effective CO_2 storage capacity, before applying regulatory, land use, economic and other constraining overlays. The only regulatory constraint explicitly considered by the US DOE Subgroup is that CO_2 storage in saline aquifer should be at depths greater than 800 m and below the depth of protected groundwater, generally defined by water salinity less than 10,000 mg/l. This constraint has been recognized also by the CSLF Task Force, but no specific value has been recommended, allowing for each jurisdiction to establish its own.

In certain respects the work of the US DOE Capacity and Fairways Subgroup represents an advance on the work of the CSLF Task Force (CSLF, 2008). Particularly, the assignment of actual values for the storage efficiency coefficients makes the DOE-proposed methodology readily applicable for estimating static effective storage capacities from the basin- to site scale. An additional strength of the DOE Atlas product is that all capacity estimations are done within a GIS system, which allows for fast and easy data updates, the addition of new aquifers, changes in grid calculations, incorporating other geographic layers (distance to emission sources), and adding new geographic areas. The DOE-proposed methodology is particularly useful for regional- and basin-scale storage capacity estimates and general assessment of storage space availability, for which detailed three-dimensional distribution of reservoir parameters are not available and not necessary. However, storage mechanisms other than stratigraphic and structural trapping are ignored and CSLF (2007) and Bachu et al. (2007) stress the importance of numerical simulations at the local- and site scale to help constrain the contribution each trapping mechanisms has on the total CO_2 storage capacity and how the respective efficiency coefficients (Table 2) vary over time.

Table 2. Applicability of current methodologies for estimating CO_2 storage capacity in aquifers to various assessment scales and storage mechanisms (CSLF, 2007).

Trapping mechanism	Temporal nature	Coefficients needed	Assessment scale				
			Country	Basin	Regional	Local	Site
Stratigraphic/structural	No	Yes	x	X	x	x	X
Residual gas	Yes	?	-	-	-	x	X
Solubility	Yes	Yes	-	-	(x)*	x	X
Mineral precipitation	Yes	Yes	-	-	-	x	X
Hydrodynamic	Yes	yes	-	-	-	x	X

* Some US Regional Partnership members calculated CO_2 storage capacity for CO_2 in solution in selected aquifers.

Most capacity estimates are based on initial pressure and temperature conditions, assuming that elevated pressure due to injection are limited to a small radius that quickly dissipating away from the injection well in an “open” aquifer that has no lateral flow boundaries. However, when injecting into closed structures or heterogeneous formations, increasing reservoir pressures can have a more substantial effect on storage capacity and injectivity. Zhou et al. (2008) propose an assessment method of CO_2 storage capacity in closed and semi-closed saline aquifers to compliment existing capacity estimation methods for open systems. Their quick-assessment method is based on the fact that native brine displaced by injected CO_2 occupies additional pore volume within the aquifer and aquitards, provided by pore and brine compressibility in response to pressure build-up.

Global Capacity Estimations

According to Bradshaw et al. (2007), existing regional- to basin-scale capacity estimates are highly variable and in many instances contradictory. As a result, global estimates of the CO_2 storage capacity vary within several orders of magnitude, yielding conflicting results (Figure 4).

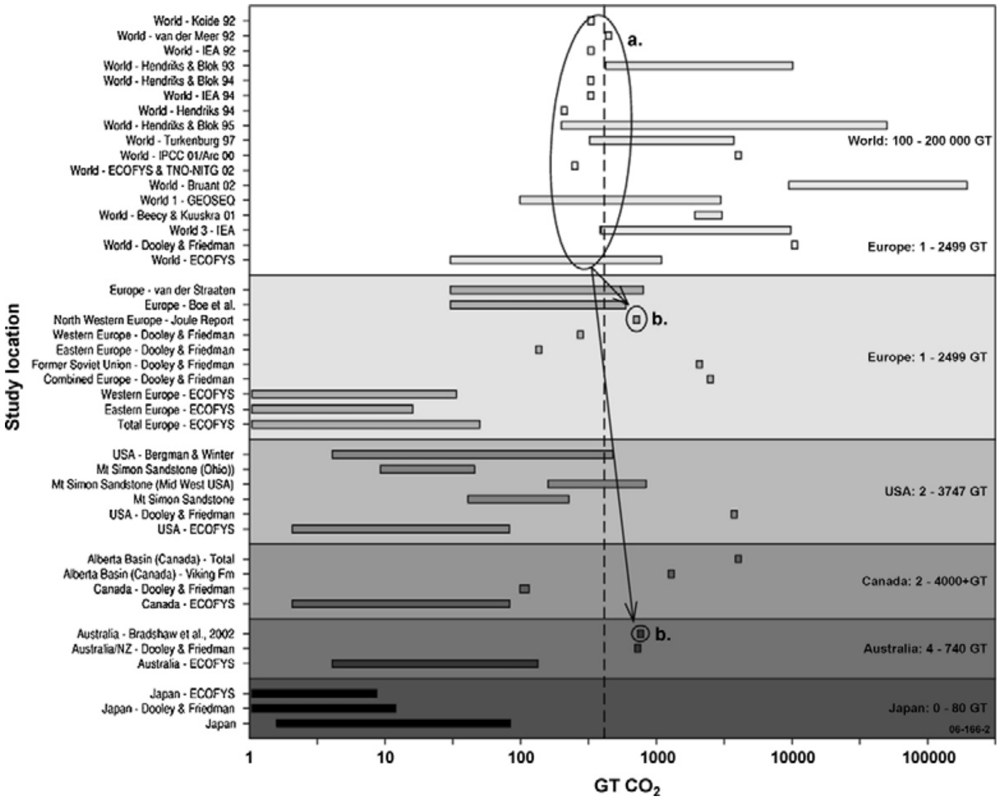


Figure 4. Listing of various CO_2 storage capacity estimates for the world and selected regions. There are world estimates (a) that are smaller than some regional estimates (Bradshaw et al., 2007).

Notwithstanding the inherent issues with the estimation methodologies, CO_2 storage capacity estimates are needed by government and industry to assess the viability of reducing greenhouse gas emissions by injection CO_2 into the subsurface. However, it is important to compare the assumptions and data sources that form the basis of the various capacity estimates in order to assess their reliability and accuracy. Global storage capacity estimates from 1992 to 2002 have been compiled and discussed by Manancourt and Gale (2005).

Although different assumptions underlie global capacity estimations, they are all based on a general form of free-phase trapping of CO_2:

$$G_{CO2} = A \times h \times \Phi \times \rho \times E \qquad (1)$$

Mostly within the following range in physical parameters:

- Areal extent of worldwide sedimentary basins (A): 70 – 80 million km^2
- Aquifer thickness (h): 50 – 400 m
- Porosity (Φ): 0.05 – 0.30
- CO_2 solubility (S): 20 – 80 kg/m^3; Efficiency factor (Es): 0.01 – 0.5 (*0.0001 – 0.01)
- CO_2 density (ρ): 400 – 800 kg/m^3; Efficiency factor (Ef): 0.01 – 0.03 (*0.0001 – 0.0006)

* In the case of traps, the efficiency factor is multiplied with the percentage of structural traps contained within an aquifer (0.01 – 0.02).

Equation 1 can be applied for estimating storage capacity based on solubility trapping when the CO_2 density ρ is replaced with the CO_2 solubility *S*, having the same units kg/m^3. Efficiency factors, generally order-of magnitude estimations, are different for the two trapping mechanisms.

Applying the parameter ranges above, result in the range of theoretical global capacity estimates presented in Table 3 and explains the wide variations in storage capacity estimates by different authors.

Table 3. Range of global CO_2 storage capacity values differentiated according to storage type and trapping mechanism based on previously published assumed values (Koide et al., 1993; Bruant Jr et al., 2002; Hendriks et al., 2004). The "best" values are based on A = 75 million km^2, h = 200 m, $\Phi = 0.1$, S = 50 kg/m^3, $E_s = 0.05/1.0$ (entire aquifer/traps only), $\rho = 600$ kg/m^3, $E_f = 0.02$ and 2 % of the aquifer are occupied by structural traps.

Storage Type	Trapping mechanism	Capacity (Gt)		
		Minimum	Maximum	Best
Structural traps	Solubility	0.4	15,360	**750**
	Free-phase	7	4,608	**360**
Entire aquifer	Solubility	35	384,000	**3,750**
	Free-phase	700	230,400	**18,000**
	Total range	0.4	384,000	

Generally, there are two different approaches to estimate the CO_2 storage capacity based on the parameters listed above: a) considering only structural traps within a saline aquifer (i.e., Koide et al., 1993; Hendriks et al., 2004) or b) taking in account the entire aquifer (i.e., Bruant Jr et al., 2002). This alone may results in a two order of magnitude difference between capacity estimates if assuming that only 1 % of an aquifer will form structural traps (i.e., Koide et al., 1993; Hendriks et al., 2004).

With respect to the phase of the stored CO_2, the capacity estimates also fall into two categories: a) CO_2 remaining in a separate, supercritical fluid phase or b) CO_2 dissolving completely in formation water. In the case of solution trapping, the solubility of CO_2 in formation water ultimately constrains the storage capacity and a larger pore volume is needed than for the same mass of CO_2 stored as a separated phase fluid displacing the formation water. For the same physical parameters this results in approximately one order of magnitude lower capacity of CO_2 store in solution than free-phase. The reason some regional capacity estimates based on dissolved CO_2 are still higher than many global values (i.e., Mt. Simon aquifer in Figure 4) lies in the fact that the former consider the entire pore volume of the aquifer, which translates to an efficiency factor E = 1 versus E < 0.01 for most global capacity estimations. While it seems reasonable to assume CO_2 dissolved in formation water occupying most of a structural trap, it will be unlikely that injected CO_2 dissolving into a regional aquifer will contact all the brine contained within it. For the later case for example, Li et al. (2005) suggest using an efficiency ratio of approximately 0.05, accounting for "effective aquifer thickness" and "sweep efficiency".

Instead of applying a single methodology, Dooley et al. (2006) compiled values of storage capacity from different parts of the world (Figure 5) dependent on data availability and previous calculations by other organizations and authors as described in Dooley and Friedman (2004). The result is "a global but regionally disaggregated accounting of CO_2 storage capacity", which incorporates more "robust" estimates, in those areas of the world were regional capacity assessments have been performed (i.e., USA, Western Europe), with more theoretical capacity estimates for those areas with sparse data coverage or lack of existing studies (i.e., Africa, Latin America…). These capacity estimates, totalling 10,711 Gt, should be updated as soon as more accurate data become available for the various parts of the world.

Figure 5. First-order assessment of the global theoretical CO_2 storage capacity, approximately 90 % of which is in saline formations (Dooley et al., 2006).

Since the publication of the IPCC SRCCS, new storage capacity estimates have been produced by the US Regional Carbon Sequestration Partnership program, as well as individual studies in Japan, China and Europe (Table 4). In Figure 6, the map by Dooley et al. (2006) has been updated with these new capacity estimates. In addition, there are active projects like GEOCAPACITY in Europe and CARBMAP in Brazil that anticipate the presentation of regional capacity estimates for their respective regions within the next year or two. In Australia, regional-, and basin-scale studies in Victoria, Western Australia and Queensland were aimed at finding suitable injection sites for CO_2 emissions from various coal power plants (Gibson-Poole et al., 2006; Marsh and Scott, 2005; Sayers et al., 2006; Varma et al., 2007). The result is a regionally refined characterisation of suitability and storage capacity, significantly improving on initial assessments by the Australian GEODISC project (Bradshaw et al., 2004; Bradshaw et al., 2002). Except for the initiation of CCS research programs almost no progress has been made in obtaining reliable CO_2 storage estimates for Latin America, Africa, and large parts of Asia.

Table 4. New national storage capacity estimates in saline aquifers since 2004 (see Appendix 1 for details).

Country	Storage capacity (Gt)	Comments	Source
Brazil	2000		(Ketzer et al., 2007)
China	1435		(Li, 2007)
Germany	20	selected regional studies	(May et al., 2005)
Great Britain	14	selected aquifers	(Holloway et al., 2006)
India	300	Basalt (Deccan Traps)	(Sonde, 2007)
Japan	102	various trapping mechanisms (residual gas, in solution and selected traps)	(Suekane et al., 2008)
Poland	5	18 structures	(Wojcicki et al., 2007)
South Africa	20	selected aquifers	(Engelbrecht et al., 2004)
USA + Canada	2150 (920 – 3380)	selected aquifers	(DOE, 2007a)

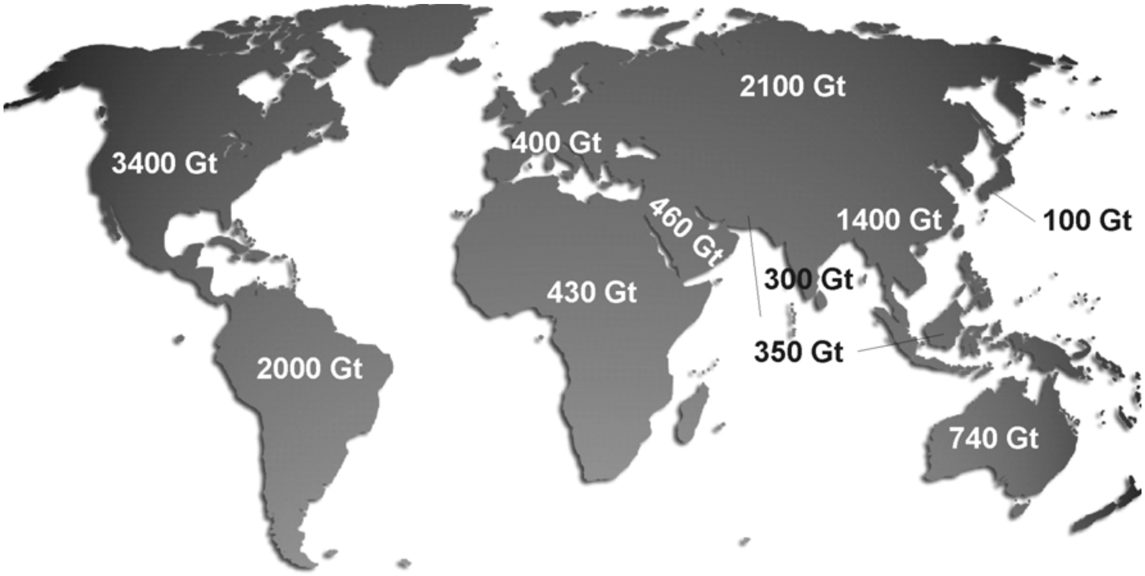


Figure 6. Updated first-order theoretical storage capacity estimates based on the map by (Dooley et al., 2006) and updated with values for North America (DOE, 2007a), Japan (Li et al., 2005), Brazil (Ketzer et al., 2007), and China (Li, 2007).

Summary and Recommendations

The publication of the Carbon Sequestration Atlas of the United States and Canada (DOE, 2007a) and the Phase 2 report on the Estimation of CO_2 Storage Capacity in Geological Media by CSLF (2007) represent significant progress towards developing consistent methodologies for the classification and determination of CO_2 storage capacity in saline aquifers. CO2CRC (2008) in Australia proposes to adopt a combination of the US DOE methodology of capacity calculation with the CSLF classification scheme of storage estimates, and to expand the latter by incorporating the SPE Petroleum Resources Classification framework (SPE, 2007).

The main cause for the large discrepancy between and range in existing global and regional CO_2 storage capacity estimates is the use of two fundamentally different concepts: 1) considering the entire aquifer versus accounting only structural traps for CO_2 storage, and 2) assuming CO_2 storage in solution versus storage as free-phase fluid. These differences are largely reflected in the respective "efficiency factors/coefficients", which should be clearly identified when reporting capacity estimates. The example of the US DOE Atlas shows that, by knowing the underlying assumptions in each regional partnership's estimation methodology, the results obtained by different methods can be easily converted into comparable capacity estimates. In addition, when presenting regional or global storage capacity values, they should be clearly classified within the CSLF Techno-Economic Resource-Reserve pyramid.

Most methodologies for the estimation of global or regional storage capacity are not that different from each other. Even if it might prove difficult to decide globally on a single method or workflow to obtain storage estimates, at a minimum capacity estimates should clearly state the three basic assumptions used in the respective calculations:

1. Storage in the entire aquifer or only in structural traps;

2. Storage of free-phase or dissolved CO_2;

3. Range/magnitude and origin of storage efficiency factor/coefficient.

Remaining gaps:

- Universal agreement on methodology and classification, particularly whether the estimates are based on a) only structural traps within the aquifer, b) the entire aquifer, c) CO_2 in solution and/or d) CO_2 as separate phase/residual;

- Should only economically feasible sites be included in the estimations, i.e., within a certain radius of CO_2 emission sources?

- (Reliable) regional estimates for Latin America, Africa, and Asia (except Japan and China).

Best Practice and Site Characterisation Requirements

The aim of this section is to review the work on Best Practice and related experience on CO_2 injection in deep aquifers, and comment on site characterisation requirements for deep saline aquifer storage and whether they are different from those for other storage reservoirs. Two key documents dealing with Best Practice and site characterisation have been published since the IPCC Special Report on CO_2 Capture and Storage (IPCC SRCCS), completed in late 2005. These are the Best Practice Manual from the SACS and CO2STORE projects (Chadwick et al., 2007) and the CO2CRC report 'Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects' (CO2CRC, 2008). The discussion on site characterisation in the CO2CRC (2008) report draws heavily from (Gibson-Poole, 2008).

Site characterisation is identified by Chadwick et al. (2007) as refining storage capacity estimates to confirm capacity requirements, and to provide the geological information necessary to show that, as far as can be discerned prior to injection, the site will perform effectively and safely. This section will focus on the geological site characterisation with discussion on other topics covered elsewhere in this report

Best Practice in Site Characterisation

Best Practice Manuals are being developed internationally to set standards for national authorities and regulatory organisations in their assessment of CCS projects, in imposing safety criteria for site design, and in the initial selection and characterisation of storage sites. However, generic 'standards' may be difficult to establish due to site-specific geological conditions, the complexity of the processes involved, and in some instances, the availability of only partial geological characterisation details.

Early approaches to developing Best Practice Manuals were published by GEO-SEQ (Benson et al., 2004) and the Saline Aquifer CO_2 Storage project (SACS) (Holloway et al., 2004). The multi-disciplinary GEO-SEQ team aimed at presenting their key research relevant to the practical implementation of CO_2 storage in the form of a Best Practices Manual. It was the first such manual developed and focused on characterisation and project development aspects of the design phase of an injection project.

The SACS Best Practice Manual (Holloway et al., 2004) was based on experiences gained from the Sleipner project. The manual briefly covers operational aspects of the project and then outlines recommendations based on experiences gained from monitoring the injection phase of the project. However the manual was regarded by its authors as an accumulation of knowledge and experiences from the Sleipner project and was not intended to be a set of standard procedures for the investigation or monitoring of potential CO_2 storage projects.

Since the IPCC SRCCS was completed in late 2005, the most significant new publication on best practice in relation to saline aquifer storage is the SACS/CO2STORE Best Practice Manual titled "Best Practice for the Storage of CO_2 in Saline Aquifers – Observations and Guidelines from the SACS and CO2STORE Projects" (Chadwick et al., 2007). This manual is an updated version of the earlier SACS document (Holloway et al., 2004) including the well-documented Sleipner project and four new case-studies covering the selection and characterisation of potential storage sites, in both offshore and onshore settings in Europe.

Chadwick et al. (2007) consolidates some of the key findings from a series of SACS and CO2STORE publications into a manual of observations and recommendations relevant to underground saline aquifer storage, and aims to provide a set of technically robust guidelines for effective and safe storage of CO_2 in a range of geological settings. As well as establishing procedures for conventional geological, geochemical and geophysical characterisation and monitoring, significant effort was put into evaluating requirements for site risk assessment. This manual is described as "intending to set the scene for companies, regulatory authorities, non-governmental organisations, and ultimately, the interested general public, in evaluating possible new CO_2 storage projects in Europe and elsewhere".

Procedures or recommendations highlighted in Chadwick et al. (2007) may clearly vary from site to site due to the natural variability of geological systems. The utility of such 'Best Practice' therefore is, and will continue to be, improved as further case studies are examined and added to the manual. Nevertheless, Chadwick et al. (2007) includes a range of geological, environmental and planning issues from five case studies and the document is considered to establish sound procedures and recommendations for the planning and development of prospective CO_2 storage projects. The manual is framed around a seven-stage template for site development, from initial project inception to eventual site closure. It is based mainly on the authors experiences with a number of case-studies identified as: Sleipner (offshore Norway), Kalundborg (onshore/offshore Denmark), Mid Norway (including three potential sites offshore Norway), Schwarze Pumpe (onshore Germany), and the Valleys (offshore western UK).

Studies are continuing with establishing guidelines for 'Best Practice' and the *IEA Greenhouse Gas R&D Programme website* includes a recent addition for the collection of documents which can ultimately be used to help create internationally accepted best practice for the capture and storage CO_2. The Best Practice Support database is intended to provide a central point at which documents which can ultimately be used to help create internationally accepted best practice for CO_2 capture and storage can be collected. The aim is to collect the most relevant documents or information and to identify material which should be considered in the development of definitive best practices and standards for CCS.

The CO_2 *Capture Project* has a stated objective to identify and address critical issues around assurance of geological storage of CO_2 and to contribute to global efforts to establish best practices for site characterisation, process optimization, monitoring-verification and risk assessment. It is worth noting that one focus for their phase 2 study, which is due to be completed in 2008, was networking best practice.

The European CASTOR project has a goal of improving the 'Best Practice Manual' through the addition of four new storage facility case studies representative of the geological variety of existing sites across Europe. These case studies will consist of: storage in an abandoned reservoir in the Mediterranean (the Casablanca field, operated by Repsol, Spain), storage in a deep saline aquifer (Snøhvit, North Sea, operated by Statoil, Norway, injection started in April 2008); storage in two depleted gas reservoirs, one at a depth of 2500 m (K12-B in the North Sea, Netherlands, operated by Gaz de France, injection tests started in 2004), and the other shallower and on onshore, at 1600 m depth (Atzbach-Schwanenstadt gas field in Austria, operated by Rohoel). Risk and environmental impact studies, methodologies for predicting the future of these sites and for monitoring them are to be included.

The European Parliament is working towards a legal framework for the geological storage of CO_2, and has developed a template for Best Practice which is provided in their 2008 proposal for a 'Directive' on the geological storage of CO_2 (Commission of the European Communities 2008). Their proposal has split the characterisation and assessment of storage sites into four steps; data collection, computerised simulation of the storage complex, security, sensitivity and hazard characterisation, and risk assessment See Sections on Regulations and Risk Assessment for a more detailed review of these topics in other parts of the world.

Site Characterisation Approaches

A range of different approaches to site characterisation have been published since the release of the IPCC SRCCS. The Best Practice Manual uses a template of operations as follows:

- Statement of storage aims and benefits
- Site screening, ranking and selection
- Site characterisation
- Site design and planning consent
- Site construction
- Site operations
- Site closure

Site characterisation includes geological characterisation, predictive flow modelling, geochemical and geomechanical assessment, risk assessment, monitoring programme design and transport.

However, CO2CRC (2008) defines the selection of a suitable site for the storage of CO_2 as comprising mainly geological evaluation on progressively more and more detailed scales. The different levels of site assessment are stated to range from an initial regional screening to very detailed site-specific characterisation, and summarized in the workflow presented in Figure 7 (Gibson-Poole, 2008). Each level of detail progressively reduces uncertainty, but requires greater effort, and increasing amounts and types of data, time and costs. Once potential storage sites have been identified and ranked, a prospective site has to be further evaluated through a process of detailed site characterisation.

Site characterisation is considered the most time-consuming and costly part of the CO_2 storage site selection process. It may involve re-evaluation of regional geology, generation of new data and/or updating of existing static geologic and seismic data and dynamic engineering data and numerical flow simulation models. Typical steps for site characterisation proposed by the CO2CRC (2008) are structural and stratigraphic interpretation based on available subsurface data, building of geological models with realistic stratigraphic heterogeneity, building of geochemical, geomechanical and hydrogeological models, and constructing numerical flow simulations to predict CO_2 plume migration (Figure 7) (Gibson-Poole, 2008; Gibson-Poole et al., 2005).

Three key factors that require further detailed evaluation (modified from five originally suggested by Bradshaw et al., 2002) are: injectivity, containment and capacity (Figure 7). These three factors encompass the fundamental elements needed to characterise any potential CO_2 geological storage site, and are described in detail in Appendix 2 (CO2CRC, 2008). A similar approach has been proposed by Friedmann (2006) who suggests that site selection should proceed around three primary characterisations; these being injectivity, capacity and effectiveness (ICE). Effectiveness is basically the same as the CO2CRC 'containment', defined by Friedmann (2006) as the ability of the site to store CO_2 beyond the lifetime of the project. He agrees effectiveness is the most difficult to characterize for a site, and expects it to be primarily dependent on analogue information for saline aquifers, in comparison to well derived data which is expected to be more readily available for depleted oil/gas fields and enhanced recovery projects.

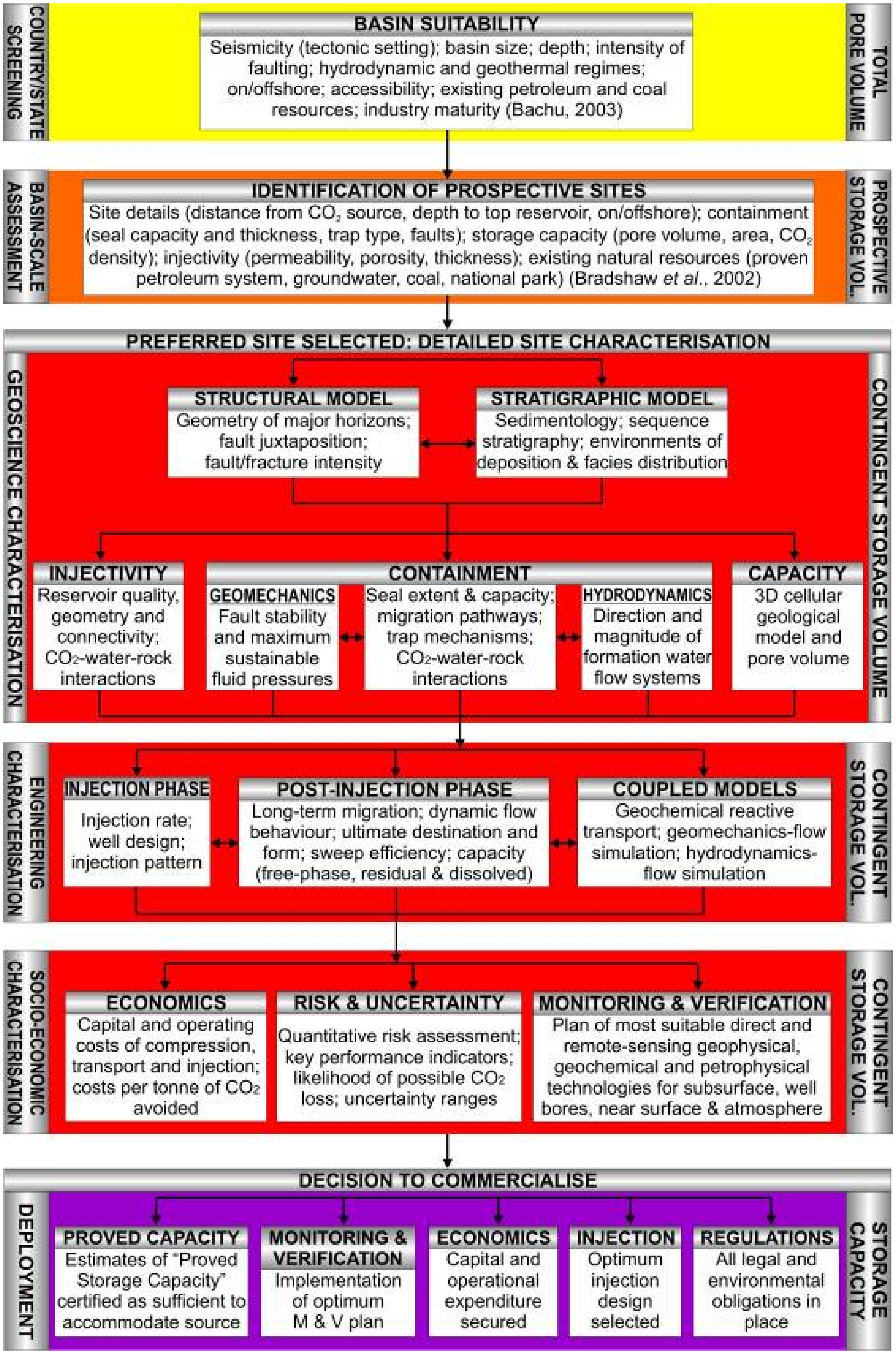


Figure 7. Site characterisation workflow for geological storage of CO_2 (modified from (Gibson-Poole, 2008).

Site screening

Chadwick et al. (2007) suggest the identification of sites requiring further characterisation is best completed through an initial screening process. A ranked list of sites may be developed using the geological criteria of reservoir depth, thickness, porosity, permeability, seal integrity and salinity. Key indicators, including positive and cautionary indicators are summarized in (Table 5), although given the geological variability of potential sites such indicators should be treated as a guide rather than a strict cut off.

Table 5. Key geological indicators for storage site suitability (Chadwick et al., 2007).

	Positive indicators	**Cautionary indicators**
Storage capacity		
Total storage capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source.	Total capacity of reservoir estimated to be similar to or less than the total amount produced from the CO_2 source.
Reservoir properties		
Depth (pressure)	>1000 m <2500m	<800 m, >2500 m
Reservoir thickness (net)	>50 m	<20 m
Porosity	>20%	<10%
Permeability	>300 mD	<10 – 100 mD
Salinity	>100 gl^{-1}	<30gl^{-1}
Caprock properties		
Lateral continuity	Unfaulted	Lateral variations, faulting
Thickness	>100 m	<20 m
Capillary entry pressure	Capillary entry pressure much greater than buoyancy force of maximum predicted CO_2 column height.	Capillary entry pressure similar to buoyancy force of maximum predicted CO_2 column height.

The CO2CRC (2008) devised a ranking scheme for site screening, based on five factors fundamental to each potential storage site (Table 6), which represents a modified version of the approach that had been utilized previously in the GEODISC project in the assessment of potential Australian storage sites (Bradshaw and Rigg, 2001).

Table 6. Ranking factors for saline formations and petroleum reservoirs as prospective CO_2 storage sites (modified from Bradshaw, 2002; Bradshaw, 2001; Rigg, 2001).

Factor	Chance Being Assessed	Considerations
Storage capacity	Will meet the volume requirements of neighbouring, currently identified CO_2 sources	Temperature, pressure, area, pore volume
Injectivity potential	Reservoir conditions viable for injection	Porosity, permeability, thickness
Site logistics	Site is economically and technically viable	Distance from CO_2 source, water depth, reservoir depth, overpressure
Containment	Seal and trap will work for CO_2	Seal capacity and thickness, trap, faults
Existing natural resources	No viable natural resources in the site that may be compromised	Proven or potential petroleum system, groundwater, coal or other natural resource (e.g. National Park)

The determination of storage capacity is covered earlier in this report; however it is worth noting a few summary points from Chadwick et al. (2007). While storage capacity in large structural traps is readily defined, determining the storage capacity of regional flat lying reservoirs poses greater difficulty and lower storage efficiencies may be encountered. Any intra-reservoir heterogeneity such as encountered in the Sleipner Field will improve the situation, causing the CO_2 to interact with a greater volume of pore space, promoting stratigraphic trapping of CO_2 as an immobile residual phase, encouraging dissolution of CO_2 into the formation fluids, and promoting geochemical reactions leading to mineral trapping (see *Numerical Modelling* Section). The assessment of effective storage capacity in an aquifer therefore requires detailed treatment of reservoir structure, stratigraphy and fluid flow.

Geological characterisation

Key aspects of the geological characterisation of the site are listed as reservoir structure, reservoir properties, and overburden and caprock properties.

Reservoir structure needs to be characterized on both local and regional scales and should include, as a minimum, structure mapping of depth to top reservoir, reservoir thickness and reservoir structural compartmentalisation. Chadwick et al. (2007) has discriminated between two basic storage geometries and discusses the accuracy to which structure needs to be resolved based on each geometry:

- The structural closure or anticlinal trap, whereby free-phase CO_2 is held buoyantly within a distinct volume, spatially limited by impermeable rocks surrounding the top of the CO_2 accumulation. Here containment is well constrained and small uncertainties in reservoir geometry are not significant.

- The open or dipping aquifer, whereby CO_2 may spread laterally, largely unhindered, provided there are no lateral flow boundaries (compartmentalisation) within the reservoir. In this case the reservoir may have gentle dips and only minor topography at its top (as at Sleipner), therefore requiring very detailed depth mapping to predict migration direction and rate.

The utility of open or dipping aquifers was evaluated for the Mid-Norway case-study in Chadwick et al. (2007). Provided the dips are relatively low angle ($< 2.8^o$), and horizontal permeabilities are not too high (e.g. < 2700 mD), then the CO_2 plume buoyantly rises to the base of the seal and spreads out laterally facilitating a combination of residual and solution trapping, and leakage can be near-zero. Even relatively poor (laterally variable) caprocks may provide sufficient seal to assure containment in such situations. Hence, open, dipping aquifers may provide effective CO_2 storage options, given reasonable reservoir parameters (particularly horizontal permeability) and adequate distances between the injection well and the potential leakage point. However, pressure is a key limit on injectivity for small reservoirs.

The identification and mapping of any faults on any structure is clearly critical, not just to consider their impact on containment or fault sealing capacity (e.g. by empirical fault gouge shale ratio estimation), but also in terms of possible reservoir compartmentalization and/or the potential for fault-related migration. Pressure could significantly limit injectivity in regions of structural compartmentalisation and identification of fault flow properties is considered a key input to reservoir simulations. In such cases, 3D data (with adequate resolution) will be required to accurately map fault networks.

Chadwick et al. (2007) emphasize the importance of core material, augmented by well logs from regularly distributed wells across the region of interest, for the determination of reservoir properties. Core should be from the reservoir close to the proposed injection point and preferably from likely CO_2 migration pathways. Outcrop correlatives and analogues are recommended to be included in reservoir characterisation and should prove to be particularly valuable in the development of static models for the 3D reservoir simulation stage. The types of analyses completed on the reservoir core would typically also be prioritised according to the requirements of the reservoir (transport and reaction-transport) simulator. It is worth noting that sedimentary facies models require a good understanding of the depositional systems, preferably based on a sequence stratigraphic framework.

Similar to reservoir properties, the caprock properties should preferably be determined from a combination of core and well log data with grids of 2D and 3D seismic data. This will enable analytically derived properties to be extrapolated across the volume and areal extent of the caprock. Experience from Sleipner emphasizes the importance in obtaining representative samples of the caprock volume, especially in regions of structure influencing the CO_2 migration pathways. This may include regions of deformation (e.g. faults, joints and fractures) which could require detailed local assessment. Generally 3D seismic is required for smaller faults, but fractures and joints are beneath the limit of seismic resolution.

In cases where micro-fractures may be present, Chadwick et al. (2007) recommend that core analysis is aided by numerical simulation, supported by experimental studies, of coring-induced damage and of the pore pressure evolution during compaction. This could be supplemented with, high-resolution well-logs (e.g., FMS) which are able to reveal the presence of microfractures in the borehole walls.

Chadwick et al. (2007) comment that injection-induced pressure changes could lead to compromising of the caprock seal. They suggest geomechanical assessment of two effects be considered: fracture dilation due to increased pore-pressures and induced seismic slip due either to raised pore pressures or a reduction in normal stress due to buoyancy forces exerted by the CO_2 plume. Chadwick et al. (2007) suggest that indicators of hydrocarbon migration into and through the caprock may reveal the inability of a caprock succession to provide a long-term seal for the underlying reservoir. Furthermore, seismic amplitude anomalies and gas shows in the cap rock may signify the presence of shallow gas, and pockmarks and vents at the seafloor may indicate gas migration from the underground into the seawater. The possible biogenic source of shallow gas needs to be evaluated however if indicators of its presence are to be used in assessing caprock integrity. The degree of correlation between seismically-imaged gas migration indicators and mapped faults is clearly of potential importance in evaluating fault-related leakage.

At the site characterisation stage, Chadwick et al. (2007) suggest that flow modelling is likely to be rather rudimentary, since key controlling parameters may be dependent on the monitoring data. But the authors do agree that full ‘dynamic’ flow simulations should be considered a mandatory component of the site characterisation phase; in constraining or validating injectivity, storage capacity, plume migration extent and likely reservoir pressures. Chadwick et al. (2007) identify a generic issue with injectivity, emphasizing the importance of drive mechanisms, related to water displacement during injection, being accurately included in simulations. This will be critically important in compartmentalized storage reservoirs, where formation pressures may increase beyond acceptable limits.

The SACS and CO2STORE projects have assessed the chemical impacts of CO_2 injection on the Utsira reservoir at Sleipner, and various caprocks and reservoirs from a number of case-studies, via long-term geochemical modelling and laboratory experiments. Chadwick et al. (2007) identify the integration of laboratory, analogue and modelling studies to advancing our understanding of water-rock-CO_2 geochemical reactions. They suggest the repeated testing of models against laboratory data or observations of natural systems to demonstrate the necessary high degree of confidence in understanding the geochemical reactions caused by interacting fluid-rock-CO_2 processes.

The risk assessment procedures in CO2STORE followed more or less the Features and Events Process (FEP) and Scenario methodology (Chadwick et al., 2007). The various risk assessment methodologies for CO_2 aquifer storage are reviewed in more detail in the Risk Assessment section.

Data requirements for site characterisation

The key datasets for a robust characterisation of reservoir and overburden are:

- A regular grid of 2D seismic data or adequate well data (stratigraphic picks, lithology information) over sufficient area to characterise broad reservoir structure and extent;
- A high quality 3D seismic volume over the injection site and adjacent area, tuned if possible for satisfactory resolution of both reservoir and overburden;
- Sufficient well data to permit characterisation of reservoir and overburden properties.

Reservoir properties can best be determined by an analysis of seismic and well log data augmented by rock material (core and cuttings). Geological models of the reservoir must be constructed as the basis for reservoir volume calculations. The geological models can be used in reservoir simulation models to explore the effects of uncertainty via different CO_2 injection strategies (number of wells, spacing, orientation, injection intervals and rates) and to predict sweep efficiencies. Efficient storage strategies should be developed in order to avoid wasting of underground storage structures and to avoid conflicts with other options of future use, e.g. geothermal energy utilization.

A good summary of the main data types used in site characterisation is provided in CO2CRC (2008), where the main data needs (required as well as desirable) for site characterisation are compared against data requirements for various levels of storage volume assessment (Table 7).

Table 7. Summary of the main data needs (required as well as desirable) for the various levels of site characterisation and storage capacity assessment (CO2CRC, 2008).

Data Needs		Country/ State-Scale Screening; Total Pore Capacity	Basin-Scale Assessment; Prospective Storage Capacity	Site Characterisation; Contingent Storage Capacity	Site Deployment; Proved Storage Capacity
Maps	Regional geology	✓	✓	D	
	Detailed/local geology		D	✓	✓
	Structural contour		D	✓	✓
	Reservoir geometry		D	✓	✓
	Reservoir quality		D	✓	✓
	Fault	D	D	✓	✓
	Seismicity	D	D	✓	✓
	Hydrologic	D	D	✓	✓
	Surface infrastructure	D	D	✓	✓
	Topographic	D	D	✓	✓
Seismic	2D	D	✓	✓	
	3D		D	✓	✓
Well logs	Gamma ray		D	✓	✓
	Porosity		D	✓	✓
	Permeability		D	✓	✓
	Sonic			✓	✓
	Density			✓	✓
	Image			✓	✓
Core	Porosity	D	✓	✓	✓
	Permeability	D	✓	✓	✓
	Langmuir volume (coal)	D	D	✓	✓
Special core analysis	Ratio vertical/ horizontal permeability			✓	✓
	Relative permeability			✓	✓
	Mercury injection capillary pressure		D	✓	✓
	Mineralogy		D	✓	✓

Data Needs		Country/ State-Scale Screening; Total Pore Capacity	Basin-Scale Assessment; Prospective Storage Capacity	Site Characterisation; Contingent Storage Capacity	Site Deployment; Proved Storage Capacity
	Rock strength		D	✓	✓
Subsurface history	Oil/gas production		D	✓	✓
	CSM reservoir conditions		D	✓	✓
	Water chemistry			✓	✓
Pore pressure	Repeat formation tests; drill stem tests		D	✓	✓
	Subsurface fluid properties		D	✓	✓
	Leak-off tests; formation integrity tests		D	✓	✓
Reservoir characterisation	Sequence stratigraphy	D	D	✓	✓
	Regional tectonic history/model	✓	✓	D	
	Regional stress analyses	D	✓	D	
	Biostratigraphy	D	D	✓	✓
	Analogues		D	✓	✓
	Static models			✓	✓
	Dynamic models			✓	✓
Economics				✓	✓
Regulatory framework				✓	✓

✓ = required; D = desirable

The necessity, or desirability, of specific data needs in Table 5 should be considered on a site-by-site basis and further data acquisition carefully reviewed to ensure that it indeed added value to the existing geological interpretations. Such tabulations provide a useful guide to data requirements but should not be taken to be prescriptive. Apart from actually obtaining new data (e.g. drilling new wells, acquiring new 2D or 3D seismic), which can be expensive, there is the additional cost in money and time for processing and interpretation of the new data. Therefore, in most instances, the early stages of site characterisation for saline aquifers will initially rely on data already available from regional geological surveys, geothermal, or more commonly petroleum exploration and development activities. Such data will by default be focused around existing fields or potential prospects, which will generally be mainly focused on traditional structural or stratigraphic traps. Dense data coverage (well logs and 3D seismic) will only be available in proven resource basins, and more specifically in presently or formerly producing oil and gas fields. A key lesson learned from the case studies in Chadwick et al. (2007) was that prospects identified in areas with few wells and petroleum discoveries are difficult to develop to the level of confidence required to trigger investment. In addition the combination of low profitability and high site characterisation costs, in comparison to petroleum exploration, is likely to put investors off unless the balance of risk to reward changes.

Gap Analysis - Recommendations

A review of the Best Practice in site characterisation since the IPCC Special Report on CO_2 Capture and Storage (IPCC SRCCS), completed in late 2005, has identified a number of gaps in knowledge with the following recommendations.

- Due to the variability in the subsurface it is recommended that a broadly representative range of case studies be added to the Best Practice Manual.

- Current Best Practice manuals have a European focus. It would be advantageous to have additional examples from other regions (e.g., USA, Australia, Canada etc).

- Combining Best Practice and Site Characterisation manuals developed in different parts of the world should be attempted to ensure that a wide range of geological, political and economic environments are covered.

- The existing SACS/CO2STORE manual is extensive and comprises some 270 pages. However, it would be usefully to develop a summary document of generic findings and perhaps a Best Practice quick reference guide, which may be cross-referenced against developing regulatory requirements.

- It would be useful to have Best Practice guides for other CO_2 storage options (e.g. depleted reservoirs, EOR/EGR and coal seams).

Risk Assessment

Existing risk assessment methodologies are predominately described by factors of likelihood and consequence (Bowden and Rigg, 2004; Turner et al., 2006; van Egmond, 2006). Risks are proportional to magnitude and probability. Where the hazard is a result of local elevated CO_2 concentrations risk is dependent on the probability of leakage. Van Egmond (2006) notes two exceptions where risk is not proportional to probability: where spatial and temporal distributions are the main factors determining local impacts: i.e., acute and point leakage will have bigger impacts than chronic or dispersed leakages.

Deterministic, probabilistic and qualitative risk assessment methodologies have been built around the basics of likelihood and consequence with variations to deal with uncertainty, complex processes and social and regulatory priorities. Van Egmond (2006) suggests that deterministic risk assessment gives accurate results if input parameters are exactly known but cannot deal with parameter uncertainty. Probabilistic risk assessment is suggested by Van Egmond (2006) as the most preferable method for assessing long-term risks in complex systems because it can treat uncertainty explicitly by statistically quantifying the level of uncertainty. It is noted that a probabilistic approach was used for example for the Weyburn project (Walton et al., 2005). Qualitative risk assessment methods include:

- FEP (feature, event process) analysis is considered by Van Egmond (2006) to provide a complete qualitative risk assessment but with the disadvantage that for site selection it is a diligent and time consuming approach which requires considerable information. FEP-type risk assessment was implemented at three of the European CO2STORE sites (Chadwick et al., 2007).

- MAUT is based on multi attribute utility theory to provide a screening and ranking process, has been used for assessment of storage sites based on health, safety, and environmental (HSE) risks. Past approaches have not used modelling or simulations nor assigned probabilities.

- SWIFT (structured-what-if technique) was not considered useful as an approach to formalise expert knowledge and develop a repeatable and structured framework.

- RISQUE – (risk identification and strategy using quantitative evaluation) is a systematic and quantitative approach that uses formal groups to provide expert judgements that are incorporated into a quantitative risk analysis and management framework. The process has been used more broadly by (Bowden and Rigg, 2004) and in unpublished risk assessments for Weyburn.

Van Egmond (2006) suggests that for site selection processes that rely on expert judgement with dependency on non-repeatable and intuitive expert knowledge, the outcomes of such assessments are not robust.

Performance assessment is an alternative approach to probabilistic assessments which still involves consideration of potential events that may cause impact, but also requires the development of system understanding over long timescales (Maul et al., 2007). Part of the output from a performance assessment may be expressed in terms of risks, but a key aspect is the handling of uncertainties in system characteristics and behaviour, and the implications of such uncertainties for conclusions that can be drawn about confidence in the expected long-term performance of the system. Performance assessments are structured to include: scenario development; conceptual model development, mathematical model development, consequence analysis, uncertainty and sensitivity analysis, and confidence building.

A screening and ranking framework (SRF) has been developed to evaluate potential CO_2 storage sites on the basis of HSE risk rising from CO_2 leakage (Oldenburg, 2008). It is intended for cases where sufficient data for a full FEP analysis are not available. The SRF approach is based on the assumptions that leakage risk is dependent on: 1) the potential for primary containment by the injection horizon; 2) the potential for secondary containment if the primary formation leaks; and 3) the potential for attenuation and dispersion of leaking CO_2 if the primary formation leaks and secondary containment fails (Oldenburg, 2008). The SRF is implemented in a spreadsheet with three simple worksheets (one for evaluation of each of the three basic characteristics) and a summary page, which was designed so that it can be applied to multiple sites with limited data. No modelling is performed nor are probabilities assigned; instead the user can arbitrarily weight and assign uncertainty to the basic attribute properties. Oldenburg (2008) emphasizes that the SRF spreadsheet is a screening and ranking tool, that has been tested for three case studies (Rio Vista gas field, Ventura oil field, Mammoth Mountain) , but needs further verification with data from actual CO_2 storage sites.

Only a few paper and reports deal specifically with the risks of the geological storage of CO_2 in saline aquifers (Larsen et al., 2007; Chadwick et al., 2007; Nicot, 2008). A key aspect of CO_2 storage in saline aquifers that is different from other storage options is the availability of data and the uncertainty associated with reservoir characterisation and capacity estimation. For abandoned hydrocarbon reservoirs it is likely that abundant core, geophysical logs, pressure measurements, and production data exist; whereas saline aquifers are less studied, which increases the uncertainty, risk, and the need for additional data (Bentham and Kirby, 2005). Another issue is the conflict of interest with respect to aquifer usage, i.e., natural gas storage, deep waste disposal and the potential interference of CO_2 storage with hydrocarbon production from nearby fields (Bentham and Kirby, 2005).

The Latrobe Valley CO_2 Storage Assessment report (Gibson-Poole and Svendsen, 2005) includes a section on risk assessment and storage assurance. A quantified risk assessment of geological storage was undertaken in a similar manner as was undertaken for the four GEODISC storage sites (Bowden and Rigg, 2004). This approach relied on inputs from an expert panel. The context was risk events that relate to containment of CO_2 and the assessment was undertaken using the URS RISQUE software. The analysis compared risks between three different sites. The infrastructure risk assessment was undertaken using the methodology described in (Turner and Hardy, 2005). Results of the infrastructure risk assessment suggest that the transport of CO_2, using high integrity technology, does not pose higher risks than those already tolerated for transmission pipelines or other industrial sources. No safety risks were identified that cannot be controlled or adequately mitigated using existing, proven technology. The RISQUE approach was used also for the risk assessment Gorgon project by Chevron as outlined in the Environmental Impact Statement document (unpublished).

A semi-quantitative risk assessment was conducted for four potential CO_2 storage sites to support the preparation of an Environmental Impact Statement (EIS) for the FutureGen Project (DOE, 2007b). The risk assessment was conducted according to a work plan reviewed by a panel of carbon capture/storage and risk assessment experts. The approved work plan provided a detailed description of the approach applied to the analysis of the identified pre- and post-injection risk issues. There were five primary elements outlined in the risk assessment: 1) Conceptual Site Models (CSMs); 2) Toxicity Assessment; 3) Risk Evaluation for the Capture and Transport of Gaseous Emissions (Pre-Injection); 4) Risk Evaluation for the Storage of CO2 and Hydrogen Sulphide (H_2S) in Subsurface Reservoirs (Post-Injection); and 5) Risk Screening and Performance Assessment.

A preliminary modelling study that investigated the effects of brine displacement induced by large-scale CO_2 injection could not find significant disturbances of shallow groundwater resources (Nicot, 2008). Induced water-level changes in the investigated Gulf Coast aquifer were predicted to be on the order of magnitude of seasonal and interannual variations (Nicot, 2008). However, the model considered single-phase flow; hence looking only at pressure effects in the far-field of injection and neglecting dissolution of CO_2 along the flow path and possible hydrochemical changes. As one of the outcomes, Nicot (2008) recognizes the need to further explore the effects of brine displacement on, for example, spring discharges along flow-focusing faults and the development of simple numerical models to help regulatory decision making.

Compared to the deep injection of liquid wastes, hydrologic issues and technical approaches associated with CO_2 geological storage in saline aquifers are more complex for a variety of reasons (Tsang et al., 2008):

- The relatively high buoyancy forces and the large volumes of the injected supercritical CO_2 result in an extensive area that must be considered for the potential of CO_2 leakage i.e., through abandoned wells or fractures in the overlying aquitards.

- The buoyancy pressure during CO_2 injection requires that the hydromechanical effects on the overlying aquitards be assessed along potential leakage pathways extending from the injection horizon to shallow groundwater aquifers.

- In contrast to liquid waste injection CO_2 leakage into shallow aquifer systems may not present a serious environmental problem.

- Verification of CO_2 storage efficiency requires properly designed site-specific monitoring system.

To date, no consistent risk assessment methodology exists for CCS projects. The IEA (2007) report, resulting from the Third Workshop of the International Research Network on Risk Assessment, notes discussion about whether to use quantitative, qualitative, or simple analytical methods to analyse CCS risk. It reports that debate concluded that whilst, there might be a desire to have a fully quantitative risk assessment process, currently it would not be possible for anything more than a semi-quantitative or predominantly qualitative process to be used for CO_2 storage simply because not enough about is known about the underground to allow us to define probabilities of geological events with confidence.

Review of CO_2 Injection Projects in Saline Aquifers

Operational and Technical Characteristics

In this section various projects are reviewed that currently inject CO_2 into aquifers; either for a combination of socio-economic reasons or for research purposes. In the current political environment, a multitude of CO_2 injection projects are proposed and are in various planning stages, but it is difficult to determine the likelihood of the actual implementation of specific projects. For example, projects that appeared to have a high probability of going ahead and had numerous associated research activities, e.g., FutureGen (Mattoon) or Schweinrich (CO2STORE/Europe), were cancelled due to the re-allocation of funding or change in site operators. Hence, the likelihood other future projects to be implemented should be considered with caution. A database accompanying this report has been compiled that includes information on operational, technical, and geological aspect of projects presently injecting or having injected CO_2 into saline aquifers. It should be noted that due to confidentiality issues and rapid changes in the CCS political environment, the availability of data for some injection operations may be limited or not up-to-date. A detailed description of each of these operations can be found in Appendix 3.The location of these storage projects is shown on Figure 8. Table 8 and Table 9 provide a summary and comparison of all those projects included in the database.

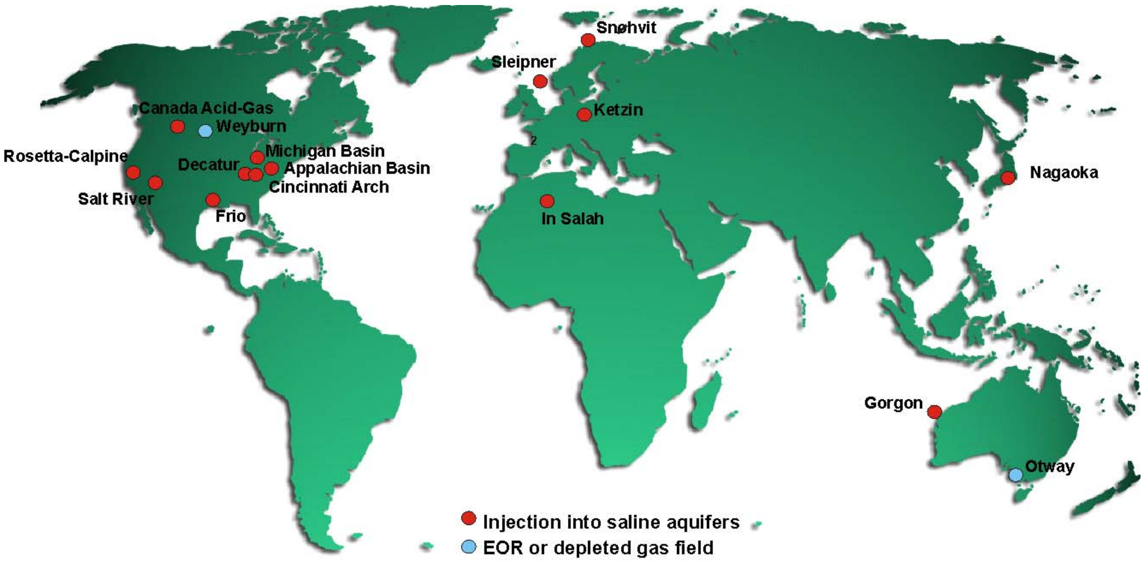


Figure 8. Map showing projects injecting or having injected CO_2 into deep saline aquifers. Also shown are projects in an advanced planning stage (see text for details) as well as the Weyburn and Otway pilot projects.

Table 8. List of operations injecting or having injected CO_2 in saline aquifers. Some projects in an advanced planning stage are also shown.

ProjectID	Name	Location	Type	Status	Scale	Project Start Year	Injection Start Year	Injection Finish Year	Total Storage (kt)
69	In Salah	Krechba, Algeria	Saline Aquifer	Injection Underway	Commercial		2004		17000
75	Nagaoka	Nagaoka City, Japan	Saline Aquifer	Completed	Micro Pilot Test Pr	2000	2003	2005	10.4
80	Ketzin	Ketzin, Brandenburg, Germany	Saline Aquifer	Injection Underway	Pilot	2007	2008	2010	60
86	Sleipner	Sleipner Field, North Sea	Saline Aquifer	Injection Underway	Commercial		1996		20000
87	Snøhvit	NE of Hammerfest, Barents Sea	Saline Aquifer	Injection Underway	Commercial		2008		23000
91	Alberta Basin (Acid Gas)	Alberta, Canada	Saline Aquifer	Injection Underway	Commercial	1989	1990		
99	Frio	Liberty County, Texas, USA	Saline Aquifer	Monitoring Underway	Pilot	2002	2004	2004	1.6
130	MGSC Decatur	Decatur, Illinois, USA	Saline Aquifer	Planned	Demonstration	2008	2009	2012	1000
134	MRCSP - Cincinnatti Arch	Duke Energy East Bend facility, Kentucky, USA	Saline Aquifer	Planned	Pilot	2008	2009		3
129	MRCSP Appalachian Basin	Shadyside, Ohio, USA	Saline Aquifer	Work Underway	Pilot		2008		3
128	MRCSP Michigan Basin	Gaylord, Michigan, USA	Saline Aquifer	Monitoring Underway	Pilot		2008	2008	10.241
131	WESTCARB Rosetta-Calpine Saline	Rio Vista, California, USA	Saline Aquifer	Planned	Micro Pilot Test Pr	2007	2009	2009	2
104	WESTCARB Salt River	Northeast Arizona, USA	Saline Aquifer	Planned	Micro Pilot Test Pr	2007	2009	2009	2
114	Gorgon	Barrow Island, WA, Australia	Saline Aquifer	Planned	Commercial		2009		129000

Table 9. Comparison of reservoir characteristics of injection operation in saline aquifers.

Project Name	Location	Inj. Rate (t/d)	Injection Unit	Lithology	Depth (m)	Thickness (m)	Net Pay (m)	Porosity (%)	Perm. (mD)	Seal Lithology	Thickness (m)	Trap Mechanism	TDS (mg/l)	Temp (C)	Pressure (kPa)
In Salah	Krechba, Algeria	3500	Krechba Formation	Sandstone	1850	29			5	Mudstone	950				
Nagaoka	Nagaoka City, Japan	40	Haizume Formation	Sandstone	1100	60	12		6	Mudstone	133	closed anticline	7113	46	11900
Ketzin	Ketzin, Brandenburg, Germany	86	Suttgart Fm.	Sandstone	650	80		23	750	Mudstone With Dolomite Beds	210	Structural - anticline	250000	34	7300
Sleipner	Sleipner Field, North Sea	2700	Utsira Formation	Sandstone	1000	250	90	37	5000	Shale	75	Structural - Anticline	35000	37	10300
Snøhvit	NE of Hammerfest, Barents Sea	2000	Tubåsen Formation	Sandstone	2550	60	50	13	450	Shale	30	Structural trap			28500
Alberta Basin (Acid Gas)	Alberta, Canada 27 operations	5-190	Various	Various	950-2814	15-343	4-100	4-26	1-413	Various	15-218	Various	23,750 -340,000	26-103	6,000 -27,000
Frio	Liberty County, Texas, USA	160	Upper Frio C	Sandstone	1546	24	7	30	1500	Shale	78	Tilting Horizon	92633.3	56	15200
MGSC Decatur	Decatur, Illinois, USA	1000	Mt. Simon Sandstone	Quartzose Sandstone	1980	300		15	225	Shale	100		120000		15000
MRCSP - Cincinnatti Arch	Duke Energy East Bend facility, Kentucky, USA	100	Mt. Simon Sandstone	Sandstone	1000	100				Shale	1500				
MRCSP Appalachian Basin	Shadyside, Ohio, USA	75	Clinton Sandstone	Sandstone	2170	78				Limestone	70				
MRCSP Michigan Basin	Gaylord, Michigan, USA	500	Bass Islands Dolomite/Bois Blanc	Dolomite	1061	22		21	22	Limestone	76			28	13858
WESTCARB Rosetta-Calpine Saline	Rio Vista, California, USA		McCormick sand	Sandstone	1052					Shale					
WESTCARB Salt River	Northeast Arizona, USA		Martin Formation	Quartzose Sandstone	1081	200		15		Shale	620	lithological			
Gorgon	Barrow Island, WA, Australia	10000	Dupuy Formation	Massive Sandstone	2300			20	25	Shale	250	open anticline	7000	100	22000

Monitoring Experience

The experience of monitoring at operations injecting into saline aquifers is summarized in Table 10 and Table 11 and a more detailed site specific review can be found in Appendix 3. With respect to monitoring and verification of CO_2 storage reservoirs, 4D seismic proved to be very successful at Sleipner, but has the disadvantage of being relatively expensive and might prove challenging for onshore storage sites related to repeatability problems due to changing weather, soil humidity and contact conditions. Also, successfully implemented at Sleipner was 4D gravity, which has lower costs and works well for qualitatively assessment of CO_2 saturation in the subsurface, but requires a detailed, well-characterized geological model. Promising geophysical methods that worked well at Frio and Nagaoka for the quantitative tracking of the CO_2 plume was 4D vertical seismic profiling (VSP), which allows for a good source signal control, and cross-well seismic and electro-magnetics. However, these two methods require a monitoring well in addition to the injector. Also, the transmission distance between injection and monitoring well might get too big in the case of commercial projects with large CO_2 plume sizes, resulting in a loss of resolution unless multiple monitoring wells at appropriate distances were installed. Monitoring technologies for the shallow groundwater, soil and atmosphere have been developed, however they have not yet been successfully demonstrated to detect potential CO_2 leaks from the reservoir unit due to relatively high natural CO_2 fluctuations in these environments. Tracer monitoring has been successfully tested at the Frio Brine project (Freifeld et al., 2005) and the Otway Pilot project (Stalker et al., 2006) to verify the onset of CO_2 breakthrough at monitoring wells. Furthermore, tracers can aid in the understanding of the change in reservoir characteristics caused by CO_2 saturation, and, by fingerprinting the injected CO_2, monitor leakage and verify the origin of CO_2 in various environments between the storage horizon and the ground surface (Stalker et al., 2006).

The various techniques available for the monitoring and verification of CO_2 storage (Figure 9) have to be tested more comprehensively for a larger portfolio of storage environments. There is also the potential for new monitoring techniques not yet applied at existing sites. One technology that has not been tested at CO_2 injection operations, but which has been employed successfully at oil and gas operations is Surface Deformation Monitoring (SDM). Ground dilation or subsidence caused by the injection or production of fluids can be detected using tiltmeters, Differential GPS and Interferometic Synthetic Aperture Radar (InSAR). The SDM technology particularly shows potential to be able to monitor the extent of a CO_2 plume and possible fracture development for large-scale injection volumes (McColpin, 2008).

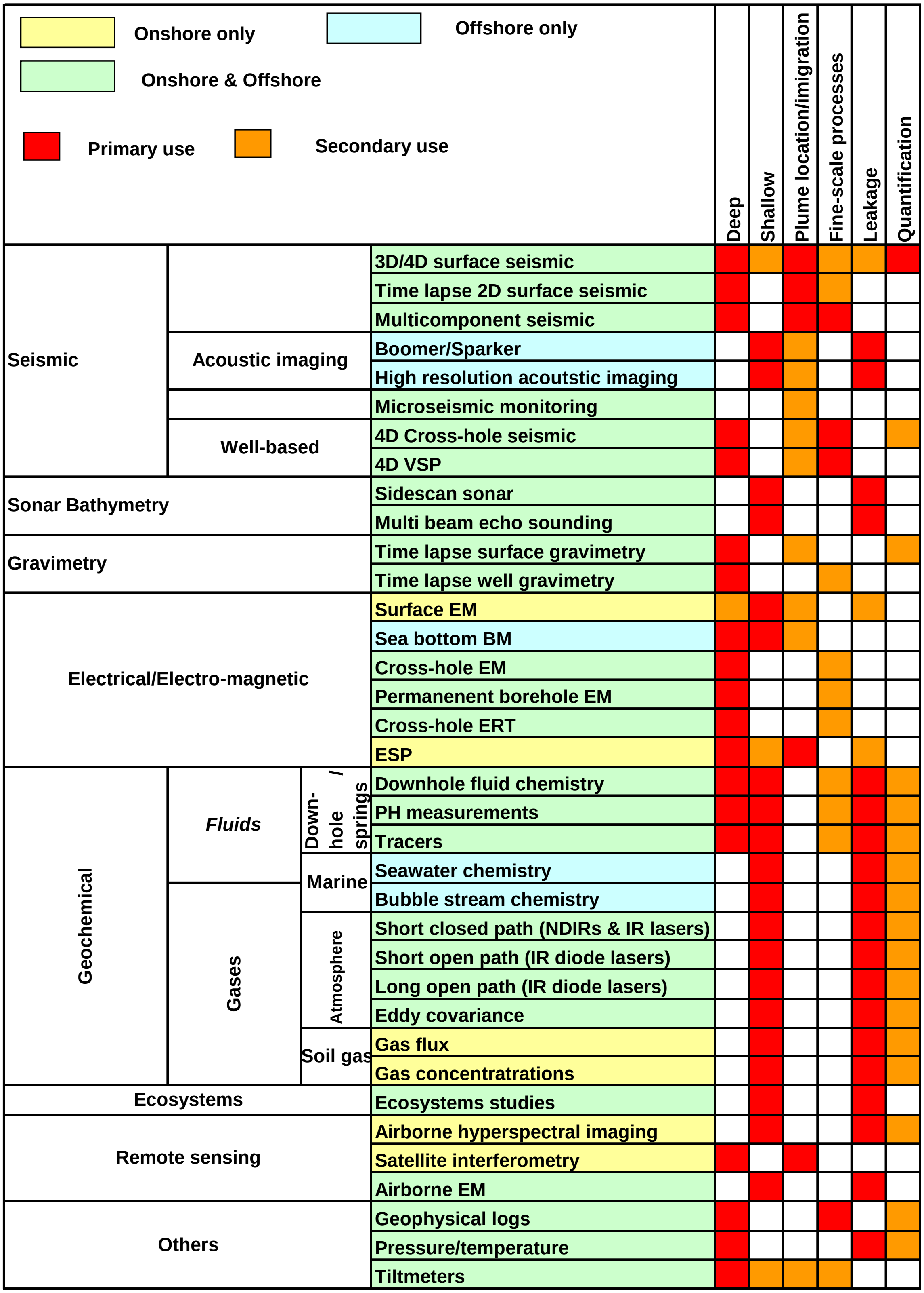
Requisite monitoring plans in future regulations for CO_2 storage projects should carefully weigh the necessary requirements for ensuring storage verification and safety against cost and suitability of various monitoring techniques for specific storage environments.

Table 10. Summary of monitoring technologies (at the ground surface) from active injection operations.

Type of monitoring		Current state	Assess limitations	New technology/Further development
Pressure and temperature measurements		- Applied at Frio, Nagaoka. - Provides basic data on the conditions of the CO_2 reservoir. Pressure data can be used to avoid injecting the gas at too high rate.	- Not practical in case of highly permeable rocks with an enormous pore volume	- Fiberoptic pressure and measurements sensors are needed to be tested.
Direct Measurements for CO2 Detection	**Geochemistry**	- Applied at Sleipner, Frio, Nagaoka, - U-tube was developed especially for Frio-1 (allow collection of CO_2/brine mixture under pressure).		Development of complex geochemical models
	Measuring soil-gas CO_2 fluxes and concentrations	- Applied at Frio, Nagaoka,		
	Tracers	- Applied at Frio, In Salah (?). - Includes perfluorocarbon tracers, the noble gases, krypton, neon, xenon, sulphur hexafluoride. - Used to quantify CO_2 saturations and CO_2 dissolutions.	- Further, more extensive trials are needed. - The effective use of tracers requires geochemical reactive transport coupled to reservoir models that capture field heterogeneities adequately	--
Remote Sensing		Surface deformation monitoring (SDM) using tiltmeters and InSAR is used in the oil & gas industry	- Limited use for offshore operation; - needs to be demonstrated for deep CO_2 injection	

Table 11. Summary of monitoring technologies (subsurface) from active injection operations.

Type of monitoring	Current state	Assess limitations	New technology/Further development
4D Seismic	- Applied at Sleipner, Nagaoka - Capable to monitor the movements of CO_2 in reservoirs and out of the reservoir but does not have the resolution to detect low level leakage. - Using time-lapse surface seismic 1.4 million m3 (2500 tonnes) of CO_2 is the minimum detectable. - As for 3D surface seismic it can cover the whole area of interest but in most situations is unable to resolve discontinuities in the geological structure smaller than around 10 m.	- Can be expensive, especially offshore. - Not suitable for use in very deep thin reservoirs. - Not suitable where karsts systems present. - Shouldn't be used alone but as part of a suite of monitoring techniques. - Rather challenging for onshore sites because of obvious problems with repeatability (changing of weather, soil humidity, contact conditions).	- Seismic is being used in industry and as a result the technology is rapidly developing. - 3D seismic can identify the faults. - Passive seismic theoretically can detect leakages but need further investigations.
4D VSP	- Applied at Frio. - Costs less then 4D seismic. - Provide progressively greater resolution than surface seismic. - Better signal-to-noise ratio as compared to 4D seismic. - Best control of borehole environment. - Method can be used for detecting and monitoring saturation changes in thin porous layers (Goloshubin et al., 2001).	Costly	--
Cross-well seismic	- Applied at Frio and Nagaoka. - Provide progressively greater resolution than surface seismic. - Image CO_2 clearly: detected the CO_2 breakthrough and estimated CO_2 saturation history. - detected P-wave velocity decrease (CO_2 invaded zone) and allowed to recognize the shape of CO_2 invasion. - High level of background noise can be overcome with massive stacking.	- Required development of novel instrumentation (including the "piezo-tube" seismic source, patent pending). - Not applicable in larger offshore fields.	- Continuous Active Source Seismic Monitoring (CASSM) - future deployments can incorporate multiple sources, thus enabling acquisition of data suitable for continuous tomographic monitoring
4D Gravimetry	- Applied at Sleipner, In Salah(?) - Good areal coverage with lower costs. - Provides estimates for CO_2 density and saturation. - Multicomponent gravity gradient data may provide useful density information for the upper 2000m if the model is well constrained.	- Poor spatial resolution and borderline sensitivity. - Is only applicable under the most favourable circumstances of large volumes of fluid displaced by CO_2 in the gas phase at shallow depth.	- New inversion and interpretation procedures need to be developed along with enhanced data accuracy through improved acquisition technology for gravity to be an effective method in most situations.
Cross-well Electro Magnetics	- Applied at Frio, In Salah(?). - Successful in measuring CO2.	- Too expensive. - Lower resolution than seismic methods.	- Good to use in complex with other methods, for example - VSP and cross-well seismic.
Well-logging	- Applied at Frio, Nagaoka, - Sonic logging can provide resolution in the order of centimetres, but the high frequency signal cannot penetrate a formation further than about 1 m from the borehole. - Onshore existing wells can be utilized. - RST logging was applied at Frio.	- Limited spatial resolution. - Expensive, especially offshore too much for a research project. - Possible increased risk of leakage if new wells drilled through cap rock.	--



🟨 Onshore only
🟦 Offshore only
🟩 Onshore & Offshore
🟥 Primary use
🟧 Secondary use

				Deep	Shallow	Plume location/imigration	Fine-scale processes	Leakage	Quantification
Seismic			🟩 3D/4D surface seismic	🟥	🟧	🟥	🟧	🟧	🟥
			🟩 Time lapse 2D surface seismic	🟥		🟥	🟧		
			🟩 Multicomponent seismic	🟥		🟥	🟥		
	Acoustic imaging		🟦 Boomer/Sparker		🟥	🟧		🟥	
			🟦 High resolution acoutstic imaging		🟥	🟧		🟥	
			🟩 Microseismic monitoring			🟧			
	Well-based		🟩 4D Cross-hole seismic	🟥		🟧	🟥		🟧
			🟩 4D VSP	🟥		🟧	🟥		
Sonar Bathymetry			🟩 Sidescan sonar		🟥			🟥	
			🟩 Multi beam echo sounding		🟥			🟥	
Gravimetry			🟩 Time lapse surface gravimetry	🟥		🟧			🟧
			🟩 Time lapse well gravimetry	🟥			🟧		
Electrical/Electro-magnetic			🟨 Surface EM	🟧	🟥	🟧		🟧	
			🟦 Sea bottom BM	🟥	🟥	🟧			
			🟩 Cross-hole EM	🟥			🟧		
			🟩 Permanenent borehole EM	🟥			🟧		
			🟩 Cross-hole ERT	🟥			🟧		
			🟨 ESP	🟥	🟧	🟥		🟧	
Geochemical	*Fluids*	Down-hole / springs	🟩 Downhole fluid chemistry	🟥	🟥		🟧	🟥	🟧
			🟩 PH measurements	🟥	🟥		🟧	🟥	🟧
			🟩 Tracers	🟥	🟥		🟧	🟥	🟧
		Marine	🟦 Seawater chemistry		🟥			🟥	🟧
	Gases		🟦 Bubble stream chemistry		🟥			🟥	🟧
		Atmosphere	🟩 Short closed path (NDIRs & IR lasers)		🟥			🟥	🟧
			🟩 Short open path (IR diode lasers)		🟥			🟥	🟧
			🟩 Long open path (IR diode lasers)		🟥			🟥	🟧
			🟩 Eddy covariance		🟥			🟥	🟧
		Soil gas	🟨 Gas flux		🟥			🟥	🟧
			🟨 Gas concentratrations		🟥			🟥	🟧
Ecosystems			🟩 Ecosystems studies		🟥			🟥	
Remote sensing			🟨 Airborne hyperspectral imaging		🟥			🟥	🟧
			🟨 Satellite interferometry	🟥		🟥			
			🟩 Airborne EM		🟥			🟥	
Others			🟩 Geophysical logs	🟥			🟥		🟧
			🟩 Pressure/temperature	🟥				🟥	🟧
			🟩 Tiltmeters	🟥	🟧	🟧	🟧		

Figure 9. A selection of potential monitoring tools for CO_2 storage (Chadwick et al., 2007).

Regulations

This section describes the national, provincial and state regulatory regimes and jurisdictions under which current CO_2 injection projects operate. At the time this report was written, no legislation and regulatory regimes specific to CO_2 geological storage existed. Draft legislations for CCS are currently under development in the North America, Europe, and Australia.

Europe & Africa

The Sleipner, Snøhvit, and In Salah projects are being regulated primarily under the petroleum regulations in the host country. There are no generic regulations in either Norway or Algeria for regulating the geological storage of CO_2. Although Algeria and Norway are not member states of the European Parliament, the proponent companies have complied with the requirements for management of geological storage of CO_2 that are set out in the proposed Directive of the European Parliament and Council on the geological storage of CO_2 and amending Council Directives 85/337/EEC, 96/61/EC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC and Regulation (EC) No 1013/2006.

This proposed Directive sets out details on requirements relating to site selection, exploration permits, storage permits, requirements for environmental impact assessment and public consultation, operational matters including closure and post-closure obligations, monitoring and reporting obligations, inspections, measures in case of irregularities and/or leakage, and provision of a financial security. The Directive also addresses related matters including access to transport and storage, transboundary co-operation, and the required amendments to other legislation, including the necessary adaptations to the water and waste legislation.

The proposed Directive builds on recent decisions in other countries to allow geological storage of CO_2 under the sea-bed. Legal barriers to the geological storage of CO_2 in sub-seabed geological formations have been removed through the adoption of related risk management frameworks both under the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (1972 London Convention) and under the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR Convention).

New policies in the EU and in member countries are under development to compliment the current EU Emissions Trading Scheme (EU-ETS) and to provide more attractive incentives for the implementation of CCS (Groenenberg and De Coninck, 2008). According to these authors, new policies include financial instruments such as investment subsidies, a feed-in scheme, or a CO2 price guarantee, as well as a CCS mandate or a low-carbon portfolio.

Canada

The application and permitting process of acid-gas injection operations is regulated in the province of Alberta in Canada by the Energy Resources Conservation Board (ERCB) under the Oil and Gas Conservation and the Coal Conservation acts and associated regulations. Directives related to the petroleum industry can be downloaded from the ERCB webpage (www.ercb.ca). These are reviewed and discussed in detail by (Bachu, 2008b), and the following is an excerpt of that document. Most relevant to future CCS projects is the section in ERCB Directive 65 (ERCB, 2007) on acid-gas disposal, which requires the applicant to prove that:

- It has the right to dispose in the respective geological formation;
- Disposal will not impact hydrocarbon production;
- The disposal fluid will be confined to the injection horizon;

- The owners of neighbouring wells within a certain distance of the disposal well have been consulted and have no objections; and

- Containment and isolation requirements, including well construction, are being met.

Acid-gas disposal wells usually fall within Class III in Directive 51 (ERCB, 1994) on well classification, completion, logging and testing requirements, which covers: a) injection of hydrocarbons, inert or other gases for the purpose of storage or enhanced recovery; b) solvent or other hydrocarbon products for enhanced recovery, c) sweet natural gas for storage, d) CO_2, N_2, O_2, air or other gases for storage or enhanced recovery; and e) sour or acid gases for disposal, storage or cycling. The construction and operating requirements for Class III wells are:

- Hydraulic isolation of the host zone and hydrocarbon-producing zones (all wells – exploration, production or injection – require isolation through surface casing of potable groundwater defined as water with salinity less than 4000 mg/l);

- Annulus filled with corrosion-inhibiting fluid;

- Installation of safety devices (e.g., valves against backflow);

- Cementing across the potable-groundwater zone;

- Logging for cement top, hydraulic isolation and casing inspection;

- Initial casing/annulus pressure test;

- Annual packer isolation test;

- Wellhead pressure limitation; and

- Injection through tubing.

Additional general regulations about well construction regarding Surface Casing and Cementing are found in ERCB Directives 8 and 9 (ERCB, 1990, 1997), respectively.

USA

The regulatory framework in the United States of America with respect to CO_2 geological storage is discussed in detail by Wilson and Gerard (2007). The core premise of the Underground Injection Control (UIC) regulations is the containment of the injected material and protection of underground sources of drinking water. Operators must obtain a permit from the state agency or the Environmental Protection Agency (EPA) regional office before beginning injection operations. A detailed description of information required for the permitting process is set out in the Drinking water Academy (2002) document and includes comprehensive information on well sighting and construction, planned operation and monitoring, and plugging and abandonment.

(Nicot and Duncan, 2008) propose that State and Federal governments should be responsible for developing regional assessments and assigning areas that are “sequestration ready” to simplify the site characterisation and approval processes for industry stakeholder interested in implementing CCS.

Under the current regulatory regime in the US, injection of CO_2 for geological storage would be permitted through Class I or Class II wells (Wilson and Gerard, 2007). Class I regulations cover hazardous and industrial wastes, whereas Class II wells are used for wastes associated with hydrocarbon production. Therefore, CO_2 injected into saline aquifers originating from industry sources like power plants, refineries, and cement factories would require a Class I permit. Class II wells include CO_2 used for EOR and CO_2

produced in upstream gas operations. Neither regulation explicitly addresses storage time, reliability, or issues of long-term liability. According to Wilson and Gerard (2007), there are problems with permitting the injection of large quantities of a buoyant fluid in a Class I well, and a new Class VI category should be considered that excludes "no migration from the injection zone" and that represents a classification specifically tailored to CO_2 geological storage. For example, the Frio Pilot project applied for a Class V permit rather than a Class I non-hazardous injection permit for the reasons summarized by Hovorka et al. (2003) in their application to the Texas Commission on Environmental Quality. Subsequently, the US EPA issued guidelines in 2006 to support the regulatory agencies in the United States by providing guidance on how to permit the Regional Partnerships injection wells under the existing Class V well category (http://www.epa.gov/safewater/uic/wells_sequestration.htm). In addition, The US EPA has released a draft rule for a Class VI carbon sequestration well, which is expected to be finalised by 2011.

The Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geologic Storage produced A Legal and Regulatory Guide for States and Provinces as a result of a two-phase, five-year effort (IOGCC, 2007). This Phase II report takes the form of a Guidance Document that includes a model statute and regulations for U.S. states and Canadian provinces. Its purpose is to provide to a state or province contemplating adoption of a legal and regulatory framework for the storage of CO_2 in geologic media the resources needed to draft a framework that meets the unique requirements of that particular state or province.

Australia

As the geological sequestration component of the Gorgon project is located onshore, the regulatory framework is primarily that of the Western Australian Government through the *Petroleum Act 1986 (WA)*, the *Environment Protection Act (WA)* and the *Barrow Island Act 2003 (WA).* Approval was also required under the federal *Environment Protection and Biodiversity Conservation Act* because of the location of the facilities in conservation reserves which include a number of matters of national environmental significance. Bilateral agreements between the Australian Government and Western Australian Government have led to an integration of the assessment and approval processes.

No generic legislation currently exists in WA for regulating geosequestration. However, the *Barrow Island Act 2003 (WA)* has provisions that allow the Minister to approve CO_2 disposal on Barrow Island. The function of this Act is to, inter alia, ratify and authorise the implementation of an agreement between the State and the Gorgon Joint Ventures (GJV) relating to the offshore production of natural gas and other petroleum, and a gas processing and infrastructure project on Barrow Island. The Act also makes provisions for the transport and underground disposal of CO_2 recovered during gas processing on Barrow Island. Specifically, the Act requires the GJV to seek approval to dispose of CO_2 on Barrow Island. The application for approval must include information on the methods to be used; the capacity and capability of the underground target reservoir; the rate of disposal; the volume/composition of the CO_2 to be disposed; and the expected duration of the disposal. Under Schedule 1 of the Act the GJV is also required to submit a closure plan that addresses the long term management of injected CO_2. Approvals under the Barrow Island Act 2003 (WA) and its Schedule 1 are subject to environmental approval under the Environmental Protection Act 1986 (WA). The CO_2 disposal component along with all other aspects of the Gorgon Project must also comply with any imposed Ministerial environmental conditions. In late 2007, the GJV obtained State and Commonwealth environmental approvals for a 10 Mt/a LNG development on Barrow Island. The State (Statement No. 748) and Commonwealth (EPBC Ref: 2003/1294) environmental approvals contain specific conditions relating the to the proposed CO_2 injection project.

Future Regulation Requirements

Regulations are currently in place in various countries under which commercial (Sleipner, Snøhvit, acid gas, Gorgon) and pilot projects (Nagaoka, Frio, Ketzin, US RCSPs) were approved or are in the progress of being approved. These projects operate for the most parts under the respective national petroleum legislations and/or received special approvals for scientific purposes. Key issues that have to be addressed better in regulations for future commercial projects currently under development are:

- Long-term liability/stewardship for storage sites (post-injection);
- Definition of M & V requirements;
- Emission Trading Scheme (ETS) implications;
- Resolution of conflict of interests (affect of storage on other resources;
- Surrender of storage tenements and KPIs;
- Royalties/lease fees for storage space;
- Differences in requirements for on- and offshore injection of CO_2.

Economics of Projects Injecting into Saline Aquifers

The main elements of geological storage costs are capital costs (drilling wells, infrastructure development and constructing infield pipelines) and operating costs (labour, maintenance and energy). Additional costs include verification and materials, monitoring requirements, regulatory compliance and remediation methods, which may be required to prevent or minimize CO_2 leakages from the sink. Costs vary because of the influence of site-specific factors (storage formation type, location, depth and characteristics), which will affect, for example, well costs, compression requirements and injection rates (IPCC, 2005). The costs of CO_2 storage are also uncertain because they depend on uncertainties in the cost of fuel, steel, labour, construction, etc. The IPCC (2005) estimates that the total cost for saline aquifer storage ranges from US\$0.60 to US\$8.00 per tonne of CO_2 avoided (US\$0.50 to US\$7.70 per tonne of CO_2 avoided, with added monitoring costs of \$0.10 to \$0.30 per tonne CO_2).

The costs of CO_2 storage exclude the costs of separating the CO_2 from the source gas mixture. In much of the literature, it also excludes the initial cost of compressing the CO_2 for subsequent transport and injection. In some of the literature, the initial compressions costs are instead included in the costs of storage. In fact, the carbon capture and storage process is an integrated system process and the amount of compression required strongly depends on the transport and injection conditions. The attempt to separate the process and the costs into "capture" and "storage" is therefore to some extend arbitrary.

We reviewed available literature on various studies and pilot, demonstration and commercial projects in order to collate data on the costs of storing CO_2 in deep saline aquifers. Estimates of storage costs are site specific and can vary significantly because they depend on variable and uncertain factors such as storage reservoir characteristics. Estimates of costs per tonne avoided are influenced significantly by the assumptions used to generate them. The assumptions used by the CO2CRC are described in *CCS economics methodology and assumptions* (Allinson et al., 2006). Costs of specific projects are discussed individually in Appendix 3, and a review of general studies that assess the economics of CO_2 geological storage is shown in Appendix 4.

Comparing the costs for operations storing CO_2 in saline aquifer is difficult for a variety of reasons: a) cost data are scattered and patchy; b) costs are quoted for different years, c) costs are quoted in different currencies, d) quoted costs are based on different methodologies, e) costs for fuel, steel, labour, and construction vary globally and regionally. As a result, considerable analysis would be required to normalize the cost data and construct predictive analytical tools for future projects. Alternatively, although not mutually exclusively, computerized costing models and equations could be created, based on vendor quotes that reflect current economic circumstances.

Lessons Learned and Remaining Issues

The experience from CO_2 injection at pilot projects (Frio, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) (Figure 8; Figure 10) shows that CO_2 geological storage in saline aquifers is technological feasible. By the end of 2007, approximately 15 Mt of CO_2 had been successfully injected into saline aquifers by these operations. Particularly, Sleipner, In Salah, and Snøhvit demonstrate that, given the right geological and reservoir conditions, injecting industrial-scale volumes on the order of 1 Mt/year CO_2 into saline aquifers is achievable. However, these projects are not necessarily representative for conditions encountered globally. For example, aquifer permeability at Sleipner is probably unusually high compared to what could be expected for other sites. In Salah operates 3 injection wells in a low-permeability aquifer, but there is limited monitoring information. Nagaoka and Frio have comprehensive M & V programs, but_injection rates/volumes are very low. The various acid-gas injection operations in Alberta cover a wide range of reservoir properties, but again injection rates are relatively low and very limited subsurface monitoring is done. Hence, there remains the need for a more comprehensive portfolio of aquifer storage projects that covers the range of variability of different subsurface environments (e.g., on-/offshore, low/high permeability, sandstone/carbonate/basalt, pressure, temperature, salinity) as well as different monitoring strategies, regulation requirements and economics. The funding by the US DOE of a variety of small to large-scale injection projects in the various Regional Carbon Sequestration Partnerships (Litynski et al., 2008) is a promising step towards gathering experience for different storage scenarios. However, it is interesting to note that, with the exception of the Michigan Basin project, all other operation inject into sandstone aquifers.

The existing expertise in CO_2 injection technology currently resides mainly with the petroleum industry and other industries have to be introduced and, maybe more importantly, become more comfortable with the concept of geological storage. The first commercial implementations of CCS from coal-fired power plants are expected to commence in 2011 (E.ON, UK) and in 2012 (ZeroGen, Australia) (Figure 10).

The remaining issues with respect to site characteristics, M & V requirements, economics and regulations for projects injecting CO_2 into saline aquifers can be summarized as follows:

1. A larger portfolio of storage projects, preferably injecting at industry-scale rates, is needed to confirm injectivity, storage capacity, confinement, and applicability of various monitoring techniques in different geological and economic environments.

2. It remains to be demonstrated that leakage of CO_2 can be detected, which might require the improvement or development of new monitoring techniques.

3. Regulations currently under development need to address better the long-term liability/steward ship for storage sites, the definition of M & V requirements, Emissions Trading Scheme implications, resolution of interest conflicts with other resources, royalties/lees fees for storage space.

4. Cost data for different injection projects need to be gathered on a common and consistent basis.

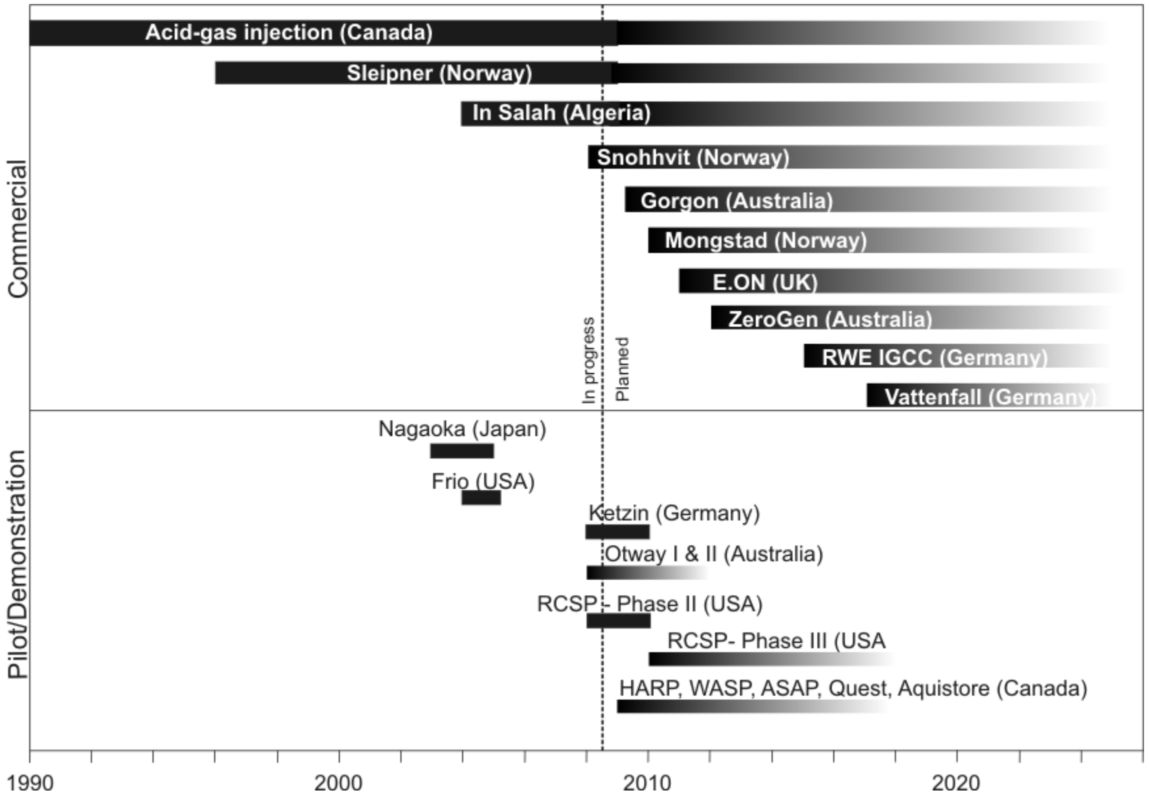


Figure 10. Past and future implementation of CO_2 geological storage in saline aquifers.

Summary & Conclusions

Injecting CO_2 into deep saline aquifers is one of three main options for the geological storage of CO_2 in order to reduce anthropogenic greenhouse gas emissions into the atmosphere. Previous studies have shown that, compared to the other two options (storage in depleted hydrocarbon reservoirs and in deep, unminable coal seams), deep saline aquifers have the highest potential capacity globally for CO_2 storage. The geological storage of CO_2 in saline aquifers is a technology that can be successfully and safely applied today as shown by the experience from active commercial storage projects at Sleipner, In Salah, Snøhvit, and acid-gas injection sites in Canada. Research at pilot storage operations at Frio, Nagaoka, Ketzin, Otway and at the EOR operation in Weyburn have significantly advanced the science and numerical modelling of CO_2 geological storage, tested various monitoring technologies and resulted in Best Practice recommendations for the sighting and characterization of CO_2 storage sites. However, at the same time, there are many uncertainties regarding the extent to which potential capacity can be turned into useable storage capacity.

Since the release of the IPCC SRCCS in 2005 there has been considerable progress in the development of technology and knowledge relating to the geological storage of CO_2. There have been a number of demonstration projects and commercial projects initiated. This chapter provides a summary of the scientific and technological progress made since 2005 and lists the knowledge targets identified in the review relative to their importance for the development of commercial scale storage of CO_2 in saline aquifers (Table 12).

Many of the knowledge gaps and issues identified in this report are either of a purely academic nature and do not represent significant road blocks towards the implementation of commercial aquifer storage Additional large-scale injection projects are needed to answer some of the remaining question and to provide data for the verification of modelling results and the development of new, cost-effective monitoring schemes. The main challenges and barriers to the deployment of CCS are therefore of a more general nature and refer to all storage options (Bachu, 2008a):

1. Unattractive economics, particularly for the capture portion of CCS;
2. Public acceptance, particularly perception of safety risks; and most importantly,
3. The absence of a comprehensive policy, legislation, and regulatory framework.

Table 12. Geological storage of CO_2 in saline aquifers – issues, progress and remaining knowledge gaps.

	Issue	2008 Progress	Remaining gaps	Comments	Importance for commercial implementation
Storage Capacity	Uncertainty in capacity estimates	US DOE Atlas Japan (Europe, Australia*)	Africa, Asia, Latin America (Europe, Australia*)	*Work in progress, but not yet published	🟩
	Inconsistent methodology	US DOE Atlas CSLF Report CO2CRC Report	Universal document	Should be consistently applied	🟩
Storage Science	Geochemistry	Advances in *solution composition* and *surface processes*	Use of reactive surface area in models; experiments addressing specific aspects of geochemical trapping	Field-relevant experimental data is needed	🟧
	(Coupled) numerical models	Modelling of experimental and natural analogue data; well leakage	Data for calibration; up-scaling of processes	Need more demonstration projects	🟨
Storage Engineering	Local-scale capacity		Portfolio of storage environments		🟨
	Injectivity				
Monitoring	Need for testing and improvement	Results from Frio, Nagaoka & Sleipner	Long-term monitoring and verification data		🟨
	Detection of leaks	-	Cost-effective monitoring strategies		🟧
	Verification of storage	-			🟧
Regulations	Lack of proper regulatory framework	Draft legislations in Australia, US, Europe	Final legislation and trading schemes		🟥
Economics	Cost for storage projects not well known		Comparability of different cost estimates	Economics depend significantly on location and legislation	🟥
Risk/Operation safety	Lack of quantitative methods				🟧
	Need for protocols for storage duration and safety	Best Practice Manual(s)			🟧

red = significant road block; orange = substantial research gaps, but not crucial for commercial application; yellow = some research needed, but depends largely on new data from large-scale injection projects for verification; green = sufficient knowledge, might need minor improvements & consistency.

Progress in CO_2 Storage Science in Saline Aquifers since 2005 and Remaining Knowledge Gaps

Geochemistry

There has been a considerable increase in the number of publications addressing aspects of the geochemistry of CO_2 sequestration. The ability to simulate the dissolution of CO_2 into variable salinity NaCl dominated formation water is demonstrated to match experimental data although there is a need for more experimental data in the P-T-x space typical of CO_2 sequestration conditions. Geochemical modelling codes are sufficiently well developed to enable speciation and saturation index calculation for complex aqueous solution composition and many mineral phases. More experimental and field data for single- and multi-mineral phase-aqueous solution systems are required to ensure reaction path models are representative of natural systems. Incorporation of kinetics of reactions introduces significant uncertainty because of the number of variables required to adequately represent the controls on rates and the reaction mechanisms. However, the geochemical modelling of experimental, field and natural analogue data is being carried out and the uncertainty is recognized and can be addressed. Even with this uncertainty, numerical simulations of aquifers and reservoirs that do not incorporate geochemical interactions will always overestimate the amount of CO_2 that is sequestered as an immiscible phase and thereby elevate the predicted risk of leakage.

Remaining knowledge gaps in geochemistry do not represent major road block towards the commercial implementation of CO_2 storage in saline aquifers. Still, following issues should be addressed by the research community to improve the quantification of CO_2 stored by different storage mechanisms and numerical modelling results:

1. Conceptual models of the geochemical system need to be provided in detail. Choices of reactant and product phases are often the product of the numerical model rather than constrained by experimental and observational data.

2. More thermodynamic data especially for Pitzer equation formulation is required for saline solutions.

3. Thermodynamic properties of mixed mineral phases (solid solutions) and poorly defined mineral phases like clays are not well constrained.

4. Surface processes like adsorption and exchange can act as a significant buffer to pH changes and can be a store of cations that may be involved in mineral trapping. Many modelling codes include the ability to simulate adsorption and ion exchange making sensitivity analysis possible. More experimental data is required.

5. Kinetic rate parameters still need to be refined for some mineral phases especially mixed mineral phases and poorly defined mineral phases like clays. Dawsonite precipitation kinetics need to be investigated as this is one of the most common product phases of numerical simulations and yet is not a common phase observed in natural analogues or experiments.

6. Reactive surface area – determination, calculation, estimation. The most common difficulty described in the recent literature is the selection of a value for the reactive surface area to include in rate equations.

7. Surface reaction mechanisms and how they influence the rates of reaction is poorly understood and difficult to model.

8. Precipitation nucleation and degree of supersaturation required for precipitation for many important phases is not well known.

9. Upscaling of reaction kinetics from the mineral surface to the continuum scale of reactive transport modelling is poorly constrained.

10. Integration of experimental and natural analogue observations with geochemical reaction path and reactive transport modelling is receiving considerable attention and has promising outputs for helping constrain predictive models. More extensive datasets need to be gathered to populate model systems.

11. Experiments addressing specific aspects of the mechanisms of geochemical trapping need to be undertaken – dissolution/precipitation kinetics, multiphase systems, mineral surface processes. All require more attention.

Numerical Modelling

In the last decade, the numerical modelling of geological storage in saline aquifers has progressed from the examination of completely generic models - usually homogeneous and with simple geometry - to generic models with more realistic geological framework and the simulation of more complex geological models for hypothetical sites or actual field projects. In part this progress has been achieved by taking standard modelling and simulation tools from the petroleum industry, and applying them to CO_2 storage.

However there have also been advances that are specific to CO_2 storage, and these can be summarized in relation to the knowledge gaps identified in section 5.10 of the IPCC SRCCS relate to numerical modelling. One was the development of “Reliable coupled hydrogeological-geochemical-geomechanical simulation models to predict long-term storage performance accurately”. The simulation software for coupled models is well-developed, particularly for reactive transport models, although the coupled geomechanical codes are still at a more preliminary stage. Code comparisons are important to developing greater confidence in these modelling tools, and another one is currently underway for flow simulations. More comparison is needed, especially for coupled geochemical and geomechanical models. The use of such coupled models to probe scenarios for CO_2 storage is still in an early phase, since there is a very wide spectrum of possibilities (e.g., the range of mineralogies in reactive transport simulations). In many domains, the capabilities of the coupled models are well ahead of laboratory or field data that could constrain or verify their predictions. Remaining issues include the further development and comparison of geomechanical models, coupling of density effects in reactive transport simulations and comparisons with field data or analogue data.

General flow simulation of saline aquifer storage since 2005 has emphasized the roles of heterogeneity, relative permeability hysteresis and convective mixing on CO_2 migration and trapping. Well placement issues such as deep injection (to maximize trapping) and brine co-injection (to maximize dissolution) have been explored. Analogues to gravity currents have been used to predict the migration of CO_2 plumes and dissolved CO_2. Specific issues that still remain to be further investigated include the simulation of tracer effects in CO_2, coupling with hydrogeology, and the upscaling of simulating various processes (i.e., solubility, residual gas trapping, convective mixing, and vertical CO_2 migration).

Another IPCC knowledge gap was the “Quantification of potential leakage rates from more storage sites”. Progress has been made here on exploring a variety of scenarios for leakage to surface, including the possibilities of sudden large releases. Both self-limiting and self-enhancing effects are present, but no risk of catastrophic release has yet been identified. Coupling from near-surface leakage to the atmosphere has been examined in field trials. Caprock integrity is also germane to leakage rates, and the competition between self-sealing and self-enhancing processes in caprock leakage has also been investigated. Relevant here too is the IPCC knowledge gap on “Risks of leakage from abandoned wells caused by material and cement degradation”. Progress has been made on laboratory studies on CO_2-cement interactions and analysis of some field samples, but the key issue appears to be the nature of pre-existing flow paths in the cement. Further work is needed to quantify potential leakage rates, especially from faults and fractures, and for this analogue or field data is required. Simulation of near-surface leakage or shallow aquifers requires better models of CO_2 gas/liquid transitions and hydrate formation. Quantification of wellbore leakage requires better characterization of leakage pathways through wellbore cement, and simulation of the coupling between flow along these pathways and CO_2-cement reactions.

The current knowledge gaps can be summarized in three categories. The first is technical simulation issues, such as processes that are not adequately modelled in current software. The second is theoretical issues, where simulation tools are being used to explore and optimize scenarios for CO_2 storage. The third is data issues, where laboratory, field or analogue data is needed to check and improve the existing numerical models.

Technical simulation issues:

1. Code comparisons need to be extended to more detailed examinations of coupled geochemical and geomechanical models.

2. Improved flow modelling of CO_2 liquid/gas transitions in shallow reservoirs or near-surface leakage, possibly including hydrate formation.

3. Better simulations of tracer effects in CO_2, especially density effects due to accumulation of relatively insoluble tracers at the front.

4. Inclusion of fluid density changes in reactive transport simulations, for coupling to fluid convection.

Theoretical issues:

5. Upscaling of CO_2 simulations e.g. upscaling of solubility, residual gas trapping, convective mixing or vertical migration of CO_2.

6. Improved quantification of potential leakage rates of CO_2 and CO_2/gas mixtures to the surface, especially through faults and fractures, with coupling to geomechanics.

7. Simulation of CO_2 leakage rates through wellbore cement, including coupling to CO_2-cement reactions, to arrive at a better assessment of the overall risk of well leakage.

8. Simulation of surface leakage of CO_2, including screening of scenarios for sudden releases, and coupling with the atmosphere (onshore) and the sea (offshore).

9. Simulation of coupling CO_2 injection to hydrogeology, including assessment of effects on CO2 migration and adjacent aquifer units.

Data issues:

10. Data sets to test models for convection of dissolved CO_2 and coupled reactions on large time scales (beyond what is possible in demonstration projects, so would need to be from natural systems).

11. Data sets to test geomechanical models for fault reactivation (if faults are to be deliberately reactivated to test models this would involve water rather than CO_2).

12. Data sets to test leakage models, perhaps using natural systems.

13. Data sets to test and calibrate tracer/CO_2 behaviour in laboratory and field, including partitioning coefficients between a dense CO_2 phase and water.

14. Field data sets to characterize leakage pathways through wellbore cement.

Storage Capacity Classification and Estimation

The publication of the Carbon Sequestration Atlas of the United States and Canada (DOE, 2007) and the Phase 2 report on the Estimation of CO_2 Storage Capacity in Geological Media by the CSLF (2007) represent significant progress towards developing consistent methodologies for the classification and determination of CO_2 storage capacity in saline aquifers. CO2CRC (2008) in Australia proposes to adopt a combination of the US DOE methodology of capacity calculation with the CSLF classification scheme of storage estimates, and to expand the latter by incorporating the SPE Petroleum Resources Classification framework (SPE, 2007). The main cause for the large discrepancy between and range in existing global and regional CO_2 storage capacity estimates is the use of a combination of two fundamentally different concepts: 1) considering the entire aquifer versus accounting only structural traps for CO_2 storage, and 2) assuming CO_2 storage in solution versus storage as free-phase fluid. However, the example of the US DOE Atlas shows that, by knowing the underlying assumption in each regional partnership's estimation methodology, the results obtained by different methods can be easily converted into comparable capacity estimates. In addition, when presenting regional or global storage capacity values, they should be clearly classified within the CSLF Techno-Economic Resource-Reserve pyramid.

Since the publication of the IPCC SRCCS, new storage capacity estimates have been produced by the US Regional Partnership program, individual studies in Japan, China and Europe, and regional, basin-scale studies in Australia. In addition, there are active projects like GEOCAPACITY in Europe and CARBMAP in Brazil that anticipate to present regional capacity estimates for their respective regions within the next year or two. However, except for the initiation of CCS research programs almost no progress has been made in obtaining reliable CO_2 storage estimates for Latin America, Africa, and large parts of Asia.

Remaining gaps:

1. Universal agreement on methodology and classification, particularly whether the estimates are based on a) only structural traps within the aquifer, b) the entire aquifer, c) CO_2 in solution and/or d) CO_2 as separate phase/residual;

2. Development of regional capacity estimates that incorporate all mechanisms of saline aquifer storage.

3. Consistent consideration of economics in capacity estimates.

4. (Reliable) regional estimates for Latin America, Africa, and Asia (except Japan & China).

Best Practice and Site Characterisation

Site characterisation is the most time-consuming and costly part of the CO_2 storage site selection process. Site characterisation involves greater detail than basin assessment investigations and may involve re-evaluation of regional geology, and generation of new and/or updating of existing data such as geologic and seismic data (static) and engineering data (dynamic), computer models, flow simulation, and ultimately injection. Site characterisation considers factors such as injectivity and containment. Data sources can include 2D and 3D seismic surveys, well log and core data, drill cuttings, biostratigraphy, field production and fluid data. Typical steps in site characterisation are structural and stratigraphic interpretation based on available subsurface data, building of geological models with realistic stratigraphic heterogeneity, and flow simulations to predict CO_2 plume migration. The ultimate goal of a storage project is to have a commercially and technically viable operational site for deployment. Site deployment thus requires all the geological, engineering, economic and regulatory considerations of a site being taken into account, and operational storage capacity being determined. The Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects (CO2CRC, 2008) provides a useful summary on the topic of site characterisation.

With respect to the site specific assessment of a prospective CO_2 storage site, the Best Practice Manual from the SACS and CO2STORE projects (Chadwick et al., 2007) represents significant progress towards comprehensive guidelines regarding site selection, site characterisation, risk assessment and monitoring and remediation plans. Due to the extremely variable natural systems present in the subsurface, properties may be highly site specific and hence the applicability of procedures or recommendations may become more generally applied as further case studies are examined and added to the Best Practice manual. Nevertheless, a wide range of geological, environmental and planning issues are addressed in the Best Practice Manual from the SACS and CO2STORE projects (Chadwick et al., 2007), and the document forms a sound basis for establishing recommended procedures for the planning and setting up of a potential CO_2 storage operation. The document relies heavily on the experience gained from five CCS operations and research in Europe, particularly from the Sleipner project. A number of projects are working towards improvements in best practice. For example, CASTOR and CO_2 Capture Project are further developing the Best Practice Manual through the addition of case studies and establishment of best practice networks. Furthermore, the IEA Greenhouse Gas R&D programme website provides a support database for the collection of documents with the aim of ultimately developing definitive best practices in both carbon capture and storage. The Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects (CO2CRC, 2008) provides an additional Australian perspective to these topics in a single document.

The review of the best practice in site characterisation since the IPCC Special Report on CO_2 Capture and Storage (IPCC SRCCS), completed in late 2005, has identified a number of gaps in knowledge with the following recommendations.

1. Due to the variability in the subsurface it is recommended that a broadly representative range of case studies be added to the Best Practice Manual.

2. Current best practice manuals have a European focus. It would be advantageous to have additional examples from other regions (e.g. USA, Australia, Canada etc).

3. Combining Best Practice and Site Characterisation manuals developed in different parts of the world should be attempted to ensure that a wide range of geological, political and economic environments are covered.

4. The existing SACS/CO2STORE manual is extensive and comprises some 270 pages. However, it would be usefully to develop a summary document of generic findings and perhaps a Best Practice quick reference guide, which may be cross-referenced against developing regulatory requirements.

5. It would be useful to have Best Practice guides for other CO_2 storage options (e.g. depleted reservoirs, EOR/EGR and coal seams).

Experience from Existing Storage projects

The experience from CO_2 injection at pilot projects (Frio, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) shows that CO_2 geological storage in saline aquifers is technological feasible. By the end of 2007, approximately 15 Mt of CO_2 had been successfully injected into saline aquifers by these operations. Particularly, Sleipner, In Salah, and Snøhvit demonstrate that, given the right geological and reservoir conditions, injecting industrial-scale volumes on the order of 1 Mt/year CO_2 into saline aquifers is achievable. However, these projects are not necessarily representative for conditions encountered globally. For example, aquifer permeability at Sleipner is probably unusually high compared to what could be expected for other sites. In Salah operates 3 injection wells in a low-permeability aquifer, but there is limited monitoring information. Nagaoka and Frio have comprehensive M&V programs, but injection rates/volumes are very low. The various acid-gas injection operations in Alberta cover a wide range of reservoir properties, but again injection rates are relatively low and very limited subsurface monitoring is done. Hence, there remains the need for a more comprehensive portfolio of aquifer storage projects that covers the range of variability of different subsurface environments (e.g., on-/offshore, low/high permeability, sandstone/carbonate/basalt, pressure, temperature, salinity) as well as different monitoring strategies, regulation requirements and economics. The funding by the US DOE of a variety of small to large-scale injection projects in the various Regional Partnerships is a promising step towards gathering experience for different storage scenarios. However, it is interesting to note that in North America, all saline aquifer operations inject onshore and, with the exception of the Michigan Basin project, into sandstone aquifers.

With respect to monitoring and verification of CO_2 storage reservoirs, 4D seismic proved to be very successful at Sleipner, but has the disadvantage of being relatively expensive and might prove challenging for onshore storage sites. Challenges at other sites may include repeatability problems due to changing weather, soil humidity and contact conditions. Also, successfully implemented at Sleipner was 4D gravity, which has lower costs and works well for qualitatively assessment of CO_2 saturation in the subsurface, but requires a detailed, well-characterized geological model. Promising geophysical methods that worked well at Frio and Nagaoka for quantitative tracking of the CO_2 plume was 4D vertical seismic profiling (VSP), which allows for a good source signal control, and cross-well electro-magnetics. However, these two methods require a monitoring well in addition to the injector and might loose the advantage of high resolution in the case of commercial injection projects with large plume extents. Monitoring technologies for the shallow groundwater, soil and atmosphere have been developed, however they have not yet been successfully demonstrated to detect potential CO_2 leaks from the reservoir unit due to relatively high natural CO_2 fluctuations in these environments. Requisite monitoring plans in future regulations for CO_2 storage projects should carefully weigh the necessary requirements for ensuring storage verification and safety against cost and suitability of various monitoring techniques for specific storage environments.

Remaining gaps/issues:

1. Pilot sites have generally a comprehensive monitoring program, but injection rates/volumes are low compared to potential commercial projects. Also, pilot site monitoring programs are not necessarily cost-effective, which should be considered when the applicability of their results is evaluated.

2. Existing commercial projects inject considerable volumes of CO_2, however monitoring programs are often limited (i.e., In Salah, Alberta acid-gas) or reservoir properties are "unrepresentatively good" (i.e., relatively high permeability at Sleipner).

3. Still need to "prove" that leakage can be detected and need to develop better methodologies for seismic imaging of $CO_{2.}$

4. Testing of new methods.

Regulations and Economics

Regulations are currently in place in various countries under which commercial (Sleipner, Snøhvit, acid gas) and pilot projects (Nagaoka, Frio, Ketzin) were approved, but mainly done under petroleum legislation. Key issues that have to be addressed better in regulations currently under development are:

1. the long-term liability/stewardship for storage sites (post-injection);

2. the definition of M & V requirements;

3. Emission Trading Scheme (ETS) implications;

4. Resolution of conflict of interests (affect of storage on other resources;

5. Surrender of storage tenements and KPIs;

6. royalties/lease fees for storage space.

The aim of a review of the costs of storage in saline aquifers is to provide a means to benchmark and predict costs in other situations as well as to act as a guide for policy making and incorporation on to site assessment studies. This review found a number of issues making it difficult to compare costs for different projects and studies. Published data is scarce and incomplete. Where data is available, it is often aggregated and not explained in enough detail. Because a variety of methodologies are used to determine costs, it is not possible to compare costs when the methodology used has not been explained. Costs have also been reported in different years and currencies. Therefore, the key knowledge target is the need to gather cost data for different projects on a common, consistent basis.

Roadmap towards Commercialization of CO_2 Geological Storage in Saline Aquifers

The IEA 2008 report "Towards a sustainable energy future" highlighted in its section on CCS that one of the key goals for the G8 governments to achieve their target reductions in greenhouse gas emissions is to commit to 20 fully integrated industrial-scale demonstration projects by 2010 and to enable broad deployment of CCS by 2020. This target of significant deployment of CCS by around 2020 has been integral in a number of earlier published roadmaps (e.g., CLSF Technology Roadmap (CSLF, 2004), CO2CRC Roadmap (CO2CRC, 2004), US DOE Roadmap (DOE/NETL, 2007) and the Canadian CCS Technology Roadmap (CETC, 2006)).

This section presents a roadmap aimed at progressing towards such a commitment to a significant number of commercial-scale saline aquifer storage projects by 2020. Key goals and milestones for the main knowledge gaps discussed in the previous chapter are established and discussed below and summarised in Table 13 and Figure 11.

Storage Capacity/ Site Characterisation:

Significant progress in the areas of regional storage capacity estimates has been made since the release of the IPCC CCS report in 2005. The remaining gaps in knowledge identified in this review are not a significant barrier to commercial scale storage in saline aquifers. However, over the next 5 years there is a need to agree on applying consistent, internationally accepted methods for storage capacity calculation on different scales and incorporating all aspects of saline aquifers. Once this has been achieved consistent, regional and global storage capacity estimates for saline aquifers can be made.

Similarly significant progress has been made in developing site characterisation and best practice methodologies for storage in saline aquifers. Although not a critical barrier to continued development of commercial-scale saline aquifer projects, there is still a need to develop consistent methodologies and internationally accepted approaches to best practice. Over the next 5 years there is a need to develop site characterisation/best practice methodologies for a more diverse range of case studies, geological settings, geographic locations and trapping mechanisms.

Storage Science:

The experience from CO_2 injection at pilot projects (Frio, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) shows that CO_2 geological storage in saline aquifers is technologically feasible. However, these projects are not necessarily representative of the range of saline aquifer conditions encountered globally. There is a need to develop more demonstration and commercial scale projects focusing on injection into a range of saline aquifer types (e.g. low permeability and/or heterogeneous aquifers).

There are key knowledge gaps associated with the understanding of long-term geochemical processes of CO_2 in the subsurface, the use of coupled simulation models to make long-term predictions, the quantification of leakage rates from storage sites, and the risks of wellbore leakage due to cement degradation from CO_2. Similarly, factors such as "reactive surface area" and the role of adsorption and ion exchange have not yet been incorporated in published models. The key goals in the next 5 years are to undertake laboratory, natural analogue and field experiments to provide calibration data for numerical modelling studies focusing on these issues.

It should be emphasized that the currently remaining knowledge gaps in the storage science and modelling should not be considered as barriers to the implementation of large-scale CO_2 storage projects in aquifers. On the contrary, over the next 5-10 years, more CO_2 storage operations are needed to provide realistic data for model calibration and substantiation of time frames for various trapping mechanisms.

Table 13. Knowledge gaps, key goals and milestones.

	Issue	2008-2014	2014-2020+
Storage Capacity	Uncertainty in capacity estimates	Continued focus on determining regional storage capacity estimates.	Develop revised global capacity estimates using consistent methods applied to all aspects of saline aquifers. Identify priority locations for large-scale commercial storage in saline aquifers.
	Inconsistent methodology	Agree on consistent methodologies that are accepted internationally	
Site Characterisation	Inconsistent methodology		
Storage Science	Geochemistry	Undertake laboratory, natural analogue and field experiments to provide calibration data for numerical modelling studies focusing on these issues	Commitment to a number of commercial scale storage projects in saline aquifers that will have a manifest impact on reducing CO2 emissions.
	(Coupled) numerical models		
	Quantification of leakage & rates		
Monitoring And Verification	Need for testing and improvement	Test new technologies on a range of commercial or demonstration projects	
	Detection of leaks	Through simulation and field testing, prove the capability of monitoring technology to detect subsurface and surface leaks.	
	Verification of storage	Develop internationally acceptable verification protocols	Apply to demonstration/ commercial scale projects
Regulations	Lack of proper regulatory framework	Formulate regional policy and regulations.	Develop internationally accepted regulations and policy framework.
Economics	Cost for storage projects not well known	Develop consistent approaches to economic assessment.	Integration of consistent economic assessments in to site assessment and global capacity estimation.

Monitoring and Verification:

Since the IPCC CCS special report in 2005 there has been significant progress in the assessment and development of technologies for monitoring and verification. However, there is an immediate need for more field testing (commercial- or demonstration-scale projects) of long term monitoring and verification technologies. Also, new and particularly cost-effective monitoring technologies should be tested at new CCS projects. At the same time, nationally and internationally accepted monitoring and verification protocols need to be established. This will have a significant impact on the development of legal and regulatory frameworks.

Regulations and Economics:

Potentially the most significant barriers for the wider commercial implementation of CO_2 storage in saline aquifers by 2020 is that appropriate regulatory frameworks are still lacking in many jurisdictions and there is not a consistent framework for economic assessment and comparison of storage sites internationally. To enable broad uptake of CCS by 2020 it is essential that over the next 5 years countries with significant CCS potential in saline aquifers develop appropriate regulatory frameworks. Similarly to aid in the development of regulatory frameworks, government policy, site characterisation methodologies, and more consistent approaches to economic assessment are required.

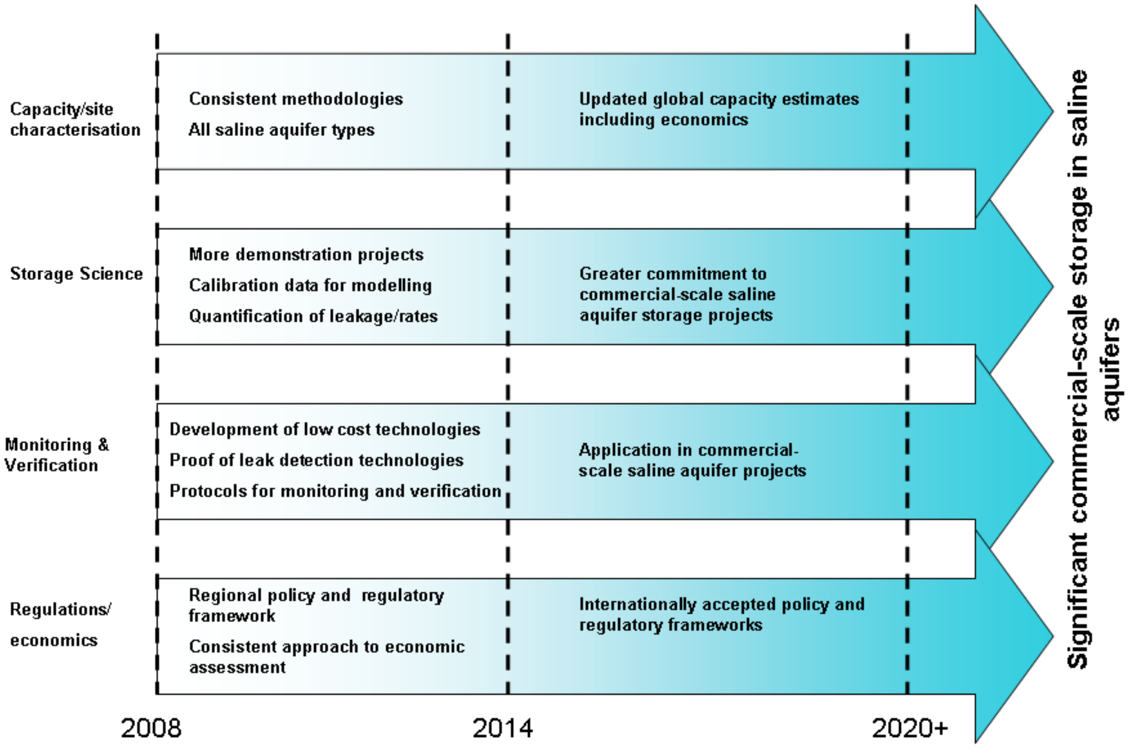


Figure 11. Roadmap towards significant implementation of commercial-scale geological storage of CO_2 in saline aquifers.

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Appendix 1: Capacity Estimation of CO_2 Storage in Saline Aquifers

The storage capacity of CO_2 is an estimate of the amount of CO_2 that can be stored in subsurface geologic formations. Because of uncertainties inherent to subsurface evaluation, exact quantification of geological properties is not possible and therefore storage capacity is always at best an approximation of the amount of CO_2 that can be stored. Storage capacity estimates rely on the integrity, skill and judgment of the evaluator and are affected by the geological complexity, stage of exploration or development, amount of existing storage and of available data.

Global storage estimates are imperfectly known due to inconsistency in assessment methodologies and gaps in global, regional and local estimates, particularly data from Africa, South America and large parts of Asia (IPCC, 2005). As a result, two major works providing methodologies for the estimation of storage capacity of CO_2 in geological formations have been published since the IPCC Special Report in 2005. These are the 'Methodology for Development of Carbon Sequestration Capacity Estimates' prepared for the Carbon Sequestration Program of the National Energy Technology Laboratory, U.S. Department of Energy (DOE) by the Capacity and Fairways Subgroup of the Geologic Working Group of the DOE Regional Carbon Sequestration Program in December 2006, and the 'Estimation of CO_2 Storage Capacity in Geological Media – Phase II' prepared by the Task Force on CO_2 Storage Capacity Estimation for the Technical Group of the Carbon Sequestration Leadership Forum (CSLF) in April, 2007 (CSLF, 2007). The results and summary of the CSLF study were published subsequently in the Journal of Greenhouse Gas Technologies (Bachu et al., 2007). Also, the two methodologies were compared in Phase III of the CSLF work (CSLF, 2008).

Methodologies for Capacity Estimations in Saline Aquifers

Both the DOE (2007) and the CSLF (2007) publications provide methodologies for the estimation of storage capacity of CO_2 in saline aquifers, hydrocarbon reservoirs and coal seams. Only the former will be reviewed in this section because the others are beyond the scope of this study. Detailed comparisons between the methodologies implemented in the two studies were performed by the (CSLF, 2008) and the CO2CRC (2008). Former methodologies, proposed for example by (Hendriks et al., 2004) or (Li et al., 2005), represent simplifications of or derivations from the DOE and CSLF methods and are only reviewed briefly the end of the this section.

DOE-Proposed Methodology

The DOE (2007) study provides a volumetric equation for capacity calculations in saline aquifers. Displacement of saline water in the pore volume by immiscible CO_2 is the fundamental mechanism implicit in the calculations. No distinction is made between CO_2 that is stored as an immiscible phase within structural or stratigraphic geologic traps; CO_2 that is stored as an immiscible phase outside of traps (for example, trapped in pores by capillary processes); CO_2 that is stored as dissolved phase in saline water; and CO_2 that is precipitated as minerals. The expected uncertainty in efficiency of the storage capacity from a combination of trapping mechanisms is estimated using a Monte Carlo approach. The equation for capacity calculations in saline aquifers as proposed by the DOE (2006) is as follows:

$$G_{CO2} = A \times h_g \times \Phi_{tot} \times \rho \times E \qquad (1)$$

Variable and units are defined in Table 14.

Table 14. Volumetric equation parameters for capacity calculation in saline formations (DOE, 2007).

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline-formation CO_2 storage capacity
A	L^2	Geographic area that defines the basin or region being assessed for CO_2 storage-capacity calculation
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A
ϕ_{tot}	L^3/L^3	Average total porosity of entire saline formation over thickness h_g
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over the depth range associated with h_g
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled, or contacted, by CO_2 (see Table 15)

* L is length; M is mass

The storage efficiency factor (E) adjusts total gross thickness to net gross thickness, total area to net area and total porosity to effective (interconnected) porosity actually containing CO_2. Without the CO_2 storage efficiency factor (E), Equation 1 presents the Total Pore Volume or maximum upper limit to storage capacity in free phase. Inclusion of the storage efficiency factor provides a means of estimating storage volume for a basin or region with the level of knowledge (uncertainty) in specific parameters determining the type of CO_2 storage capacity estimated. Monte Carlo simulations for parameter ranges typical for US sedimentary basins estimated a range of E between 1 and 4 percent of the bulk volume of saline formations for a 15 to 85% confidence range.

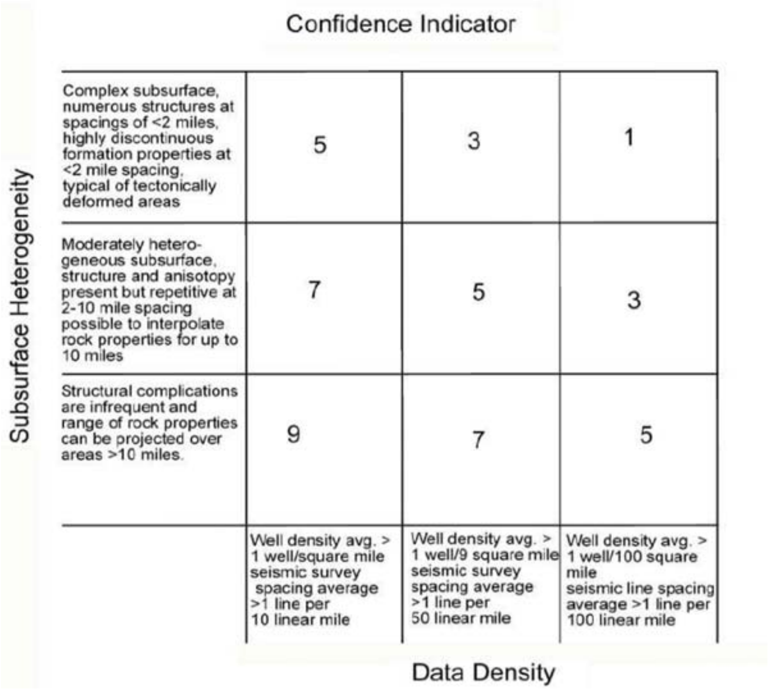
A reasonable maximum Effective Storage Capacity may be estimated by assuming CO_2 injection wells are placed regularly throughout the basin, or region, and multiplying the storage efficiency terms in Table 15 together to determine the storage efficiency factor for the basin or region. In Table 14, the first three terms (A_n/A_t, h_n/h_g and ϕ_e/ϕ_{tot}) are used to define the regional effective pore volume, and the next three terms (E_A, E_I and E_g) are used to define the fraction of that volume accessed by CO_2 from injection wells. The remaining term (E_d) in Table 15 accounts for the proportion of the effective pore volume filled with CO_2. Ideally, the last four terms would be determined for each potential well site and combined to estimate the total storage volume; however, practically it may be easier to determine the average volume of pore space accessed by injecting CO_2 into a single well and then multiplying by the expected number of wells.

Although the capacity estimates given in the Atlas are based on CO_2 stored as a separated fluid phase, some Regional Partnerships initially used the assumption of CO_2 dissolved in formation water in their calculations. In those cases, the efficiency factor E for dissolved CO_2 was converted to an E for free-phase CO_2, using a single conversion factor representative of the average pressure, temperature and salinity conditions for each basin or region.

Table 15. Terms included in storage efficiency factor for saline formations (from DOE, 2007).

Term	Symbol	Description
Terms used to define the entire basin/region pore volume		
Net to total area	A_n/A_t	Fraction of total basin/region area that has a suitable formation present
Net to gross thickness	h_n/h_g	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection
Effective to total porosity ratio	ϕ_e/ϕ_{tot}	Fraction of total porosity that is effective, i.e. interconnected
Terms used to define the fraction of pore volume accessed by CO_2 from injection wells		
Areal displacement efficiency	E_A	Fraction of immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy
Vertical displacement efficiency	E_I	Fraction of vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by the CO_2 plume from a single well; most likely influenced by variations in porosity and permeability between sublayers in the same geologic unit. If one zone has higher permeability compared with others, the CO_2 will fill this one quickly and leave the other zones with less CO_2 or no CO_2 in them
Gravity	E_g	Fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in situ water. In other words, $(1-E_g)$ is that portion of the net thickness not contacted by CO_2 because the CO_2 rises within the geologic unit
Microscopic displacement efficiency	E_d	Portion of the CO_2-contacted, water-filled pore volume that can be replaced by CO_2. E_d is directly related to irreducible water saturation in the presence of CO_2 or residual CO_2 saturation, dependent on position within the plume

Due to the variability in data quality and data distribution, the complexity of the subsurface and various levels of subsurface characterisation by different assessors or scientist, the DOE suggests the use of a 1 (low) to 9 (high) relative index that indicates the level of confidence in the capacity estimations:



Confidence Indicator

Complex subsurface, numerous structures at spacings of <2 miles, highly discontinuous formation properties at <2 mile spacing, typical of tectonically deformed areas	5	3	1
Moderately heterogeneous subsurface, structure and anisotopy present but repetitive at 2-10 mile spacing possible to interpolate rock properties for up to 10 miles	7	5	3
Structural complications are infrequent and range of rock properties can be projected over areas >10 miles.	9	7	5
	Well density avg. > 1 well/square mile seismic survey spacing average >1 line per 10 linear mile	Well density avg. > 1 well/9 square mile seismic survey spacing average >1 line per 50 linear mile	Well density avg. > 1 well/100 square mile seismic line spacing average >1 line per 100 linear mile

CSLF-Proposed Methodology

CSLF (2007) provides individual equations for structural and stratigraphic (volumetric) trapping, residual-gas saturation trapping, dissolution trapping, as well as a detailed discussion on the processes and time frames involved for mineral precipitation and hydrodynamic trapping. Separated equations are given for the estimation of theoretical and effective storage capacities. In the following only the equations for effective storage capacities are shown, which can be converted easily to theoretical capacity by omitting the capacity coefficient C, which describes trapping efficiency.

For calculating the storage capacity in **structural and stratigraphic traps** the CSLF Taskforce proposes the use of two equations that result in either estimates of storage volume or corresponding mass of CO_2. The effective storage volume is given by:

$$V_{CO2} = A \times h \times \Phi \times (1 - S_{wirr}) \times C_c \qquad (2)$$

where A = trap area, h = average thickness, Φ = average porosity, S_{wirr} = irreducible water saturation and C_c = capacity coefficient that incorporates trap heterogeneity, CO_2 buoyancy and sweep efficiency.

The corresponding mass of CO_2, M_{CO2}, that can be effectively stored depends on the average subsurface temperature, T, and the subsurface pressure, which can range between the initial formation pressure, P_i and the maximum approved bottomhole injection pressure P_{max}:

$$\min M_{CO2} = \rho_{CO2}(P_i, T) \times V_{CO2} \leq M_{CO2} \leq \max M_{CO2} = \rho_{CO2}(P_{\max}, T) \times V_{CO2} \qquad (3)$$

Relations (2) and (3) can be applied to both theoretical and effective storage capacity estimates for basin- and regional-scale assessments by applying them individually to all the structural and stratigraphic traps identified as potential candidates for CO_2 storage and summing the resulting individual capacities. They can be applied also to the case of a plume of CO_2 that is not necessarily contained in a stratigraphic or structural trap (CSLF, 2008).

Unlike in the case of structural and stratigraphic traps, **residual-gas trapping** is time-dependant and the corresponding CO_2 storage capacity has to be evaluated at a specific point in time. The storage volume can be estimated by:

$$V_{CO2t} = \Delta V_{trap} \times h \times \Phi \times S_{CO2t} \qquad (4)$$

where ΔV_{trap} = rock volume previously saturated with CO_2 that is invaded by water and S_{CO2t} = trapped CO_2 saturation after flow reversal.

The mass of stored CO_2 by residual gas trapping is obtained by multiplying the storage volume by the density of CO_2 at in-situ conditions, but this density is both time- and position-dependent as pressure and temperature vary along the flow path and as, for the same location, pressure builds up or decays, depending on the stage of the storage operation.

The dissolution of CO_2 in formation water is a continuous, time-dependent process, which depends on pressure temperature and water salinity, as well as the amount of CO_2 coming into contact with formation water under-saturated with CO_2. Therefore, the CO_2 storage capacity through **solubility trapping** has to be evaluated for a specific period of time. For average aquifer thickness and porosity, the following equation gives the effective storage capacity of CO_2 in solution:

$$M_{CO2t} = A \times h \times \Phi \times (\rho_s X_s^{CO2} - \rho_0 X_0^{CO2}) \times C \qquad (5)$$

Where ρ = formation water density, X = CO_2 content (mass fraction), subscripts 0 and S denote initial CO_2 content and CO_2 content at saturation, respectively, and C = coefficient that includes the effect of all factors that affect the spread and dissolution of CO_2 in the whole aquifer volume under consideration.

The estimation of CO_2 storage capacity in mineral and hydrodynamic traps is discussed only with respect to the processes and timeframes involved. Like residual-gas and solubility trapping, mineral trapping is a time-dependent process, operating on the scale of millennia and storage capacity needs to be estimated for a particular point in time. Because hydrodynamic trapping is based on several CO_2 trapping mechanisms acting at times simultaneously and sometimes being mutually exclusive, the CO_2 storage capacity has to be evaluated at a specific point in time as the sum of the individual storage capacities. Given the complexity of the processes involved, only local- and site-scale numerical modelling backed up by laboratory experiments and field data can provide capacity estimates and timeframes for mineral and hydrodynamic trapping of CO_2.

Other Methodologies for Calculating CO_2 Storage Capacity

The methodology employed by Hendriks et al. (2004) to estimate global storage capacity values used general values for aquifer thickness and porosity, and represents a somewhat simplified version of the DOE-proposed methodology (Equation 1). Low, best, and high storage estimates for supercritical CO_2 in gigatonnes are calculated according to:

$$G_{CO2i} = A \times h_i \times \Phi_i \times \rho_{CO2} \times 0.01 \times 0.02 \times 10^{-12} \tag{6}$$

where the subscript *i* denotes minimum, best and maximum values for aquifer thickness (50 m, 100 m 300 m) and porosity (0.05, 0.2, 0.3), A = surface area of sedimentary basin (m^2), and ρ_{CO2} = average density of CO_2 (750 kg/m^3). Multiplication by 0.01 and 0.02 assumes that 1 % of the aquifer is part of a structural trap and 2 % sweep efficiency, respectively.

(Brennan and Burruss, 2006) define a Specific Storage Volume (m^3/t) for saline aquifer storage, which incorporates free-phase CO_2 storage and solubility trapping:

$$SSV_{SA} = \Phi\left(\frac{1 - S_{wr}}{\rho_{CO2}} + \frac{S_{wr}}{X_{CO2} \times \rho_{aq}}\right) \tag{7}$$

where S_{wr} = residual water saturation after CO_2 injection, ρ_{CO2} = CO_2 density (t/m^3), ρ_{aq} = density of formation water at given pressure and temperature conditions and CO_2 saturation (t/m^3) and X_{CO2} = concentration of CO_2 dissolved in formation water (t of CO_2 per t of aqueous solution).

The SSV_{SA} increases with time as free-phase CO_2 dissolves into formation water and the residual water saturation increases until the saturation point is reached. In other words, a given mass of injected CO2 in solution will occupy a larger volume of the aquifer than free-phase supercritical CO_2.

The Research Institute of Innovative Technology for the Earth (RITE) uses a hybrid of the DOE and CSLF-proposed technologies to estimate storage capacity and select preferred storage sites in Japan. Following the classification by (Tanaka et al., 1995), Li et al. (2005) assess the capacity of selected storage sites in four separate categories: 1) oil and gas reservoirs and neighbouring aquifers, 2) aquifers in anticlinal structures, 3) aquifers in monoclinal structure – onshore, and 4) aquifers in monoclinal structure – offshore. For the sites in Category 1, a volumetric storage capacity is estimated assuming trapping of supercritical CO_2, whereas capacity estimates (in grams CO_2) for categories 3 and 4 are based on solubility trapping. A site is divided into 500 m thick blocks (Figure 12) and the capacity of each block is then calculated based on its average temperature and pressure.

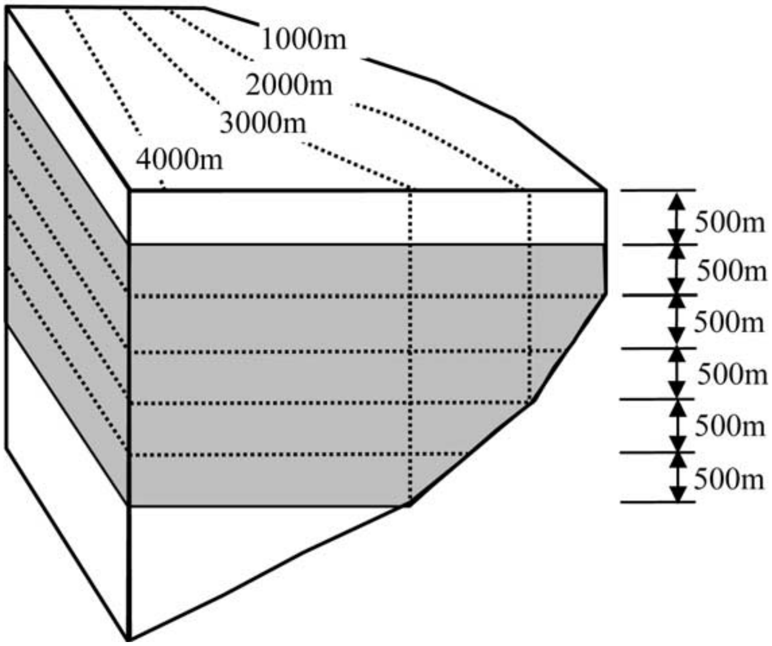


Figure 12. Dividing a site into blocks. Only the grey blocks are considered to contribute to storage, (Li et al., 2006). A site is bounded on the sides by vertical surfaces through coastline, the 1000-m sedimentary isopach, and/or the 500-m sea-depth isogram. At its top is the 500-m isopachous surface, and at the bottom are the 3000-m sedimentary isopachous surface and/or basement.

The total capacity at each site is calculated by summing the capacity of individual blocks according to:

$$\begin{aligned} G_{CO2} &= A_1 \times \eta \times \Phi \times E_f \times \rho_1 \times 500[R_{500} + 0.75R_{1000} + 0.25R_{1500}] \\ &+ A_2 \times \eta \times \Phi \times E_f \times \rho_2 \times 500[R_{500} + R_{1000} + R_{1500} + 0.75R_{2000} + 0.25R_{2500}] \\ &+ A_3 \times \eta \times \Phi \times E_f \times \rho_3 \times 500[R_{500} + R_{1000} + R_{1500} + R_{2000} + R_{2500}] \end{aligned} \tag{8}$$

where A_1 = area between 1000 and 2000 m isopach, A_2 = area between 2000 and 3000 m isopach, A_3 = area corresponding to a depth of 3000 m or more (m^2), R_x = CO_2 solubility under the pressure, temperature and salinity at x m depth (N m^3/m^3), η = effective aquifer ratio (0.075 – 0.1), E_f = sweep efficiency (0.5), and ρ_ξ = CO_2 density for pressure and temperature conditions of block x (g/N m^3). The subsurface temperature is estimated from the average annual ground surface temperature and a temperature gradient map, whereas the pressure is assumed to increase linearly with depth based on a fluid column with constant 29,800 mg/l salinity.

Li et al. (2005) also ranked the sites based on site capacity, size of and distance to emission sources (Table 16). Although RITE uses more generalized parameters (pressure, temperature, sweep efficiency) in their capacity estimations, the ranking of sites adds consideration of technical and economic aspects, moving the calculated capacity values from Effective more towards Practical Storage Capacity in the Resources-Reserves Pyramid than the DOE and CSLF estimates.

Table 16. Ranking criteria for selected storage sites in Japan (Li et al., 2005). Depleted oil & gas reservoirs (Category 1) are excluded from the ranking as they are not considered to be available for storage within the next 50 years.

Criteria	Categories	Rank 1	Rank 2	Rank 3
Capacity (Mt)	2, 3, 4	>= 50 and	>= 50 And	< 50 And
Emissions (Mt/year)	2 3 4	E_{50} >= 2 E_0 >= 2	E_{50} < 2 and E_{100} >= 2 E_0 >= 2 and E_{50} >= 2	E_{100} < 2 E_{50} < 2
E_x are the annual emissions from the sources within a distance of x km. E_0 are the emissions from sources inside the site boundary.				

Storage Capacity in Closed and Semi-Closed Aquifer Systems

All of the methods described above are based on “open” or “infinite” aquifer systems, which are assumed not to be bounded by lateral flow barriers. Consequently, pressure build-up caused by CO_2 injection is usually not a limiting factor in open aquifer systems except for maximum bottomhole injection pressures in the near vicinity of the well. However, in many geological environments, aquifers may be compartmentalised in the presence of lateral low-permeability zones formed by natural heterogeneity and/or faults. Depending on whether the lateral flow barriers are totally or partially impervious, the enclosed portions of the aquifer may act as “closed’ or “semi-closed” systems (Figure 13). Therefore, (Zhou et al., 2008) propose an assessment method of CO_2 storage capacity in closed and semi-closed saline aquifers (summarized below) to compliment existing capacity estimation methods for open systems. Their quick-assessment method is based on the fact that native brine displaced by injected CO_2 occupies additional pore volume within the aquifer and aquitards, provided by pore and brine compressibility in response to pressure build-up.

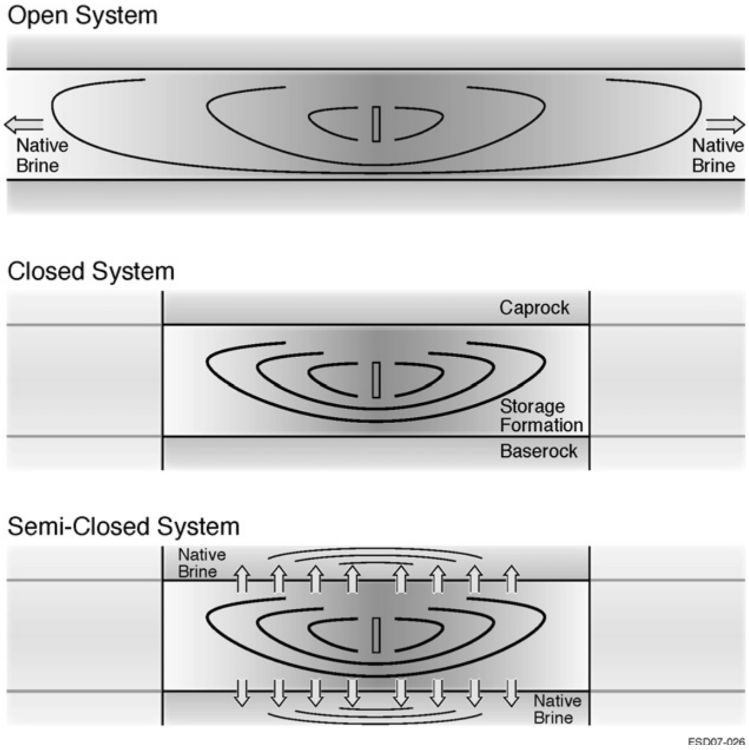


Figure 13. Schematic showing open aquifer systems versus closed or semi-closed systems (Zhou et al., 2008).

Injection into closed systems is a time-dependant process and the volume of CO_2 stored under the final storage conditions after a given injection time t_I can be estimated by:

$$V_{CO2}(t_I) = (\beta_p + \beta_w) \times \Delta p(t_I) \times V_f \tag{9}$$

where β_p = pore compressibility, β_w = brine compressibility, $\Delta p(t_I)$ = pressure build-up after injection time t_I, and V_f = initial total pore volume.

In relation (9), $(\beta_p + \beta_w) \times \Delta p(t_I)$ represents the storage efficiency factor of the closed system and only storage of free-phase CO_2 is considered.

In a semi-closed system, the pressure build-up is non-linear and transient, affecting brine leakage rates through the seals and vice versa. However, continued injection would eventually result in a steady-state condition at which the volumetric CO_2 injection rate, Q_{CO2}, is equal to the rate of brine leakage through the seals, assuming that the integrity of the rock framework is not altered. The pressure build-up at steady-state conditions can be calculated as:

$$\Delta p_s = \frac{Q_{CO2}}{2Ak_s / \mu_w B_s}, \qquad Q_{CO2} = \frac{G_{CO2}}{\rho_{CO2}(\Delta p_s)} \tag{10}$$

where G_{CO2} = injection rate of CO_2 mass, A = lateral area, k_s = seal permeability, and B_s = seal thickness.

If Δp_s is sufficiently small, there is enough brine leakage through the seals and the storage capacity is not pressure constrained, the aquifer acting like an open system. On the other hand, if Δp_s is unrealistically high, the storage capacity needs to be evaluated at various discrete time steps according to:

$$\Delta p(t_i) = \frac{V_{CO2}(t_i) - 2Ak_s\Delta t / \mu_w B_s \sum_{j=0}^{i-1} \Delta p(t_j)}{(\beta_p + \beta_w)V_f + 0.5(\beta_{ps} + \beta_w)V_s + Ak_s\Delta t / \mu_w B_s}, i = [1, n] \tag{11}$$

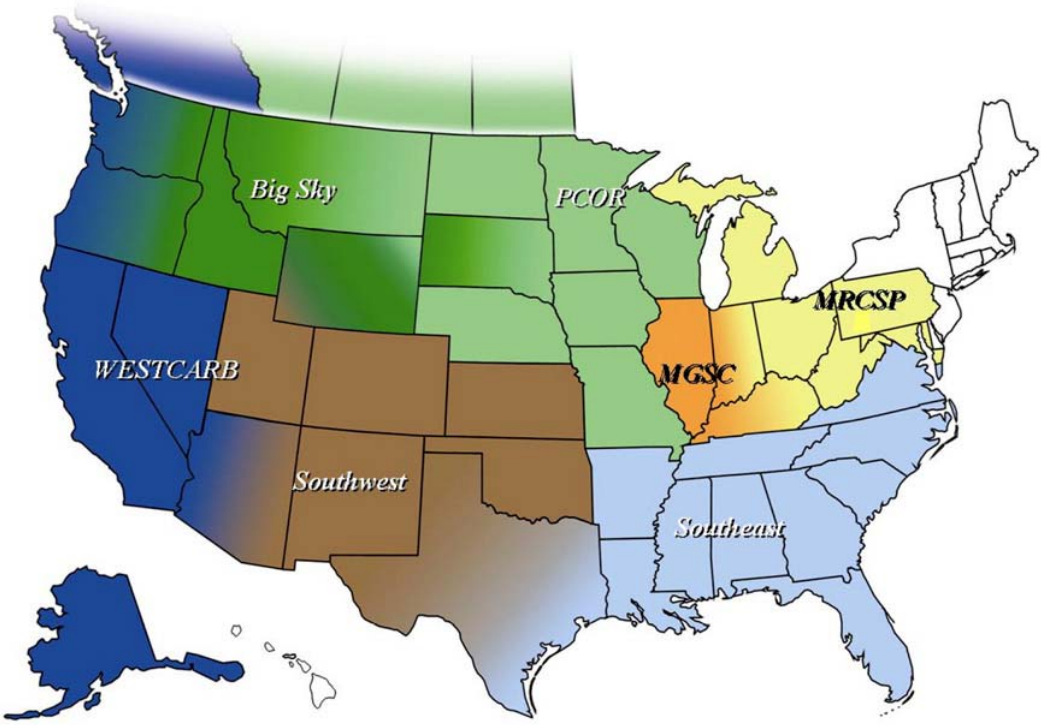
For various example cases, Zhou et al. (2008) compare the simple results obtained by their method with results from numerical modelling with Laurence Berkeley's TOUGH2 numerical simulator to demonstrate the validity of their proposed method. The findings by Zhou et al. (2008) suggest that the permeability of the over- and underlying aquitards is an important parameter impacting the pressure build-up in closed aquifers, which can result in small storage efficiency as low as 0.5 % of the initial pore volume for very low aquitard permeabilities < 10^{-20} m^2.

Country- to Regional-Scale Capacity Estimations

An increasing number of countries around the world have started to compile estimates of CO_2 storage capacity. In many cases, the initial estimations are restricted to oil and gas reservoirs or coal seams because these storage options are easier to assess than saline aquifers, mainly due to the availability of data. Even when saline aquifers were included in the assessment; either only storage in selected stratigraphic and structural traps or the capacity in selected aquifers was considered. To the knowledge of the authors of this report, apart from for first-order estimates, no country- or basin-scale assessment of aquifer storage has been performed to date that takes in account the capacity in all suitable aquifers in a sedimentary succession. In the following, a compilation of recent country-scale capacity estimates shows the various approaches taken to assess the country's CO_2 storage capacity. Emphasis is put on the estimation of storage capacity in saline aquifers.

USA and Canada

The most comprehensive work on large-scale CO_2 storage capacity estimations to date has been produced by the USDOE Regional Carbon Sequestration Partnership (RCSP) program in form of the Carbon Sequestration Atlas of the United States and Canada (DOE, 2007). This DOE project developed the methodology for CO_2 capacity estimations described in the previous section and each RCSP employed this methodology to calculate consistent CO_2 storage capacities for the various parts of the Unites States and parts of Canada (Figure 14). While a consistent methodology was employed to estimate the CO_2 storage capacity in saline aquifers in the various RCSPs, these results are not (and were not intended to be) based on a comprehensive assessment of all existing aquifers potentially suitable for CO_2 geological storage. Depending on the individual research strategies in each RCSP and on the geological data available, only selected aquifers were included in the capacity assessment. It is expected that CO_2 storage capacity estimates will be updated annually as new data are acquired and methodologies improve and estimates are expanded to previously unassessed aquifers

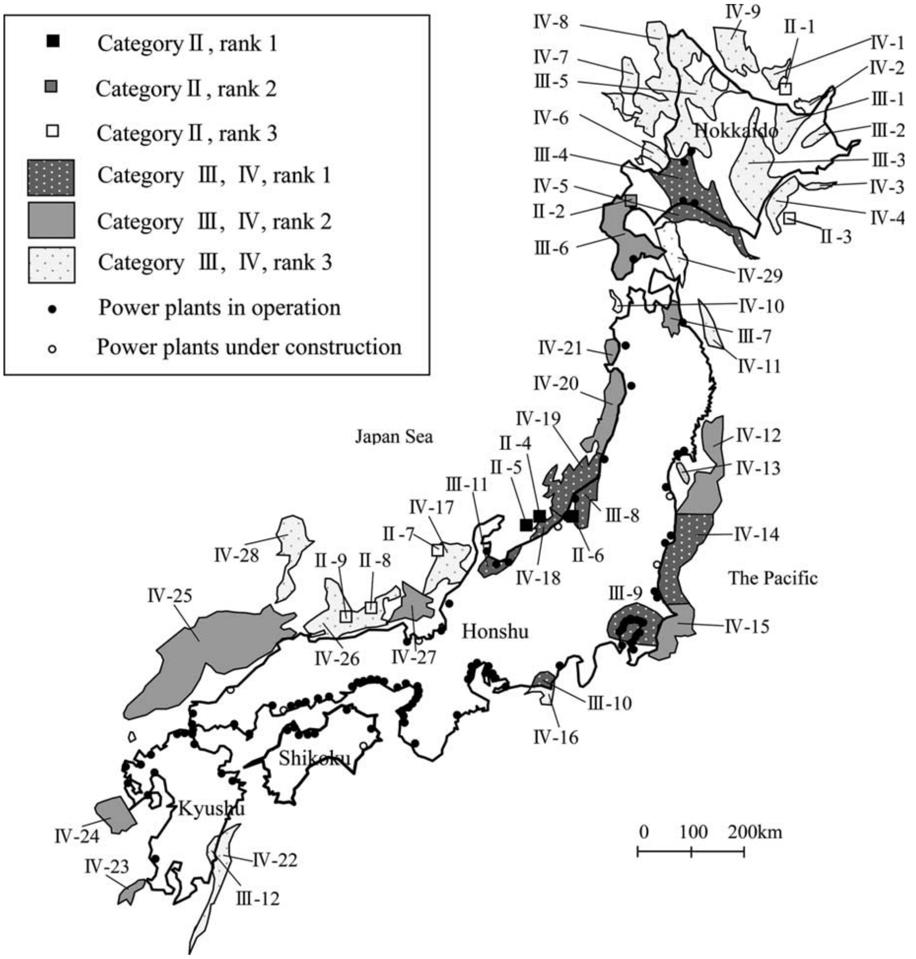


Regional Partnership	CO_2 Capacity (Billion tonnes)	
	Low	High
Big Sky Carbon Sequestration Partnership	271	1,085
Midwest Geological Sequestration Consortium	29	115
Midwest Regional Carbon Sequestration Partnership	47	189
The Plains CO_2 Reduction Partnership	97	97
Southeast Regional Carbon Sequestration Partnership	360	1,440
Southwest Regional Partnership on Carbon Sequestration	18	64
West Coast Regional Carbon Sequestration Partnership	97	388
Total	**919**	**3,378**

Figure 14. CO_2 capacity estimates in saline aquifers by Regional Partnership (DOE, 2007; Litynski et al., 2008).

Japan

The Research Institute of Innovative Technology for the Earth (RITE) assessed 69 sites with respect to their capacity to store CO_2 in saline aquifers following the methodology described in the Li et al. (2005) (Figure 15). Subsequently, RITE published a study in 2006, which estimates the CO_2 storage capacity in supercritical phase in closed structures to be 30.1 Gt (RITE, 2006). In addition, (Suekane et al., 2008) evaluated the supplementary CO_2 storage potential in open aquifers based on residual gas and solubility trapping to be 71.6 Gt, which results in a total of 101.8 Gt of CO_2 storage capacity.



Region	Capacity (Gt)	Sources	Annual CO_2 supply (Mt/year)					
			E_0	E_{10}	E_{20}	E_{30}	E_{40}	E_{50}
Southwest Hokkaido	12.2	5	4.3	4.3	4.3	5.3	5.3	5.3
Niigata	10.3	4	1.9	15	15	15	15	17
Joban	10.0	9	27	27	27	37	37	37
Toyama	2.2	4	7.5	7.5	7.5	7.5	7.5	7.5
Kanto	12.4	13	51	51	51	51	51	51
Total	**47.1**	**45**	**92**	**106**	**106**	**116**	**116**	**118**

Figure 15. CO_2 storage sites and capacity estimates in saline aquifers and emission sources in Japan (Li et al., 2005). See Table 16 for ranking scheme.

EUROPE (GESTCO)

The ENERGIE Programme of the European Union 5th Framework formed the GESTCO project, in which various national geological surveys and research organizations assessed the CO_2 storage capacity in selected European countries (Table 17). The GESTCO project ran from March 2000 to February 2003 and the results were published in October 2003 with a second edition in November 2004 (GESTCO, 2004). As part of the project, the storage potential of selected saline aquifers in and surrounding the southern North Sea was investigated in nine case studies and the results are shown in Table 17). The combined total storage capacity of up to 390 Gt appears small compared to the 600 Gt storage capacity that Statoil believes to exist for the Utsira Formation under the North Sea alone (Statoil, 2000).

An update of European capacity estimates is expected for the end of 2008 as a result of the EU GeoCapacity project, which will include full assessments of previously not-covered countries and sedimentary basins, as well as updates for formerly covered areas in the GESTCO project. The GeoCapacity project intends to cover all parts of the sedimentary basins suitable for CO_2 storage within the EU and the Central and Eastern European new member states and candidate countries.

Table 17. CO_2 storage capacity of selected aquifers in participating EU countries (GESTCO, 2004).

Region	Capacity (Gt)	Years of Storage	Comments
UK (southern North Sea)	14.7	51	Bunter Sandstone
Denmark (selected)	16	424	11 individual structures
Germany	23 – 43	45 – 84	Mainly northern GER
Norway (offshore)	286 (13)	435	Traps only in brackets
Netherlands	1.6	13	
Greece	2.2	39	
Belgium (Campine Basin)	0.1	1	
France (Paris Basin)	26 (0.6)	3	Traps only in brackets
Total	**71 – 390**		

Various European countries have been working on national storage capacity estimates within as well as independent from the GESTCO/GeoCapacity project.

Germany

First-order theoretical storage capacity estimates originate from various regional- to local-scale studies (Figure 16), covering approximately half of the area of sedimentary basins in Germany (May et al., 2005). Storage estimates restricted to closed structures are on the order of 20 +/- 8 Gt, assuming that traps occupy 5 % of the aquifers and a 0.12 Mt/km^2 (40 % efficiency) specific storage capacity.

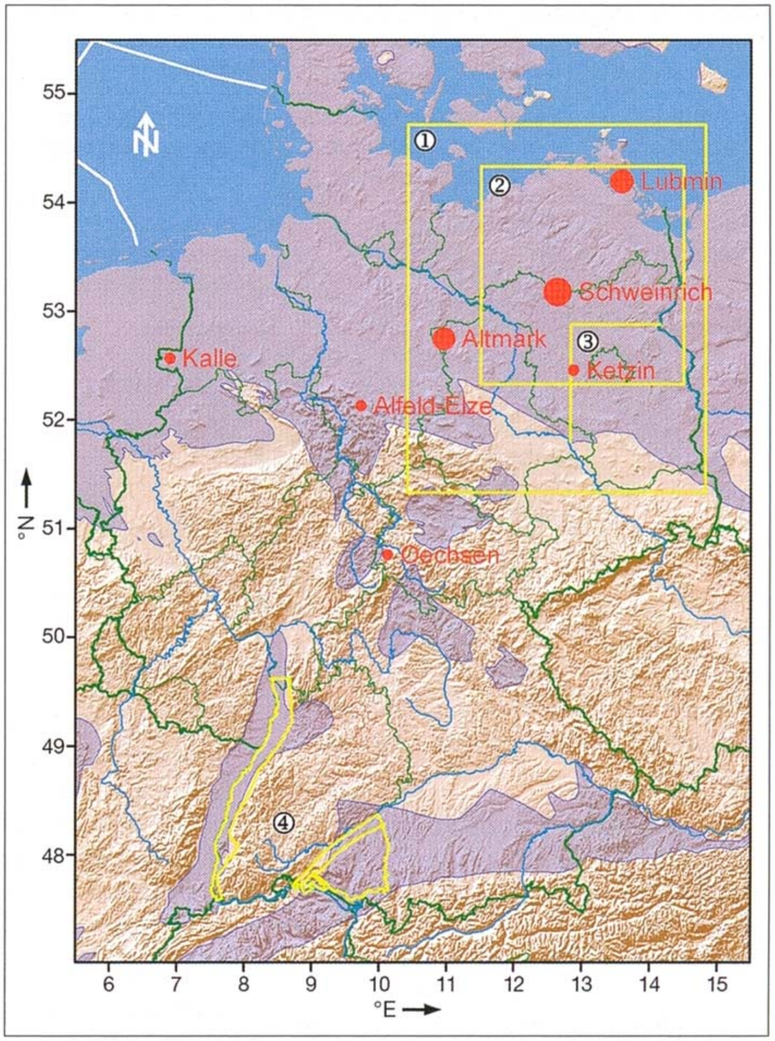
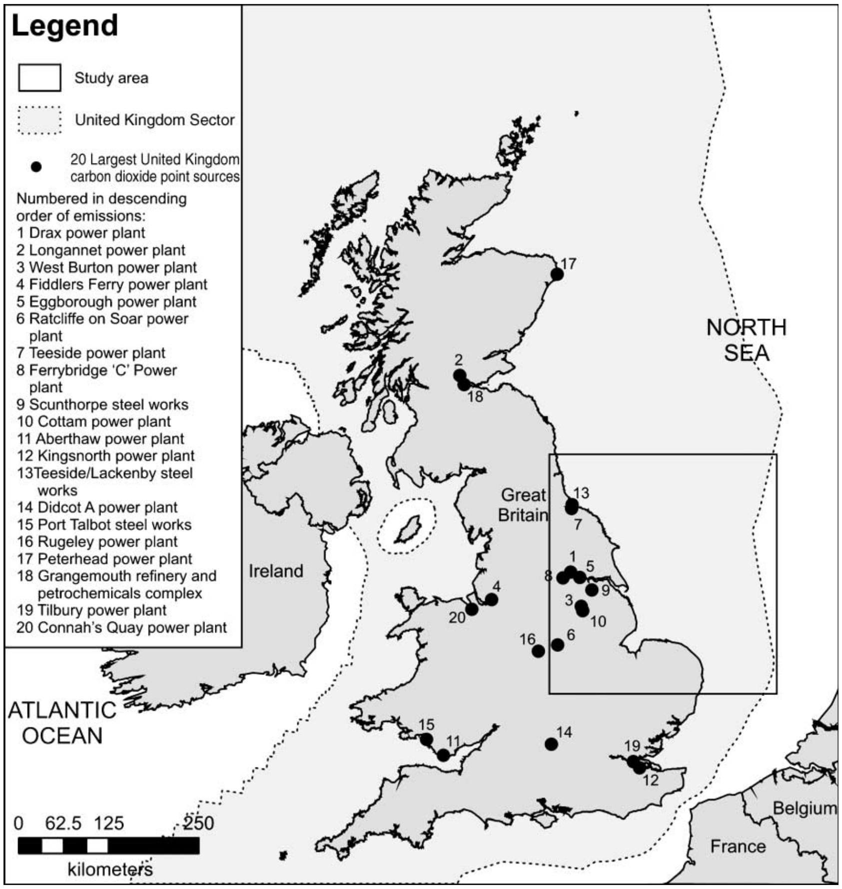


Figure 16. Areal coverage of various CO$_2$ storage capacity studies in Germany: deep sedimentary basins (purple), regional aquifer studies (yellow), and local case studies (red) (May et al., 2005). 1: (Mueller et al., 2003), 2: (Zemke et al., 2003), 3: Vattenfall Europe (unpublished), 4: (Turkovic, 2002).

Great Britain

Supplementing the assessment of the Bunter Sandstone in the GESTCO report, storage capacity was calculated for additional aquifers and gas field in the southern North Sea Basin (Holloway et al., 2006)(Figure 17). The authors used these values to calculate the amount of CO_2 stored per unit area (42 – 260 kg/m^2) and the amount of CO_2 stored per unit of pore volume (1.8 – 10 kg/m^3), which could be used to extrapolate capacity estimates to areas in which the prospective storage formation is present but no detailed structure contour, porosity, and isopach maps are available. Additional storage potential of 0.63 Gt CO_2 in closed structures of the Ormskirk sandstone aquifer have been suggested for geological storage in the East Irish Sea Basin (Gough and Shackely, 2005).

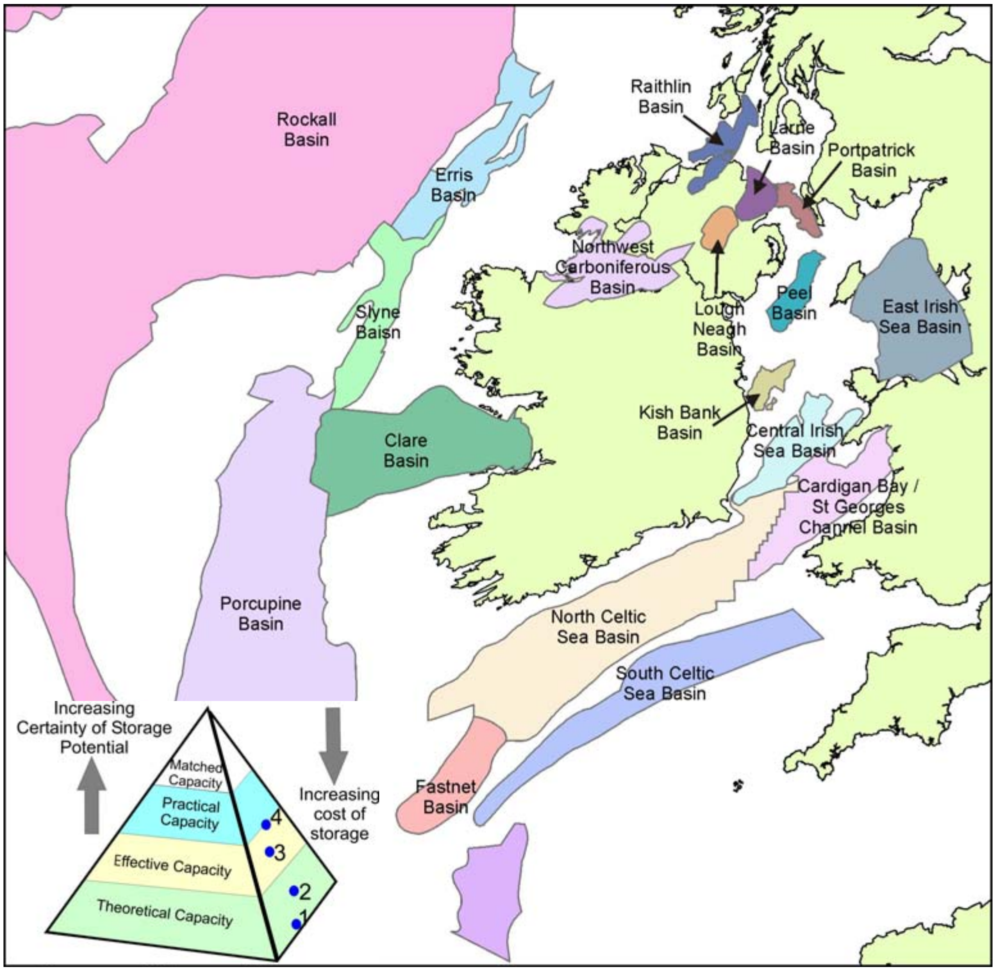


Storage target	Capacity (Gt)	Comments
Bunter Sandstone aquifer	14.2	Closed structures
Bunter Sandstone	0.4	Gas fields
Leman Sandstone	3.2 – 3.3	Gas fields
Carboniferous	0.2	Gas fields
Carboniferous (closed) and chalk aquifers	unquantified	
Total	**18**	

Figure 17. Location of area assessed for CO_2 storage capacity and 20 largest industrial sources of CO_2 in the United Kingdom. The attached table shows capacity estimates for selected geological formations (from Holloway et al, 2006).

Ireland

Suitable onshore and offshore sedimentary basins in Ireland were assessed for their geological storage capacity (CSA, 2008). Depending on storage type and data availability, capacity estimates for individual basins and hydrocarbon fields were classified following the CSLF (2007) techno-economic resource pyramid (Figure 18). The study estimates that Ireland has a total storage capacity of 93 Gt, of which approximately 4 Gt can be classified as Effective and/or Practical Capacity in oil and gas fields, whereas the remaining 89 Gt are mainly allocated to saline aquifers and classified as Theoretical Capacity.



Basin	Structure Type	CSLF Capacity Classification	Capacity (Gt)
N. Celtic Sea, E. Irish Sea	oil/gas fields	Effective/Practical (4)	1.5
Portpatrick, L. Neagh, E. Irish Sea, Kisk Bank, C. Irish Sea	selected structures	Effective (3)	2.8
Portpatrick, Larne, Peel, C. Irish Sea, Dowra	whole basins	Theoretical (2)	88.8
Other	selected aquifers	Theoretical/un-quantified (1)	-
		Total	93.1

Figure 18. Assessment of CO2 geological storage capacity in sedimentary basins in Ireland (CSA, 2008).

Poland

Poland as partner in the European GESTCO project has started to assess Mesozoic formations of the Polish Lowlands with respect to CO_2 storage suitability and capacity (Figure 19). So far, 18 structures in saline aquifer have been investigated, resulting in an estimated storage capacity of 5.3 Gt CO_2 (Tarkowski and Uliasz-Misiak, 2006; Wojcicki et al., 2007).

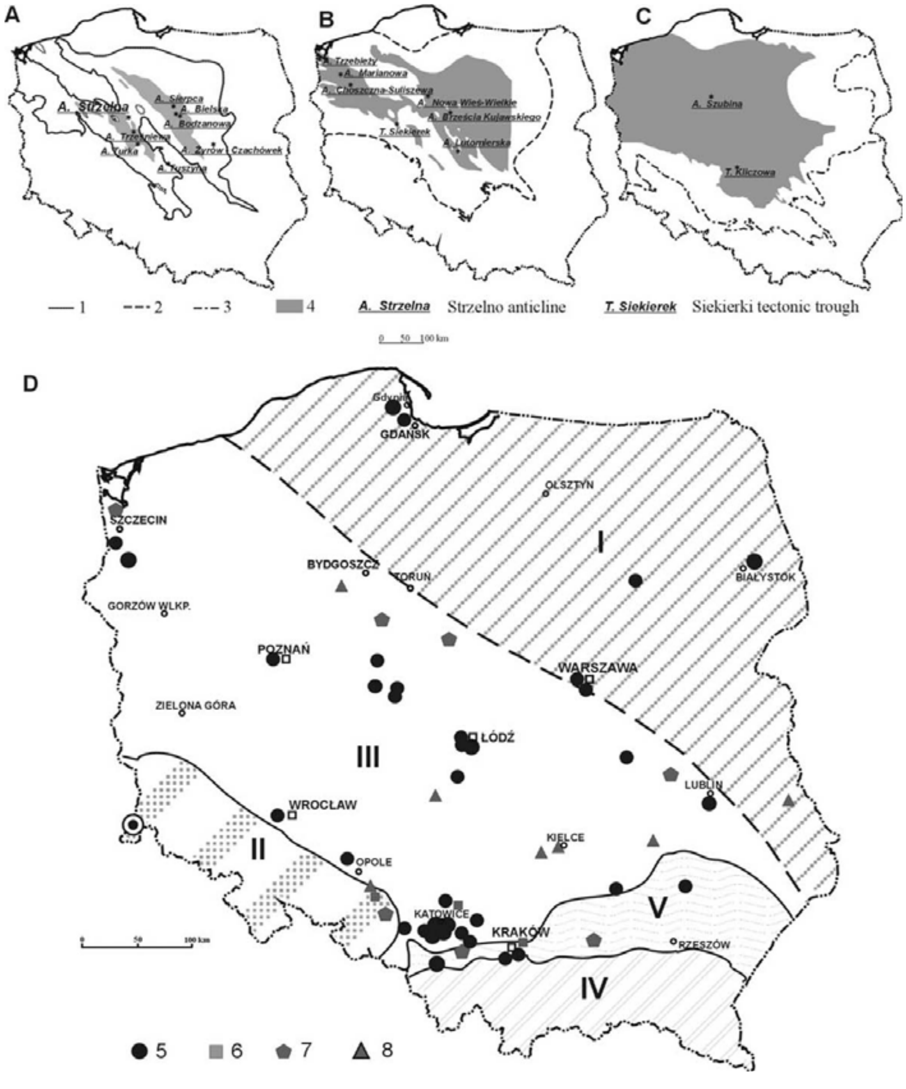


Figure 19. Prospective areas and geological structures selected for underground CO_2 storage in Lower Cretaceous (A), Lower Jurassic (B) and Lower Triassic (C) rocks and distribution of major point sources of CO_2 emission in relation to major geological structures of Poland (D); 1, 2, 3—extent of Lower Cretaceous, Lower Jurassic and Lower Triassic rocks, 4—areas recognized as perspective for underground CO_2 storage, 5—power and power and heat plants, 6—steelworks, 7—chemical plants, 8—cement plants, I—East European Precambrian platform, II—Sudety Mts, III—Paleozoic Platform, IV—Carpathian Mts, V—Carpathian Foredeep (Tarkowski and Uliasz-Misiak, 2006).

Brazil

The CARBMAP project is in the progress of assessing stationary emission sources in Brazil and in estimating CO_2 storage capacity on a country- to basin scale. Preliminary results suggests that sedimentary basins, which cover approximately 4.8 million square kilometres (Figure 20), provide up to 2000 Gt effective storage capacity in saline (Ketzer et al., 2007). Matching emission sources to potential sinks indicate that particularly the basins in south-eastern Brazil are well located, whereas large effective storage capacity in the northern part of the country probably would require transport distances that are too long to be economically feasible.

Basin	Capacity (Gt)	"Source-sink" matched Capacity (Mt/year)
Campos	4.8	31
Santos	148	80
Solimoes	252	2.5
Parana	462	135
others	~ 1133	-
Total	**~ 2000**	**248.5**

Figure 20. Effective storage capacity and capacity matched to potential sources in aquifers in selected sedimentary basins in Brazil (from Ketzer et al., 2007).

Australia

As a result of the GEODISC program of the Australian Petroleum Cooperative Research Centre (APCRC), the predecessor of the CO2CRC, a portfolio of geological storage sites across all Australian sedimentary has been produced (Bradshaw et al., 2003; Bradshaw et al., 2002). Out of more than 300 sedimentary basins, 48 basins were considered viable for detailed study (Figure 21). In excess of 100 "Environmentally Sustainable Sites for CO_2 Injection" (ESSCIs) were evaluated by the project, by applying deterministic risk assessment based on storage capacity, injectivity potential, site details, containment and impact on natural resources. The total storage capacity was estimated to be 740 Gt of CO_2 (approximately 700 Gt in hydrodynamic traps), resulting in a more realistic storage potential of 100 – 115 Mt CO_2/year when considering economics and technical viability (Bradshaw et al., 2002).

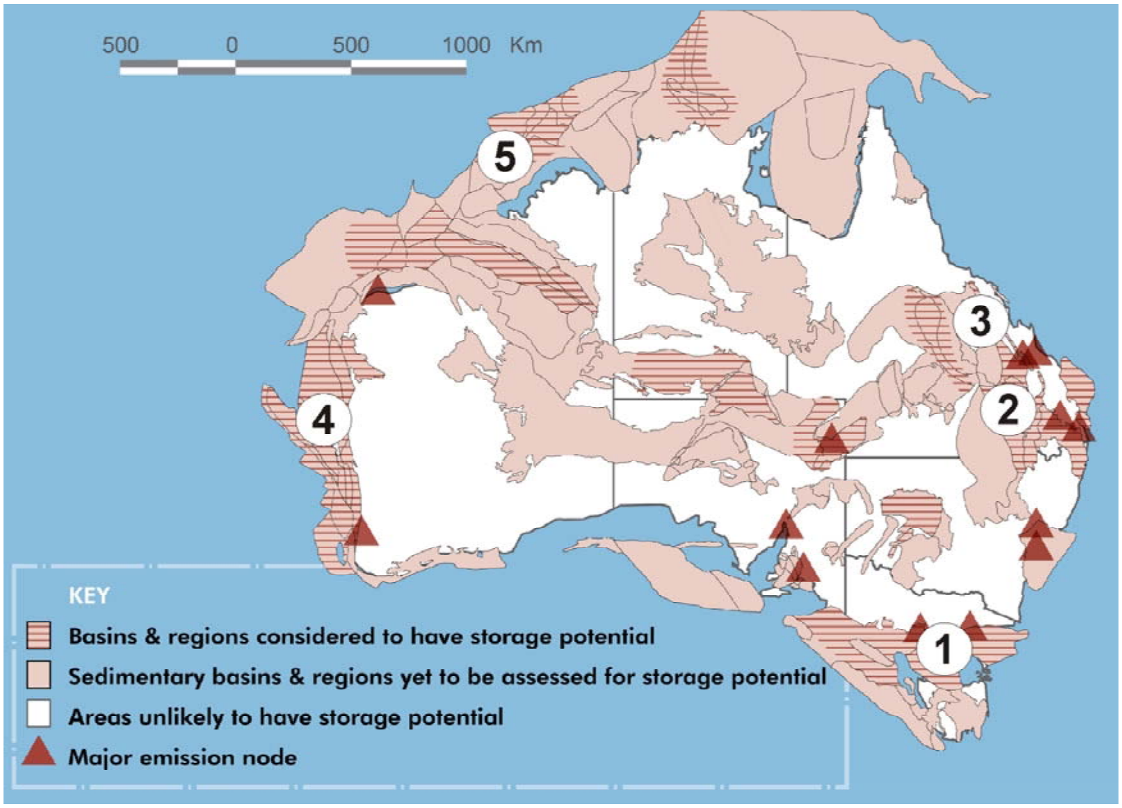
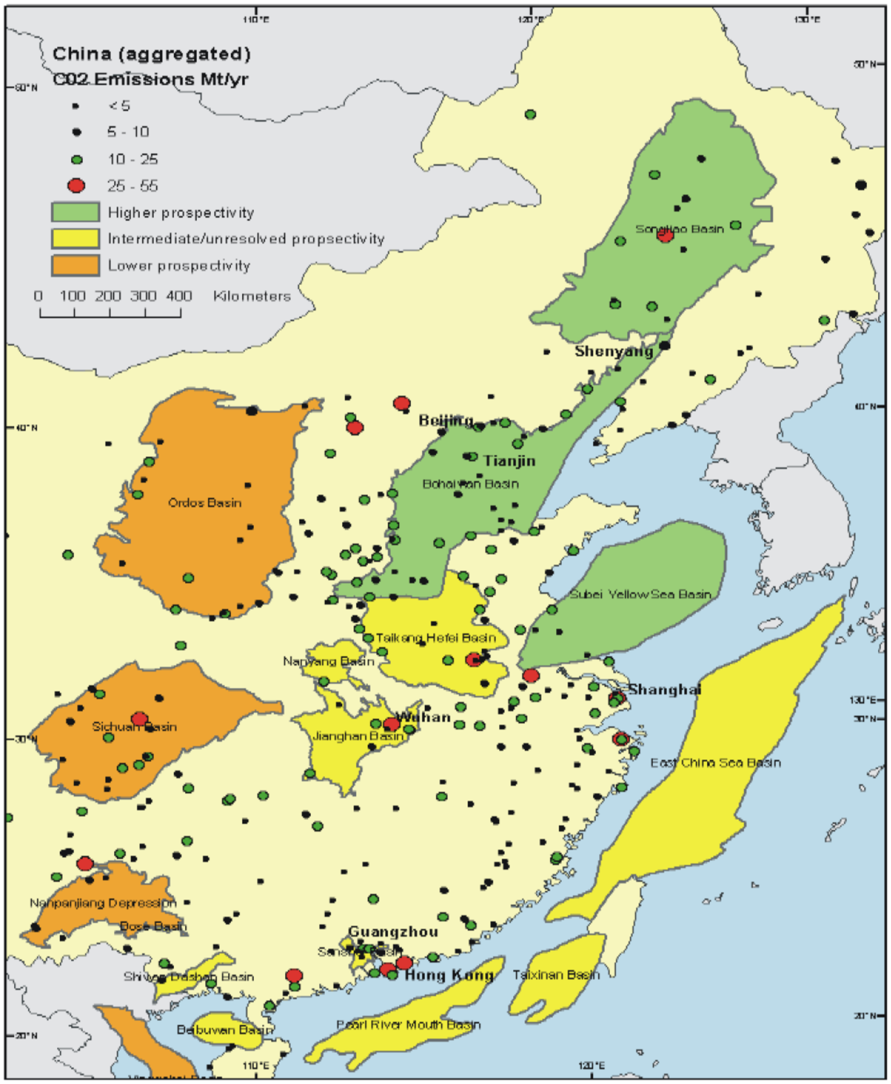


Figure 21. Assessment of CO_2 geological storage capacity in selected sedimentary basins in Australia: 1) Gippsland Basin (and others) – Victoria (Gibson-Poole et al., 2007; Gibson-Poole et al., 2008; Gibson-Poole et al., 2006), 2) Bowen Basin – Queensland (Sayers et al., 2006), 3) Dension Trough – Queensland (Marsh and Scott, 2005), 4) Perth Basin – Western Australia (Varma et al., 2007), 5) Browse Basin – Western Australia. The various reports are available for download at the CO2CRC webpage: www.co2crc.com.au.

Recent regional studies, of selected sedimentary basins in the states of Victoria (Gibson-Poole et al., 2006; 2007; 2008), Western Australia (Varma et al., 2007) and Queensland (Sayers et al., 2006) were aimed at finding suitable injection sites for CO_2 emissions from various coal power plants in these states and have resulted in a refined characterisations of suitability and storage capacity.

China

Quotes for the CO_2 storage capacity estimates in China are sparse, at least in the English-speaking literature; consequently conference and workshop presentations form the only source of information used in this study. According to Li (2007), China's sedimentary basins have the capacity to store up to 1435 Gt CO_2 in the form of solubility trapping (Figure 22). Estimates for the volumetric storage capacity calculated according to the ECOFYS-TNO method (Equation 6) range from 10 to 364 Gt.



Location	Capacity (Gt)			
	Volumetric			In solution
	low	best	high	
Onshore	7.7	123.0	276.6	773.8
Offshore	2.4	38.8	87.4	661.2
Total	**10.1**	**161.8**	**364.0**	**1435**

Figure 22. Assessment of CO_2 geological storage prospectivity and capacity in saline aquifers in selected sedimentary basins in China (Newlands and Langford, 2005; Li, 2007).

India

Assessment of CO_2 storage capacity in saline aquifers in India is still in its early stages. Preliminary characterization of sedimentary basins in India resulted in a general classification of “good”, “fair”, and “limited” storage potential (Holloway et al., 2008)(Figure 23). The areal extensive Deccan flood basalts in northwest India are assessed as an additional storage target. The storage capacity at depth below 800 m is tentatively estimated to range between 150 to 300 Gt (Jayaraman, 2007; Sonde, 2007). A pilot study by the National Thermal Power Corporation (NTPC) in collaboration with Pacific Northwest National Laboratories (PNNL) and the National Geophysical Research Institute (NGRI) will investigate whether CO_2 injection into basalts is technically feasible in India.

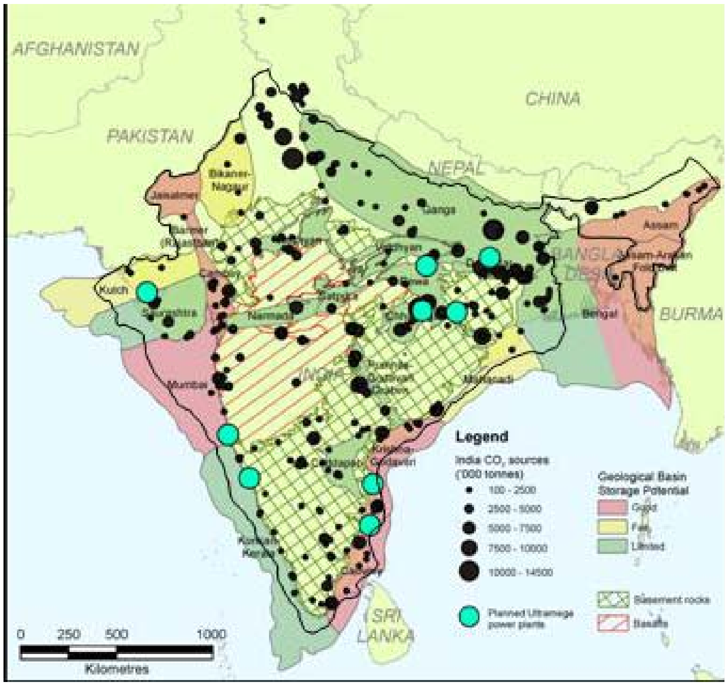
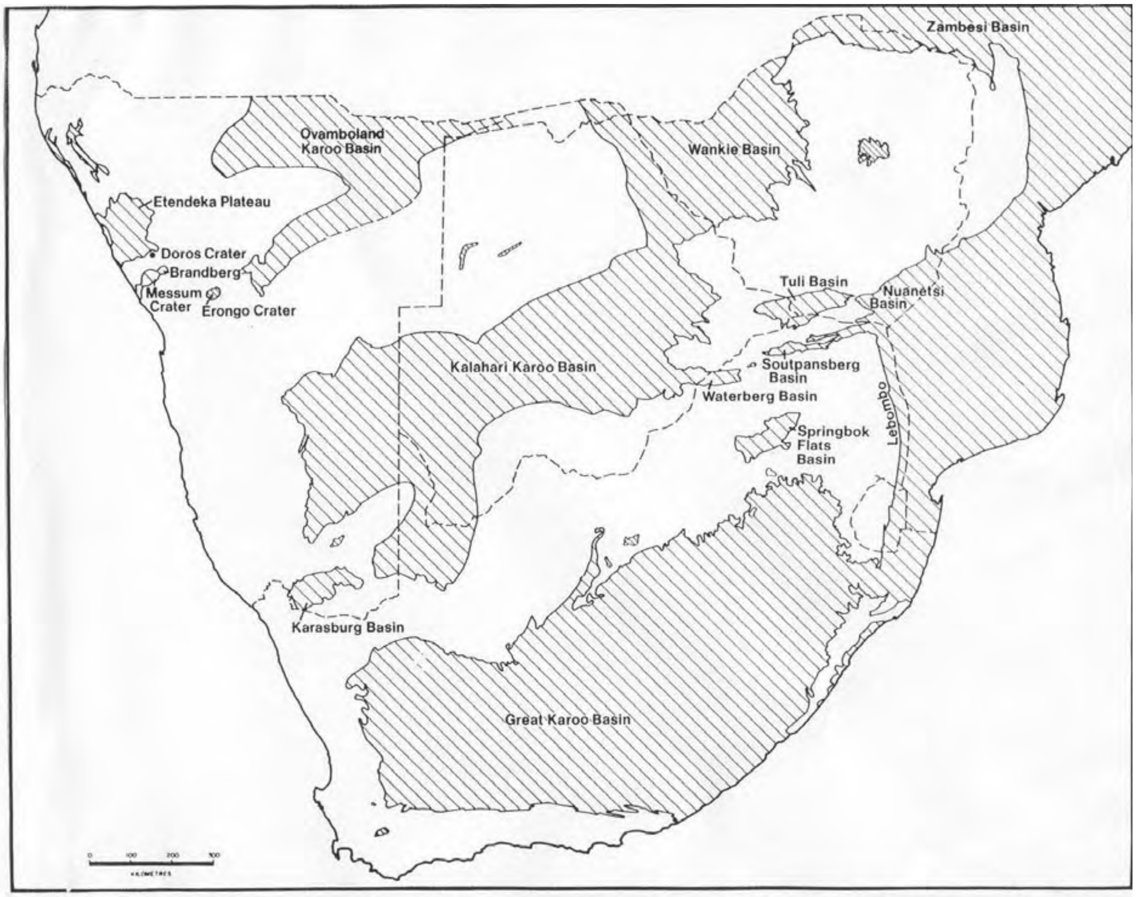


Figure 23. Preliminary assessment of CO_2 geological storage potential of sedimentary basins in India (Holloway et al., 2008).

Africa

Emissions of greenhouse gases in Africa are relatively low compared to the rest of the world. Aside from the existing CO_2 injection operation at In Salah in Algeria, South Africa, dominating CO_2 emissions on the African continent is the only country that has started to look at geological storage options (Sengul et al., 2007). Initial storage capacity estimations were published in form of a report by the Council for Scientific and Industrial Research (CSIR) to the South African Department of Minerals and Energy (Engelbrecht et al., 2004). The most prospective basin with respect to saline aquifers suitable for CO_2 geological storage is the Greater Karoo Basin in the southern part of South Africa (Figure 24). Engelbrecht et al. (2004) have assessed the CO_2 storage capacity in two sandstone formations in the Karoo Supergroup, the Vryheid Formation and the Katberg Formation, which provide considerable storage volume below 800 m depth. The combined potential storage capacity for the two formations, assuming 2 % of the aquifer volume being accessible and 10 % effectiveness, is 20 Gt, which would be sufficient to store South Africa's CO_2 emissions for approximately 50 years.



Geological Formation	Thickness (m)	Area (km^2)	Porosity (%)	Capacity (Gt)	Comments
Vryheid	350	26,500	3 - 5	18.4	Relatively poor permeability
Katberg	1000	8,000		1.6	
Total				**20.0**	

Figure 24. Assessment of CO_2 geological storage capacity in the Karoo Basins in Southern Africa (Engelbrecht et al., 2004).

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Appendix 2: Best Practice and Site Characterisation Requirements - Additional Information

Annex 1 from Commission of the European Communities 2008

The European Parliament is working towards a legal framework for the geological storage of CO_2, and a useful template for Best Practice is provided in their 2008 proposal for a 'Directive' on the geological storage of carbon dioxide (Commission of the European Communities 2008). The proposal states that the characterisation and assessment of storage sites shall be carried out in four steps;

1. Data collection,
2. Computerised simulation of the storage complex,
3. Security, sensitivity and hazard characterisation, and
4. Risk assessment

Step 1: Data collection

For the data collection, sufficient data shall be accumulated to construct a *volumetric and dynamic three-dimensional (3-D)-earth model* for the storage site and storage complex including the caprock, and the surrounding area including the hydraulically connected areas. This data shall cover at least the following intrinsic complex characteristics:

1. Reservoir geology and geophysics;
2. Hydrogeology (in particular existence of potable ground water);
3. Reservoir engineering (including volumetric calculations of pore volume for CO_2 injection and ultimate storage capacity, pressure and temperature conditions, pressure volume behaviour as a function of formation injectivity, cumulative injection rate and time);
4. Geochemistry (dissolution rates, mineralisation rates);
5. Geomechanics (permeability, fracture pressure);
6. Seismicity (assessment of potential for induced earthquakes);
7. Presence and condition of natural and man-made pathways which could provide leakage pathways.

The following characteristics of the complex vicinity shall be documented:

8. Domains surrounding the storage complex that may be affected by the storage of CO_2 in the storage site;
9. Population distribution in the region overlying the storage site;

10. Proximity to valuable natural resources (including in particular Natura 2000 areas pursuant to Directives 79/409/EEC and 92/43/EEC, potable groundwater and hydrocarbons);
11. Possible interactions with other activities (e.g. exploration, production and storage of hydrocarbons, geothermal use of aquifers);
12. Proximity to the potential CO_2 source(s) (including estimates of the total potential mass of CO_2 economically available for storage).

Step 2: Computerised simulation of the storage complex

Using the data collected in Step 1, a three-dimensional static geological earth model, or a set of such models, of the candidate storage complex including the caprock and the hydraulically connected areas shall be built using computer reservoir simulators. The static geological earth model(s) shall characterise the complex in terms of:

1. Geological structure of the physical trap;
2. Geomechanical and geochemical properties of the reservoir;
3. Presence of any faults or fractures and fault/fracture sealing;
4. Overburden (caprock, seals, porous and permeable horizons);
5. Areal and vertical extent of the storage formation;
6. Pore space volume (including porosity distribution);
7. Any other relevant characteristics.

The uncertainty associated with each of the parameters used to build the model shall be assessed by developing a range of scenarios for each parameter and calculating the appropriate confidence limits. Any uncertainty associated with the model itself shall also be assessed.

Step 3: Security, sensitivity and hazard characterisation

Step 3.1 Security characterisation

Security characterisation shall be based on dynamic modelling, comprising a variety of timestep simulations of CO_2 injection into the storage site using the three-dimensional static geological earth model(s) in the computerised storage complex simulator constructed under Step 2. The following factors shall be considered:

1. Possible injection rates and CO_2 properties;
2. The efficacy of coupled process modelling (i.e. the way various single effects in the simulator(s) interact);
3. Reactive processes (i.e. the way reactions of the injected CO_2 with in situ minerals feedback in the model);
4. The reservoir simulator used (multiple simulators may be required in order to validate certain findings);
5. Short and long-term simulations (to establish CO_2 fate and behaviour over decades and millennia including the solution velocity of CO_2 in water).

The dynamic modelling shall provide insight to:

6. Pressure volume behaviour vs. time of the storage formation;
7. Areal and vertical extent of CO_2 vs. time;
8. The nature of CO_2 flow in the reservoir including phase behaviour;
9. CO_2 trapping mechanisms and rates (including spill points and lateral and verticalseals);
10. Secondary containment systems in the overall storage complex;
11. Storage capacity and pressure gradients in the storage site;
12. The risk of fracturing the storage formation(s) and caprock;
13. The risk of CO_2 entry into the caprock (e.g., due to exceeding the capillary entry pressure of the caprock or due to caprock degradation);
14. The risk of leakage through abandoned or inadequately sealed wells;
15. The rate of migration (in open-ended reservoirs);
16. Fracture sealing rates;
17. Changes in formation(s) fluid chemistry and subsequent reactions (e.g. pH change, mineral formation) and inclusion of reactive modelling to assess affects;
18. Displacement of formation fluids.

Step 3.2 Sensitivity characterisation

Multiple simulations shall be undertaken to identify the sensitivity of the assessment to assumptions made about particular parameters. The simulations shall be based on altering parameters in the static geological earth model(s), and changing rate functions and assumptions in the dynamic modelling exercise. Any significant sensitivity shall be taken into account in the risk assessments.

Step 3.3 Hazard characterisation

Hazard characterisation shall be undertaken by characterising the potential for leakage from the storage complex, as established through dynamic modelling and security characterisation described above. This shall include consideration of *inter alia*:

1. Potential leakage pathways;
2. Potential magnitude of leakage events for identified leakage pathways (flux rates); (c) Critical parameters affecting potential leakage (e.g. maximum reservoir pressure, maximum injection rate, sensitivity to various assumptions in the static geological Earth model(s) etc.);
3. Secondary effects of storage of CO_2 including displaced formation fluids and new substances created by the storing of CO_2;
4. Any other factors which could pose a hazard to human health or the environment (e.g. physical structures associated with the project);

The hazard characterisation shall cover a range of potential scenarios including scenarios that test the security of the storage complex to the extreme.

Step 4: Risk assessment

The risk assessment shall cover the range of scenarios developed under the hazard characterisation of Step 3 and shall comprise the following:

1. Exposure assessment – based on the characteristics of the environment and distribution of human population above the storage complex, and the potential behaviour and fate of leaking CO_2 from potential pathways identified under Step 3;

2. Effects assessment – based on the sensitivity of particular species, communities or habitats linked to potential leakage events identified under Step 3. Where relevant it shall include effects of exposure to elevated CO_2 concentrations in the biosphere (including soils, marine sediments and benthic waters (asphyxiation; hypercapnia) and reduced pH in those environments as a consequence of leaking CO_2). It shall also include an assessment of the effects of other substances that may be present in leaking CO_2 streams (either impurities present in the injection stream or new substances formed through storage of CO_2). These effects shall be considered at a range of temporal and spatial scales, and linked to a range of different magnitudes of leakage events.

3. Risk characterisation – This shall comprise an assessment of the safety and integrity of the site in the short and long term, including an assessment of the risk of leakage under the proposed conditions of use, and of the worst-case environment and health impacts. The risk characterisation shall be conducted based on the hazard, exposure and effects assessment. It shall include an assessment of the sources of uncertainty.

Site Characterisation - CO2CRC (2008)

The selection of a suitable site for the storage of significant volumes of CO_2 comprises mainly geological evaluation on progressively more and more detailed scales. The different levels of site assessment that can be undertaken range from an initial regional screening to very detailed site-specific characterisation. A useful workflow that summarises the different scales of site assessment is presented in Figure 25 (Gibson-Poole, 2008). Each level of detail progressively reduces uncertainty, but also results, typically, in a decrease of the storage volume. In addition, each level of detail in site selection requires greater effort, and increasing amounts and types of data, time and costs. The correlation from characterisation scale level to storage volume classification level as displayed may not always be a one-to-one correlation, but rather represents the likely maximum level of storage capacity assessment achievable given the likely database available at that level of characterisation.

Once potential storage sites have been identified and ranked during the basin-scale assessment stage of investigation, a prospective site has to be further evaluated through a process of detailed site characterisation. (Cook, 2006) defines site characterisation as "the collection, analysis and interpretation of subsurface, surface and atmospheric data (geoscientific, spatial, engineering, social, economic, environmental) and the application of that knowledge to judge, with a degree of confidence, if an identified site will geologically store a specific quantity of CO_2 for a defined period of time and meet all required health, safety, environmental and regulatory standards".

Site characterisation is the most time-consuming and costly part of the CO_2 storage site selection process. Because CO_2 site characterisation taps into a vast array of expertise, and requires skills in reservoir engineering, structural geology, sedimentology, stratigraphy, hydrogeology and geological modelling, this stage of CO_2 storage is best done in a multidisciplinary team environment. It is also the stage that clearly goes beyond the "pre competitive" stage of a study and may therefore be more properly seen as the role of industry or a project proponent, rather than of government. Site characterisation requires greater detail than basin-scale assessment investigations and may involve re-evaluation of regional geology, generation of new data and/or updating of existing static geologic and seismic data and dynamic engineering data and numerical flow simulation models. Data sources can include 2D and 3D seismic surveys, well log and core data, drill cuttings, biostratigraphy, field production and fluid data. Typical steps in site characterisation are structural and stratigraphic interpretation based on available subsurface data, building of geological models with realistic stratigraphic heterogeneity, building of geochemical, geomechanical and hydrogeological models, and constructing numerical flow simulations to predict CO_2 plume migration (Gibson-Poole, 2008; Gibson-Poole et al., 2005). Models have to be continuously updated as additional data become available, a process that must extend to the post-injection phase for monitoring purposes.

Depending on data coverage and quality, all of the above steps should incorporate appropriate levels of uncertainty in interpretation, which should be reflected in the various outcomes of multiple flow simulation scenarios. An important aspect of site characterisation is the determination of acceptable versus unacceptable levels of uncertainty in order to determine the amount of risk associated with the site and the amount and type of additional data required to reduce the uncertainty. These additional data have associated costs, both financially and in effort, as well as an additional time component that must be built into the project management (CO2CRC, 2008).

Three key factors that require further detailed evaluation (modified from the five suggested by (Bradshaw et al., 2002) are: injectivity, containment and capacity (Figure 25). These three factors encompass the fundamental elements needed to characterise any potential CO_2 geological storage site and are described in more detail below. The following discussion is mostly extracted or modified from Gibson-Poole et al. (2005) and Gibson-Poole (2008).

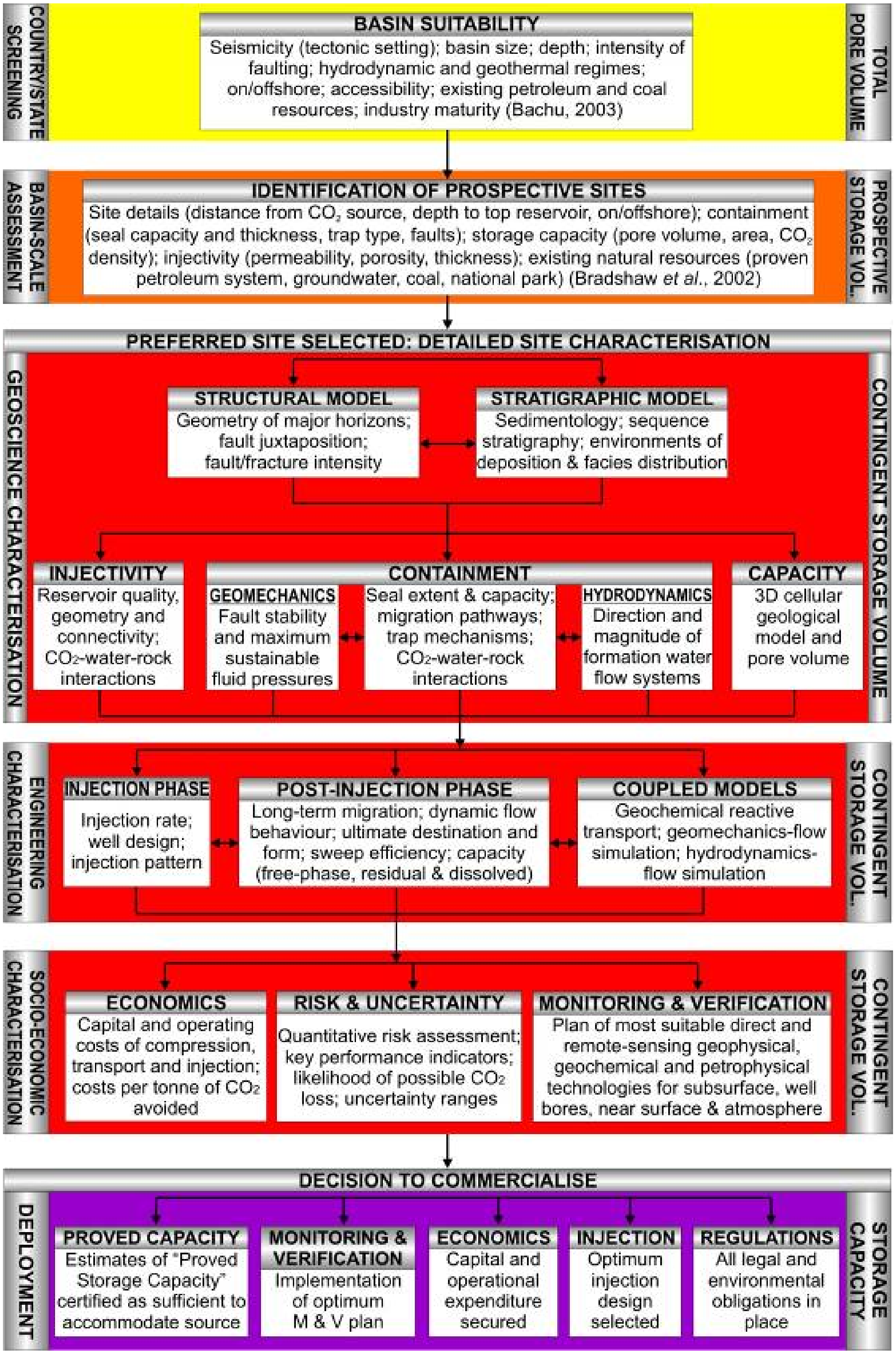

Figure 25. Site characterisation workflow for geological storage of CO_2 (modified from (Gibson-Poole, 2008).

Geoscience Characterisation: Injectivity

Injectivity is the rate at which CO_2 can be injected into a given reservoir interval (a volume of CO_2 per unit of time) and the ability of the subsequent CO_2 plume to migrate away from the injection well. Low injectivity potential for an interval might turn a site with otherwise excellent capacity and containment characteristics turning out to be uneconomic and, therefore, unsuitable for CO_2 storage. During CO_2 injection into a reservoir, the injectivity and nature of plume migration will depend on parameters such as the viscosity ratio, injection rate and relative permeability. These parameters will in turn depend on variables such as depositional environment and reservoir heterogeneity, stratigraphic architecture, post-depositional diagenetic alteration, structural dip, fault distribution and fault seal capacity, pressure distribution, and the nature of the formation fluids. Injectivity issues that can be assessed through the geoscience characterisation include the geometry and connectivity of individual flow units, the nature of the heterogeneity within those units (i.e., the likely distribution and impact of baffles such as interbedded siltstones and shales) and the physical quality of the reservoir in terms of porosity and permeability characteristics.

Reservoir quality can be assessed by evaluating core (porosity and permeability) and wireline logs (petrophysical interpretations) of existing wells. Well data is one-dimensional and away from these points, rock properties have to be inferred through well log correlation and use of analogues, guided by seismic interpretation. Geological (static reservoir) models need to be constructed to provide likely reservoir distribution and horizontal and vertical connectivity of flow units. These are best placed in a sequence stratigraphic framework, which allow improved predictions of heterogeneity and barrier/baffle distribution. Since important levels of heterogeneity can fall below seismic resolution, uncertainties in interpretation increase with distance from the wells. These uncertainties are best handled by allowing for multiple model realisations. Both favourable and unfavourable outcomes must be considered, with the overriding parameter that all realisations honour existing data. The uncertainties will greatly decrease if the site has pre-existing boreholes or is in an area with 3D seismic coverage.

Evaluation of injectivity for a site should also incorporate examination of the mineralogical composition of the reservoir for potential post-injection effects. CO_2 dissolution into the formation water may result in CO_2-water-rock interactions, which may alter the mineralogy and pore system of the rock (Watson et al., 2004). This can have important implications for injectivity, as mineral dissolution may lead to increased porosity and permeability. However, it could also result in mobilisation of fine clay particles or the precipitation of new minerals, either of which can occlude the porosity and permeability of the reservoir rock, thereby decreasing injectivity. Determination of which, if any, of these reactions might occur is dependent on the specific geological properties at each site.

Injectivity in Low Permeability Reservoirs

CO_2 storage in saline formations has several advantages over other geological storage options (i.e. depleted oil and gas reservoirs, coal seams), such as greater storage volume potential and less risk of compromising existing resources. However, many deep saline formations suffer from low permeability, due either to depositional processes (fine grained sediments and corresponding small pore throat sizes) or diagenetic processes (post-depositional mineralogical modification of pores and pore throats). Numerical investigations show that formation permeability is one of the main controlling parameters of CO_2 storage in geological formations (Ennis-King and Paterson, 2001; Law and Bachu, 1996; van der Meer, 1995).

For low permeability formations, numerical simulations show that there will be large pressure gradients near the wellbore, which will restrict the injectivity considerably. Thus, high permeability formations would be desirable for injection. However, high permeability formations would allow relatively fast migration of CO_2, lowering the proportion of CO_2 trapped behind the main plume by residual trapping. Slower movement provides greater residence time and thus several advantages such as enhancement of the dissolution potential of CO_2 in formation water and high volumes of CO_2 trapped by capillarity (Flett et al., 2005). Bachu et al. (1994) suggest that while higher permeability may be required near the wellbore to increase injectivity, lower permeability is desirable outside the radius of influence of the wellbore to increase residence times and encourage the rate of residual trapping, dissolution and mineral trapping.

Geoscience Characterisation: Containment

Containment refers to the retention of injected CO_2 within the subsurface site relative to the overall risk of its escape. Containment is an issue in CO_2 storage because injected supercritical CO_2 is less dense than water and has the tendency to be driven upward due to buoyancy forces. Loss of containment can occur through vertical fluid migration via the top seal, faults/fractures and existing well penetrations, or lateral migration to a point where stratigraphic loss of seal occurs. Possible containment issues, therefore, include the distribution and continuity of the seal, the seal capacity (maximum CO_2 column height retention), CO_2-water-rock interactions (potential for mineral trapping), potential migration pathways (structural orientations and dips), distribution and extent of intraformational seals (acting as localised barriers and baffles to flow), hydraulic gradient (formation water flow direction and rate) and the integrity of the reservoir and seal (rock strength, fault/fracture stability and maximum sustainable pore fluid pressures). Migration through existing well bores and leaking faults are considered the greatest containment risks in CO_2 storage (Celia and Bachu, 2003).

CO_2 injection into the geological subsurface increases the formation pressure, which can then potentially reactivate pre-existing faults or generate new fractures. Opening of fractures or causing slip (movement) on faults could lead to a loss of containment (Bergman and Winter, 1995; Holloway and Savage, 1993; Streit and Hillis, 2004). Thus, an understanding of the pressure regime and geomechanical modelling needs to be undertaken to estimate maximum sustainable fluid pressures for CO_2 injection that will not induce fracturing and faulting. This requires the determination of prevailing stresses, fault geometries and rock strengths. Details on geomechanical modelling techniques are described in Streit and Hillis (2004) and others.

The properties of the seal, both in terms of CO_2 retention capacity as well as distribution and continuity, can be assessed by a combination of laboratory and sequence stratigraphic analyses. The seal capacity of regional top seals and localised intraformational seals is calculated by determining the capillary pressure properties of the sealing rock and the physio-chemical properties of both the CO_2 and formation water (e.g. density, wettability and interfacial tension) through Mercury Injection Capillary Pressure (MICP) analysis. Standard procedures for MICP analysis are reviewed by Vavra et al. (1992), Dewhurst et al. (2002) and Daniel and Kaldi (in press).

CO_2 introduced into a reservoir system can also chemically interact with the host rock. Detailed reservoir petrology, water chemistry and pressure-temperature conditions provides information necessary for modelling of potential mineral reactions associated with CO_2, including dissolution, alteration and precipitation. Whereas for injectivity, CO_2-water-rock interactions could either enhance or reduce the injectivity through mineral dissolution or mobilisation, mineral precipitation can lead to mineral trapping of CO_2 and therefore increased containment security as the CO_2 is permanently trapped (Bachu et al., 1996; Perkins and Gunter, 1996; Watson et al., 2004; Watson and Gibson-Poole, 2005).

Sequence stratigraphic assessment of both the reservoir and the seal can predict facies distribution even in areas of poor data coverage. This is based on the predictable occurrence of strata packages with changes in potential space available for sedimentation and sediment supply, inferred from subsurface wireline and seismic data. In a homogeneous reservoir, the buoyancy of the free-phase (immiscible) CO_2 will cause it to migrate vertically up to the top of the reservoir. Stratigraphic heterogeneities, such as intraformational siltstones and shales, have the potential to reduce this type of flow and create a more tortuous migration pathway. Once the CO_2 plume has reached the top of the reservoir, the structural dip and geometry at the base of the overlying sealing unit will have a strong influence on the subsequent migration direction and rate. The details of the exact geometries and heterogeneities at the reservoir/seal boundary can prove especially important and can result in unexpected plume migration and possible loss of containment. Trapping mechanisms that can be identified through geoscience characterisation include physical structural closures and stratigraphic pinch-outs, and potential hydrodynamic (Bachu et al., 1994) or ‘rate seal’ traps.

An understanding of the existing formation water flow system within a geological reservoir is important for site characterisation as the rate and direction of flow of the formation water system will impact the effectiveness of hydrodynamic trapping, as well as dissolution and residual trapping along the migration pathway. Hydrodynamic modelling assesses the vertical communication between reservoir units, and hence the effectiveness of a seal, and provides information about the horizontal hydraulic continuity (e.g. fault compartments) and the impact of low permeability zones. In areas where there has been fluid removal from the subsurface (e.g. water extraction or oil production), an assessment of the pre-production hydrodynamic regime is used to provide an understanding of the long-term (hundreds to thousands of years) influence of the formation water flow systems on the injected CO_2. However, it is also necessary to interpret the present-day hydrodynamic regime, as it may have been affected by hydrocarbon/water production-induced pressure decline. The present-day (post-production) hydrodynamic regime can be used to evaluate the potential short-term (tens to hundreds of years) influence on the predicted migration pathway of CO_2 immediately after injection. The past and present formation water flow systems can be characterised from pressure-elevation plots and hydraulic head distribution maps using standard hydrodynamic analysis techniques as presented by Dahlberg (1995), Bachu (1995), Otto et al. (2001) and Bachu and Michael (2002).

Geoscience Characterisation: Capacity

Storage capacity evaluates the commercially available pore volume for CO_2 storage at a particular site. This is controlled by parameters such as the size of the containment area, the thickness of the reservoir, the effective porosity and the density of the CO_2. Storage capacity is discussed in detail in the main body of the report and in Appendix 1.

Engineering Characterisation

The engineering characterisation phase continues on from the geoscience characterisation. Short-term numerical simulation models of the injection phase are needed to provide data on the injection strategy required to achieve the desired injection rates (e.g. number of wells, well design and injection pattern). Post-injection phase numerical simulations evaluate the long-term storage behaviour, modelling the likely migration, distribution and form of the CO_2 in the subsurface. Coupled simulation models, such as geochemical reactive transport, can also be undertaken to further evaluate the CO_2 storage potential of a site. Optimising reservoir engineering via integration of reservoir characterisation with well placement, completion, conformance control, and injection strategies may in fact increase storage capacity.

Socio-Economic Characterisation

The final stage in detailed site evaluation is the socio-economic characterisation. This includes economic modelling to establish such aspects as the likely capital and operating costs, as well as the cost per tonne of CO_2 avoided. Also, the acceptability of a site by the community will be dependant of the community's perception of the environmental and social impact of geological storage. Risk and uncertainty analysis is crucial to establish whether a selected site can be classed as a safe and effective storage site for thousands of years. The design of a monitoring and verification program is dependent on the geological characteristics of the selected site and needs to be carefully evaluated to produce an optimum program both in terms of efficiency and cost.

Data Needs for Site Characterisation

One of the main objectives of site characterisation is to accurately predict CO_2 behaviour in the subsurface, with respect to injectivity, containment, and storage capacity at a specific site. It is also essential to evaluate the uncertainty in these predictions. Making reliable predictions about subsurface CO_2 behaviour is closely related to data availability and quality, and therefore understanding the uncertainties associated with various types of data used in subsurface work is crucial for a successful CO_2 storage project. Poor understanding of data quality can result in unrealistic geological models and unreliable flow simulation results, and hence misleading assessment of the suitability of a CO_2 storage site.

This section (CO2CRC, 2008) briefly summarises some of the main data types used in site characterisation and highlights the key problems of data resolution with respect to resolving various components of site characterisation. A summary of the main data needs (required as well as desirable) for site characterisation is compared against data requirements for various levels of storage volume assessment in Table 18.

Table 18. Summary of the main data needs (required as well as desirable) for the various levels of site characterisation and storage volume assessment (CO2CRC, 2008).

Data Needs		Country/ State-Scale Screening; Total Pore Volume	Basin-Scale Assessment; Prospective Storage Volume	Site Characterisation; Contingent Storage Volume	Site Deployment; Proved Storage Capacity
Maps	Regional geology	✓	✓	D	
	Detailed/local geology		D	✓	✓
	Structural contour		D	✓	✓
	Coal/reservoir geometry		D	✓	✓
	Coal/reservoir quality		D	✓	✓
	Fault	D	D	✓	✓
	Seismicity	D	D	✓	✓
	Hydrologic	D	D	✓	✓
	Surface infra-structure	D	D	✓	✓
	Topographic	D	D	✓	✓
Seismic	2D	D	✓	✓	
	3D		D	✓	✓
Well logs	Gamma ray		D	✓	✓
	Porosity		D	✓	✓
	Permeability		D	✓	✓
	Sonic			✓	✓
	Density			✓	✓
	Image			✓	✓
Core	Porosity	D	✓	✓	✓
	Permeability	D	✓	✓	✓
	Langmuir volume (coal)	D	D	✓	✓
Special core analysis	Ratio vertical/ horizontal permeability			✓	✓
	Relative permeability			✓	✓

Data Needs		Country/ State-Scale Screening; Total Pore Volume	Basin-Scale Assessment; Prospective Storage Volume	Site Characterisation; Contingent Storage Volume	Site Deployment; Proved Storage Capacity
	Mercury injection capillary pressure		D	✓	✓
	Mineralogy		D	✓	✓
	Rock strength		D	✓	✓
Subsurface history	Oil/gas production		D	✓	✓
	CSM reservoir conditions		D	✓	✓
	Water chemistry			✓	✓
Pore pressure	Repeat formation tests; drill stem tests		D	✓	✓
	Subsurface fluid properties		D	✓	✓
	Leak-off tests; formation integrity tests		D	✓	✓
Reservoir characterisation	Sequence stratigraphy	D	D	✓	✓
	Regional tectonic history/model	✓	✓	D	
	Regional stress analyses	D	✓	D	
	Biostratigraphy	D	D	✓	✓
	Analogues		D	✓	✓
	Static models			✓	✓
	Dynamic models			✓	✓
Economics				✓	✓
Regulatory framework				✓	✓

✓ = required; D = desirable

Apart from actually obtaining new data (e.g. drilling new wells, acquiring new 2D or 3D seismic), which can be expensive, there is the additional cost in money and time for processing and interpretation of the new data. Therefore, in most instances, the early stages of site characterisation for saline aquifers will initially rely on data already available from regional geological surveys, geothermal, or more commonly petroleum exploration and development activities. Such data will by default be focused around existing fields or potential prospects, which will generally be mainly focused on traditional structural or stratigraphic traps. Dense data coverage (well logs and 3D seismic) will only be available in proven resource basins, and more specifically in presently or formerly producing oil and gas fields. In addition, for an injection site near an existing or partially depleted hydrocarbon field, for example, the most likely scenario will be to inject down-dip from the actual accumulation or in the deeper, sub-accumulation saline formation. However, in this location the data is likely to be relatively sparse, even in areas with overall good data coverage (e.g. Gippsland Basin, Gibson-Poole and Svendsen, 2005). Poor data coverage is one of the leading causes of uncertainty in assessing areas for CO_2 storage. Obviously if a site is to progress to the stage of being operational, then key data sets will need to be collected and the cost of doing this has to be accepted as part of the total capital cost of developing the site. In fact it may be difficult to trigger investment for development of projects until such key data are collected for initial site characterisation.

Various data types can be used for CO_2 site characterisation, such as 2D and 3D seismic data, wireline logs, pressure data, core data, biostratigraphy, and production data among others. Different data sources have different resolutions and are capable of capturing different levels of subsurface information. Seismic data, well log, and core data are the most important subsurface data sources and understanding their advantages and limitations is of vital importance in generating robust geological models.

Seismic Data

2D seismic data has long been used for resolving structural deformation in the subsurface. Recent improvements in 3D seismic technology have also made possible the direct imaging of stratigraphic heterogeneity, such as locating palaeo-valleys and channels and reservoir properties (porosity and saturation). Seismic data is routinely used for working out the three-dimensional distribution of faults and anticlines, understanding regional structural and stratigraphic dips, and working out the internal architecture of sedimentary packages. Such knowledge is directly applicable to (and often guides) the generation of geological models and prediction of CO_2 migration in the subsurface.

Seismic data inherently carries several sources of uncertainty: (1) the data has to be processed, which can be done in different ways and with varying results (i.e. processing can lead to more than one solution); (2) conventional seismic data has poor vertical resolution, which can be tens of metres at typical reservoir depths; (3) any interpretations based solely on seismic data will not include potentially important levels of sub-seismic scale stratigraphic heterogeneity and structure. This in turn can lead to important levels of reservoir heterogeneity (in the extreme, entire reservoir compartments and flow units) not being incorporated in a geological model; (4) seismic data away from areas with well control can become especially unreliable, since migration of the seismic data has to be performed based on rock velocities that are inferred rather than measured, and there is a lack of other means to calibrate the seismic data to real depth; and (5) 2D seismic data, which is more commonly available in saline aquifer sites compared to the more expensive 3D seismic data often only associated with petroleum exploration, is much less reliable and associated with higher levels of uncertainty.

Models based on interpreted seismic data should allow for suitable levels of uncertainty based on the quality of the seismic data and other aspects of the area of interest. One of the best ways to decrease uncertainty and associated risk is to use seismic data along with other data sources, such as well logs or cores, which have vastly superior vertical resolution. Seismically surveyed areas with poor well control will inherently carry large levels of uncertainty.

Well Log and Core Data

Well log (wireline) data provide continuous measurement of physical parameters of rock and fluids along a borehole. Availability of well log data is controlled by the number of wells in an area, which can range from sub-kilometre spacing densities over mature fields in prolific resource basins, to wells which are spaced tens to hundreds of kilometres apart in under explored areas. Commonly used logging tools measure properties such as electric resistivity, spontaneous potential, natural, scattered and induced radioactivity, and acoustic properties (Zimmerle, 1995). These are commonly used as proxies for various rock and fluid properties such as grain size, porosity, density, stratigraphic dip and composition of formation fluids. Well log data, calibrated by core data, in conjunction with seismic data can be used to guide both geological interpretation and populate geological models with petrophysical properties. A common difficulty arises from the need to combine data at very different scales, necessitating experienced subsurface specialists, familiar with integration and interpretation of such data.

The quality of well log-based geological interpretation is highly dependent on the well spacing (i.e. density of data points). Dense well spacing normally found in regions of petroleum or geothermal exploration can result in detailed correlation, which allows mapping of individual reservoir compartments and realistic predictions of subsurface porosity and permeability distribution. Large well spacing can lead to extreme uncertainty in correlation and geological interpretation, and poor predictability of CO_2 migration. Generally, for heterogeneity to be resolvable, well spacing has to be smaller than the scales of the feature mapped. Well spacing of tens of kilometres or higher can be used to calibrate seismic data and to evaluate the overall reservoir potential of an interval, but should only be used with extreme care for direct correlation of potential flow units. Many potential saline aquifer storage sites will have insufficient well spacing for detailed correlation, and will require other methods, such as use of analogues to approximate an appropriate level of heterogeneity within an interval.

Well log patterns can be used to infer the sedimentary environment of deposition, which is one of the most important parameters that determines stratigraphic heterogeneity, and choice of analogues. Since log patterns are only a proxy of real rock properties, and can give misleading results due to unusual mineralogies or formation fluids, examination of core from an interval can significantly decrease the uncertainties in geological interpretation. Cores, or rock samples extracted during drilling, allow direct observation of rock properties (e.g. sedimentary facies, mineralogy porosity/permeability, strength or capillary pressure measurements), and are therefore extremely valuable for site characterisation. Unfortunately, partially because of added cost, core data are rarely available at most wells locations, as many operators view core as only complementary to other data types. As is also true for well log data, the main drawback of core data is that it is representative of a very small area of the reservoir or seal being evaluated and, therefore, may not sample important rock properties beyond the immediate wellbore.

Use of Analogues

Analogues are data compilations or case studies of areas with high quality data (modern, outcrop or subsurface), which can be used to provide levels of expected heterogeneity for a reservoir of a given depositional setting. An example of this would be a database of channel width-to-thickness ratios for braided rivers, which can be used to populate a geomodel with cell properties that approximate channels with appropriate ranges of channel sinuosity, thicknesses and widths. Appropriate use of analogues depends on accurate identification of depositional environments and other factors affecting sedimentation, which can be challenging in data-limited areas. Presence of core data, from which depositional environments can be most accurately inferred, is the most important factor for limiting uncertainties in choosing appropriate analogues.

Formation Pressure

Knowledge of the in situ formation pressure is integral to any site characterisation and underpins the hydrogeological modelling, injectivity studies, geomechanical modelling, seal capacity estimations, flow modelling, and understanding of the horizontal and vertical communication. Formation pressure is sourced from wireline tests, such as the repeat formation tester (RFT) or modulus dynamic tester (MDT), and from drill stem tests (DSTs). Both types of testing can provide information about the pressure, permeability, fluid type and density and the location of fluid contacts. Wireline formation tests consist of a set of measurements taken close to the surface of the wellbore and as such, represent local permeability and pressure. They are also subject to wellbore issues, such as supercharging and formation damage. They are, however, carried out in many petroleum exploration bores and are a very reliable estimate of pressure, permeability and fluid properties. DSTs are a much larger-scale test and are usually carried out over several metres of reservoir and for extended periods of time (several hours to days). This leads to very accurate estimates of formation pressure, permeability and fluid properties. Analysis of the flow and build-up curves can also identify barriers to flow (i.e. sealing faults) and dual permeability systems that were affected by radius of the test. In depleted oil and gas reservoirs, the pressure decline observed in a well or field is used to calibrate the reservoir simulation model and predict the behaviour of injected CO_2 in this type of storage model.

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Appendix 3: CO_2 Injection Projects in Saline Aquifers

In this Appendix various projects are reviewed that currently inject CO_2 into aquifers; either for a combination of socio-economic reasons or for research purposes. In the current political environment, a multitude of CO_2 injection projects are proposed and are in various planning stages, but it is difficult to determine the likelihood of the actual implementation of specific projects. For example, projects that appeared to have a high probability of going ahead and had numerous associated research activities, e.g., FutureGen (Mattoon) or Schweinrich (CO2STORE/Europe), were cancelled due to the re-allocation of funding or change in site operators. Nevertheless, some projects that are in an "advanced" planning stage are included in the review if they provide detailed information related to site characterisation, reservoir properties, regulatory issues, costing and/or well completion. It should be noted that due to confidentiality issues and rapid changes in the CCS political environment, the availability of data for some injection operations may be limited.

Commercial Operations

Sleipner, Norway

The first commercial geological CO_2 storage project within a saline aquifer was the Statoil operated Sleipner Project in Norway. More than 10 Mt of CO_2 have been stored in the Utsira formation since the Sleipner project was started in October, 1996 (Carbon Capture Journal, 2008). Each day, approximately 2.7 kt of CO_2 are removed from natural gas produced from the Sleipner West field in the North Sea. Capture of CO_2 is done with a conventional amine process on an offshore platform in the North Sea, 250 km from land. The CO_2 is piped over to the Sleipner East Gas Field, where it is reinjected into the Utsira Sand, a saline formation above the methane production interval (Baklid et al., 1996). The formation is a 50 m to 250m thick sandstone unit located at a depth of approximately 1,000 m directly below the Sleipner field (Figure 26) which extends over a large area in the Norwegian sector of the North Sea. With a thickness of 250 m, the formation can store 600 Gt of CO_2 (Statoil, 2000). The injected CO_2 is extracted from natural gas, which contains approximately 9% CO_2. It is expected that 25 Mt of CO_2 will be injected into the aquifer over the life of the project. Before injection, CO_2 is brought to a supercritical state, requiring compression to 80 bars and cooling to 40 degrees Celsius. This is achieved using a compressor train, consisting of 4 units, each with a fluid knockout drum to remove water, compressor, cooler and gas turbine driver. One horizontal injection well is used to inject CO_2 into the storage reservoir. The 3,752 m long well was drilled to a vertical depth of 1,163 m, with a terminal inclination of 83 degrees, and completed with 25 % chromium duplex steel tubing.

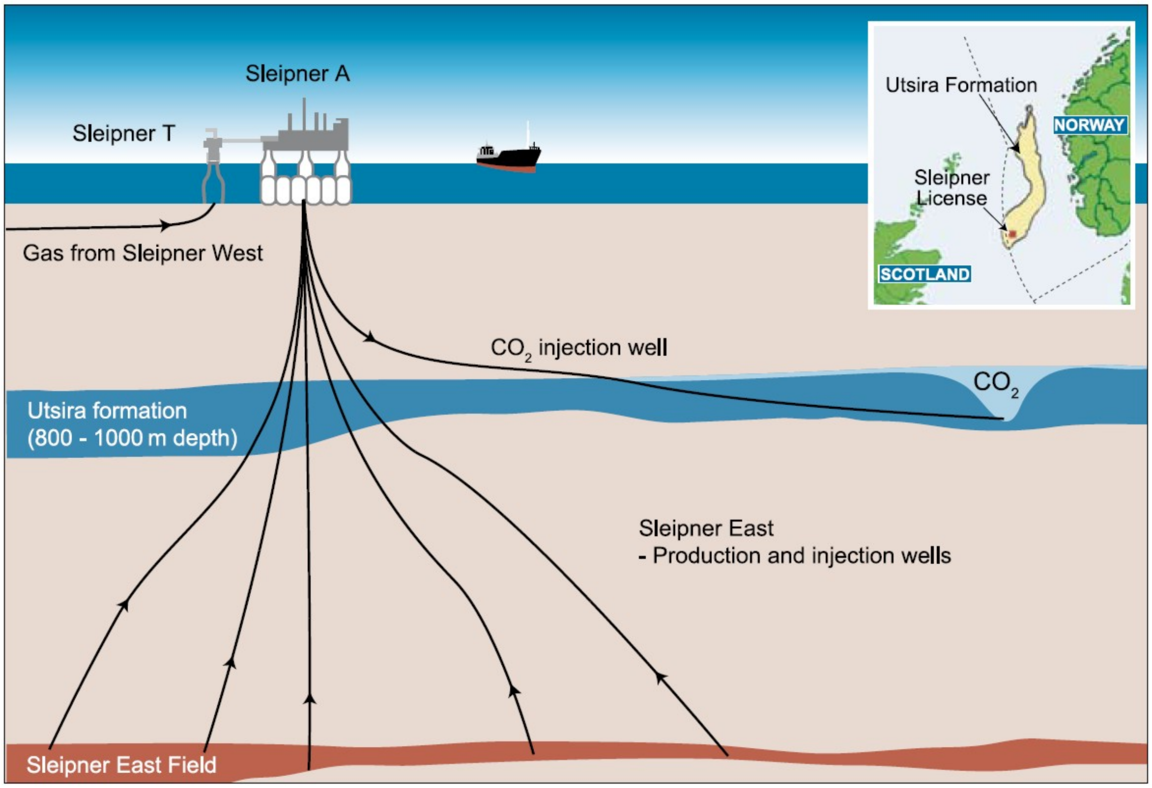

Figure 26. Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira Formation (IPCC, 2005).

Monitoring

Prior to injection, the site was characterised with the help of 3D seismic surveys, well logging and coring the Utsira sandstone and sealing shales, from 1993 to 1994. Reservoir simulations predicted CO_2 behaviour within the formation. The Saline Aquifer CO_2 Storage (SACS/CO2STORE) Project was an R&D program (Kårstad, 2002), established in 1998 to monitor CO_2 behaviour after injection at Sleipner. Monitoring of the injected CO_2 has been underway since 1999. Statoil's review of monitoring options at Sleipner suggested that observation wells and well seismic would be too complicated and to expensive. Repeat seismic surveys were therefore considered to be the most promising option. Four seismic surveys have now been completed at Sleipner (Figure 27). The injected CO_2 has had a significant impact on the seismic signal, causing large increases in the seismic reflectivity, clearly demonstrating the position of the injected CO_2 within the Utsira Sand (Arts et al., 2004). Seismic surveys have also demonstrated that the CO_2 is still successfully contained within the Utsira Sand (Arts et al., 2004). By 2005, the CO_2 plume had extended over an area of approximately 5 km^2 around the injection point, and over time it is predicted to be completely dissolved within the formation water (IPCC, 2005). Even with the CO_2 in a supercritical, rather than a gaseous, state it has been shown that CO_2 accumulations with a thickness as little as about one metre can be detected, which is significantly less than the conventional seismic resolution limit of approximately 7 m. Even these thin accumulations cause significant, observable and measurable changes in the seismic signal, both in amplitude and in travel time due to the high porosity of the weakly consolidated Utsira sand.

Time lapse gravity surveying offers a lower cost complementary technique to seismic surveying. A baseline gravity survey was completed at Sleipner in 2002 and a repeat survey was completed in 2005. It is possible to measure gravity on the seafloor with uncertainties of <5 µGal, even in a relatively shallow water, high noise environment. Additionally, is has been shown that by simultaneously measuring water pressure, seafloor depth can be determined to sub-centimeter accuracy, relative to a ‘fixed’ point on the seafloor. These depth measurements are very important for correcting the gravity measurements for anomalous changes in benchmark height, such as from sediment scouring. In the future at shallow high-current environments such as Sleipner, more care should be taken in designing and deploying benchmarks, in order to reduce the effects of scouring and biological disturbances. Techniques such as laying gravel or carpet down prior to benchmark emplacement, or anchoring the benchmarks to the seabed could be employed.

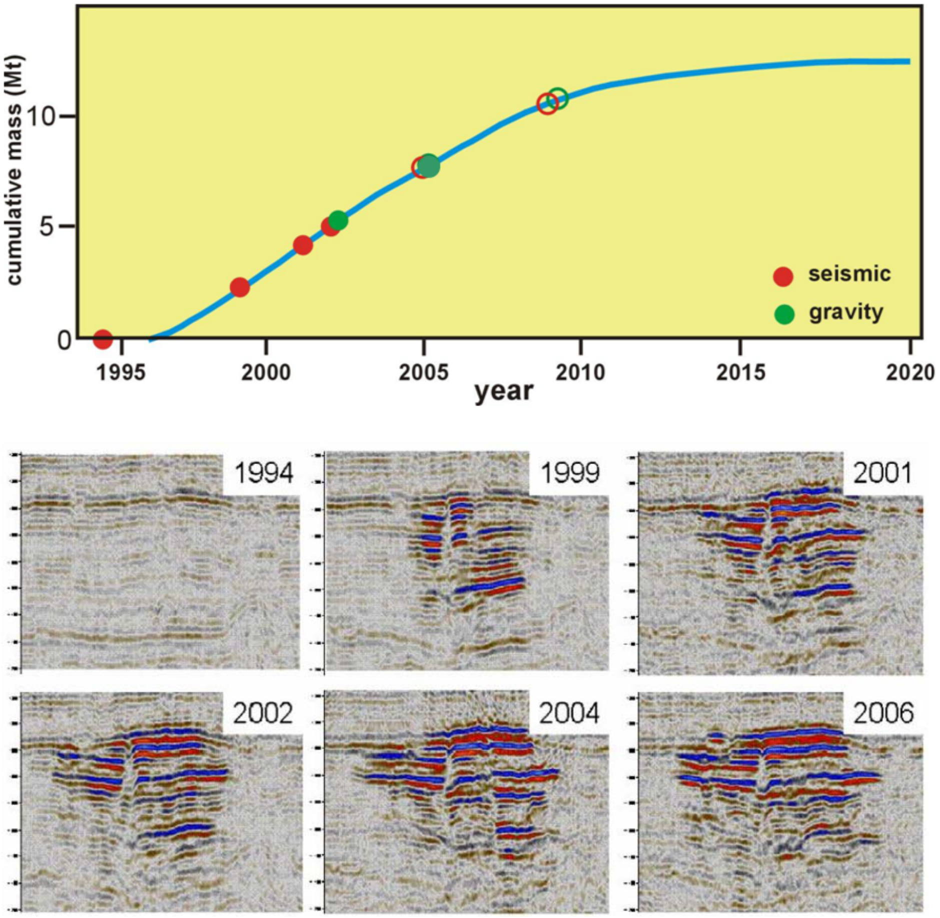

Figure 27. Geophysical monitoring at Sleipner: a) timing of time-lapse seismic and gravity surveys, and b) time-lapse dataset visualising the spread of the injected CO_2 in the Utsira Formation.

The Utsira Formation is highly permeable with an enormous pore volume compared to the planned injection volume of CO_2 and the cap rock has shallow dome structures that allow free gas columns of only 15–25 m. Because of these features, it has been concluded that monitoring of the storage reservoir pressure is not a key issue as the shape and size of the storage reservoir cap and spill points will only lead to minor pressure build up. Therefore, the pressure increase in the aquifer due to CO_2 injection is expected to be in the sub-one bar range, i.e. far below estimated limits to avoid mechanical failure or gas penetration through undisturbed cap rock.

The time-lapse gravity results and modelling support evidence from heatflow measurements and other temperature measurements in the vicinity of Sleipner which suggest that the Utsira formation is warmer than previously thought. This is only a beginning step in characterising the aquifer using time-lapse geophysical measurements. Additional gravity and seismic measurements are needed to further constrain this reservoir property by putting tighter bounds on the in situ CO_2 density. Ideally, future 3D seismic measurements and gravity measurements will be made within a few months of each other, so that the geometry of the CO_2 plume determined from seismic can be directly related to observed changes in gravity.

Time-lapse gravimetric reservoir monitoring may play a role in future CO_2 sequestration efforts, however, this detection technique relies on the density contrast between injected CO_2 and the aquifer fluids, limiting its applicability to fluid-filled reservoirs and excluding formations such as depleted coal beds. The best results will be obtained when monitoring shallow reservoirs less than 1000 m deep, where the density of CO_2 is much less than that of the reservoir fluids. In order to slow CO_2 emissions, as is needed to mitigate anthropogenic climate change, hundreds of sites such as Sleipner will be needed along with many other carbon reduction strategies. Undoubtedly, gravity will be a useful tool for monitoring injected CO_2 for a number of these sites.

Costs

Capital costs for the Sleipner Project cannot be determined exactly as it is an integral part of the overall Sleipner field development. However, (Torp and Brown, 2005) have developed estimates for these costs (in terms of 1996 US dollars) Torp and Brown (2005) estimate that the total cost of site characterisation was US$1.9 million, the cost of designing and installing the compressor train to be US$79 million and the cost of the well is estimated to be US$15 million. The operating costs identified by Torp and Brown (2005) consist of the fuel required to run the gas turbines for compression (approximately 4,000 standard cubic metres per tonne CO_2) and US$40 per tonne CO_2 offshore emissions tax, labour and maintenance costs. The total costs amount to approximately US$7 million per year. The breakdown of cost components is shown in Table 19.

Table 19. Sleipner site characterisation costs.

Procedure	**Cost (US$ million)**
3D seismic survey	0.4
Coring “Utsira” sand and well logs	0.9
Coring cap rock shales	0.5
Reservoir simulations	0.1
Total cost	**1.9**

Source: Torp and Brown (2005)

The Saline Aquifer CO_2 Storage (SACS/CO2STORE) Project was a US$4.5 million R&D programme (Kårstad, 2002), established in 1998 to monitor CO_2 behaviour after injection at Sleipner. (Torp and Gale, 2004) describe the project and state that the cost of a monitoring well, up to €45 million (US$54.7million) according to Statoil estimates, would be too high. The European Commission (2004) estimates that the cost of monitoring at Sleipner is €2.1million/yr.

Snøhvit, Norway

At the Statoil operated Snøhvit LNG project, CO_2 is currently being injected into a deep saline formation in the Barents Sea. The Snøhvit project is the first LNG development in Europe. Production from the Askeladd, Albatross and Snøhvit fields began in September 2007 and the project is expected to have a 30-year lifetime. The CO_2 content of the field gas must be decreased from 5-8% to less than 50 ppm prior to conversion to LNG. The 0.75 Mt/yr CO_2 removed from the natural gas, using amine technology, is injected into the Tubåsen Formation situated below the Stø formation (Figure 28), a Jurassic gas reservoir (Maldal and Tappel, 2004). Injection of CO_2 at Snøhvit commenced in May, 2008.

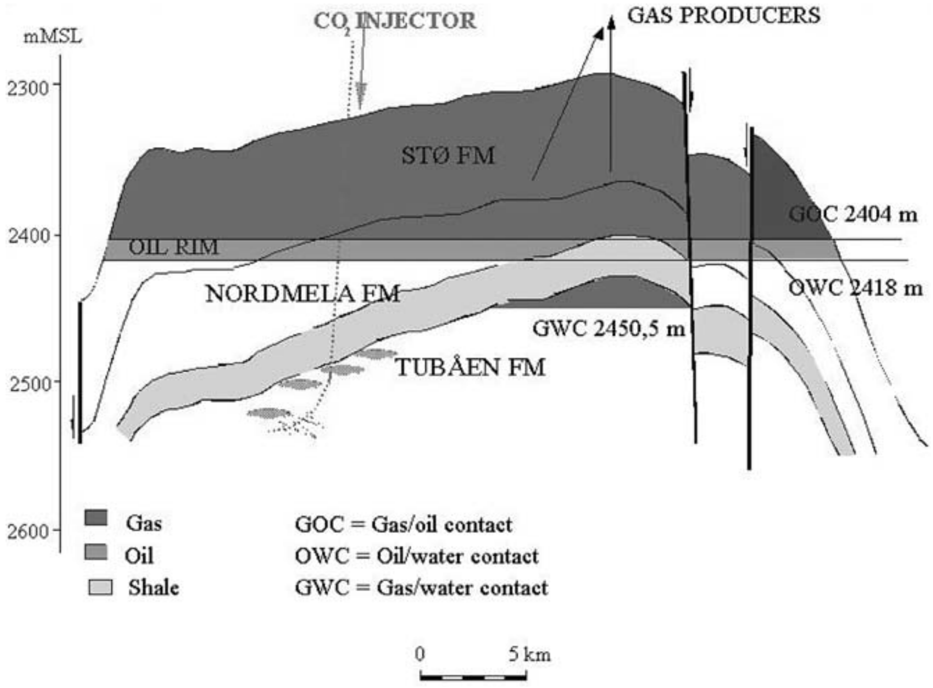

Figure 28. Simplified cross section through the Snøhvit field (from Maldal and Tappel, 2004).

Costs

Kårstad (2002) provides estimates of the capital costs of storage in terms of 2001 US dollars. Kårstad estimates the total capital cost to be US$191 million, a figure which covers the cost of a deviated, offshore injection well completed with 7 inch injection tubing, a 160km, 8 inch internal diameter pipeline to transport CO_2 from the LNG plant to the Snøhvit field, a sub-sea control umbilical, a sub-sea well frame and a compressor train for the compression and dehydration of CO_2. Table 20 shows a breakdown of these costs.

Table 20: Snøhvit capital costs

Item	**Cost (2001 US$ million)**
Drilling injection well	16
Well completion and other well related	9
Pipeline, 160km	73
Sub-sea control umbilical	11
Sub-sea well frame	12
Compressor train	70
Total	**191**

Source: Kårstad (2002)

In Salah, Algeria

The In-Salah Gas Project, a Sonatrach, BP and Statoil joint venture, exploits the natural gas resources found within Algeria's Ahnet-Timimoun Basin. The In Salah Project is one of BP's two major gas projects in Algeria and is the largest dry gas joint-venture project in the country. The venture involves the development of seven proven gas fields in the southern Sahara, 1,200 km south of Algiers. The field gas, containing up to 10% CO_2, requires a decrease in CO_2 content to 0.3% prior to export to European markets

(Riddiford et al., 2005; Riddiford et al., 2003). From July 2004, 1.2 Mt/yr CO_2 have been injected into the aquifer section of the Krechba field, the Carboniferous Tournaisian sandstone reservoir at 1,800 metres depth. The project is expected to store up to 17 Mt CO_2 over its lifetime, decreasing CO_2 emissions of the project by 60%. Following separation from the natural gas stream at the Krechba processing plant, the CO_2 is compressed in four stages up to 200bar and dehydrated. It is then injected using three injection wells into the storage formation (Wright, 2007a, b). Unfortunately, technical information from the In Salah project is largely limited to conference presentations and the company webpages of Statoil and BP.

Monitoring

The In Salah CO_2 Assurance R&D Programme was established to ensure that CO_2 is being safely sequestered and to assess various monitoring options. Techniques used include 4D seismic surveys, 4D gravity surveys, 4D electrical/electromagnetic techniques, dynamic modelling, tracers, analysing formation fluids, soil gas sampling and injection monitoring (Espie 2006, Wright 2007a).

The following monitoring plan was proposed for In Salah:

- Soil gas depth testing, lineament analysis, microseismic testing, tiltmeters, surface flux monitoring, hydrogeology, microbiology, gravity test (4th quarter 2007);

- Full soil gas survey, microseismic array, gravity survey, shallow observation well(s), further data acquisition from new production wells, hydrogeology/microbiology (early 2008)

- 3D seismic survey, surface flux, gravity measurements, logging (early to mid 2008)

Costs

The total cost of CO_2 storage is estimated to be US$100million (Wright, 2007a, b).

Regulations (Europe/Africa)

The Sleipner, Snøhvit, and In Salah projects are being regulated primarily under the petroleum regulations in the host country. There are no generic regulations in either Norway or Algeria for regulating the geological storage of carbon dioxide. Although Algeria and Norway are not member states of the European Parliament, the proponent companies have complied with the requirements for management of geological storage of CO_2 that are set out in the proposed Directive of the European Parliament and Council on the geological storage of carbon dioxide and amending Council Directives 85/337/EEC, 96/61/EC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC and Regulation (EC) No 1013/2006.

This proposed Directive sets out details on requirements relating to site selection, exploration permits, storage permits, requirements for environmental impact assessment and public consultation, operational matters including closure and post-closure obligations, monitoring and reporting obligations, inspections, measures in case of irregularities and/or leakage, and provision of a financial security. The Directive also addresses related matters including access to transport and storage, transboundary co-operation, and the required amendments to other legislation, including the necessary adaptations to the water and waste legislation.

The proposed Directive builds on recent decisions in other international forums to allow geological storage of carbon dioxide under the sea-bed. Legal barriers to the geological storage of CO_2 in sub-seabed geological formations have been removed through the adoption of related risk management frameworks both under the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (1972 London Convention) and under the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR Convention).

Gorgon, Australia (planned)

The Gorgon Joint Venture (ChevronTexaco, Shell and ExxonMobil) exploits the large natural gas resources of the Greater Gorgon area, offshore Western Australia. The natural gas in Gorgon contains up to 14 % CO_2. The CO_2 will be separated from the produced gas at the gas-processing facility on the island, compressed to a supercritical state, and then transported by a 12 km pipeline to the injection site for storage. If feasible, the project will involve the reinjection of 2.7-3.2 Mt/yr CO_2 extracted from the field gas into the Dupuy Saline Formation 2,300 m below Barrow Island (Figure 29). A total of 125 Mt CO_2 is expected to be stored over the life of the project.

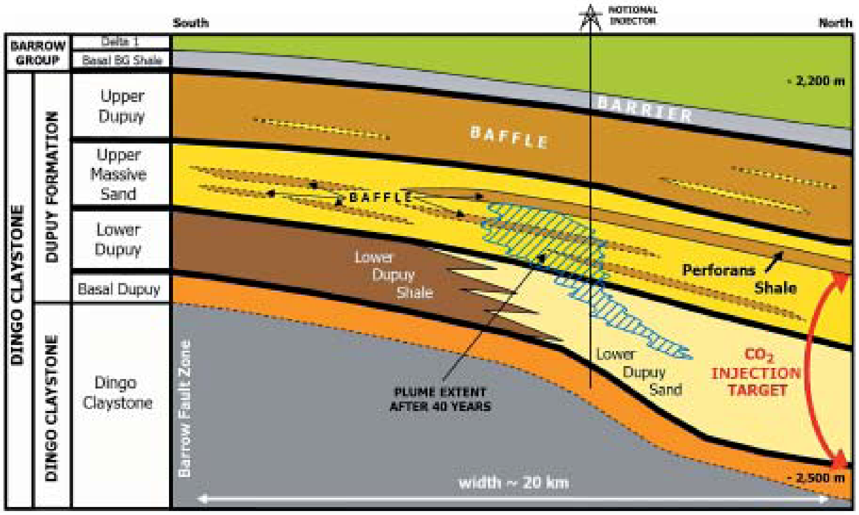

Figure 29. Diagrammatic geological cross-section showing the target injection horizon of the Gorgon Project (Chevron, 2005).

Seven injection wells are currently planned. These will be drilled directionally from 2 or 3 locations. A monitoring programme is currently being developed to keep track of CO_2 behaviour after injection. The programme will include a number of observation wells for monitoring injection rates and pressures, seismic monitoring of CO_2 migration, wireline logging, geochemical analyses of Dupuy Formation waters and installation of CO_2 detection devices to detect leakages. Three water production wells are planned to manage reservoir pressures and brine displacement (Chevron, 2005).

Costs & Regulations

According to the IEA (2008), the total capital cost for CO_2 compression, pipelines and injection wells is A$300-400 million (US$265-350 million).

As the geological sequestration component of the Gorgon project is located onshore, the regulatory framework is primarily that of the Western Australian Government through the *Petroleum Act 1986 (WA)*, the *Environment Protection Act (WA)* and the *Barrow Island Act 2003 (WA)*. Approval was also required under the federal *Environment Protection and Biodiversity Conservation Act* because of the location of the facilities in conservation reserves which include a number of matters of national environmental significance. Bilateral agreements between the Australian Government and Western Australian Government have led to an integration of the assessment and approval processes.

No generic legislation currently exists in WA for regulating geosequestration. However, the *Barrow Island Act 2003 (WA)* has provisions that allow the Minister to approve CO_2 disposal on Barrow Island. The function of this Act is to, inter alia, ratify and authorise the implementation of an agreement between the State and the Gorgon Joint Ventures (GJV) relating to the offshore production of natural gas and other petroleum, and a gas processing and infrastructure project on Barrow Island. The Act also makes provisions for the transport and underground disposal of carbon dioxide recovered during gas processing on Barrow

Island. Specifically, the Act requires the GJV to seek approval to dispose of CO_2 on Barrow Island. The application for approval must include information on the methods to be used; the capacity and capability of the underground target reservoir; the rate of disposal; the volume/composition of the CO_2 to be disposed; and the expected duration of the disposal. Under Schedule 1 of the Act the GJV is also required to submit a closure plan that addresses the long term management of injected CO_2. Approvals under the Barrow Island Act 2003 (WA) and its Schedule 1 are subject to environmental approval under the Environmental Protection Act 1986 (WA). The CO_2 disposal component along with all other aspects of the Gorgon Project must also comply with any imposed Ministerial environmental conditions. The draft of the Environmental Impact Statement (EIS) including a detailed risk assessment was submitted by Chevron in 2005 (Chevron, 2005). In late 2007 the GJV obtained State and Commonwealth environmental approvals for a 10 Mt/yr LNG development on Barrow Island. The State (Statement No. 748) and Commonwealth (EPBC Ref: 2003/1294) environmental approvals contain specific conditions relating the to the proposed CO_2 injection project. Currently, the GJV is working on an update of the EIS document to reflect the increase of the project to 15 Mt/yr.

Acid-Gas Injection (Alberta & British Columbia, Canada)

Over the past two decades, oil and gas producers in the Alberta basin in western Canada (Alberta and British Columbia) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H_2S), which is produced from “sour” hydrocarbon pools. Since surface desulphurization is uneconomic and the surface storage of the produced sulphur constitutes a liability, increasingly more operators are turning to the disposal of acid gas (H_2S and CO_2 with minor traces of hydrocarbons) by injection into deep geological formations. The first acid-gas injection operation in Alberta was approved in 1989 and started injecting in 1990 into a depleted gas reservoir. Injection into the first aquifer commenced in 1994. By 2007, 48 operations for injection of acid gas had been approved in western Canada (41 in Alberta and 7 in British Columbia), of which 27 operations currently inject into aquifers. By the end of 2007, approximately 4 Mt CO_2 and 3 Mt H_2S had been injected into deep hydrocarbon reservoirs and saline aquifers in western Canada. The contents of CO_2 in the injection stream of operations disposing of acid gas into saline aquifers ranges between 17 and 88 % and approximately 2 Mt CO_2 were injected into aquifers. General as well as some site specific information with respect to acid-gas injection in Western Canada can be found in (Bachu and Gunter, 2004; Bachu et al., 2005); (Buschkuehle and Michael, 2006); (Michael and Buschkuehle, 2006; Michael and Haug, 2004).

The average injection depth in saline aquifers varies between 950 and 2814 m (Table 21). The relatively shallower injection zones (i.e., between 800 and 1100 m depth) correspond mostly to injection of acid gas dissolved in or mixed with water. The thickness of the injection formation, as defined geologically, varies between 15 and 343 m; however, the actual net pay, defined by layers with porosity and permeability adequate for injection, reaches only a maximum of 100 m. At 9 operations, acid gas is injected into sandstone aquifers and at 18 operations injection occurs into carbonates. In most cases shales and shaly siliciclastics constitute the overlying confining unit (top seal); the remainders of the injection zones are confined by tight limestones, evaporites and anhydrites. The caprock thickness varies between 15 and 218 m, which only refers to the top seal directly overlying the injection unit. In many cases additional low-permeability formations contribute to a larger overall aquitard thickness. The porosity of the injection zone varies between 4% and 26%, the carbonate rocks generally having lower porosity. Only the porosity in sandstones displays a general trend of decreasing porosity with increasing depth. Rock permeability varies from as low as 1 mD to as high as 413 mD.

The original formation pressure is generally sub-hydrostatic with respect to freshwater, which is characteristic of the Alberta Basin, and varies between 5915 kPa at 950 m depth and 27,000 kPa at 2814 m depth. Formation temperature varies between 26^oC and 103^oC. The widespread variation of temperature with depth for the acid-gas injection zones is due to the variability in geothermal gradients across the Alberta Basin, which exhibits a trend of increasing gradients from the south, where they are as low as 20^oC/km, to the north, where they reach more than 50^oC/km. Generally, formation waters are very saline, with salinity varying in a very wide range, from ~20,000 mg/l—~341,000 mg/l.

Table 21. Characteristics of acid-gas injection operations injecting into saline aquifers in western Canada.

Characteristic	Minimum Value	Maximum Value
Injection depth (m)	950	2814
Formation thickness (m)	15	343
Net pay (m)	4	100
Porosity (%)	4	26
Permeability (mD)	1	413
Caprock thickness (m)	15	218
Formation pressure (kPa)	6,000	27,000
Formation temperature (^{o}C)	26	103
Water salinity (mg/l)	23,742	341,430
CO_2 in injection stream (%)	17	88
Injection rate (m^3/day)	2,000	150,000

Monitoring

Pressure, temperature and gas composition are monitored at the wellhead and generally no subsurface monitoring requirements are imposed on the operators. As a result, there is very limited information on the subsurface spread and reactions of the injected acid gas.

Regulations

The application and permitting process is regulated in Alberta by the Energy Resources Conservation Board (ERCB) under the Oil and Gas Conservation and the Coal Conservation acts and associated regulations. Directives related to the petroleum industry can be downloaded from the ERCB webpage (www.ercb.ca). These are reviewed and discussed in detail by (Bachu, 2008), and the following is an excerpt of that document. Most relevant to future CCS projects is the section in ERCB Directive 65 (ERCB, 2007) on acid-gas disposal, which requires the applicant to prove that:

- It has the right to dispose in the respective geological formation;
- Disposal will not impact hydrocarbon production;
- The disposal fluid will be confined to the injection horizon;
- The owners of neighbouring wells within a certain distance of the disposal well have been consulted and have no objections; and
- Containment and isolation requirements, including well construction, are being met.

Acid-gas disposal wells usually fall within Class III in Directive 51 (ERCB, 1994) on well classification, completion, logging and testing requirements, which covers: a) injection of hydrocarbons, inert or other gases for the purpose of storage or enhanced recovery; b) solvent or other hydrocarbon products for enhanced recovery, c) sweet natural gas for storage, d) CO_2, N_2, O_2, air or other gases for storage or enhanced recovery; and e) sour or acid gases for disposal, storage or cycling. The construction and operating requirements for Class III wells are:

- Hydraulic isolation of the host zone and hydrocarbon-producing zones (all wells – exploration, production or injection – require isolation through surface casing of potable groundwater defined as water with salinity less than 4000 mg/l);
- Annulus filled with corrosion-inhibiting fluid;
- Installation of safety devices (e.g., valves against backflow);

- Cementing across the potable-groundwater zone;
- Logging for cement top, hydraulic isolation and casing inspection;
- Initial casing/annulus pressure test;
- Annual packer isolation test;
- Wellhead pressure limitation; and
- Injection through tubing.

Additional general regulations about well construction regarding Surface Casing and Cementing are found in ERCB Directives 8 and 9 (ERCB, 1990, 1997), respectively.

In the context of current efforts to reduce anthropogenic emissions of CO_2, these acid-gas injection operations represent a commercial-scale analogue to geological storage of CO_2. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., design, materials, leakage prevention and safety) can be adopted for large-scale operations for CO_2 geological storage, since a CO_2 stream with no H_2S is less corrosive and less hazardous. Although the fate of the injected acid gas has not been monitored to date, the subsurface information about aquifer, and reservoir rocks and fluids provides a wealth of information as to what characterises a good CO_2-storage site. This information can be used for the screening and identification of future sites for geological sequestration and storage of CO_2.

Pilot Sites (Research)

Frio

The Frio Brine Pilot Experiment began in 2002, funded by the U.S. DOE National Energy Technology Laboratory. The site for this experiment is in the South Liberty oilfield, northeast of Houston. Before injection, extensive monitoring, including baseline aqueous geochemistry, wireline logging and vertical seismic profiling, and modelling was conducted. Injection began on October 4, 2004, and over 10 days 1,600 tonnes of CO_2 was injected 1500 m below the surface into a high permeability brine-bearing 24 m thick interval of sandstone of the Frio Formation.

Monitoring

The Frio test has a dedicated monitoring well that is offset 30-m updip (Figure 30). The project was monitored before, during and after the injection. Techniques used include RST logging, cross-well seismic, vertical seismic profiling, fluid sampling, measuring soil gas fluxes and concentrations and introduced tracers (Hovorka et al., 2006; Hovorka and Knox, 2003). The Frio project can be divided into two phases: Frio-1 (October, 2004 –January, 2006) and Frio-2 (September, 2006 – December, 2007). The main purposes of first stage were:

Subsurface Characterization:

- High-quality geologic characterization prior to injection, and
- Numerical modelling integrated with all phases of the project,

Monitoring and Verification:

- Integration of multiple types of measurements, and
- Use of wireline logs for monitoring plume movement.

Following the Frio-1 test, planning began for a second small-scale injection of about 300 tons of CO_2 in the 17-m-thick Blue sand reservoir at 1650-m depth at the Frio site. The Blue sand has similar porosity (about 25%) and permeability (>2 Darcies) as the Frio-1 sand. A description of the Frio site and Frio-1 results is given in Hovorka et al. (2006).

During the second stage, 320 tonnes of CO_2 were injected. The main objectives were:

- To focus on storage permanence—quantifying residual saturation and dissolution.
- Post-injection monitoring under stable conditions.
- Establishing the effectiveness of buoyancy in moving CO_2 through pore networks.
- To observe arrival time and to capture associated geochemical changes.
- Quantification of residual saturation trapping mechanism.
- Quantification of dissolution during plume evolution.
- To field test new tools (U-Tube, continuous X-well seismic).
- To integrate chemistry and geophysics for model verification.

Time-lapse cross-well tomographic imaging of the Frio-1 CO_2 plume demonstrated that large changes in seismic velocity (a 500 m/s decrease within the plume) were caused by the injection of supercritical CO_2 into the brine reservoir (Ajo-Franklin et al., 2007; (Daley et al., 2006; Hovorka et al., 2006).

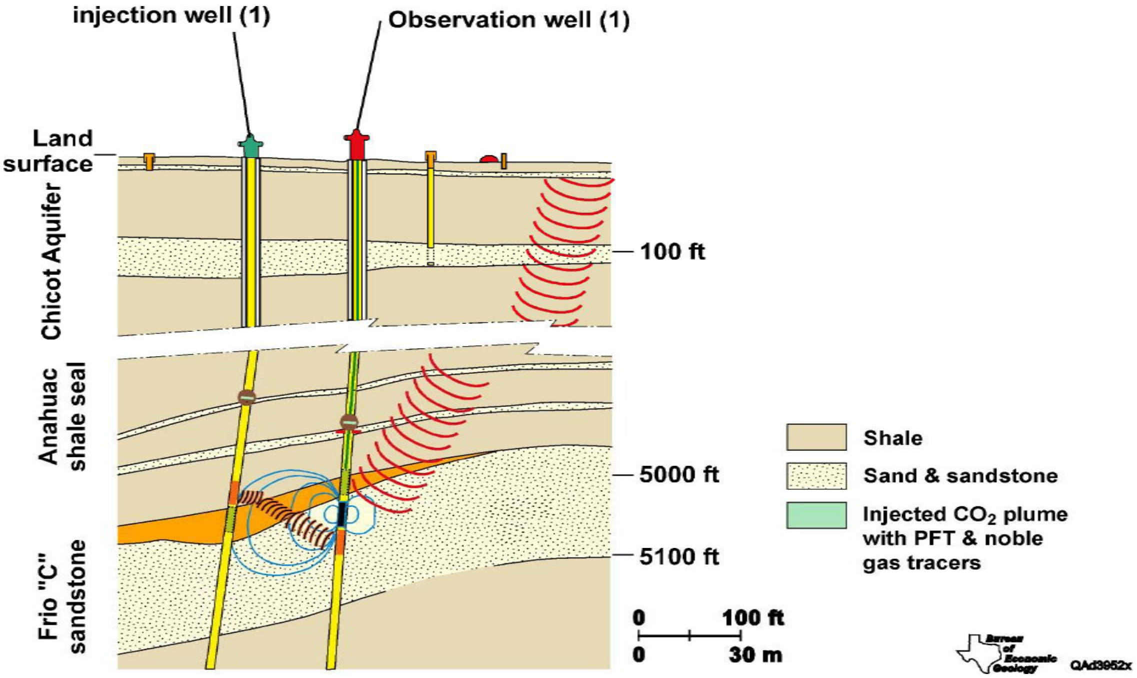

Figure 30. Monitoring set up at the Frio pilot project (Source: www.beg.utexas.edu/environqlty/co2seq/fieldexperiment.htm).

An innovative geochemical sampling tool, the U-Tube, was installed in both the injection and the observation well 30 m updip of the injector to support in-zone fluid chemistry sampling. Formation fluid that was collected in the U-Tube was driven at reservoir pressure into evacuated sample cylinders at the surface by high pressure ultra-pure nitrogen. Samples were collected hourly to facilitate accurate delineation of CO_2 breakthrough and recover uncontaminated and representative samples of two-phase fluids. Initial CO_2 breakthrough occurred 51 hours after initiation of injection, resulting in an increase from 100 to 3,000 mg/l bicarbonate and decrease in pH from 6.7 to 5.7 in the analysed brine due to mineral dissolution (Kharaka et al., 2006).

Monitoring at the surface for a leakage signal was not effective because the natural and induced noise was large and the pre-perturbation period was shot. Examples of natural variability include a variably high water table , which resulted in little or no soil gas, and high natural CO_2 flux because of the swampy forest setting (Klusman, 2004).

Costs & Regulations

The operators of the Frio Pilot project applied for a Class V experimental permit to the Texas Commission on Environmental Quality to inject CO_2 into a saline aquifer as opposed to a Class I non-hazardous waste injection permit for a variety of reasons (Hovorka et al., 2003):

- The injection period will be brief and concluded within a few months;
- The volume injected will be small (3,000 tons);

- The substance to be injected is benign (food-grade CO_2);

- The purpose of the experiment involves extremely close monitoring;

- The area selected for the study is not suitable for a normal Class I injection well because it is faulted and penetrated by many oil wells; and

- It is of benefit to all stakeholders to quickly, safely, and economically obtain information that will be useful in moving to a larger scale test, which is likely to be undertaken within the next few years. Information and experience obtained during this federally-funded experiment should be of substantive use in designing permit and monitoring strategies for that test.

Nagaoka

In 2000, a project was begun in Japan at the Iwanohara base near Nagaoka, Niigata Prefecture, to inject CO_2 underground. The METI-funded project was conducted by the Research Institute of Innovative Technology for the Earth (RITE). From July 2003 to January 2005, 10,400 tons of CO_2 were injected (Figure 31) 1,100 m underground into a saline aquifer that is about 60 m thick. The caprock is a pelitic rock layer about 140 m thick. For the purposes of the test, purchased CO_2 (a by-product of ammonia production) was delivered by road in liquid form to the injection site. A 1,230 m deep injection well was then used to inject the CO_2 into the aquifer. The injection facilities included a liquefied CO_2 vessel with an evaporator, booster, three main pumps controlling the injection pressure and volume and a heater to control the temperature. Carbon dioxide was injected at a rate of 20 t/day beginning in July 2003. Then, following a fifty-day intermission, it was injected at 40 t/day (Kikuta et al., 2005). During the injection period there were two planned breaks and an additional interruption due to an earthquake; nonetheless all of the CO_2 was injected according to schedule. The magnitude-6.8 earthquake occurred about 20 km from the field site but other than causing a black-out that halted the operation of the aboveground facilities, no major abnormality occurred and operations resumed once safety was confirmed (Xue et al., 2006a).

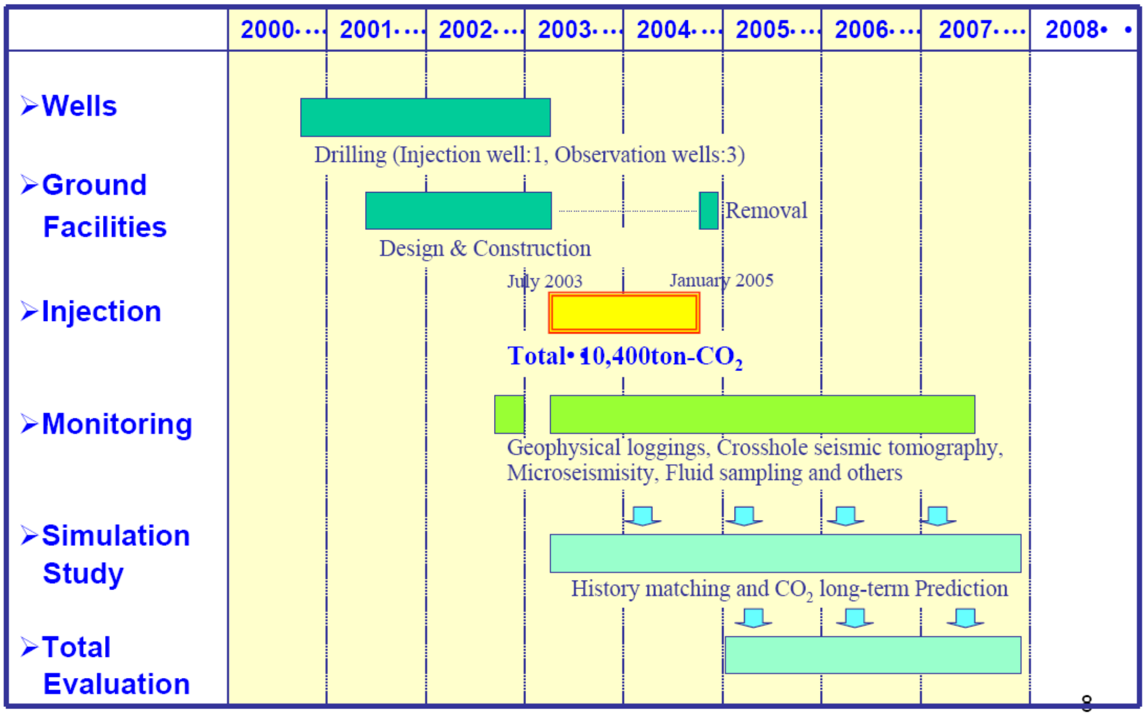

Figure 31. Time-line of Nagaoka CO_2 injection project.

Monitoring

For monitoring tests, three monitoring wells were installed around the injection well to monitor the CO_2 and predict long-term CO_2 movements through simulation. Three observation wells were drilled to depths of 1,319 m (OB-2), 1,270 m (OB-3) and 1,322 m (OB-4). The various methods that were employed for the monitoring process include geophysical logging (including induction, gamma ray, neutron and sonic logging), cross-hole seismic tomography, pressure and temperature measurement, induced seismicity monitoring sampling of fluids from the aquifer and observation of microseismicity (Xue, 2007). Sound waves that were used for observation confirmed that CO_2 had respectively reached the observation wells located 40 m and 60 m from the injection well when 3 kt and 5 kt of CO_2 had been injected (Xue at al., 2006b). Observations using cross-hole seismic tomography allowed visualisation of how the CO_2 was spreading between the two observation wells sandwiching the injection well (Figure 32). Cross-well data were acquired before and after injection (6 times) (Figure 33). The cross-well seismic tomography detected a P-wave velocity decrease (CO_2 invaded zone). An area of P-wave velocity decrease appeared near the injection well and the injected CO_2 was found to be migrating along the formation in an up-dip direction. The results confirmed the usefulness of cross-well seismic tomography (Saito et al., 2006).

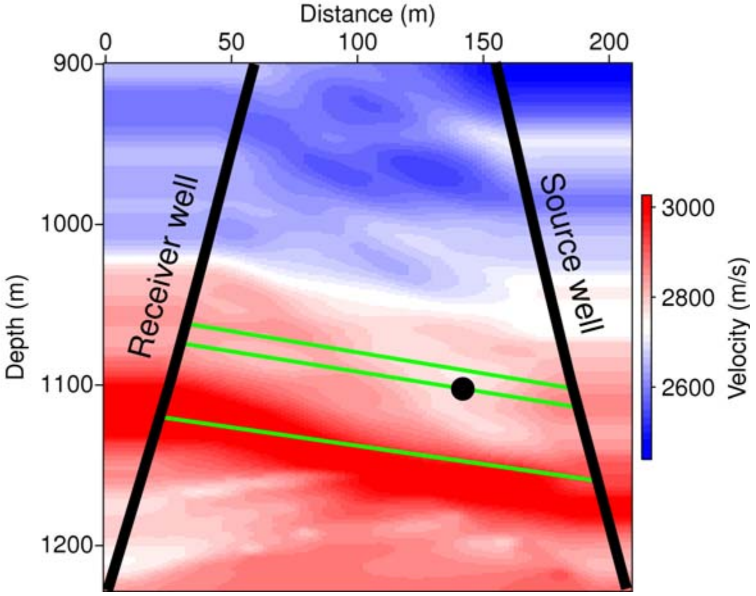

Figure 32. The source and receiver well geometry and the reference velocity field at the Nagaoka pilot site (Spetzler et al., 2008). The solid circle indicates the point of CO_2 injection.

One of the improvements of monitoring techniques by applying differential analysis to cross-well seismic tomography was described by Onishi et al. (2007). Advanced well-logging was repeated 31 times during the experiment. Observed changes include decreases in P-wave velocity, and neutron porosity and an increase in resistivity. Repeat surveys allow mapping of breakthrough with time. This can be combined with fluid sampling to calibrate logging responses to provide estimates of CO_2 saturation. Repeat borehole logging also allows comparison between estimates of porosity between different techniques (neutron and NMR) (Xue et al., 2006c). Spinner tests monitored flow within the borehole.

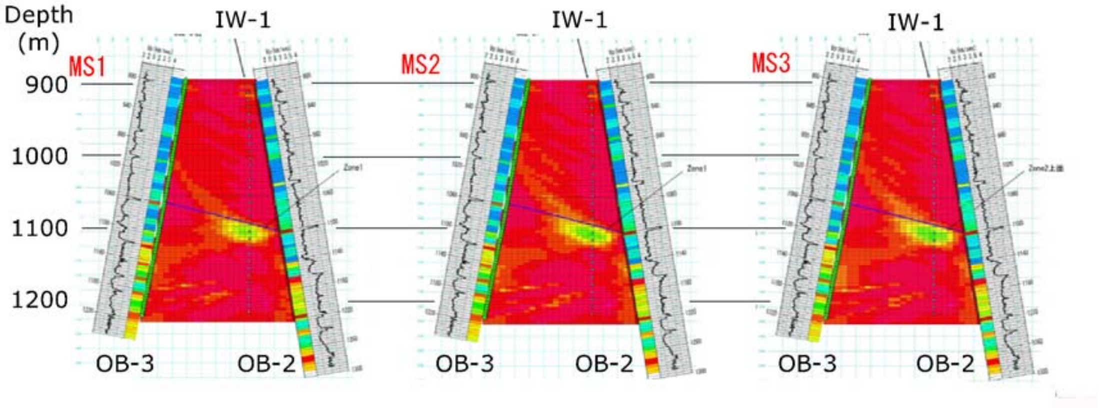

Figure 33. Seismic tomography monitoring results from the Nagaoka pilot site (Saito et al., 2006).

The geochemical analyses confirmed that the CO_2 was dissolving into the saline aquifer water and that the CO_2 would react with the rock to become mineralised and fixed in place. These data were used with simulation technology (GEM-GHG) to predict CO_2 behaviour, indicating that after 1,000 years the CO_2 will still be in almost the same place and that there is little possibility of it spreading in a wider area (Murai, 2007).

Costs

An analysis of the costs of CCS was carried out for four different types of CCS systems. For example, the total storage cost, assuming that power was supplied by a new coal-fired power plant, at a cost of 5yen/kWh, is estimated to be approximately 4,230 yen/t CO_2 avoided (US$35.87/t CO_2 avoided). This includes the costs of compressing 1 Mt/yr CO_2 to 10 MPa, transport over 20 km and injecting by extended reach drilling (ERD) at a rate of 0.1 Mt/yr per well. The analysis found that geological storage costs in Japan were greater than the average costs stated in the IPCC *SRCCS (2005).* Transport costs are influenced by Japan's dense population, while injection costs reflect the fact that the storage formations have low permeabilities. Figure 34 shows the estimates for each CCS component of the four systems.

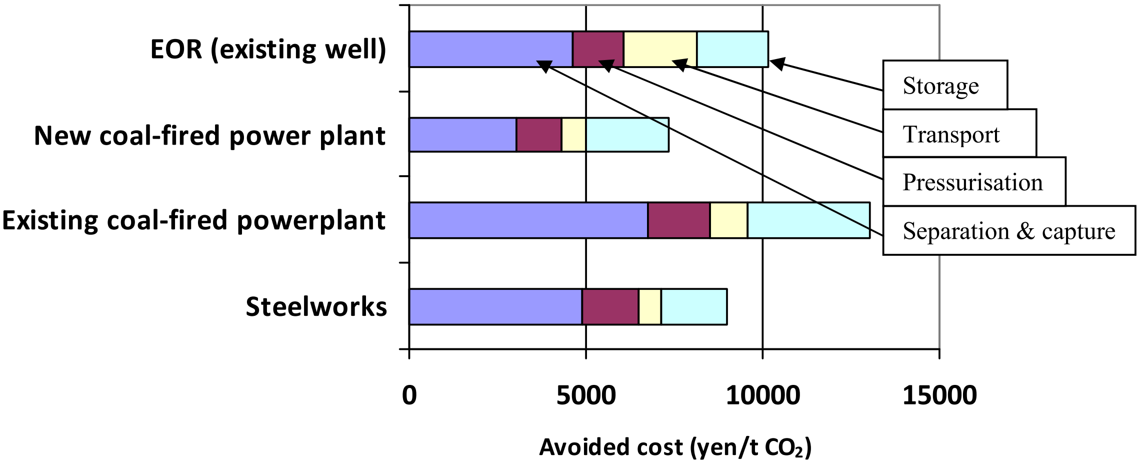

Figure 34. Cost analysis based on model site survey (RITE, 2007)

Using data for storage costs obtained from the Nagaoka injection tests, (Akimoto et al., 2007) estimated the costs of CO_2 aquifer storage in Japan. They found costs to be highly dependent on the scale of the operations, as well as the characteristics of the storage formation, transport distance and rate of injection.

Akimoto et al (2007) estimated injection costs for a range of scenarios based on an injection rate of 1 Mt CO_2/yr. These are onshore injection into an inland reservoir and an offshore formation (by ERD), over a range of depths, and injection to a depth of 1,000 m using an offshore platform and subsea wellhead, for varying distances from the shore. For example, the cost of injecting 0.1 Mt CO_2/yr/well to a depth of 1,000 m is estimated to be approximately 1,300 yen/t CO_2 (US$11.18/t CO_2) using an onshore well, 2,000 yen/t CO_2 (US$17.20/t CO_2) using ERD, 2,200yen/t CO_2 (US$18.92/t CO_2) using an offshore platform 10 km from the shore and 3,000 yen/t CO_2 (US$25.80/t CO_2) using a sub-sea wellhead 10 km from the shore (Table 22).

Table 22. Costs for injecting 1Mt/yr CO_2, 0.1Mt/yr/well to a depth of 1,000 m.

Injection system	Cost (JPY/t CO_2)	Cost (US$/t CO_2)
Onshore well	1,300	11.18
ERD	2,000	17.20
Offshore platform (10km from shore)	2,200	18.92
Sub-sea well head (10km from shore)	3,000	25.80

Source: Akimoto et al (2007)

Transport costs were estimated for onshore pipelines, offshore pipelines and tankers as a function of transport distance, and also for onshore pipelines based on transport capacity. For example, Akimoto et al (2006) estimate that transporting 1 Mt CO_2/yr over a distance of 100 km would cost approximately 3,300yen/t CO_2 (US$28.37/t CO_2) for an onshore pipeline and 1,800 yen/t CO_2 (US$15.48/t CO_2) using an offshore pipeline. It would cost over 3,800 yen/t (US$32.67/t) to transport CO_2 in liquid form using a tanker for distances greater than 500km. Again, because of the high population density in Japan, the authors found that transport using onshore pipelines was more costly than using offshore pipelines. Furthermore, taking into account the influence of economies of scale, the cost of onshore pipelines is estimated to be as much as 5 to 10 times the average cost quoted in the IPCC *SRCCS*.

Ketzin (CO2SINK)

The CO2SINK project officially started in April 2004 and is aimed at developing an in-situ laboratory for the investigation of onshore CO_2 storage (Förster et al., 2006). The target for the storage of CO_2 is a sandstone aquifer in the Upper Triassic Stuttgart Formation in the Ketzin anticline in northern Germany (Figure 35). The migration of salt has formed several of these anticlinal structures in this part of Germany, which could act as traps for hydrocarbons. Approximately 30,000 tons per year are anticipated to be injected over 3 years and injection started in June 2008. The injection target is located at depths between 500 – 700 m and as a result, part of the CO_2 will be in a gaseous state at the prevalent subsurface pressure and temperature conditions. The Stuttgart Formation sandstone aquifer is capped by an aquitard consisting of clay and gypsum of the Weser and Arnstadt formations. One injection well is used, with a true vertical depth of approximately 800m. The well was completed with 5.5 inch outer diameter production casing and 3.5 inch injection string.

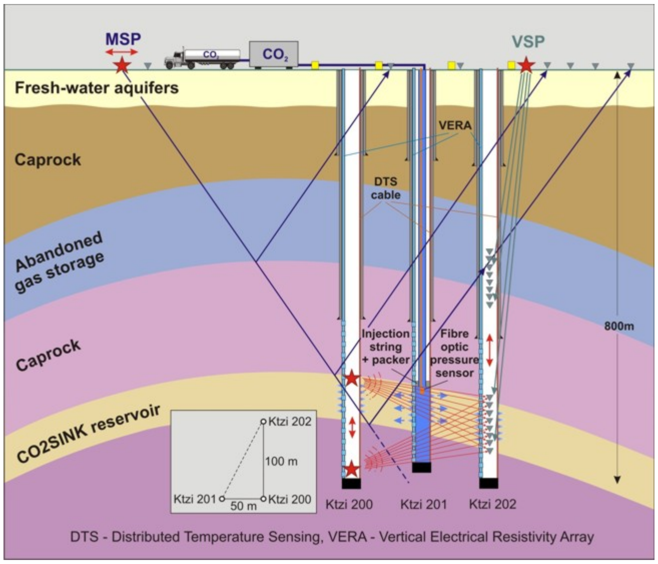

Figure 35. Monitoring set-up of the CO2SINK project at Ketzin (Source: www.co2sink.org).

Monitoring

The CO2SINK project incorporates a comprehensive monitoring program. Two observation wells were drilled 50 and 100 m away from the injection well, also with 800 m true vertical depth (Figure 35) and 5.5 inch outer diameter production casing. These wells allow borehole-based seismic and electrical measurements as well as extensive logging. A total of 200 m of core, covering the reservoir rock as well as the caprock formation, were collected and analysed.

Seismic monitoring methods that will be applied include cross-well, vertical seismic profile (VSP), moving source profiling (MSP), 2D and 3D time lapse techniques. A 3D 25-fold seismic survey with a 12 by 12 m resolution and about 12 km^2 of subsurface coverage was acquired in 2005 to verify earlier geologic interpretations and to obtain a baseline for future seismic surveys (Juhlin et al., 2007; Jullien et al., 2005). During the autumn of 2007, baseline cross-well, VSP and MSP data were acquired at the injection site. Cross-well seismics will be repeated several times in the early stages of the injection process to map the time evolution of the CO_2 plume in the vicinity of the injection well. Acquisition of VSP and MSP will be repeated twice during the injection period to map migration of the CO_2 away from the injection well. The 2D seismic will be at the end of the injection period and will allow mapping of possible migration of the CO_2 up towards the top of the anticline. Continuous Wavelet Decomposition (CWT) was successfully used as a valuable aid in enhancing the ability to map thin beds in seismic data. The CWT method can be used as a quick indicator of gas (hydrocarbon) and is an important technique in the monitoring phase of the CO2SINK project. Electrical Resistivity Tomography (ERT) will be used to complement seismic methods.

Risk Assessment

The Ketzin project will develop an integrated, cross-discipline methodology for risk assessment and management (Figure 36). In practice, this means the combining of individual risk issues identified at the specialist level into a common, comprehensive decision model and framework that will help project leaders to reduce risks to levels that are as low as reasonably practicable (ALARP). The top-level risks include all aspects of safety, cost, schedule and system performance, i.e., that the storage facility will retain the injected CO_2 for the very long time required to mitigate climate change as illustrated in Figure xx.

The goals of the risk management work process for the CO2SINK project are to identify specifically for this CO_2 storage site:

- All potential sources of risk, including those to the local community,

- Project decisions related to those risk sources, and
- Alternative, mitigating actions to reduce risks to ALARP.

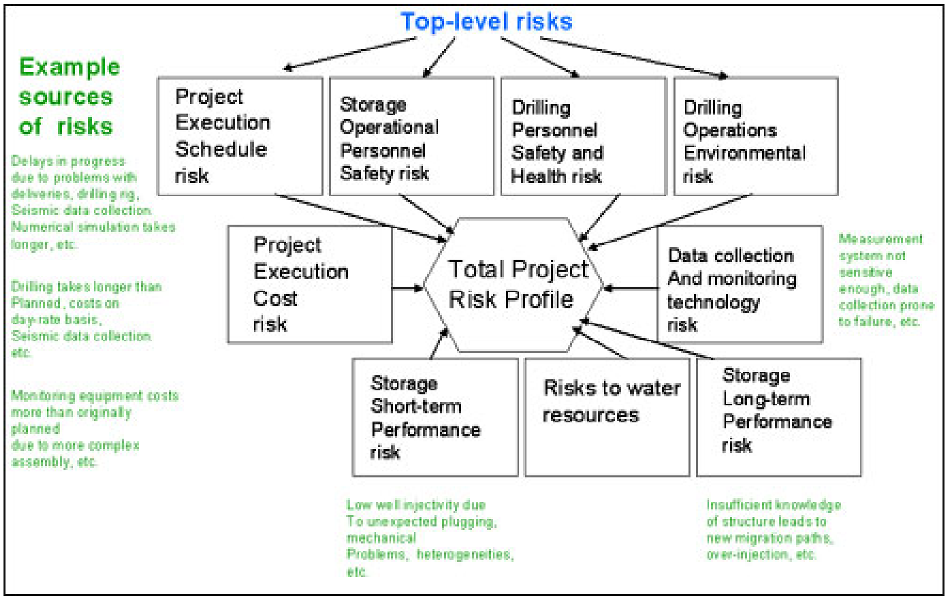

Figure 36. Illustration of top-level risks for the Ketzin Pilot project (CO2SINK project website).

Costs & Regulations

The total cost of the project is estimated to be €14 million (US$19 million) (CO2SINK 2007).

US Regional Carbon Sequestration Partnership Program

The US Department of Energy (DOE) has established seven regional carbon sequestration partnerships (RCSPs) to study CCS technologies. These are (NETL 2005):

- Big Sky Regional Carbon Sequestration Partnership (BSCSP), led by Montana State University – covering Montana, Wyoming, South Dakota, Idaho, eastern Washington and Oregon
- Midwest Geological Sequestration Consortium (MGSC), led by the Illinois State Geological Survey, in conjunction with the Indiana Geological Survey and the Kentucky Geological Survey – covering Illinois, south-western Indiana and western Kentucky;
- Midwest Regional Carbon Sequestration Partnership (MRCSP), led by the Battelle Memorial Institute – covering Indiana, Kentucky, Ohio, Pennsylvania, New York and West Virginia
- Southeast Regional Carbon Sequestration Partnership (SECARB), led by the Southern States Energy Board – covering Georgia, Florida, South Carolina, North Carolina, Virginia, Tennessee, Alabama, Mississippi, Arkansas, Louisiana and southeast Texas
- Southwest Regional Partnership for Carbon Sequestration (SWP), coordinated by the New Mexico Institute of Mining and Technology – covering New Mexico, Oklahoma, Kansas, Colorado, Utah and portions of Texas, Wyoming and Arizona
- Plains CO_2 Reduction Partnership (PCO_2R), led by the Energy & Environmental Research Centre at the University of North Dakota – covering North Dakota, South Dakota, Minnesota, Montana, Wyoming, Nebraska, Iowa, Missouri and Wisconsin and the Canadian provinces, Alberta, Saskatchewan and Manitoba
- West Coast Regional Carbon Sequestration Partnership (WESTCARB), led by the California Energy Commission – covering California, Oregon, Washington, Alaska, Nevada, west Arizona, Hawaii and the Canadian province, British Columbia

The Programme consists of three phases (Battelle 2005):

- Phase I, Characterisation phase (October 2003 to September 2005) – assessing storage options in the region, including characterising sources and sinks, assessing costs, risks and regulations and raising public awareness of CCS
- Phase II, Validation Phase (October 2005 to September 2009) – conducting pilot projects to demonstrate and gather data on CO_2 storage; and
- Phase III, Deployment Phase (October 2009 to September 2017) – implementing large-scale pre-commercial geologic storage projects

Details of the CO_2 storage projects being conducted by the RCSPs are described in a series of factsheets and presentations prepared for the Regional Carbon Sequestration Partnerships Annual Project Review Meeting, held 12-13 December 2007. The projects that inject or plan to inject into saline aquifers are listed in Table 23. Additional information can be found at the various RCSPs webpages accessible through the NETL website (www.fossil.energy.gov/sequestration/partnerships/index.html) and in Litynski et al. (2008).

Table 23. Pilot and demonstration projects injecting or planning to inject CO_2 into saline aquifers in the US Regional Partnership program.

RCSP	Project	Injection Start	Project Status	CO_2 Storage	Injection Unit	Project Cost
BSCSP	Moxa Arch Injection	2008	unknown	2 Mt	Nugget Fm.	$110,443,505
MGSC	Decatur	2009	Well to be drilled January2009	1 Mt	Mt Simon Sandstone	$91,826,766
MRCSP	Michigan Basin	2008	Injection complete & monitoring underway	10 kt	Bass Islands Dolomite/Bois Blanc	$23,745,399 total for 3 projects
MRCSP	Cincinnati Arch	2009	Injection due to start June 2009	1-3 kt	Mt. Simon Sandstone	
MRCSP	Appalachian Basin	2008	Injection due to start October 2008	3 kt	Oriskany, Clinton, and Rose Run Sandstone	
MRCSP	Phase III	2010	Funded	1 Mt	Mt Simon Sandstone	$93,000,000
PCOR	Fort Nelson	2010	Funded	10.8 Mt	Unidentified Devonian carbonate	$135,586,059
SECARB	Mississippi	2008	Injection due to start late-2008	3 kt	L. Tuscaloosa Fm	$20,344,442 for all Phase II tests
SECARB	Early Test Saline	2009	Funded	1.5 Mt	L. Tuscaloosa Fm	$98,689,241
SECARB	Anthropogenic Test Saline	2010	Funded	1.0 Mt	L. Tuscaloosa Fm	
SWP	Farnham Dome	2008	Site Characterisation underway	3 Mt	Two Jurassic Sandstones	$88,845,571
WESTCARB	Salt River	2009	Permit applications underway	2 kt	Martin Formation	$5,500,000
WESTCARB	Rosetta-Calpine Saline	2009	Site Characterisation completed	2 kt	McCormick sand	$5,925,223
WESTCARB	Kimberlina	2010	Funded	1 Mt	Olcese and Vedder Sandstones	$90,719,100

Regulations

The regulatory framework in the United States of America with respect to CO_2 geological storage is discussed in detail by (Wilson and Gerard, 2007). The core premise of the Underground Injection Control (UIC) regulations is the containment of the injected material and protection of underground sources of drinking water. Operators must obtain a permit from the state agency or the Environmental Protection Agency (EPA) regional office before beginning injection operations. A detailed description of information required for the permitting process is set out in the Drinking water Academy (2002) document and includes comprehensive information on well sighting and construction, planned operation and monitoring, and plugging and abandonment.

Under the current regulatory regime in the US, injection of CO_2 for geological storage would be permitted through Class I or Class II wells (Wilson and Gerard, 2007). Class I regulations cover hazardous and industrial wastes, whereas Class II wells are used for wastes associated with hydrocarbon production. Therefore, CO_2 injected into saline aquifers originating from industry sources like power plants, refineries, and cement factories would require a Class I permit. Class II wells include CO_2 used for EOR and CO_2 produced in upstream gas operations. Neither regulation explicitly addresses storage time, reliability, or issues of long-term liability. According to Wilson and Gerard (2007), there are problems with permitting the injection of large quantities of a buoyant fluid in a Class I well, and a new Class VI category should be considered that excludes “no migration from the injection zone” and that represents a classification specifically tailored to CO_2 geological storage. For example, the Frio Pilot project applied for a Class V permit (class used for all wells that do not fit classes I – IV) rather than a Class I non-hazardous injection permit for the reasons summarized by Hovorka et al. (2003) in their application to the Texas Commission on Environmental Quality (see Frio section).

The Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geologic Storage produced A Legal and Regulatory Guide for States and Provinces as a result of a two-phase, five-year effort (IOGCC, 2007). This Phase II report takes the form of a Guidance Document for U.S. states and Canadian provinces. Its purpose is to provide to a state or province contemplating adoption of a legal and regulatory framework for the storage of carbon dioxide (CO_2) in geologic media the resources needed to draft a framework that meets the unique requirements of that particular state or province.

MGSC (Phase II & III) - Decatur

The MGSC (Midwest Geological Sequestration Consortium), ISGS, and Archer Daniels Midland Company (Khattri et al.) will work together on this carbon sequestration project, which will involve the capture and storage 333,000 tonnes of CO_2 per year from ADM’s ethanol fermentation facility in Decatur, Illinois for three years. The originally planned Phase II small-scale injection of 10 kt of CO_2 has been expanded to a combined Phase II and Phase III large-scale injection of 1 Mt of CO_2 over 3 years. The injection target is the Cambrian Mt. Simon Sandstone (Figure 37), the most widespread saline reservoir in the Illinois basin, occurring at a depth interval of 1800-2300m at the test site. The Deployment Phase NETL factsheet for MGSC (2008) states that the Mt. Simon Sandstone is overlain by the Cambrian Eau Claire Formation, a regionally extensive, low-permeability shale and underlain by Precambrian granitic basement. The Mt. Simon is used extensively for natural gas storage in the northern half of Illinois, and detailed reservoir data from these projects show that the upper 200 feet of the Mt. Simon has the necessary porosity and permeability to be a good sequestration target. MGSC estimates that the average porosity of the Mt. Simon at the ADM site will be around 12%. The top of the Mt. Simon Sandstone at the ADM site is estimated to lie at a depth of approximately 5,500 feet. Within the Illinois Basin, the Devonian New Albany Shale and Ordovician Maquoketa Formation shale units will also function as significant regional seals. Also, many minor, thinner Mississippian and Pennsylvanian shale beds form seals for known hydrocarbon traps within the basin. All three significant seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile radius of the test site. The Eau Claire is estimated to be 300-500 feet thick and is expected to be the primary seal at the ADM site. The Ordovician Maquoketa Shale and the New Albany Shale are anticipated to act as secondary seals. There are no mapped regional faults and fractures within a 25-mile radius of the ADM site.

The CO_2 will be obtained from ADM's Ethanol Production Facility. Outlet CO_2 streams from ethanol fermentor vents are typically 99%-plus pure CO_2, and common impurities are ethanol and nitrogen in the range of 600 to 1000 ppmv each. Other impurities in lesser amounts often include oxygen, methanol, acetaldehyde, and hydrogen sulphide. The CO_2 will be purified, dehydrated, compressed to ~2,000 psi and delivered to the wellhead as supercritical CO_2. The dehydration/compression facility is proposed to be located near the north boundary of the ADM facility.

The safety and effectiveness of the storage will be monitored by the MGSC through an extensive MMV programme. Planned techniques include High Resolution Electrical Earth Resistivity (HREER), microseismic monitoring, vertical seismic profiling, geochemical monitoring, soil gas sampling, CO_2 land surface flux monitoring, visible and infrared imaging, well logging, ground water monitoring, monitoring subsurface pressure and temperature, gas content and fluid chemistry and measuring CO_2 injection rates, volume and isotopic composition. Monitoring will occur before, during, and post-injection. The program will rely heavily on 3-D seismic data collected during the first year of injection to monitor the plume's position. The MMV program will be evaluated annually and modified as needed. Groundwater models such as MODFLOW and GFLOW will be used to develop a conceptual model for shallow groundwater flow and estimate the time for potential contaminants to travel outside the area of the injection site. This will provide a risk assessment for nearby water supplies in the unlikely occurrence of a CO_2 leak either during or following CO_2 injection. Geochemical models such as Geochemist's workbench, PHREEQCI, and TOUGHREACT will be used to conduct thermodynamic modelling of shallow groundwater and injection-formation brine. These models will provide insight on the long-term fate of injected CO_2 and will be used to study the regional impact of multiple injection wells on flow within a saline aquifer across the Illinois Basin. The project will begin in spring 2008 with the drilling of the injection well, with environmental monitoring beginning in October 2008 to collect background information over a year's time. The sequestration and injection of CO_2 is scheduled to begin in October 2009 and should conclude in 2012.

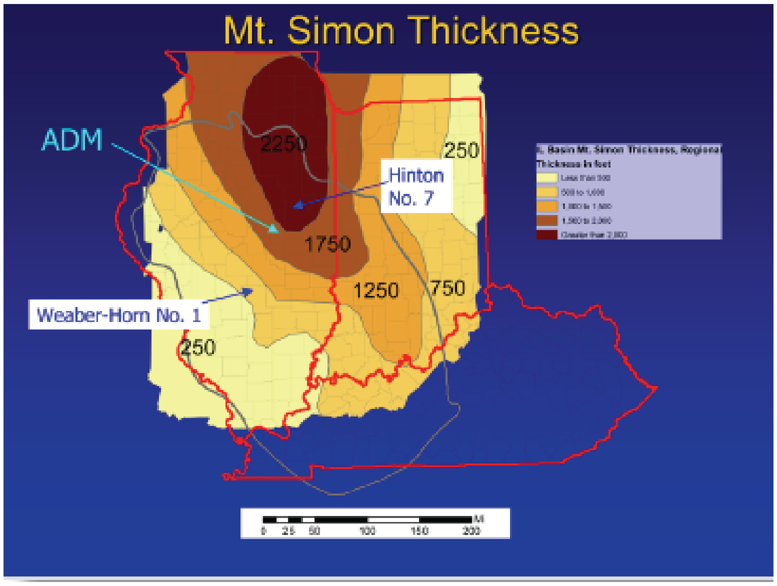

Figure 37. Regional diagram showing thickness of Mt. Simon Sandstone (Source: Deployment Phase NETL factsheet for MGSC, 2008).

The MGSC estimates that the Phase II and III project will cost US$91,826,766. US DOE funding totals US$70,353,741, while US$21,473,025 will come from non-DOE sources.

WESTCARB (Phase II) - Salt River

WESTCARB (West Coast Regional Carbon Sequestration Partnership) will conduct a three-phase field validation test in Northern Arizona to assess the CO_2 storage potential of the region, the Arizona Utilities

CO_2 Storage Pilot. Three coal-fired power plants, Navajo, Coronado and Springerville, are located in the region and emit 30-40 Mt CO_2 per year. Beginning in 2009, approximately 2,000 t purchased CO_2 will be injected into the 200 m thick Martin Formation at a depth of 1050 m below the Colorado Plateau (Figure 38). The details of the project are summarised by (Trautz, 2007a). WESTCARB evaluated a range of monitoring techniques to identify the most cost-effective combination to achieve the project objectives. The program consists of analysing fluid composition, monitoring subsurface pressure, well logging, vertical seismic profiling (VSP), cross-well seismic imaging, caprock integrity, CO_2 land surface flux monitoring and soil gas sampling. Results from the test will be used to extrapolate the regional storage potential of the Colorado Plateau in Northern Arizona. The capacity of the storage formations will be assessed relative to the size of regional sources of CO_2.

WESTCARB estimates the total cost of the project to be US$5,500,000. The US DOE will contribute US$4,400,000 and non-DOE sources US$1,100,000.

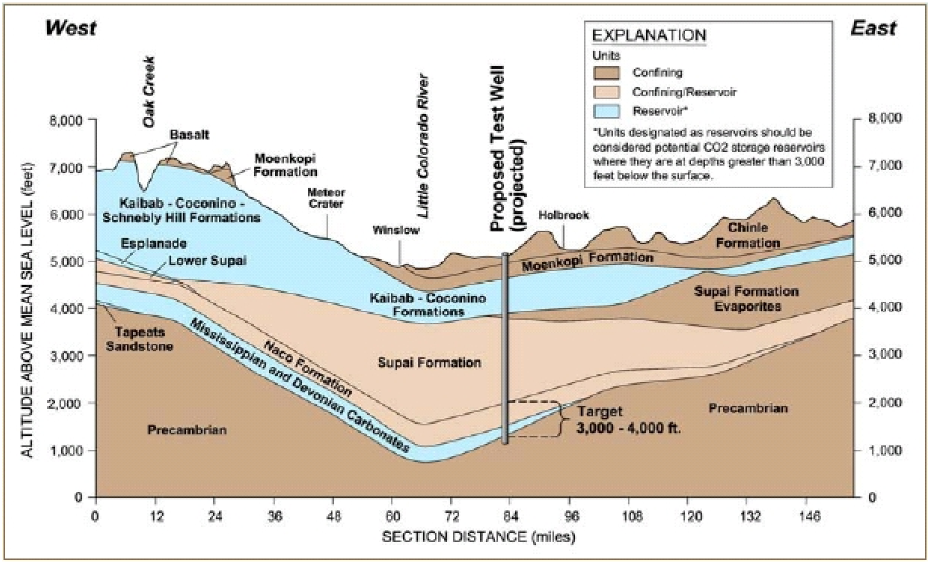

Figure 38. Schematic showing the subsurface lithology in Northern Arizona. Injection is planned for the Devonian age Martin Formation.

WESTCARB (Phase II) - Rosetta-Calpine Saline

Two pilot tests involving CO_2 injection will be performed at the Rosetta CO_2 Storage project site. A thorough review of existing and abandoned natural gas fields in the southern Sacramento Valley, California was performed. The proposed field site for the pilot test is in a small-depleted and abandoned natural gas field located north of Thornton, California. Gas production began in the mid 1940s and continued through the late 1980s, producing nearly 1.52 x 109 m^3 (53.6 billion cubic feet, Bcf) of gas from 14 wells. The Thornton Gas Field is an excellent geologic analogue to numerous gas fields in the Sacramento Valley, including the much larger 9.3 x 1010 m^3 (3.3 Tcf) Rio Vista Gas Field located a few miles away near Rio Vista, California. The Rio Vista Gas Field is the largest onshore gas field in California. Thornton was also selected based on evidence of a favourable set of stacked gas reservoirs and saline formations, its close proximity to major transportation corridors, shallow depth to the gas pay zone 928 m and geologic evidence of a well-defined stratigraphic gas trap that would safely hold the CO_2.

The first pilot test in 2009 will involve injecting up to 2000 tons of CO_2 into a brine-filled zone in the McCormick sand, a very fine to medium grained, quartzitic sandstone. Two wells, a CO_2 injector and an observation well, will be installed in a saline zone located beneath the gas trap in the McCormick sand (Figure 39). The current best estimate for the target depth of the saline test is 1037 to 1067 m. Both wells will be drilled to approximately the same depth and the casing will initially be perforated in the saline zone. CO_2 injection will commence after logging and testing the wells. The Capay shale represents a regionally extensive reservoir cap, containing pockets of natural gas in thin interbedded sand lenses. The top of the McCormick sand, a depleted water-drive reservoir at a slightly greater depth of 1003 to 1021 m, is an alternative location if the Capay sand stringer is absent at the location of the new wells. The casing will be perforated in the gas zone after completing the first experiment and cementing the well perforations shut in the lower saline zone. The second experiment will consist of injecting CO_2 into the depleted gas zone to assess the nature and extent of reservoir pressurisation and displacement of CH_4 by CO_2. The CO_2 will be purchased from a local supplier and trucked to the pilot site. Information source: Factsheet for Rosetta-Calpine saline validation test (Trautz, 2007b).

WESTCARB is evaluating a range of monitoring techniques for tracking CO_2 movement and detecting leaks. The techniques being considered include vertical seismic profiling (VSP), caprock integrity, electrical and electromagnetic techniques, CO_2 land surface flux monitoring and soil gas sampling.

WESTCARB estimates the total cost of the project to be US$5,925,223. The US DOE will contribute US$3,545,000 and US$2,380,223 will be contributed by non-DOE sources.

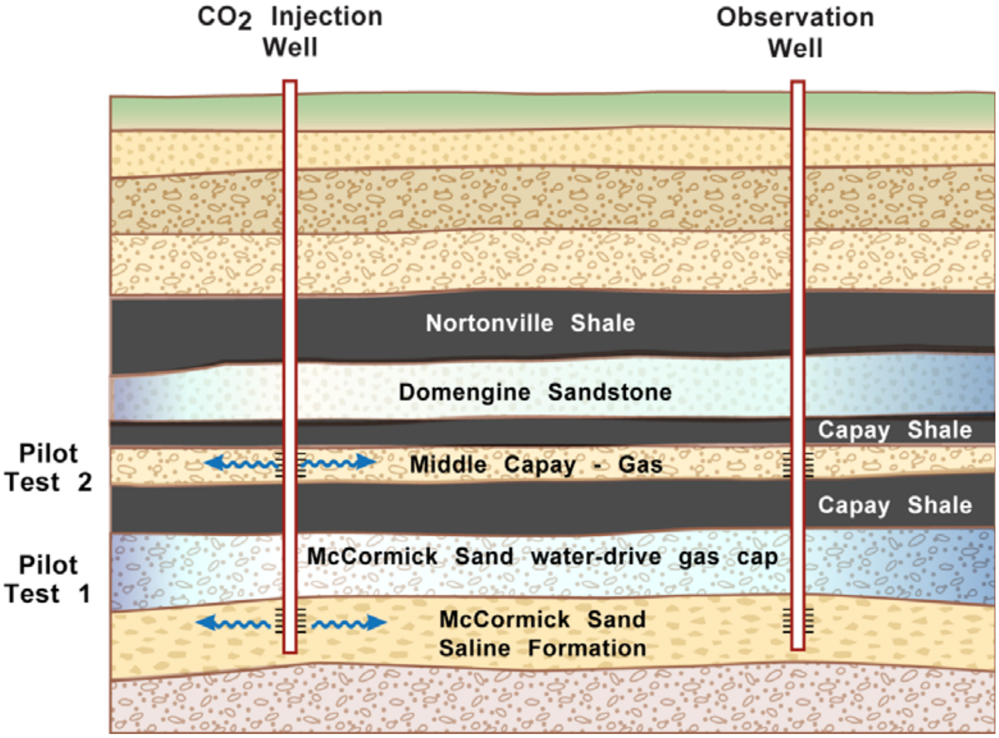

Figure 39. Geologic section at the Rosetta pilot site. Information source: Factsheet for Rosetta-Calpine saline validation test (Trautz, 2007b).

WESTCARB (Phase III) - Kimberlina

The WESTCARB Partnership will conduct a field validation test in Kimberlina, California. The details of the project are summarised by (Myer, 2007). Small-volume injection testing will be conducted in 2009. From 2010, the project will inject 250,000 tons CO_2 per year over 4 years into an aquifer in the San Joaquin Basin, below a proposed Clean Energy Systems (CES) oxy-combustion power plant with CCS. The new plant and infrastructure for capturing, compressing and injecting CO_2 will be constructed next to the CES pilot plant installed at the site for R&D purposes.

Two formations are being considered for storage. These are the Olcese and Vedder sandstones, located at depths of 2,400 m and 2,700 m respectively. The units have thicknesses of 240 m and 150 m respectively at the injection site. WESTCARB estimates that their combined storage capacity is 400Mt in dissolved and residual capacity and 1,500 Mt in physical capacity (Myer 2007).

Monitoring will occur before, during and after injection. Activities planned include vertical seismic profiling, logging, coring, pressure, temperature and fluid testing, 3D seismic surveys, microseismic monitoring, CO_2 flux monitoring and atmospheric CO_2 monitoring.

WESTCARB estimates the total cost of the project to be US$90,719,100. The US DOE share of the costs will be US$67,000,000 and the non-DOE share US$23,719,000.

MRCSP (Phase II) - Appalachian Basin

MRSCP (Midwest Regional Carbon Sequestration Partnership) will inject 3,000 tonnes of CO_2, at a rate of approximately 20 t/day, into an aquifer located in the Appalachian Basin alongside the Ohio River. The source of CO_2 will be a pilot-scale Powerspan emission control system, to be installed at FirstEnergy's R.E. Burger facility, a 413 MW coal-fired power plant. The CO_2 will be transported to the injection site by a pipeline system comprising a 150 m, 3.5 inch outer diameter, above-ground pipeline from the capture facility and a 450 m, 2.375 inch outer diameter, buried pipeline to the injection well.

A number of potential storage formations have been identified at the site. These include the Tuscarora "Clinton" sandstone located at a depth interval of 2474-2535 m and the Oriskany Sandstone at 1805-1814 m (Figure 40). The Partnership drilled an injection well to a depth of 2555 m in the year 2007, penetrating the Clinton formation.

The measurement techniques being considered for the monitoring program are those that can be applied using the injection well, as a monitoring well was judged to be uneconomic. These include analysis of water composition, monitoring subsurface pressure and logging. 3D seismic is also being considered.

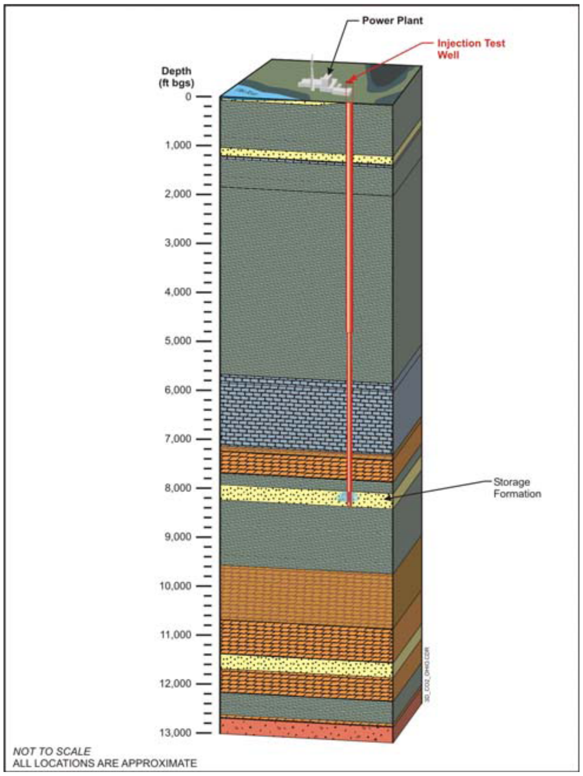

Figure 40. Conceptual diagram of CO_2 sequestration tests for Appalachian Basin site. Information source: Factsheet for Appalachian Basin saline validation test (Gupta, 2007a).

MRCSP (Phase II) - Michigan Basin

The MRCSP (Midwest Regional Carbon Sequestration Partnership) injected 10,241 tonnes of CO_2 from February 18-March 8, 2008 into a deep saline aquifer located in the Michigan Basin near the Niagaran Reefs. The CO_2 was obtained from the DTE Turtle Lake Gas Processing Plant, compressed onsite and transported to the storage location by a “White Frost” pipeline. The target aquifer is the Bass Islands Dolomite, located at a depth of 1049 -1072 m (Figure 41). The unit has an average porosity of 21 % and an average permeability of 22 mD. The confining layer is the Amherstburg Limestone. MRCSP drilled the injection well to a depth of 1770 m into the reefs in November 2006. An existing nearby oil well has also been recompleted to serve as a monitoring well.

The monitoring programme for the site includes monitoring introduced and natural tracers, water composition and subsurface pressure, soil gas sampling, well logging, vertical seismic profiling, cross-well seismic imaging and passive seismic monitoring. The MRCSP is also considering 3D seismic surveys as an option.

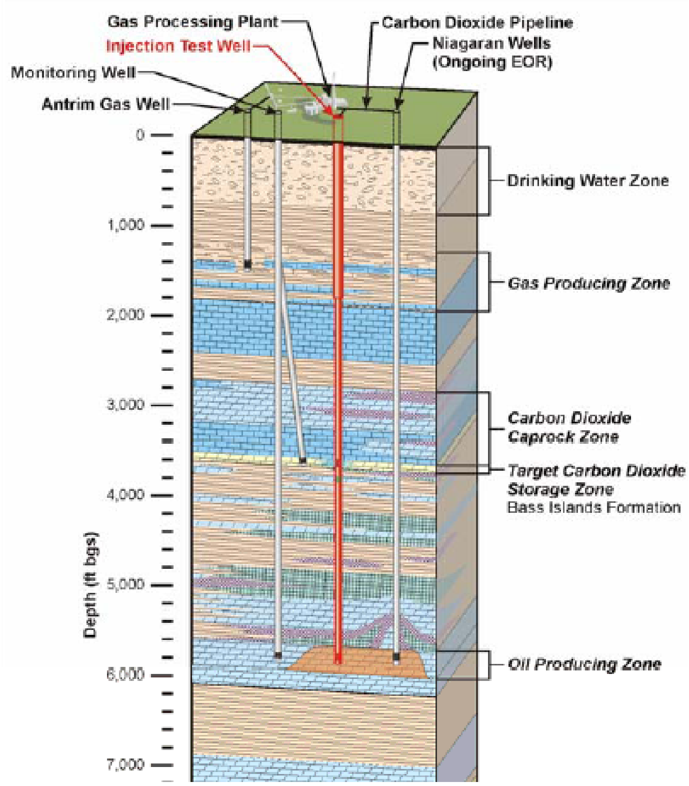

Figure 41. Conceptual diagram of CO_2 sequestration tests for Otsego County Michigan site. Information source: Factsheet for Michigan Basin saline validation test (Gupta, 2007b).

MRCSP (Phase II) - Cincinnati Arch

MRSCP will inject up to 3,000 t CO_2, at a rate of 100 t/day, into an aquifer in the sedimentary sequence along the Cincinnati Arch in Kentucky. The test will be conducted at the Duke Energy East Bend facility, a 650MW coal-fired power plant. The CO_2 will be sourced from the Babcock and Wilcox oxy-coal combustion system in southeast Ohio and transported to the storage site by truck. The target aquifer is the Mt. Simon sandstone, located at a depth interval of 3,200 - 3,500 ft. The Partnership plans to begin drilling an injection well to the bottom of the reservoir in the year 2008. A monitoring well is also being considered. A variety of techniques have been proposed for the monitoring programme. These include analysing water composition, monitoring subsurface pressure, well logging, vertical seismic profiling and cross-well seismic imaging (Gupta, 2007a).

A total cost of US$23,745,399 is expected for the three Phase II MRCSP projects.

MRCSP (Phase III)

The details of MRCSP's Phase III operations are summarised by Ball (2007). The project will involve one of two injection sites. The primary site is the Andersons Marathon Ethanol Plant currently being built in Greenville, Ohio. Beginning in late 2009, 280,000 t CO_2 would be injected per year over 4 years at the site. The optional site is a 640 MW IGCC plant in Indiana, where 2,000,000 tons CO_2 would be injected over 4 years, possibly beginning in the year 2012.

The storage formation for the primary site is the Mt. Simon Sandstone aquifer, located at a depth interval of approximately 1,000 -1,100 m. The formation has an average porosity of 12 % and permeability of 50-400 mD. CO_2 will be injected using injection wells drilled to less than 4,000 ft. Monitoring wells will also be drilled to similar depths. The site will be monitored during and after injection. Proposed activities include cross-well seismic and microseismic monitoring, 3D seismic surveys, measuring injection pressure and volume and fluid sampling. A number of storage formations are being considered for the optional test site. The main target is the Mt. Simon aquifer located at a depth interval of 2,285 - 2,625 m at the site. In this location, the formation has an average porosity of 10 % and permeability of 10-200 mD. The secondary target is the Knox Carbonates.

The total cost of the Phase III project is estimated to be US$93,000,000. The US DOE will contribute US$61,000,000 and non-DOE sources US$32,000,000.

PCOR (Phase III) Fort Nelson

The Deployment Phase NETL factsheet for PCOR (2008) states that the Fort Nelson project will utilise 1.8 million tons of CO_2 per year for six years, captured from one of the largest gas-processing plants in North America. The CO_2 will be compressed and transported in a supercritical state via pipeline to the target injection location. While a specific brine formation and injection location have not yet been chosen, it is anticipated that the target zone will be a Devonian-age carbonate rock formation located in relatively close proximity to the gas plant (< 3 km) in north-eastern British Columbia. The thickest and most comprehensive seal for the carbonate rock formations under consideration are the massive and extensive Fort Simpson Formation shales, which are characterised by low permeability and high geomechanical strength. This cap provides a very competent seal for underlying brine-saturated formations. The cumulative average thickness of the Fort Simpson Formation is approximately 500 m, and in some areas the thickness can be in excess of 1000 m. The Fort Simpson Formation is laterally extensive, underlying thousands of square miles. Secondary seals also exist above the Fort Simpson Formation, the most competent and massive being the Banff Formation, which is predominantly shale and not less than 30 m thick in the Fort Nelson area.

The source of the CO_2 will be the Spectra Energy Fort Nelson natural gas-processing plant in north-western British Columbia. The CO_2 will be captured using an existing amine-based acid gas removal system, dried, compressed, and transported by pipeline as a supercritical fluid to a nearby injection site. Its composition will be approximately 85% CO_2 and 15% H_2S.

MMV techniques used will include the following: pressure monitoring, fluid sampling (oil, gas, water), pressure and geochemical monitoring of overlying formations, downhole geophysical monitors (passive microseismic and/or tiltmeters), surface CO_2 measurements, ion chemistry and isotopes of sampled fluids, and tracer (e.g., perfluorocarbons) monitoring.

PCOR reports that this project and another project combined will cost US$135,586,059. US DOE funding totals US$67,000,000, while US$68,586,059 will come from non-DOE sources.

SECARB (Phase II) Mississippi

The Validation Phase NETL factsheet for SECARB (2008) states that the primary objective of this project is to locate and test suitable saline formations for storage of CO_2 in proximity to large coal-fired power plants along the Mississippi Gulf Coast. The target formation for this field test is the Cretaceous Lower Tuscaloosa Massive Sand Unit in Jackson County, Mississippi. The test will include building detailed geological and reservoir maps to further assess the test site and conducting reservoir simulations to estimate injectivity, storage capacity, and long-term fate of injected CO_2. Injection of 3,000 tons of CO_2 at an approximate depth of 2,620 m will take place at Mississippi Power Company's Plant Daniel, located near Escatawpa, Mississippi in late 2008. An injection well and an observation well were drilled at Plant Daniel during March-April 2008.

A total of 24 wells, including 20 oil & gas plus 4 Class II wells provided the essential deep subsurface information for the Mississippi Gulf Coast area. The nearest deep wells are about 5 to 10 miles away, limiting available geologic information for the plant area. EPA defined "Low Salinity" waters (<10,000 mg/l) are protected and exist at a depth of about 490 to 850 m below surface in Jackson County, while the freshwater (<1,000 mg/l) zone exists in shallower formations.

SECARB reports that this project and the other Phase II projects combined will cost US$20,344,442. US DOE funding totals US$14,663,953, while US$5,680,489 will come from non-DOE sources.

SECARB (Phase III) Early Test Saline and Anthropogenic Test Saline

The Deployment Phase NETL factsheet for SECARB (2008) states that it will conduct a two-step, large-volume injection test in the lower Tuscaloosa Formation, a key component of a larger, regional group of similar formations, in terms of deposition and character, called the Gulf Coast Wedge. The first step, or "Early Test," will inject 1.4 million tonnes of CO_2 per year for 18 months. The CO_2 will come from a naturally occurring source that is commercially available, of high purity, highly reliable, and low cost. The source is the Jackson Dome and it will be delivered by Denbury Resources' CO_2 pipeline. The second step, or "Anthropogenic Test," will inject 100,000 to 250,000 tonnes of CO_2 per year for four years. The CO_2 will be supplied from a pilot unit capturing CO_2 from flue gas produced from a Southern Company power plant located near the injection site.

The Early Test will focus on the down-dip "water leg" of the Cranfield unit, operated by Denbury Resources, Inc. in Adams and Franklin Counties, Mississippi, about 15 miles east of Natchez, Mississippi, and near Cranfield. The area selected for the Early Test is immediately north of the SECARB Validation Phase "Stacked Storage" study underway in the oil rim field. The Anthropogenic Test will be conducted on or in proximity to a Southern Company plant site on the Gulf Coast. The Cretaceous lower Tuscaloosa Formation is one of the named stacked sandstone formations of the Gulf Coast Wedge. The Tuscaloosa contains an upper section of alternating shales and sands and a basal section, the Massive Sand Unit, which contains a thick layer of clean, coarse-grained sand. The Formation was deposited during a major period of global sea level rise, and its deposition has been interpreted as an upward gradation from fluvial and deltaic sedimentation (the Massive Sand) to shelf deposition (alternating sands and shales). The Massive Sand was deposited in a wave-dominated shallow coastal barrier environment. The well-sorted, clean, coarse-grained nature of the Massive Sand makes it an ideal candidate for CO_2 injection due to its high permeability and porosity. As the sea level continued to rise, the shelf depositional environment gave way to a deep marine environment, during which the overlying middle (Marine) Tuscaloosa Formation was deposited. This formation consists of about 150 m of low-permeability shale, providing an excellent cap rock and primary seal to CO_2 injection into the lower Tuscaloosa Formation.

The MMV programme planned by SECARB will span the 10-year Deployment Phase of the project. Each site will be well-instrumented with multiple sensor arrays. In the "Early Test," sweep efficiency will be monitored by saturation measurements along well bores, cross well measurements, and vertical seismic profiling (VSP) and/or surface seismic methods. Proposed monitoring activities for the "Anthropogenic Test" will include:

- well bore integrity assessed through Ultrasonic Imaging Tool (USIT) logging, annular pressure monitoring, and tracer injection;

- assessment of areal extent of the plume through drilling and monitoring up-gradient wells, seismic surveys (3-D and VSP), and Reservoir Saturation Tool (RST) logs in observation wells;

- monitoring for formation leakage through RST logging and using the VSP geophones to map and trace CO_2 leakage; and

- CO_2 seepage through shallow subsurface monitoring for CO_2, carbon isotopes, and tracers.

To help predict plume movement and assess the ultimate fate of the injected CO_2, the project team will utilise two types of simulation models: GEM simulation software and TOUGHREACT.

SECARB reports that the projects will cost a total of US$98,689,241. US DOE funding totals US$66,949,078, while US$28,740,163 will come from non-DOE sources.

SWP (Phase III) – Farnham Dome

SWP's Phase III aquifer project intends to accomplish a major deep saline sequestration deployment in an area known as Farnham Dome in Central Utah. This test will follow an injection schedule over 4 years (2008-2011), leading up to 900,000 tonnes of CO_2 per year. The target formations are deep saline units present throughout the Southwest Partnership region, as well as in many states outside the region. The Farnham Dome injection site is located just southwest of the Uinta basin, near Price, Utah, 120 miles south of Salt Lake City. Farnham Dome is an elongated surface anticline located along the northern plunge of the San Rafael uplift. The area provides an excellent deployment test opportunity for analysis of high injection rates and high-resolution monitoring of CO_2 in multiple rock layer horizons. These deep saline formations are major targets for commercial-scale sequestration associated with future coal-fired power plants planned for the area (SWP, 2008).

The Deployment Phase NETL factsheet for SWP (2008) indicates that the target formations are deep saline units present throughout the SWP region, as well as in many states outside the region. In all cases, the seal is the Morrison Formation, a 120 m thick Jurassic shale/gypsum/siltstone, also regionally present throughout the SWP states. At the study site and all other sites, the target units lie within a true "stacked" system—above the Morrison formation lies the Dakota formation, a Cretaceous-aged sandstone similar to the deep Triassic and Permian sands, and capped by the Pierre/Mancos shale, a very thick (500 m to 1500 m) shale unit. The SWP has gathered porosity, permeability, mechanical, compositional, and geophysical data associated with these target formations and seals.

The sources of CO_2 include natural CO_2 from the Jurassic-aged Nugget Sandstone or a coalbed methane (CBM) production field northwest of Price, Utah; the CBM operation currently vents over 100,000 tons of CO_2 per year. A short pipeline will be required to transport captured CO_2 to the injection site. All CO_2 captured will be 97% pure, with the remainder nitrogen (air).

An extensive monitoring programme is planned to determine whether CO_2 is securely sequestered. Techniques include vertical seismic profiling, cross-well seismic imaging, monitoring of tracers, water composition and subsurface pressure, well logging, repeat 3D seismic surveys, electrical and electromagnetic techniques, microgravity techniques, visible and infrared imaging, CO_2 land surface flux monitoring and soil gas sampling. A variety of "in house" and commercial/public simulation tools will be used, including GEM, TOUGH2, TOUGHREACT, FEHM, CO2-PENS, COMSOL, THRUST3D, MRKEOS and SWEOS.

SWP estimates that the project will cost US$88,845,571. US DOE funding totals US$65,437,395, while US$23,408,176 will come from non-DOE sources.

BSCSP (Phase II & III) - Moxa Arch Injection

BSCSP will conduct two Phase II geologic storage projects. The two storage options being tested are mafic rock formations and saline aquifers. Beginning in the year 2008, the saline formation pilot test will involve injecting 3,000-5,000 tons CO_2 into the Triassic Nugget Sandstone Formation in the Riley Ridge Field, Wyoming. The details of the project are summarised by (Thyne, 2007).

The Nugget Sandstone aquifer is located at a depth of 3350 m and has a total thickness of 215 m near the injection zone. The high permeability target zones have average thicknesses over 60 m and porosities over 15%. CO_2 will be injected into the reservoir using new wells and existing wells drilled by Cimarex Energy for extracting helium and methane. Observation wells will be drilled for monitoring purposes. A variety of techniques are planned for monitoring the post-injection behaviour of CO_2. These include vertical seismic profiling, microseismic techniques, microgravity, well sampling, soil gas surveys and tracers.

The total cost of the project is estimated to be US$7,973,762. The US DOE will contribute $2,976,806 while US$4,996,956 will come from non-DOE sources.

Following the Wyoming Phase II Saline Injection test, BSCSP will conduct a large-volume injection test at the site. A total of 2 million tons CO_2 will be injected into the Triassic Nugget Sandstone Formation. The source of CO_2 will be a Cimarex Energy gas plant to be built in the year 2008. The details of the project are summarised by (Spangler, 2007).The Partnership plans to have one injection well and at least four monitoring wells. Along with the fundamental monitoring methods, the monitoring programme may also include the use of eddy-correlation towers, LIDAR and IR detection tools and hyperspectral tools.

The total cost of the project is projected to be US$110,443,505. US$41,627,108 will be contributed by the US DOE and US$68,816,397 by non-DOE sources.

Other Planned Injection Projects

Canada

There are various projects in Canada that intend to inject CO_2 into saline aquifers. All of these projects are in the early planning stages and include:

Heartland Area Redwater Project (HARP) – The Alberta Research Council (ARC) and the ARC Energy Trust of Calgary intends to evaluate a Devonian reef complex to store up to 1 Gt of CO2 in the near vicinity of the industrial complex northeast of Edmonton. Additional industry consist mainly large CO_2 producers from the Edmonton area. The Heartland Area Redwater Project has three phases: phase one will evaluate in detail the size and suitability of the site for CO_2 capture and storage, phase two will involve the drilling of a well to collect more detailed data, while phase three is planned to demonstrate actual CO_2 injection and storage. The $1.8 million first phase is being funded by ARC Energy Trust, the Alberta Energy Research Institute (AERI) and Natural Resources Canada (NRCan) and is scheduled to be completed in spring 2009.

Wabamun Area CO_2 Sequestration Project (WASP) - will assess the geological and technical requirements, economic feasibility and technical and regulatory issues related to the potential to safely store up to 1 Gt of CO2.The 16-month assessment is being coordinated by the University of Calgary's Institute for Sustainable Energy, Environment and Economy (ISEEE). The $850,000-study is scheduled to be complete by mid-2009. Government funding is provided through the Alberta Energy Research Institute (AERI) and by the federal government's Natural Sciences and Engineering Research Council (NSERC). Funding is also being supplied by energy-sector partners TransAlta, TransCanada Corporation, ARC Energy Trust and Penn West Energy Trust.

Alberta Saline Aquifer Project (ASAP) – The project is driven by Enbridge, a pipeline company, with provincial government money and 30 industry participants at 20K each in Phase I. The initial objective of this phase is to identify the top three aquifer storage sites in Alberta and is anticipated to be completed by the end of 2008. Phase 2 will involve pilot injection operations, which may be expanded to large-scale, commercial operations in future phases.

Aquistore - Storage of 1000 t/d in a deep saline aquifer near Regina, Saskatchewan. CO_2 sourced from the COOP Refinery in Regina. Project to run between 2008 and 2012, managed by the Petroleum Technology Research Centre (PTRC). The costs are budgeted at CAD 50M.

QUEST - Project started by Shell Canada to store >1 Mt/yr from its oil sands upgrader in Fort Saskatchewan into a deep saline aquifer northeast of Edmonton. Project was stopped when Shell International took over Shell Canada in May 2007, but is likely to be followed up on in the future.

Europe

As integrated project under the 6th framework programme of the European Union, three sites have been identified by DYNAMIS for further study of their potential CO_2 geological storage (http://www.dynamis-hypogen.com/index.asp):

- Mongstad, Norway, suggested by Statoil: Natural gas based plant with offshore CO_2 storage.
- Hamburg region, Germany, suggested by Vattenfall; Bituminous coal based plant with onshore or offshore CO_2 storage.
- East Midlands, England, suggested by E.ON UK; Bituminous coal based plant with offshore CO_2 storage.

A fourth site in the North East UK has plans for offshore CO_2 storage in an EOR field.

Australia

Australian projects planning to inject CO_2 into saline aquifers are (Cook and Van Puyvelde, 2008):

- Callide Oxyfuel, Queensland: Demonstration project that involves conversion of an existing 30MW unit at Callide A (currently underway), and capture of CO2. The second stage of the project will involve the injection and storage of up to 50,000 tonnes of captured CO2 in saline aquifers or depleted oil/gas fields, and will continue for up to five years, commencing in 2010. This project is expected to cost A$180 million. Partners involved in this project include CS Energy, IHI, ACA, Schlumberger, CCSD and CO2CRC.
- Coolimba Power, Western Australia: Aviva Corporation Ltd recently announced a proposal for the development of 2x200MW oxyfuel coal-fired base-load power stations, with subsequent conversion to capture carbon dioxide during the combustion of coal. Storage is projected to commence after the oxy firing conversion is completed, potentially in 2011-12.
- FutureGas, South Australia: A joint venture between Hybrid Energy Australia and Strike Oil will research and develop the carbon dioxide storage component of the FuturGas Project – an energy conversion development involving the gasification of lignite to syngas, for the production of synfuels. It is proposed that the CO2 (captured post-gasification), will be stored in the Otway Basin to the south of the lignite resources. Currently the project is at the feasibility stage, the plan being to commence full-scale CCS by 2016.
- Monash CTL, Victoria: This proposed project will involve drying and gasification of brown coal, for conversion to synthetic diesel, followed by the separation of the produced CO2 (up to 10 million tonnes a year), and its transport and injection into a suitable storage site. This project which has an indicative start date of 2015 is estimated to cost A$6-7 billion. Capture and offshore

storage is expected to commence in 2015. Partners involved in this project include Monash Energy, Anglo American and Shell.

- ZeroGen, Queensland: This Queensland Government project, proposes to demonstrate integrating coal-based gasification and CCS Commercial 2011-2012. The CO2 will be transported approximately 200kms by pipeline for storage in the Denison Trough (up to 400,000 tonnes CO2 per annum). A feasibility study is underway but the project is estimated to cost in excess of A$1 billion dollars. Companies involved in the project include Shell and Stanwell.

Other CO_2 Injection Projects

Two projects not injecting into saline aquifers, Weyburn in Canada and Otway in Australia, are presented in this section for comparison purposes, because comprehensive site characterisation and monitoring programs have been performed at these operations.

Otway, Australia

The CO2CRC has developed a research project which involves CO_2-rich gas being extracted from a gas well (Buttress) then compressed and piped to a deeper depleted natural-gas field (Naylor). Here, the CO_2 is injected through the new CRC-1 well and injection began in March 2008. Over two years, up to 100,000 tonnes of the CO_2-rich gas stream at supercritical state will be injected into a depleted gas reservoir – the Waarre C Formation - at a depth of 2050 metres. CO_2 will migrate up-dip within the 31m thick reservoir sandstone capped by the impervious thick seal rock (the Belfast Mudstone). Drilling of the new injection well to inject CO_2 into the Waarre C Formation began on 15 February 2007 and was completed within budget on 15 March 2007. Located 309 m southeast from the Naylor-1 well, it is a vertical monobore well and was drilled to a depth of 2249 m into the Eumeralla Formation. Five cores were acquired with a total length of 42.9 m. Other samples collected include fluid, mud, gas and cuttings. The CO_2 is derived from the Buttress-1 well, which was drilled in 2002 with the intention of producing natural gas. When it was found rich in CO_2 it was decommissioned. Production well tests to confirm suitability as the production site for the Otway Project were carried out by CO2CRC in June 2006. The produced gas contains a significant proportion of CH4 (19%) but it was established that injection of this Buttress gas mixture would not compromise the research objectives of the Otway Project. The confirmed absence of mercury and hydrogen sulphide allows the injection of the produced Buttress gas straight into the depleted Waarre Formation, which already contains residual methane. The CO_2 is delivered to the injection well via a pipeline that was installed between December 2007 and January 2008. It is 2.25 km long, stainless steel and 50 mm in diameter. The maximum design temperature and pressure are respectively $50^{o}C$ and 15 MPa.

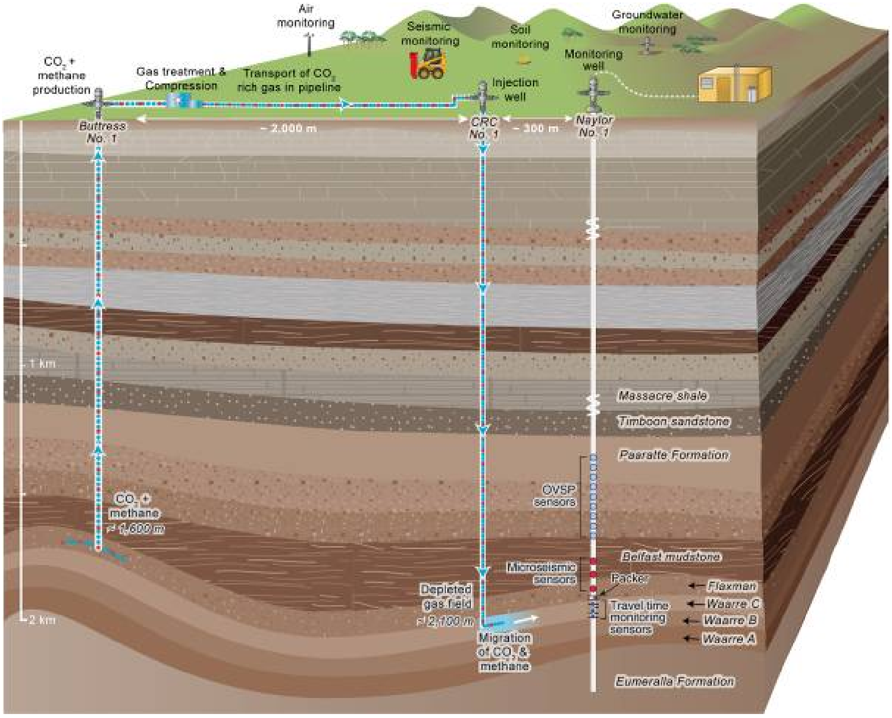

Figure 42. Conceptual diagram showing injection and monitoring installations for the Otway Pilot project.

Monitoring

A comprehensive monitoring program across the atmospheric, near surface and subsurface domains is underway. Monitoring and modelling activities will continue post-injection for several years and it is predicted that CO_2 will be detected 6-9 months after the start of injection at the Naylor-1 site. The monitoring activities include: atmospheric monitoring; geochemical monitoring; and geophysical monitoring, including seismic surveys. Monitoring includes downhole geochemical and geophysical measurements at Naylor-1 observation well; hydrological monitoring of water levels, analysing groundwater chemistry from shallow aquifers and sampling soil gas; and atmospheric monitoring of gas composition. Atmospheric monitoring underway at the Otway site includes:

- an atmospheric station with a CSIRO LoFlo CO_2 analyser continuously measuring concentrations of CO_2;

- a CO_2 flux tower continuously measuring surface-air CO_2 fluxes of a representative area of the site; soil CO_2 flux measurements taken at many point locations across the region;

- modelling of the ecosystem CO_2 and pre-existing industrial/agricultural CO_2 sources;

- measuring tracers to help confirm the origin of the CO_2 emissions to the local atmosphere and to quantify emissions; and,

- headspace gas sampling to establish the presence, concentration and distribution of any CO_2 gases or related gases, and their distribution within three nominated water boreholes adjacent to the project.

Geochemical monitoring underway at the Otway site includes:

- Chemical tracers (CD_4 (perdeuterated methane), SF_6 (sulphur hexafluoride) and Kr) are used to "tag" the CO_2 and CH_4 compounds of the injection stream in order to verify the CO_2 plume behaviour;

- Downhole samples of well-bore fluid and gas are collected at reservoir pressure from multiple levels and analysed for their chemical and isotopic composition to detect the arrival of CO_2 at the Naylor-1 site and to characterise chemical changes associated with this; and

- U-tubes are used to detect the arrival of CO_2 at Naylor-1 through the identification of tracers injected at CRC-1 in order to characterise CO_2 migration and behaviour within the Waarre C formation. During injection, the CO_2 migrates from the CRC-1 injection well to accumulate below the residual methane cap at the Naylor-1 monitoring well pushing the point of gas-water contact (GWC) down. Injection will stop when the injected CO_2 is detected at U-tube 3. These tracers enable researchers to identify the amount of time it takes CO_2 injected at CRC-1 to travel to Naylor-1, track the movement of CH_4 relative to CO_2, provide additional information on the long-term fate of injected CO_2 and confirm that there has been no leakage to shallow aquifers, soils or the atmosphere.

Seismic monitoring underway at the Otway site includes:

- 4D surface seismic surveys;

- High Resolution Travel Time (HRTT) which will enable monitoring of fine changes in fluid level and verify the volume of CO_2 injected. The injected CO_2 is expected to rise and collect beneath the gas cap. Continuous injection will force the GWC down. HRTT data will be acquired with permanently installed geophones strategically located above and below the GWC in the Naylor-1 monitoring well;

- Vertical Seismic Profiling (VSP) using seismic sources located at the surface and receivers positioned in the boreholes; and

- Microseismic surveys will check that the in-situ conditions of the reservoir have not led to fractures or fault reactivation. Downhole geophones are installed just above the packer within the Naylor-1 well and geophones are placed near the top of a nearby well.

CO2CRC finished construction for the project in April 2008. Table 24 shows a summary of the costs at this time.

Table 24. Otway Project Costs End of April 2008.

Item	Cost (2008 A$)	Cost (2008 US$)
Buttress-1 well testing	565,133	526,512
CRC-1		
- Drilling and monobore completions, 50m of core and analysis	4,744,650	4,448,350
- Extra coring	75,000	69,875
Naylor-1		
- Workover to close initial perforations and run baseline logs	786,591	732,835
- Workover to run completion	1,076,826	1,003,236
2.25km, 50mm diameter, stainless steel pipeline	1,652,063	1,539,161
Process plant, compression based	3,140,954	2,926,301
Permits/licences	117,931	109,872
Process group	1,796,000	1,673,261
Project management	2,051,515	1,911,314
Abandonment	900,000	838,494
OPEX	1,450,000	1,350,908
- Pre-operations	799,333	744,707
- Year 1	475,000	442,539
- Year 2	175,667	163,662
Operations contingencies	33,875	31,560
CO2CRC Pilot Project Limited (CPPL)	4,367,000	4,068,559
- Management (legal/bank fees, etc.)	686,000	639,119
- Operations (insurance, licence fees, etc.)	1,026,000	955,883
- Tenements (Buttress and Naylor)	2,655,000	2,473,557
Total Operations	**22,787,538**	**21,230,238**
CRC Executive OBPP	1,874,000	1,745,931
CRC Geoscience	1,046,000	974,516
CRC M&V Personnel	1,251,000	1,165,507
CRC M&V Research	2,573,000	2,397,161
- Atmospheric monitoring	670,000	624,212
- Geochemical monitoring	703,000	654,957
- Geophysical monitoring	1,200,000	1,117,992
CRC Outreach and Risk	181,000	168,630
Total Science	**6,925,000**	**6,451,746**
Total Project Costs	**29,712,538**	**27,681,983**

Source: CO2CRC (2008)

Weyburn

The Petroleum Technology Research Centre (PTRC) with EnCana Resources runs the IEA GHG Weyburn CO_2 Monitoring and Storage Project in south-eastern Saskatchewan, Canada. In September 2000, injection of CO_2 commenced into the Weyburn Unit through 18 inverted 9-spot pattern wells at a rate of 5000 tonnes/day. A total of about 20 Mt is expected to be injected over the project life. The CO_2 is captured from a coal gasification project in North Dakota and transported approximately 320 km by pipeline to the Weyburn Field. Injection occurs at a depth of 1500 m into the Mississippian Midale Beds, consisting of a lower 'vuggy' limestone unit and an overlying 'marly' dolostone unit. The reservoirs are sealed by the Midale Evaporite, which is a competent anhydrite layer.

Monitoring

The Weyburn CO_2 EOR flood has been monitored using seismic imaging and geochemical sampling methods. In each case, baseline surveys were conducted before injection began. The monitoring methods used include (Wilson and Monea, 2004):

1) Analysis of the geochemistry of reservoir fluids and gases, including major ions, alkalinity, and stable carbon isotopes ($\delta^{13}C$). The short-term geochemical processes that were observed following injection of CO_2 were: a) decreased pH caused by CO_2 dissolution; b) dissolution of carbonates and increase in alkalinity caused by lower pH of reservoir fluids; and c) increase in total dissolved solids and an increase in pH, $\delta^{13}C$, Mg^{2+}, and Ca^{2+} caused by mineral dissolution;

2) Seismic imaging methods including such time-lapse seismic data as: a) surface 3D 3-component seismic reflection surveys; b) surface 3D 9-component seismic reflection surveys for 4-patterns; and c) 3D 3-component vertical seismic profiles (VSP) for a single well. Also several non-repeat seismic surveys were conducted, including horizontal and vertical cross-well tomography surveys and vertical seismic profiles;

3) Microseismic monitoring is conducted using eight triaxial geophones cemented in a vertical well within 50 m of an injection well. Background seismicity was measured for five months prior to the start of injection into the nearby well and once injection began associated microseismicity was detected. Most seismic events that were detected appear to be associated with changes in production or injection where local pressure transients might be expected; and

4) Soil gas sampling was conducted on a 360 point grid and included analysis of: a) CO_2, O_2, CO_2 flux, which showed seasonal variations presumably due to standard metabolic pathways; b) hydrocarbons which showed temporal variations that were not easily explained; and c) tracer gases such as radon, helium, and thoron which showed consistent spatial and statistical distributions, indicating that leakage was not taking place.

Project Costs

In the four years from the beginning of the project to 2004, a total of CAN $16.38 Million was spent on the project in four different areas (Table 25):

Table 25. Total project costs per theme over project life: 2000-2004 in CAN$Millions. Theme 1: Geological characterisation of the geosphere and biosphere; Theme 2: Prediction, monitoring and verification of CO_2 movements; Theme 3: CO_2 storage capacity and distribution predictions and the application of economic limits; and Theme 4: Long term risk assessments of the storage site. (Wilson and Monea, 2004).

Theme	2000	2001	2002	2003	2004	Total
1	$0.08	$0.27	$0.84	$1.64	$0.21	$3.04
2	$2.61	$2.42	$1.92	$1.93	$0.24	$9.11
3	$0.09	$0.43	$0.69	$0.92	$0.14	$2.27
4	$0.08	$0.27	$0.40	$0.93	$0.28	$1.95
Total over Project Life =						$16.38

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Appendix 4: Economic Case Studies

The main elements of geological storage costs are capital costs (drilling wells, infrastructure development and constructing infield pipelines) and operating costs (labour, maintenance and energy). Additional costs include verification and materials, monitoring requirements, regulatory compliance and remediation methods, which may be required to prevent or minimize CO_2 leakages from the sink. Costs vary because of the influence of site-specific factors (storage formation type, location, depth and characteristics), which will affect, for example, well costs, compression requirements and injection rates (IPCC, 2005). The costs of CO_2 storage are also uncertain because they depend on uncertainties in the cost of fuel, steel, construction, etc. The IPCC (2005) estimates that the total cost for saline aquifer storage ranges from US\$0.60 to US\$8.00 per tonne of CO_2 avoided (US\$0.50 to US\$7.70 per tonne of CO_2 avoided, with added monitoring costs of \$0.10 to \$0.30 per tonne CO_2).

We reviewed available literature on various studies and pilot, demonstration and commercial projects in order to collate data on the costs of storing CO_2 in deep saline aquifers. Estimates of storage costs are site specific and can vary significantly because they depend on variable and uncertain factors such as storage reservoir characteristics. This review gathers and organises the published data on the costs of storage in different locations and conditions to enable us to understand the reasons for cost differences and to give benchmarks against which we can estimate the costs of other storage projects.

Estimates of costs per tonne avoided are influenced significantly by the assumptions used to generate them. The assumptions used by the CO2CRC are described in *CCS economics methodology and assumptions* (Allinson et al., 2006). This review compares these assumptions with those used to generate the costs quoted in the literature and attempts to recalculate costs so that they can be compared properly. All costs have been converted to US dollars using the average exchange rate for the year in terms of which costs were reported, or the year of publication where this has not been stated.

Costs of specific projects were discussed individually in Appendix 3. A review of general studies that assess the economics of CO_2 geological storage can be found below.

Battelle Memorial Institute, 2003

The US Department of Energy's National Energy Technology Laboratory funded Battelle Memorial Institute study was conducted to assess the CO_2 sequestration technologies available at the time and estimate the costs of such systems. The formations considered for CO_2 storage are the saline aquifer in Midwestern US. The analysis calculated costs on a yearly basis, assuming a project life of 25 years and a 4.1% discount rate. The results of the study are presented in *Engineering and economic assessment of CO_2 sequestration in saline aquifers* (Gupta et al., 2003b).

The study developed cost estimates in 2000 US dollar terms for sequestering CO_2 from a Pulverised Coal with Flue Gas Desulfurization (PC/FGD) power plant (the base case) and an Integrated Coal Gasification Combined Cycle (IGCC) power plant. CO_2 is compressed using three US\$18,400,000 13MW, diesel-driven, four-stage centrifugal compressors. A dehydration plant is also required, with a capital cost of US\$5.1million/t CO_2 processed each year. Gupta et al (2003b) estimated operating costs assuming a diesel cost of US\$1.00/gallon, water disposal cost of US\$0.15/1,000 gallons, US\$0.19/1,000 gallons cooling water for the compressors and maintenance costs totalling 4% of the capital costs.

A 50cm diameter carbon steel pipeline is used to transport CO_2. The capital cost of the pipeline is estimated to be US\$710/m for normal terrain, 5% higher for the entire pipeline for hilly/rocky terrain and 20% higher for the length of pipeline installed in urban terrain.

Gupta et al (2003b) estimate that site screening would cost US$330,000 and storage candidate evaluation US$1,355,000. Capital costs for injection include the US$645/m cost of an injection well and the cost of a pressurised surge storage tank, injection pumps for injection to depths greater than 1,500m, infield pipelines and flow control and monitoring equipment. Operating costs consist of the cost of analytical requirements (analysis of CO_2 and underground sources of drinking water), electricity costing US$0.065/kWh and maintenance costs assumed to be 4% of capital costs. Labour costs for compressing, transporting and injecting CO_2 are based on rates of US$30/hr for maintenance workers and operators, US$50/hr for QA and H&S support personnel and US$70/hr for supervisors.

The estimated annual costs for a range of scenarios are shown in Table 26.

Table 26: Comparison of CO_2 sequestration costs.

Case	**Annual cost (US$million/yr)**				
	Capture	**Compression**	**Pipeline**	**Injection**	**Total**
PC/FGD, 2,000m depth, 15km pipeline, normal terrain	20.0	33.4	1.8	3.9	59.1
PC/FGD, 2,000m depth, 100km pipeline, normal terrain	20.0	33.4	7.7	3.9	65.0
PC/FGD, 2,000m depth, 400km pipeline, normal terrain	20.0	33.4	28.9	3.9	86.2
PC/FGD, 1,000m depth, 15km pipeline, normal terrain	20.0	33.4	1.8	2.8	58.0
PC/FGD, 3,000m depth, 15km pipeline, normal terrain	20.0	33.4	1.8	6.1	61.3
PC/FGD, 2,000m depth, 15km pipeline, hilly/rocky terrain	20.0	33.4	2.1	3.9	59.4
PC/FGD, 2,000m depth, 15km pipeline, urban terrain	20.0	33.4	2.2	3.9	59.5
IGCC, 2,000m depth, 15km pipeline, normal terrain	4.1	28.3	1.5	3.8	37.7

Source: Gupta et al (2003b)

Table 27 shows the net present value of the total costs for each case. We calculated the values using Battelle's assumptions of a 25-year project life and a discount rate of 4.1%.

Table 27: Net present values of sequestration costs.

Case	Net present value (US$million)				
	Capture	Compression	Pipeline	Injection	Total
PC/FGD, 2,000m depth, 15km pipeline, normal terrain	321.8	537.5	29.0	62.8	951.0
PC/FGD, 2,000m depth, 100km pipeline, normal terrain	321.8	537.5	123.9	62.8	1,046.0
PC/FGD, 2,000m depth, 400km pipeline, normal terrain	321.8	537.5	465.1	62.8	1,387.1
PC/FGD, 1,000m depth, 15km pipeline, normal terrain	321.8	537.5	29.0	45.1	933.3
PC/FGD, 3,000m depth, 15km pipeline, normal terrain	321.8	537.5	29.0	98.2	986.4
PC/FGD, 2,000m depth, 15km pipeline, hilly/rocky terrain	321.8	537.5	33.8	62.8	955.9
PC/FGD, 2,000m depth, 15km pipeline, urban terrain	321.8	537.5	35.4	62.8	957.5
IGCC, 2,000m depth, 15km pipeline, normal terrain	66.0	455.4	24.1	61.2	606.7

US Department of Energy, 2003

The details and findings of a US study comparing a range of CCS options are presented in *Economic evaluation of CO_2 storage and sink enhancement options* (Bock et al., 2003). Bock et al (2003) estimated the costs using a spreadsheet model, with an accuracy of ±30 %. The estimates were generated using a 6.09 % after-tax discount rate and reported in terms of 1999 US dollars per tonne of CO_2 equivalent life-cycle greenhouse gas (LC GHG) emissions avoided. The study recognised that costs are highly variable depending on specific site characteristics.

The source of CO_2 is a 500MW IGCC power plant operating at 80% capacity, with a capture rate of 7,380 t CO_2/day. Following compression to 152 bar, the CO_2 is transported in a pipeline, costing US$20,989/in/km. Fixed operating and maintenance (O&M) costs are estimated to be US$3,100/km per year. Bock et al (2003) developed estimates for a range of CO_2 flow rates through the pipeline. The total transport cost for 2.16 Mt CO_2/yr captured from the IGCC plant, with capital costs annualised at a rate of 15% per year, is approximately US$2.20/t CO_2 per 100km.

Estimates for aquifer storage of CO_2 were generated for a base case, a high cost case and a low cost case (Table 28). Costs were calculated by first calculating the number of wells required for particular formation parameters and then determining the capital and O&M costs based on well numbers. The study assumed site screening and evaluation costs to be US$1,685,000 (taken from a Battelle Memorial Institute study). The cost of drilling wells was adapted from data from the *1998 Joint Association Survey (JAS) on drilling costs* report, while other costs were derived from the EIA report, *Costs and indices for domestic oil and gas field equipment and production operations*. The details are shown in Table 29.

Table 28: Case descriptions and results.

Parameter	Units	Low cost case	Base case	High cost case
Pressure	MPa	5.0	8.4	11.8
Thickness	m	703	171	42
Depth	m	694	1,239	1,784
Permeability	mD	585	22	0.8
Pipeline distance	km	0	100	300
Injection rate per well	t/d	889,495	9,363	82
Number of wells		1	1	91
Levelised annual CO_2 storage cost	**US$/t CO_2 equivalent LC GHG avoided**	**1.14**	**2.93**	**11.71**

Source: Bock et al (2003)

Table 29: Aquifer storage cost estimation factors.

Parameter	Value (US$/well)
Capital costs	
Injection equipment (flowlines and connections)	43,600*(7,389/(280*WellNumber))^0.5
O&M costs	
Normal daily expenses	6,700
Consumables	17,900
Surface maintenance (repair and services)	13,600*(7,389/(280*WellNumber))^0.5
Subsurface maintenance (repair and services)	5,000*WellDepth/1,219

Source: Bock et al (2003)

The study found that aquifer storage is one of the least expensive CO_2 sequestration options (excluding EOR and ECBM which have large ranges of net costs).

Battelle, 2003

An assessment of three saline aquifer sequestration scenarios was carried out by Battelle to investigate CCS as a mitigation option for BP. The details and results of the study are reported in *Geological storage of* CO_2 *from refining and chemical facilities in the Midwestern United States* (Gupta et al., 2003a).

The target aquifer is the Mt. Simon sandstone. Two cases are considered, where existing pipelines exist to transport CO_2. These involve injecting 5 MtCO_2/yr captured from northern Illinois and Indiana into the Mt. Simon formation, at a depth of 1,700 m, in west-central Indiana and 2 MtCO_2/yr from northern Ohio into the aquifer, at a depth of 1,500 m, in south-central Michigan. A third case involves sequestering 2 MtCO_2/yr from northern Ohio in western Ohio.

Gupta et al (2003a) estimate the total compression, transport and injection costs to be US$18.6/t CO_2 for the west-central Indiana scenario, US$18.3/t CO_2 for south-central Michigan and US$17.0/t CO_2 for western Ohio. The distribution of costs is given in Table 30.

Table 30: Compression, transport and injection costs.

Scenario	Component	Capex (US\$/t CO_2)	Opex (US\$/t CO_2)	Total (US\$/t CO_2)
West-central Indiana	**Compression**	3.9	1.2	5.1
	Transport	12.0	0.2	12.2
	Injection	1.1	0.2	1.3
	Total	17.0	1.6	18.6
South-central Michigan	**Compression**	5.9	1.4	7.3
	Transport	9.6	0.2	9.8
	Injection	1.0	0.2	1.2
	Total	16.5	1.8	18.3
Western Ohio	**Compression**	6.4	1.5	7.9
	Transport	7.4	0.2	7.6
	Injection	1.2	0.3	1.5
	Total	15.0	2.0	17.0

Source: Gupta et al (2003a)

GESTCO, 2003

The GESTCO project was established as part of the ENERGIE Programme of the European Union 5th Framework. (GESTCO, 2004). The project aimed to determine whether geosequestration of CO_2 was a viable greenhouse gas mitigation option in Europe. GESTCO used a Decision Support System (DSS) to analyse 17 case studies, 10 of which involved aquifer storage. Details and costs per tonne CO_2 avoided for the aquifer storage cases are shown in Table 31.

Table 31: Costs of aquifer storage of CO_2 in Europe

Case study	**N.Karvall**	**Havnso**	**Greifswalder Bodden-1**	**Greifswalder Bodden-2**	**Alfeld-Eize**
Country	Greece	Denmark	Germany	Germany	Germany
Plant	Ammonia plant	Coal-fired powerplant	NG-fired powerplant	NG-fired powerplant	Sugar factory
Capacity	138ktNH$_3$/yr	1,524MWe	1,200MWe	1,200MWe	
Load (hr/yr)	8,000	8,000	7,500	7,500	1,920
Yearly emissions (t/yr)	166	10,314	2,969	2,969	61.5
CO_2 captured (t/yr)	166	11,909	3,010	2,985	
CO_2 avoided (t/yr)	150	7,856	2,545	2,528	
Capture cost (€/t)	0.6	21.5	33.2	26.8	75.5
Compression cost (€/t)	7.2	7.4	4.4	6.1	15.9
Transport cost (€/t)	3.4	1.4	1.1	1.1	1.1
Storage cost (€/t)	2.6	1.3	0.6	0.6	8.3
Total cost (€/t)	13.8	31.6	39.3	34.6	100.8

Case study	**Komotini**	**Mongstad-2**	**Skogn**	**King's Lynn**	**Eggborough**
Country	Greece	Norway	Norway	UK	UK
Plant	NGCC	Oil refinery	NGCC	Coal-fired powerplant	NGCC
Capacity	330MWe	9,285kt/yr	721MWe	340MWe	2,005MWe
Load (hr/yr)	3,115	8,300	8,000	7,212	3,637
Yearly emissions (t/yr)	401	1,926	2,250	956	5,067
CO_2 captured (t/yr)	412	1,985	2,333	982	5,781
CO_2 avoided (t/yr)	311	1,492	1,814	753	3,869
Capture cost (€/t)	76.3	27.5	38.7	38.4	35.1
Compression cost (€/t)	13.5	7.4	5.0	8.5	9.1
Transport cost (€/t)	13.0	2.6	7.4	6.5	4.4
Storage cost (€/t)	2.5	8.0	7.2	13.2	2.6
Total cost (€/t)	105.3	45.5	58.3	66.6	51.2

Source: GESTCO (2004)

The ECOFYS/TNO Report, 2004

A range of CO_2 storage options was investigated in the 2004 ECOFYS/TNO report, *Global carbon dioxide and storage potential and costs*. A model developed by Hendriks (1994) was used to estimate global storage capacities and cost estimates were developed for the potential storage formations, including saline aquifers.

Hendriks et al (2004) estimated compression costs assuming compression of CO_2 from 0.1MPa to 12MPa using a four-step, 2.2Mt/yr capacity, centrifugal compressor. The source of electricity for the compressor is a power plant without CCS, emitting 0.70kg CO_2/kWh. Assuming operating costs of 5% of total capital costs and electricity costs of €0.04/kWh (US$0.05/kWh), estimates were generated for total compression costs for various flow rates and load factors (Hendriks et al., 2004). For example, for an occupancy rate of 97% and a 2.2Mt/yr flow rate, the cost is approximately €7/t CO_2 (US$8.70/t CO_2) (Figure 43).

The report divided CO_2 transport costs into pipeline construction costs and recompression costs for transport over long distances. Construction costs are estimated to be €1.1 million/km (US$1.4 million/km) for a 1m diameter pipeline at standard conditions. Using a 10% discount rate, a load factor of 86% and a project life of 25 years, Hendriks et al (2004) estimated the total cost for transporting CO_2 over 100km for transport velocities of 1m/s and 3m/s for a range of flow rates. For example, transport would cost €1/t CO_2 (US$1.24/t CO_2) for a velocity of 3 m/s and a flow rate of 3.2Mt/yr (Figure 44).

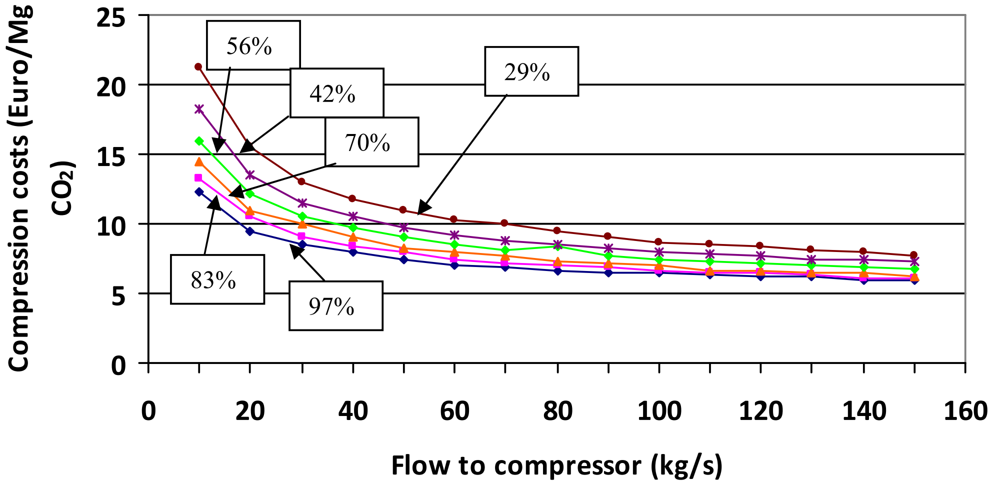

Figure 43: Cost of compression as a function of flow for various occupancy rates *(Hendriks et al 2004).*

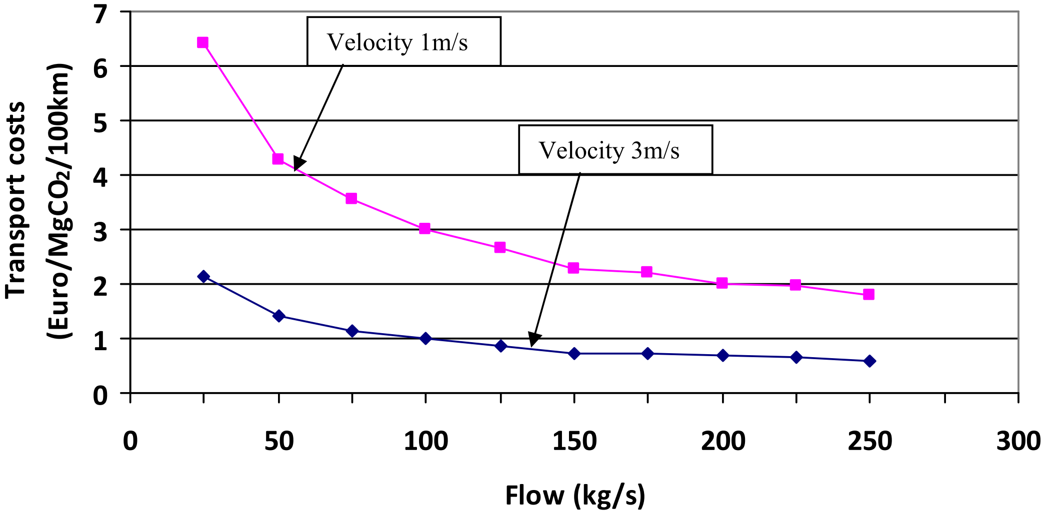

Figure 44: Transport costs over 100 km for velocities of 1m/s and 3m/s *(Hendriks et al 2004).*

Injection costs were divided into the cost for drilling injection wells and operating costs. The analysis assumed that well costs were a function of depth only. A 1km deep well would cost €1 million (US$1.2 million) and a 3km deep well €2.3 million (US$2.9 million). Drilling offshore would require the additional cost of a platform, costing €23 million (US$28.6 million). Hendriks et al (2004) estimate the total injection costs for an onshore aquifer to be €1.8/t (US$2.24/t), €2.7/t (US$3.36/t) and €5.9/t (US$7.34/t) CO_2 avoided respectively. For an offshore aquifer at the same depths, costs are higher at €4.5/t (US$5.60/t), €7.3/t (US$9.08/t) and €11.4/t (US$14.18/t) CO_2 avoided. These estimates are shown in Table 32.

Table 32: Injection costs for onshore and offshore aquifer

Depth (m)	Onshore aquifer		Offshore	
	€/t CO_2 avoided	US$/t CO_2 avoided	€/t CO_2 avoided	US$/t CO_2 avoided
1,000	1.8	2.24	4.5	5.60
2,000	2.7	3.36	7.3	9.08
3,000	5.9	7.34	11.4	14.18

Source: Hendriks et al (2004)

Latrobe Valley Australia, 2005

The economics of carbon capture and storage in the Latrobe Valley, Victoria, Australia (Neal et al., 2006) outlines the economic analysis of a large scale CCS project proposed for Australia's Latrobe Valley. The CO2CRC's CCS techno-economics model and cost data from vendor estimates were used to develop estimates for three base cases: a 5 year pilot study storing 2 Mt/yr CO_2 (A), a 40 year full-scale project storing 15 Mt/yr CO_2 captured from an IGCC power plant (B) and a 40 year large scale project storing 50 Mt/yr CO_2 captured from pre-combustion and retrofit combustion sources (C). The study identified a number of aquifers within the offshore Gippsland basin (the Kingfish field, Fortescue field, including the adjacent Halibut, Cobio and Mackerel fields, and a formation at the basin centre) that were suitable for CO_2 injection.

Estimates generated by the model have a ±30% order of accuracy for any single source-sink combination. Capital costs were phased at 50%/yr over two years. At the request of the project sponsors, the analysis excluded abandonment costs and costs associated with the period following injection. Assuming a 100% load factor, the model outputs were the real costs per tonne of CO_2 avoided in 2005 Australian dollar terms, before tax, using a real discount rate of 7%/yr. For reporting purposes, conversion factors previously developed for a US project were used to convert the values into 2005 US dollars.

CO_2 is to be compressed using a number of parallel centrifugal-compressor trains installed at the emission hubs, to pressures sufficient to allow the CO_2 to have adequate top-hole pressure for injection on arrival at the injection site. The model estimated the capital cost of the compressors based on the unit cost of the compressor frame and the number of compressor trains. A range of frame sizes was used to obtain the optimum cost, while the number of trains was selected to ensure that no compressor exceeded its operational lifetime over the 40 year injection period. Operating costs are taken to be a percentage of total capital costs, increasing from 3% to 5% over the injection life. The cost of electricity to operate the compressor trains is estimated to be US$43/MWh for case A and US$30/MWh for scenarios B and C. Power is supplied by natural gas power plants without CCS, with a capital cost of US$0.6 million/MW and operating costs based on US$3.5/GJ natural gas. The plants are assumed to emit 0.4 kg CO_2/kWh. Overall, Neal et al (2006) estimate total compression costs to be approximately US$11.6/t CO_2 avoided for case A, US$5.8/t CO_2 avoided for B and US$7.30/t CO_2 avoided for C.

The pipeline network consists of a 95 km onshore pipeline transporting CO_2 from the capture facility to Seaspray, a 95km offshore pipeline from Seaspray to the Kingfish field, and 30 km pipelines carrying CO_2 from Kingfish to the Fortescue fields and the basin centre, for cases requiring further storage capacity. Pipeline operating pressure ranges from 86 to 186bar. Using vendor estimates of capital costs and assuming fixed annual operating costs at 1% of capital costs, the study estimated that the total pipeline costs, per tonne of CO_2 avoided, would be US$12.20/t for case A, US$1.10/t for B and US$1.40/t for C.

Average reservoir properties taken from a CO2CRC study of the Kingfish field were used to estimate injection costs. The analysis divided capital costs into the cost of drilling injection wells, constructing the platform and topside facilities and remediating existing wells. Vendor costs provided the basis for the well and platform cost estimates. Injection operating costs are assumed to be fixed at 2% of injection capital costs (excluding remediation costs) per annum. Neal et al (2006) estimate that total injection costs per tonne CO_2 avoided would be US$6.50/t for scenario A, US$3.00/t for B and US$4.30/t for C.

The study highlighted a number of methods for reducing CCS costs. Injection costs were found to be highly dependent on reservoir permeability (which influences the number of injection wells needed). For example, for case B, an increase in permeability from 100 mD to 150 mD would result in a saving of approximately US$3/t CO_2 avoided. However, analysis showed that permeability increases beyond 400 mD would only allow minor savings to be achieved.

Well numbers could also be reduced by injection using horizontal wells instead of deviated wells, allowing savings of up to US$1.5/t CO_2 avoided using a 4 km horizontal section. However, cost savings would only be possible with a horizontal section longer than 1.6 km because of the greater expense of drilling horizontal wells.

Perth Region Australia, 2006

The CO2CRC and UNSW recently published a paper on the costs of carbon capture and storage in southwest Western Australia (Allinson et al., 2006). The study developed estimates for the capture of approximately 22 Mt/yr CO_2 from 30 sources within the region, including power stations, an oil refinery and metal refineries in the Kwinana Industrial Area and others surrounding Perth. Three formations were considered as injection sites: the Gage sandstone, the Dongara depleted gas field and the Neocomian subcrop.

The study assumed a 7% real discount rate, a 2 year construction period with capital costs phased (40% in the first and 60% in the second year), a project life of 25 years and a load factor of 85%. The cost of electricity was assumed to be A$55/MWh, purchased from a 1,500MW source with CCS, emitting 0.05Mt/MW of CO_2. Results are presented in real 2005 Australian dollars per tonne of CO_2 avoided, before tax.

Capital costs include the cost of constructing of pipelines transporting CO_2 from the capture plants to the storage locations, parallel centrifugal-compressor trains to compress CO_2 into a supercritical state for transport (above 86 bar) and remove water from the CO_2 to prevent corrosion of equipment and booster-compressor stations along the transport route to repressurise the CO_2. Allinson et al (2006) estimate the total capital cost to be A$727 million (US$555 million) for the Gage Sandstone, A$1,109 million (US$846 million) for the Dongara depleted gas field and A$1,216 million (US$927 million) for the Neocomian subcrop. The difference in the costs is mainly due to the increase in pipeline costs with increasing distance of the injection site from the emission hub. Cost differences in injection and compression for the 3 sites are minor.

Operating costs include the assumed fixed operating costs and the cost of electricity. The total operating costs are estimated to be A$1,557 million (US$1,188 million) for the Gage Sandstone, A$1,839 million (US$1,403 million) for the Dongara field and A$1,870 million (US$1,426 million) for the Neocomian subcrop.

Assuming 215 Mt CO_2 avoided for each injection site, the study estimated that the total storage costs per tonne CO_2 avoided would be A$10.6 (US$8.1) for the Gage Sandstone, A$13.7 (US$10.4) for the Dongara depleted gas field and A$14.4 (US$11.0) for the Neocomian subcrop. However, according to the report, these cost estimates can vary greatly depending on assumptions made for variables such as electricity costs, the real discount rate and project life. Thus, future studies will involve more detailed analysis of carbon capture and storage options in the Perth region.

Ireland, 2006

A study was carried out by Sustainable Energy Ireland (SEI) to investigate CCS as a method to limit Ireland's annual greenhouse gas emissions to 13% above 1990 levels. The methodology and results are described in Carbon dioxide capture and storage in Ireland: costs, benefits and future potential (Monaghan et al., 2006). The analysis estimated costs, using data from literature, for a coal-fired IGCC power plant at Moneypoint with CCS, building on work previously done on coal-fired CCS. Storage estimates were developed for aquifer storage and storage in depleted oil/gas fields. The storage aquifer is an imaginary aquifer located beneath the power plant because no survey of Ireland's deep geology has been carried out. Costs are presented in terms of 2005 Euros.

For the aquifer cases, CO_2 compression costs are included in the cost of the power plant. Power plant costs are given in Table 33.

Table 33: Cost for IGCC power plant with CCS.

Case	Net power (MWe)	Capital investment (million)		Annual O&M (million/yr)		Annual fuel cost (million/yr)		Annual emissions cost (million/yr)	
		€	US$	€	US$	€	US$	€	US$
IGCC1	361.9	629	780	25.2	31.6	43.5	53.9	3.0	3.7
IGCC2	371.4	631	782	25.2	31.6	42.7	52.9	3.0	3.7
IGCC3	382.6	760	942	30.4	37.7	43.2	53.6	3.3	4.1
IGCC4	359.8	597	740	23.9	29.6	43.5	53.9	1.6	2.0
IGCC5	369.4	599	743	24.0	29.8	42.7	52.9	1.6	2.0
IGCC6	380.6	728	903	29.1	36.1	43.2	53.6	2.0	2.5
IGCC7	373.5	665	825	26.6	33.0	51.8	64.2	7.9	9.8
IGCC8	491.0	955	1,184	38.2	47.4	66.1	82.0	5.6	6.9
IGCC9 2010	523.0	845	1,048	33.8	41.9	57.8	71.7	0.8	1.0
1GCC10 2020	533.2	731	906	29.3	36.3	41.1	51.0	0.0	0.0
IGCC11	351.0	905	1,122	36.2	44.9	38.7	48.0	3.6	4.5
IGCC12	359.0	773	958	30.9	38.3	39.6	49.1	4.5	5.6
IGCC13	457.0	804	997	32.2	39.9	64.6	80.1	6.3	7.8
IGCC14	404.0	940	1,165	37.6	46.6	46.4	57.5	3.5	4.3
IGCC15	455.0	1,187	1,472	47.5	58.9	51.6	64.0	3.5	4.3
IGCC16	730.0	1,239	1,536	49.6	61.5	102.5	127.1	13.2	16.4
IGCC17	742.0	1,192	1,478	47.7	59.1	102.5	127.1	13.3	16.5
IGCC18	676.0	1,428	1,771	57.1	70.8	86.6	107.4	11.4	14.1
IGCC19	492.0	1,078	1,337	43.1	53.4	64.4	80.0	5.7	7.1
IGCC20	492.0	1,078	1,337	43.1	53.4	64.4	80.0	5.7	7.1

Source: Monaghan et al (2006)

Monaghan et al (2006) estimated transport costs for an online pipeline and offshore pipeline using cost functions from literature and assuming operating pressures of 80-110 atm and 200-250 atm respectively. Estimates were also generated for a tanker ship, using data for LNG tankers, assuming a lease rate of US$25,000/day, infrastructure capital expenditure of US$335million, O&M costs to be 5.6 % of tanker capital cost, fuel costs to be 16.5% of tanker O&M costs and non-tanker O&M costs to be 0.02 % of non-tanker capital costs. The study found that the estimated specific transport costs per ton CO_2 were comparable with IPCC estimates. Table 34 compares the specific costs per ton CO_2 for the three options. However, transport of CO_2 is not required for the aquifer storage cases considered by the study because the aquifer is assumed to be located directly underneath the source of CO_2.

Table 34: Transport costs.

Case	**Annual transport Mtons CO_2/yr**	**Online pipeline (cost/ton CO_2/250km)**		**Offshore pipeline (cost/ton CO_2/250km)**		**Tanker ship (cost/ton CO_2/5,000km)**	
		€	**US$**	**€**	**US$**	**€**	**US$**
IGCC1	1.86	4.13	5.12	12.32	15.28	37.45	46.43
IGCC2	1.83	4.17	5.17	12.40	15.37	38.18	47.34
IGCC3	1.85	4.15	5.15	12.35	15.31	37.70	46.74
IGCC4	1.79	4.21	5.22	12.74	15.80	38.85	48.17
IGCC5	1.76	4.25	5.27	12.83	15.91	39.58	49.07
IGCC6	1.82	4.18	5.18	12.42	15.40	38.31	47.50
IGCC7	1.82	4.19	5.20	12.41	15.39	38.25	47.43
IGCC8	2.67	3.41	4.23	9.22	11.43	32.53	40.33
IGCC9 2010	2.17	3.83	4.75	10.86	13.47	36.00	44.64
1GCC10 2020	3.74	2.96	3.67	7.18	8.90	25.54	31.67
IGCC11	1.77	4.26	5.28	12.81	15.88	39.43	48.89
IGCC12	1.77	4.26	5.28	12.81	15.88	39.42	48.88
IGCC13	3.01	3.29	4.08	8.41	10.43	28.89	35.82
IGCC14	2.09	3.91	4.85	11.13	13.80	37.42	46.40
IGCC15	2.15	3.81	4.72	11.04	13.69	36.41	45.14
IGCC16	4.41	2.73	3.38	6.39	7.92	23.60	29.26
IGCC17	4.45	2.75	3.41	6.39	7.92	23.38	28.99
IGCC18	3.81	3.01	3.73	7.01	8.69	25.03	31.03
IGCC19	3.01	3.17	3.93	8.41	10.43	28.85	35.77
IGCC20	3.01	3.17	3.93	8.41	10.43	28.85	35.77

Source: Monaghan et al (2006)

The study estimated specific injection costs per ton CO_2 using data from the Sleipner Project. The injection cost, including monitoring costs of €2.1million/yr, was found to be €4.77/ton CO_2 (US$5.91/ton CO_2) for all cases.

China, 2006

The results of a recent Chinese study on potential CCS aquifer storage systems are presented in *Opportunities for low cost CO_2 storage demonstration projects in China* (Meng et al., 2006). By investigating a number of ammonia plants with gasifiers (for which capture costs are relatively low) and the sedimentary basins surrounding these CO_2 sources, four possible source-sink combinations were identified: from the Nanjing Chemical Industry Co. to Zhenwu (A), the Dong Ting Ammonia Plant to Wangchang (B), the Hubei Ammonia Plant to Wangchang (C) and the Yuntianhua Chemical Group to Weiyuan (D). Costs for demonstration projects involving the four cases were then estimated using economic models (Larsen et al., 2003; Ogden, 2003). The costs associated with monitoring, modelling and assessment were assumed to be small compared with compression, transport and injection costs and were omitted from the analysis.

Meng et al (2007) estimated costs for the four cases assuming a project life of 20 years, with plants operating 300 days per year at full capacity, and electricity costs of US$0.032/kWh. Estimates were developed for each case for the mean permeability cases and also the minimum permeability case for scenario D. The results are shown in Table 35.

Table 35: Specific costs for compression, transport and storage.

Case	Compression cost (US$/t CO_2)	Transport cost (US$/t CO_2)	Well cost (US$/t CO_2)	Surface facilities (US$/t CO_2)	Total (US$/t CO_2)
A	6.4	8.9	1.1	0	16.4
B	6.7	9.4	1.4	0	17.4
C	6.7	12.5	1.4	0	20.5
D (mean K)	6.7	6.4	1.6	0	14.7
D (min K)	6.7	6.4	4.8	0.6	18.6

Source: Meng et al (2007)

The study concluded that aquifer disposal of CO_2 is feasible at a number of locations in China. However, since the analysis used previously published data, rather than first-hand data, further examination of the storage sites must be carried out in order to gain better understanding of the reservoir characteristics.

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