INJECTION STRATEGIES FOR CO_2 STORAGE SITES

Report: 2010/04

June 2010

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA) was established in 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme. The IEA fosters co-operation amongst its 28 member countries and the European Commission, and with the other countries, in order to increase energy security by improved efficiency of energy use, development of alternative energy sources and research, development and demonstration on matters of energy supply and use. This is achieved through a series of collaborative activities, organised under more than 40 Implementing Agreements. These agreements cover more than 200 individual items of research, development and demonstration. IEAGHG is one of these Implementing Agreements.

ACKNOWLEDGEMENTS AND CITATIONS

This report describes research sponsored by IEAGHG. This report was prepared by:

CO2CRC, Australia

The principal researchers were:

- K. Michael — CSIRO Earth Science & Resource Engineering
- G. Allinson — University of New South Wales
- W. Hou — University of New South Wales
- J. Ennis-King — CSIRO Earth Science & Resource Engineering
- P. Neal — University of New South Wales
- L. Paterson — CSIRO Earth Science & Resource Engineering
- S. Sharma — Schlumberger

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was: Toby Aiken

The expert reviewers for this report were:

- Stefan Bachu — Alberta Innovates – Technology Futures
- John Wilkinson — ExxonMobil
- Ziqui Xue — RITE
- Charles Gorecki — EERC
- Andrew Cavanagh — Permedia
- Brian McPherson — University of Utah

The report should be cited in literature as follows:

'IEAGHG, "Injection Strategies for CO_2 Storage Sites, 2010/04, June, 2010.'

Further information or copies of the report can be obtained by contacting IEAGHG at:

IEAGHG, Orchard Business Centre,
Stoke Orchard, Cheltenham,
GLOS., GL52 7RZ, UK
Tel: +44(0) 1242 680753 Fax: +44 (0)1242 680758
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

INJECTION STRATEGIES FOR CO_2 STORAGE SITES

Background to the Study

It has been demonstrated that the geological storage of anthropogenic CO_2 emissions in depleted hydrocarbon fields and deep saline formations (DSF) is a tenable process. There are numerous pilot, demonstration and commercial storage projects in operation around the world that prove the concept. One of the next barriers to widespread deployment and implementation is the scale-up needed from these pilot and demonstration scale projects to the scale required to make significant impacts on the atmospheric levels of CO_2.

Injection strategies utilised for single or several well operations are likely to be significantly different from those used for larger, commercial scale operations. The process of moving from the earlier to the latter is dealt with in this report.

The infrastructure and number of injection wells required for CO_2 injection is likely to be an order of magnitude larger than many current operations[1], and potentially even larger than existing petroleum installations. This leads to the need to develop injection strategies for CO_2 storage sites, and by addressing this and performing a literature review on the various data sources available, the relative influence of the parameters thought to affect injection can be determined.

Related to this is the issue of pressure build-up, and this is likely to be the most limiting factor for large scale geological storage, and thus strategies for water production wells will also be considered within this study. Water production can directly affect the pressure build-up within a formation, and can also be used to control the direction and development of the CO_2 plume.

Scope of Study

The study will perform a literature review addressing the relative importance of various parameters that influence injectivity and site storage capacity, including a consideration of uncertainties in the current estimation of these parameters. The study also considers the methods required for design of injection strategies.

The study also assesses the technical aspects of CO_2 injection well design, drilling and installation, with accompanying information on costs. The report also considers the suitability of reuse of existing oil/gas production wells, and the associated cost benefits of such reutilisation. Such reuse of existing infrastructure has been considered for many scenarios, for example CO_2 injection into depleted gas fields in the southern North Sea. This option may be

[1] Some current operations operate at a comparable scale to that required for commercial deployment, for example the Weyburn operation in Canada currently injects nearly 3 Mt CO_2 per year. Also, the Sleipner project, although a large scale operation, only utilises 1 injection well, due to the very high permeability encountered in the reservoir.

particularly attractive in cases where existing oil or gas pipelines are also suitable for CO_2 transport. The project also developed a software tool to allow estimation of injection well costs.

Results & Discussion

Reservoir Engineering Principles

Single Phase Flow

Injectivity tests are used to establish the maximum rate and pressure that fluids can be pumped without causing the formation to fracture. In the case of injecting CO_2 into a reservoir, the equation is similar to a well ‘falloff test’, only the timescales are greatly increased. In such a test, fluid injection occurs at a constant rate, and the pressure build-up is measured. When injection is stopped, the pressure build-up declines, indicating flow through the reservoir from the near wellbore outwards, away from the injector. Some adjustments need to be made to simulate the conditions of a gas injection rather than a fluid, and it should be noted that these equations do not allow for buoyancy of the injected gas. There are some newly developed analytical solutions that could potentially allow for this buoyancy, but more research is required for this.

Further calculations can be used to determine the minimum and maximum radius of the CO_2 plume following the cease of injection, and these can be combined with the equation for single phase Darcy flow to determine the overall radius of influence of pressure. The report also describes the difference between these radii of influence in bounded and unbounded reservoirs.

Two Phase Flow

The concept of a bounded reservoir has been questioned by many experts, suggesting that no reservoir can be realistically bounded. CO_2 injection combined with the displacement of in-situ water will involve two fluid phases. The CO_2 will be both less dense and less viscous than the water, requiring more complex equations. The modified equations suggested by van der Meer and Egberts (2008) allow for a moving-boundary of water displaced by the injected CO_2, and the maximum reservoir pressure is assumed to occur at the end of the injection phase. Despite the developments described by van der Meer and Egberts (2008), their approach is limited as it ignores buoyancy effects and transient compressibility. Also, it does not consider any boundaries that can act as resistance to the flow.

Reservoir Modelling

Simulations of multiphase flow in porous media are all variations of solving Darcy’s law for multiphase flow, and these solutions lead to the solving of a set of linear equations. However, Obi and Blunt (2006) have developed these equations into simulations with significantly shorter timeframes.

Wells are represented in models as either sources or sinks, depending on the well purpose (injection or production), but for CO_2 injection projects, pressure constraints need to be applied as well to meet the safety criteria for prevention of hydraulic fracturing of the reservoir. This complicates the modelling, and as grid blocks within models are usually on the scale of tens of metres, the pressure within the grid blocks where wells occur is not an accurate representation.

Boundary conditions in a model become important when considering injection into an aquifer as boundaries have a direct effect on pressure build-up. Often, specific boundary conditions are simulated by creating certain types or sizes of grid block adjacent to the boundary to simulate the boundary condition desired. For example, constant flux conditions can be simulated by adding extra source or sink terms to boundary blocks.

Injectivity Strategies

Injectivity is defined as the ability of a geological formation to accept fluids by injection through a well. The factors that limit this potential are varied, but the most vital limiting factor is that of bottomhole injection pressure.

If this pressure exceeds that of the reservoir fracture pressure, then migration and leakage could occur out of the storage formation. Remaining safely within this fracture pressure is therefore of key importance in injection strategies, and many regulators stipulate that bottomhole pressure should not exceed 90% of this pressure.

Bottomhole pressure is controlled by several secondary factors; injection rate, absolute and relative permeability, thickness of formation, viscosity between brine and CO_2 and compressibility.

After briefly discussing the definition and factors affecting injectivity, the report reviewed aspects where storage efficiency can impact on injection strategies, and this was addressed in the following topics:

- Effects of heterogeneity,
- Pressure maintenance using water production wells,
- Co-injection of water and CO_2,
- Dissolution of CO_2 in brine,
- Injection in the saline-only section below the oil-water contact in oil reservoirs, and
- Regional-scale storage containment and potential resource impacts.

Effects of Heterogeneity

Heterogeneity can be shown to increase storage efficiency, as described by van der Meer and van Wees, 2006. If the formation being injected into is sufficiently thick (50-100m) then injection should occur in the deeper part of the formation. The buoyant nature of the injected CO_2 will cause the CO_2 to migrate upwards through the formation, facilitating residual trapping mechanisms to immobilise a portion of the CO_2. The instability of the CO_2 plume was thought to lead to fingering, but simulations have demonstrated that the CO_2 will actually follow preferential flow paths defined by the heterogeneity. This means that the heterogeneity that complicates simulations actually has the potential to increase trapping in thicker formations. In oil production, this heterogeneity is seen as a problem, whereas with the objective of CO_2 storage, it can be an advantage.

Pressure Maintenance Using Water Production Wells

As previously stated, formation pressure is often considered as the single most limiting factor on permissible injection pressures. When formation boundaries have a strong effect on pressure, the resultant restriction on injection quantities and rate can have a significant impact on storage potential. The use of water production wells can be demonstrated to reduce formation pressures, allowing greater injection quantities, and also by artificially controlling the formation pressure at various points, the migration of the CO_2 plume can be controlled, leading the plume through the formation.

There are associated complications and issues with water production, such as the necessity of having water disposal facilities on site, and this has an associated economic cost, but it is an issue commonly addressed in the oil production industry, and this is another example of where reuse of existing infrastructure has a significant economic benefit to CCS.

Co-Injection of Water and CO_2

Field tests have shown that trapping of injected CO_2 can be increased by either co-injecting or sequentially injecting brine with the CO_2. The effects are noticeable in the level of residual gas trapping as well as the additional rate of dissolution trapping within the injected brine. The inherent reduction in the amount of mobile CO_2 also reduces the overall risks of leakage and could also increase the number of storage sites deemed suitable worldwide.

Dissolution of CO_2 in Brine

An alternative to co-injection of water and CO_2 is dissolution of the CO_2 in brine at the surface, and then injecting the combined fluid. The associated costs are an increase in power consumption of around 3-9%, and an increase of around 60% in capital costs. These increases could, however, be offset by the reduced monitoring costs as buoyancy driven CO_2 leakage would be less likely. There would also be a reduction in the efficiency of dissolution trapping within the reservoir.

Injection in the Saline-Only Section Below the Oil-Water Contact in Oil Reservoirs

This option, as suggested by Han and McPherson (2009), suggest that the buoyancy driven CO_2 migration would be reduced, and the amount of mobile CO_2 would be kept to a minimum. The potential application of such an option could provide widespread opportunities in North America, as many of the oil basins in North America have strata that would prove suitable for such applications.

The potential impacts of displaced brine from CO_2 injection have been the subject of debate in the past. However, recent simulations (Nicot, 2008) have suggested that no significant impacts will occur. Models whereby the water-level in the Gulf Coast Aquifer were purposefully changed show an increase in the order of magnitude of normal seasonal variations. The models only factor for single phase flow, and as such do not encompass dissolution of CO_2 along the flow path. Further exploration of the effects of such displacement is recognised as necessary for a greater understanding of these effects.

Evaluation of Existing Injection Schemes

The report then detailed some commercial scale projects, with focus on the injection strategies for such scale projects. The case studies covered commercial CO_2 geological storage operations, enhanced oil recovery operations and other injection schemes. Most of the projects listed in the case studies are well published and widely known, such as Sleipner and In Salah, but the report also included case studies of Snøhvit and Gorgon, which have been less widely reported, and some detail on these is outlined in this overview.

Snøhvit, Norway

Snøhvit is LNG project operated by Statoil, where CO_2 is being injected into a DSF in the Barents Sea. LNG is produced from 3 fields, commencing in 2007, and the injection activities are anticipated to have a 30 year lifetime. The produced gas requires a decrease in CO_2 content of between 5-8% prior to conversion to LNG. Amine technologies are utilised to achieve this reduction and this generates 0.75 Mt/yr of CO_2 which is then injected into the DSF below a Jurassic gas reservoir. This is shown in figure 1.

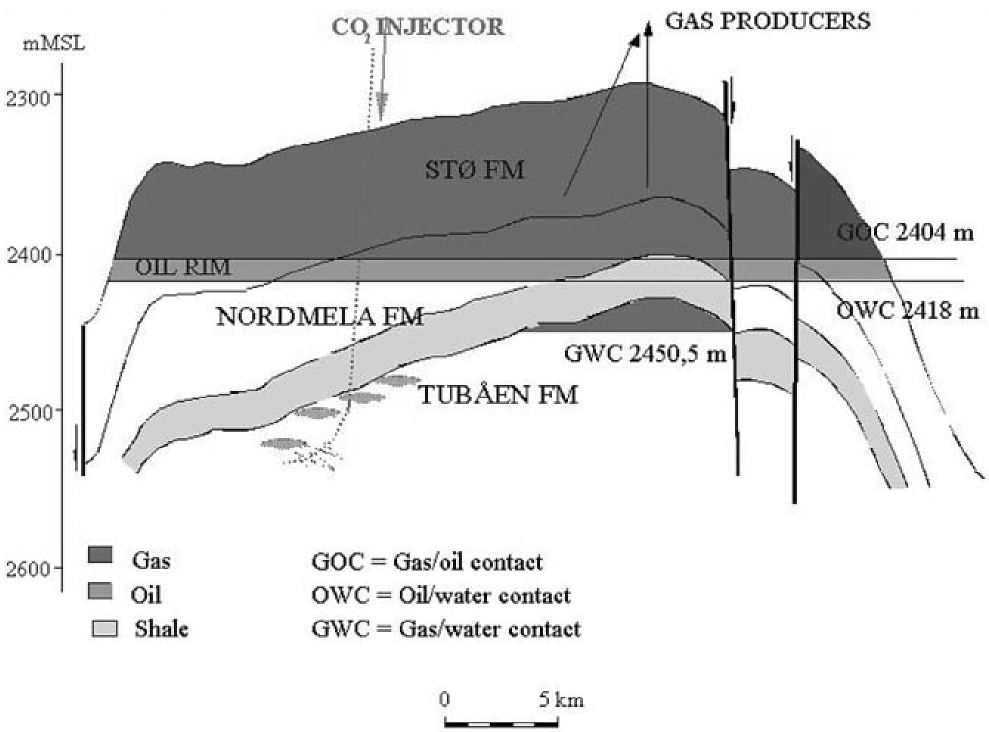


Figure 1: **Simplified cross-section through the Snøhvit field (from Maldal & Tappel, 2004.)**

Gorgon, Australia

September 2009 saw final regulatory approval granted for the Gorgon Joint Venture between Chevron, Shell and ExxonMobil. The venture will extract the natural gas reserves offshore of Western Australia. The gas that will be produced will contain approximately 14% CO_2, which will be removed at a processing plant situated on an island and compressed for transport to the storage site some 12km away via a pipeline. According to the plans, up to 4.9 Mt/yr of separated CO_2 will be injected and stored, with a projected total storage of 125 Mt of CO_2 over the projects lifetime. Injection is due to commence in 2014.

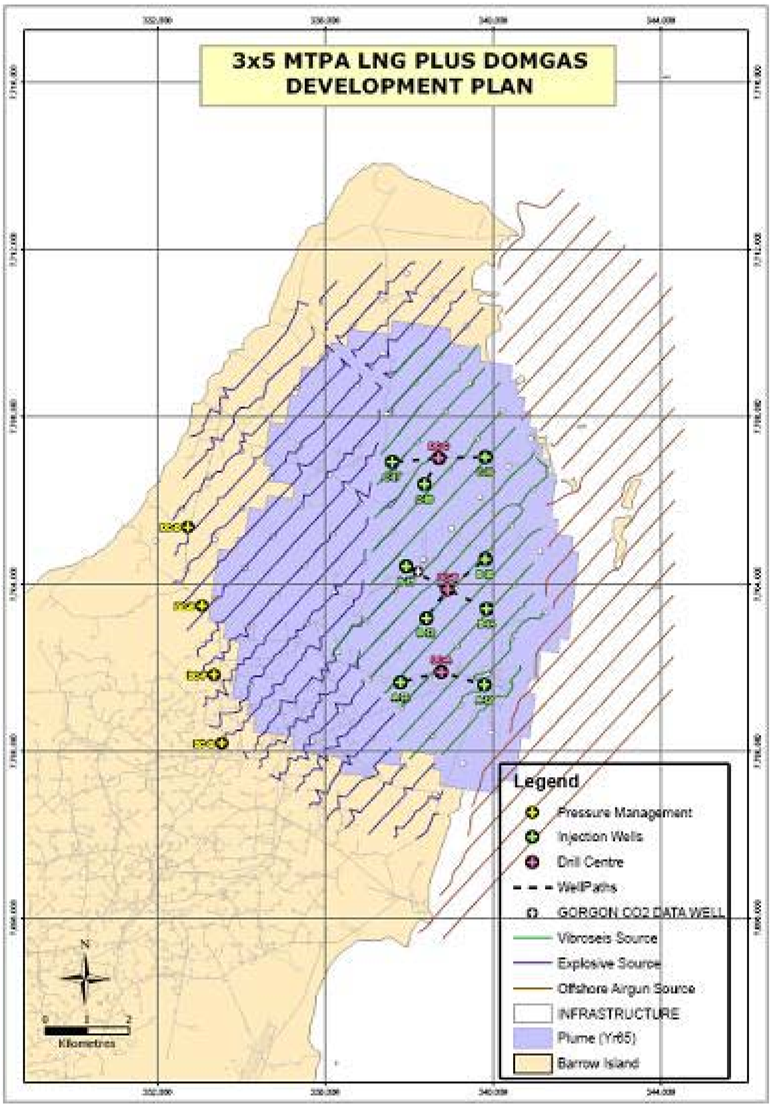


Figure 2: **Proposed locations of injection and water production wells at the Gorgon Project, showing the modelled extent of the CO_2 plume after 65 years and seismic lines for monitoring (Chevron, 2009).**

The plans for the injection process currently involve 9 directionally drilled injection wells, grouped in 3 locations and modelling predictions show the injected CO_2 migrating along preferential high-permeability pathways which will result in a non-uniform CO_2plume distribution. Forthcoming development work is being focussed on monitoring programmes to keep track of the behaviour of the CO_2 post injection. Monitoring and water production wells are also planned to maximise detection and control reservoir pressures and brine displacement.

Economics of Injection Strategies

Many papers have been written regarding costs of CCS and the elements of CCS, and a clarification of the terminology used is given here for reference throughout the report.

Cost of Injecting CO_2: includes costs for onshore or offshore wells, and any wellhead boosting or formation treatments.

Cost of Storage: includes costs of injection, plus costs of compression, transport via pipeline and intermediate boosting if required.

Cost of Transport: Includes only the costs of compression, boosting and pipelines.

Cost of CCS: includes the costs of capturing CO_2 together with the costs of storage.

A possible future IEAGHG study will focus on the costs involved with geological storage of CO_2.

For this report, the costs considered are related to the effect that the storage formation characteristics can have on the injection strategy and the associated costs. The geological properties of the formation play a significant role in determining the ease at which CO_2 can be injected, and hence have an impact on the costs of injection. These are described in table 1.

Factor	Effect on Injection Costs
Permeability	As permeability increases, injectivity increases, requiring fewer wells, and reducing costs.
Fracture Gradient	An increase in fracture gradient will increase the maximum injection pressure, reducing the number of wells needed and reducing costs.
Formation Thickness	An increase in thickness increases injectivity, reducing number of wells, and reducing costs.
Formation Depth	A 1km deep well is sensitive to permeability decreases, requiring more wells, and higher costs. A 2-3km deep well is less sensitive to permeability decreases, therefore having a lesser effect on costs.
Well Deviation	Horizontal wells maximise surface area contact with the target formation, increasing injectivity, and reducing the number of wells needed and costs.
Degree of Hydraulic Fracturing	Hydraulic fracturing creates higher permeability of the formation in the near-wellbore area, and increases injectivity. It has been shown that in low permeability situations (around 1 mD) hydraulic fracturing of the reservoir reduces costs as the increase in injectivity offsets the extra costs involved in the fracturing operation.

Table 1: Formation characteristics affecting injection costs.

Another impact on the economics of injection is the trade-off with transport costs and relief wells. The trade-off with transport costs is that of low injectivity with high proximity to CO_2

sources, against higher injectivity at greater distances to the CO_2 sources. In these situations, sensitivity analyses must be completed to determine the most economic site for storage.

The drilling of relief wells for the purposes of relieving reservoir pressures, and producing formation water will prolong the lifetime of the injection phase, and allow a higher injection rate. This must be balanced with the associated costs of drilling such relief wells, and the additional cost of any water treatment and handling equipment needed at the site to deal with the produced formation water, and this will have an additional impact on the costs.

Injection Cost Model

The report includes the development of a Microsoft Excel based spreadsheet which calculates the injection costs based on user-inputted data. The spreadsheet is a high-level indication of the injection costs, and uses a limited set of conditions. It does not calculate capture costs, transport costs, or compression at site, although it does calculate the initial compression from the point of capture.

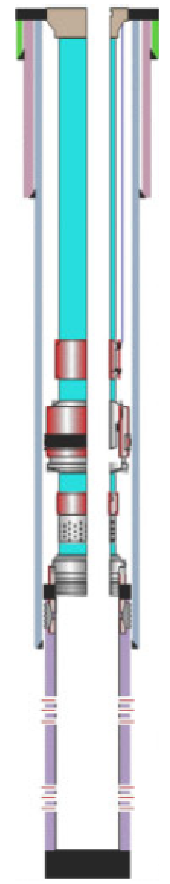
It assumes the energy supplied for the injection operations is from gas fired power plants, without CO_2 capture, but doesn't include the costs of power transmission lines from plant to site.

Timescales involved are limited to a maximum 10 years construction, 50 years minus construction for operation, and 1 year to decommission.

Only vertical wells are assumed, and reservoir conditions must be within certain limits, resulting in the product of permeability, porosity and pressure difference (khΔP) being within the range 1,222 to 1,900,000mD•m•MPa. Values outside of this range will result in errors and / or unreliable results.

Injection Well Design and Remediation

Injection wells for CO_2 must incorporate technical barriers to prevent hydraulic communication, and these are formed by various well tubulars comprising of casing, tubing and liner, and well cement. CO_2 should be dehydrated and supercritical to minimise the risk of corrosion, but corrosion resistant materials should be used in areas particularly liable to exposure to high water content. A typical downhole assembly is shown in figure 3, derived from Cooper et al., 2009.



Description	Potential Risks and Concerns	Materials
Tubing Hanger	CO_2 corrosion may be associated with well back-flushing provision and process interruptions.	CRA - Generally high Nickel Content
Conductor Casing	Some aquifers have a potential external corrosion risk.	Carbon steel - consider external coating.
Surface Casing		Carbon steel.
Injection Tubing	Provision for periodic back-flushing and process up-sets may yield water exceeding 8,000 mpy	GRE lined Carbon Steel or CRA.
Production Casing	Metallurgy in accordance with industry standards for any contaminants in CO_2.	Carbon Steel - Surface to immediately above base of sealing formation.
Production Liner	Process upsets & provision for back-flushing may result in high water content CO_2 in the injection zone. Also there may be contaminants in the CO_2 such as H_2S.	CRA. Industry standard if required for applicable contaminants.

Abbreviations used: CRA = Corrosion Resistant Alloy; GRE = resin epoxy; NACE = National Association of Corrosion Engineers.

Figure 3: Possible well design for CO_2 (from Cooper et al., 2009)

Remediation Methods for Loss of Injectivity

In this report, remediation refers to correcting reduced injectivity, and there are 7 causes noted as having the potential for reducing the injectivity. They are shown in table 2, along with checks to be completed to determine the cause of the problem, and the remedial measures to be taken.

Causes of Loss of Injectivity	Checks to be performed to find root cause of problem	Remediation Measures
1. Insufficient/lower than expected well head pressure	Reading of well head pressure gauge. Leaks in surface pipeline Compressor output pressure	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.
2. Insufficient /lower than expected bottom hole pressure	Reading of bottom hole pressure gauge and flow meter Leaks in surface pipeline Compressor output pressure	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.
3. Insufficient/higher than expected well head temperature	Reading of well head temperature gauge Compressor output temperature Check ambient temperature	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity
4. Change in composition/mixture of CO_2+impurities	Readings from monitoring equipment	Re-run wellbore and reservoir models based on new composition. Use most appropriate thermodynamic equations to define new mixture.
5. Plugged Perforations	Readings of down hole flow meter, pressure and temperature gauges	Acidize to clean up
6. Change in reservoir parameters e.g.: Skin, Permeability	Parameters obtained from previously acquired data e.g.: well test analysis, logs Re-run reservoir simulations to verify model	Re-acquisition/Verification of data • Well Test Analysis • Wireline Logs Based on above results • Update and re-run wellbore and reservoir models • Based on the simulation results above, take necessary steps to regain injectivity - Add more perforations - Acidize • Fracture (controlled)
7. Increased injectivity	Readings of down hole flow meter, pressure and temperature gauges	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.

Table 2: Summary of Causes and Remediation Measures for Loss of Injectivity

Expert Review Comments

Comments were received from numerous reviewers, including representatives of both oil companies and sponsors of the IEAGHG Programme. The review panel also included technical consultants and research organisations. On the whole, the feedback received was both constructive and complimentary of the report, with changes being suggested to some aspects to clarify some points and equations, with some statements and conclusions being moderated in terms of the language used.

Changes made were mainly for clarification and to ensure language, terminology and reference usage was consistent with other IEAGHG technical reports, and to ensure that no ambiguity could be taken or implied.

On balance, the reviewers provided a positive response and agreed with the recommendations arising from the report regarding areas for further work and research, some of which are already under consideration and action under other IEAGHG technical studies.

Conclusions

It can be concluded that pressure build-up due to injection in DSF and depleted hydrocarbon reservoirs is potentially the most significant limiting factor for large-scale geological storage. Due to this, strategies for pressure management as an element of injection strategies will need substantial consideration for future CCS projects.

As more large-scale demonstration projects are commenced, knowledge will increase, and uncertainties and variables should decrease accordingly, but at the present time, there are significant variations in opinions throughout the scientific community. It should also be noted that although the requirements for pressure control wells will increase the costs of a project, the knock-on effect should compensate for the increased initial outlay. These pressure control wells will also allow operators to manage to some degree the migration of the injected CO_2 plume, and this has proven a significant safety benefit in CO_2EOR operations, and can increase the CO_2 dissolution in formation waters.

Direct comparisons of different studies are not yet possible because the inherent properties of the models and variation in parameters and boundary conditions. This leaves much further work to be completed to allow narrower predictions on injection strategies. However, available data tends to suggest that the more optimistic estimates are potentially more realistic than some of the less optimistic. Low permeability reservoirs such as In Salah are demonstrating the ability to inject in the order of 1 Mt/yr, despite the low reservoir permeability. It is noted that optimisation of injection schemes using horizontal wells or pressure management may be necessary for such operations, but there are associated benefits of such requirements.

The economics of injection and storage are also liable to play a significant role in the future, and the effect that formation characteristics can play on the economics is considerable. Site characterisation should identify these factors at an early stage, and subsequently these should not be difficult to anticipate.

The Injection Cost Calculation tool developed as part of this report should be beneficial in the future development of commercial scale CCS, despite the restrictions on its use; it could be used as part of the site characterisation process, and give a good indication of site suitability.

Strategies for injection will vary greatly in the future from site to site, as the uncertainties involved in predicting reservoir properties imply that there will be a range of views regarding the number and type of injection wells needed for any given operation, and it can be assumed that different companies will likely follow different strategies.

Recommendations

Recommendations for further work include a possible future study focussing on the costs involved with geological storage of CO_2, and such a study will be proposed to the 37^{th} IEAGHG ExCo in spring 2010.

Based on the framework of recently developed analytical solutions (Hesse et al., 2007; Mathias et al., 2008; Neufeld & Huppert, 2009; Nordbotten & Celia, 2006), well test equations including buoyancy effects of injected CO_2 could be developed to improve modelling of single-phase flow within wells.

The effects of displaced brine are worthy of further attention (as identified by Nicot, 2008), as concerns over the effects of this have been raised in the past, but some new studies suggest that the effects would not be greater than usual seasonal variations. This is potentially of great importance for regulation of injection operations, and specific attention should be given to the potential for spring discharges along flow-focussing faults. This is the topic of another technical study currently underway by IEAGHG titled 'Pressurisation and Brine Displacement Issues for Deep Saline Formation CO_2 Storage' and is due to be reported in the 3^{rd} quarter of 2010.

Injection Strategies for CO_2 Storage Sites

Prepared for the IEA Greenhouse Gas R&D Programme
Reference IEA/CON/09/168

K. Michael[1], G. Allinson[2], W. Hou[2], J. Ennis-King[1], P. Neal[2], L. Paterson[1], S. Sharma[3]

Cooperative Research Centre for Greenhouse Gas Technologies, March 2010
CO2CRC Report No: RPT10-2020

[1]CSIRO Earth Science & Resource Engineering; [2]University of New South Wales; [3]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

Reference: CO2CRC, 2010. *Injection strategies for CO_2 storage sites*. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra. CO2CRC Report No. RPT10-2020.

Executive Summary

Existing pilot, demonstration and commercial storage projects have demonstrated that CO_2 geological storage is technically feasible. However, these projects do not operate at a scale that is necessary to result in a significant reduction in greenhouse gas emissions into the atmosphere. The infrastructure (platforms, wells, pipelines, compressors) for injecting carbon dioxide will need to be much larger than current CCS projects and larger even than existing petroleum installations. Also, geological formations close to industrial point sources may be of lower quality than has been encountered in existing projects. Reservoir quality information is particularly sparse for deep saline aquifers, resulting in large storage capacity, injectivity and sweep efficiency uncertainties. In most cases, the CO_2 injection scheme will consist of multiple wells, potentially including wells for monitoring and pressure control. Consequently, this study performed a literature review of efficient and cost-effective injection strategies and discussed the tasks of estimating the number of wells and storage economics.

Pressure build-up due to injection in both saline aquifers and depleted hydrocarbon reservoirs is potentially the most limiting factor for large-scale geological storage, and strategies for pressure management will need to be considered. Water production wells, as proposed for the Gorgon project in Australia, can help to relieve pressure build-up in the injection formation. Production wells have the additional safety benefits of (a) controlling the direction of plume migration as shown in CO_2EOR applications and (b) increasing CO_2 dissolution in the formation water. The decisions to use water pressure relief wells is a trade-off between (a) the costs of such wells and the associated water disposal and (b) in the absence of pressure relief wells, the costs of adding injection wells to maintain injectivity.

The co-injection of water and CO_2, either alternating or simultaneously via different injectors, has been successfully implemented in EOR operations and should be easily adapted to CO_2 geological storage. In the latter case, co-injection of water could be used even more broadly to direct the CO_2 plume and maximise storage capacity by accessing lower-permeability pore space that would have been otherwise by-passed by the injected gas. Optimising producer-injector configurations and alternating well operations throughout a multi-well field could be used to spread out the plume, increase the area contacted by the injected CO_2 and thereby increase the dissolution rate, the residually trapped CO_2 and, ultimately, storage efficiency. Issues encountered in some water-gas-alternating EOR operations are the availability of a water source and a decrease in gas injectivity following water injection.

Probably the largest uncertainty of CO_2 storage is associated with the economics of such operations. Variations in the injection parameters that impact the number of injection wells required, significantly affect storage costs. If we consider the impact of each injection parameter separately with all other things being the same we can assess cost implications.

- Permeability - costs per tonne avoided decrease sharply with increasing permeability up to a point when further permeability increases result only in slight cost reductions. This is because high permeability means that few wells are required and when well numbers are already low, further increases in permeability do not significantly reduce costs.
- Injection rate - increasing flow rates increases injection costs because more injection wells are required.

- Formation thickness - a decrease in formation thickness results in a larger number of wells for the same injection rate; hence costs increase.
- Formation depth/ fracture gradient - the allowable pressure build-up (difference between initial formation pressure and fracture pressure) increases with depth. Thus, as depth increases, it is easier to inject more CO_2. The larger pressure differential at greater depths means that deeper wells are less sensitive to variations in permeability. Moreover, CO_2 can be stored at greater densities in deeper formations. However, these advantages are to some extent offset by the higher costs of deep wells and temperature effects on density.
- Well type - at high permeabilities vertical wells are cheaper than horizontal wells, whereas the opposite is true for low permeabilities.
- Hydraulic fracturing - fracturing can reduce cost in low-permeability environments (less than 10 mD). However, at higher permeabilities, the advantages of fracturing are limited and are not sufficient to offset the costs.

In addition, there are cost trade-offs related to transport distance. Distant storage sites with high injectivity become cheaper compared to closer sites with low injectivity once the injection rate is sufficiently large.

Despite the advanced understanding of subsurface flow processes and development of modelling tools, there are still conflicting results in the literature on the estimation of pressure build-up, the resulting number of injection wells required for large-scale CO_2 geological storage and storage efficiency. For these issues, there do not appear to be any adequate analogues. As a result, studies on the regional impacts of CO_2 storage and the role of hydraulic properties of the sealing unit have been limited to more or less generic numerical modelling exercises. Since there are typically large uncertainties in model parameters, such as relative permeability, conclusions drawn from generic studies will have limited applicability until they can be tested against field data.

Uncertainties in predicting reservoir properties and therefore in predicting injectivity will clearly affect the design of the injection system. Therefore, strategies and contingencies will need to be incorporated in development plans to allow for unforseen changes in injection conditions during project life. Continuously updating reservoir models when new data become available and adapting injection strategies will be essential for the success of large-scale CO_2 geological storage.

Table of Contents

Figures

Tables

Acknowledgements

The authors would like to thank Neil Wildgust and Toby Aiken (IEA GHG), Mark Bunch (CO2CRC) and six anonymous external reviewers for their comments and suggestion which greatly improved the final version of the report. Thanks to Matteo Loizzo and Arutchelvi Harichandran (Schlumberger Carbon Services) for their contribution of Remediation Measures and Loss of Injectivity related to CO_2 injection.

Introduction

This project for the IEA Greenhouse Gas R&D Programme (IEA GHG) assesses injection strategies for CO_2 injection sites in relation to reducing carbon dioxide emissions into the atmosphere.

Injecting carbon dioxide (CO_2) into either deep saline aquifers, depleted hydrocarbon reservoirs or deep, un-minable coal seams is a promising option for the geological storage of CO_2 in order to reduce anthropogenic greenhouse gas emissions into the atmosphere. Previous studies and the experience from existing storage and enhanced oil recovery operations have shown that the technology and well design for carbon dioxide injection is well developed (Cooper, 2009). In addition, many studies all over the world have concluded that there is sufficient potential storage capacity in sedimentary basins for storing the global carbon dioxide emissions from industrial point sources (Bradshaw et al., 2007; Bradshaw and Dance, 2005; Li et al., 2005; USDOE, 2007). However, the current portfolio of storage operations does not sufficiently cover different geological environments and, more importantly, there is no experience with injection volumes much larger than 1 Mt CO_2/year. At the same time, there are many uncertainties regarding the extent to which potential capacity can be turned into useable storage capacity, particularly when planning to inject large volumes in the order of several megatonnes of carbon dioxide that require multiple injection wells. It is now commonly accepted that, for geological storage to be an effective greenhouse mitigation option, the infrastructure (platforms, wells, pipelines, compressors) for injecting carbon dioxide will have to be at least on the order of magnitude of current petroleum installations. Also, injectivity of geological formations at an adequate distance from industrial point sources may be of lesser quality than has been encountered in existing projects. Reservoir quality information is particularly sparse for deep saline aquifers, resulting in large uncertainties in storage capacity estimations and forecasting of injectivity and sweep efficiency. In most cases, it can be expected that the CO_2 injection scheme will have to consist of multiple wells, potentially including wells for monitoring and pressure control. Therefore, it is critical to develop efficient and cost-effective injection strategies that minimize the amount of wells and maximise the injection volume and injectivity.

Specific issues that need considering are:

- Most efficient use of pore space (effective storage capacity);
- Sweep efficiency;
- Increase of storage safety through enhancement of CO_2 dissolution in brine and mineral precipitation;
- Injectivity enhancement and remedial options in case of borehole/reservoir damage;
- Control of overpressures and brine displacement (pressure management);
- Prediction of well interference;
- Integration of economics in reservoir simulations.

Scope and Methodology

The project has two main deliverables: 1) A comprehensive review of international research and current understanding with respect to the strategies, technologies and economics of CO_2 injection into subsurface formations and 2) spreadsheet applications based on analytical methods and look-up tables for the planning of CO_2 injection schemes. The review part of the report addresses the following main topics: a) injection well hydraulics and numerical modelling of CO_2 injection; b) proposed strategies for storage optimisation and experience from existing injection operations; c) economics and trade-offs of CO_2 injection schemes; and d) injection well design and remediation methods. More specifically, the following are covered:

- Parameters that affect injectivity and storage capacity were assessed through a critical review of literature and experience from existing storage operations.
- The consequences of uncertainty in parameter estimation in numerical reservoir simulations of CO_2 injection schemes are discussed, particularly with respect to relative permeability, heterogeneity effects and economic impacts.
- Injection strategies that are believed to enhance dissolution of CO_2 in formation water (i.e., co-injection of water) or mineral precipitation, thereby increasing storage security were examined.
- Economics of well design, drilling techniques and stimulation methods were assessed for various storage environments, reservoir quality and transport distances.
- Selected existing CO_2 storage sites and pilot projects, CO_2-EOR projects and natural gas storage sites were reviewed with respect to well design, injection strategy and associated costs.

Review of Strategies, Technologies and Economics of CO_2 Injection

Injection of fluids into the subsurface is an established process with a long history in the petroleum and groundwater industries. Strategies, well technologies and reservoir engineering principles related to the injection of hydrocarbons and water are well-understood and widely documented in general petroleum engineering and hydrogeology textbooks. In the last decade, analytical solutions and numerical modelling codes developed for the simulation of multi-phase fluid flow by and for these industries have been amended to model the subsurface migration of injected CO_2. The following review puts emphasis on the injection process of CO_2 geological storage, including the estimation of injection pressures, well numbers and injection optimisation strategies because these factors determine the economics of the storage portion of CCS.

Reservoir engineering principles

Flow in porous media

For a single incompressible fluid phase, most flow in porous media (assuming a viscous-dominated domain and non-turbulent flow) can be described by Darcy's law (e.g. Hubbert, 1953):

$$\mathbf{q} = -\frac{k}{\mu}\left(\nabla p - \rho g \nabla z\right) \qquad (1)$$

where q is the vector of the volumetric flow rate per unit cross-sectional area, k is the absolute permeability of the medium, μ is the dynamic viscosity of the fluid, p is pressure, ρ is the density of the fluid and g is the gravitational acceleration vector directed downwards (in the z direction).

Neglecting gravity in the vicinity of an injection well and using the equation of mass conservation (continuity), the equation for radial flow of a fluid with small and constant compressibility is (e.g. Craft and Hawkins, 1991):

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\phi \mu c_t}{k}\frac{\partial p}{\partial t} \qquad (2)$$

where ϕ is porosity, c_t is total compressibility, t is time and r is radial distance from the well.

Single-phase flow

For steady-state outward flow from a well of radius r_w at pressure p_w in a reservoir of thickness h the solution to eq. (2) is:

$$p(r) = p_w - \frac{q\mu}{2\pi kh}\ln\left(\frac{r_e}{r_w}\right) \qquad (3)$$

where by convention q is positive for injection, and r_e is defined as the effective reservoir radius. Equation 3 is plotted in Figure 1. In the presence of a second fluid phase like CO_2, Cinar et al. (2008) modified the steady state equation to include relative permeability in a study of injection well performance and calculate the maximum reservoir pressure at the injection well at the end of injection as:

$$p_{w,\max} = \frac{qB_c\mu_c}{2\pi k k_{rc} h}\ln\left(\frac{r_e}{r_w}\right) + p_0 \qquad (4)$$

where B_c is the gas volume factor, k_{rc} is CO_2 relative permeability, and p_0 is the initial reservoir pressure.

Solutions for maximum pressures due to multiple well injection can be found by using superposition of single well solutions (Zakrisson et al., 2008):

$$p_{w,\max} = \frac{nq\mu_c}{2\pi kh}\sum_{j=1}^{n}\ln\left(\frac{r_e}{r_j}\right) + p_0 \qquad (5)$$

where n is the number of injection wells and assuming the same injection rate q for every injector.

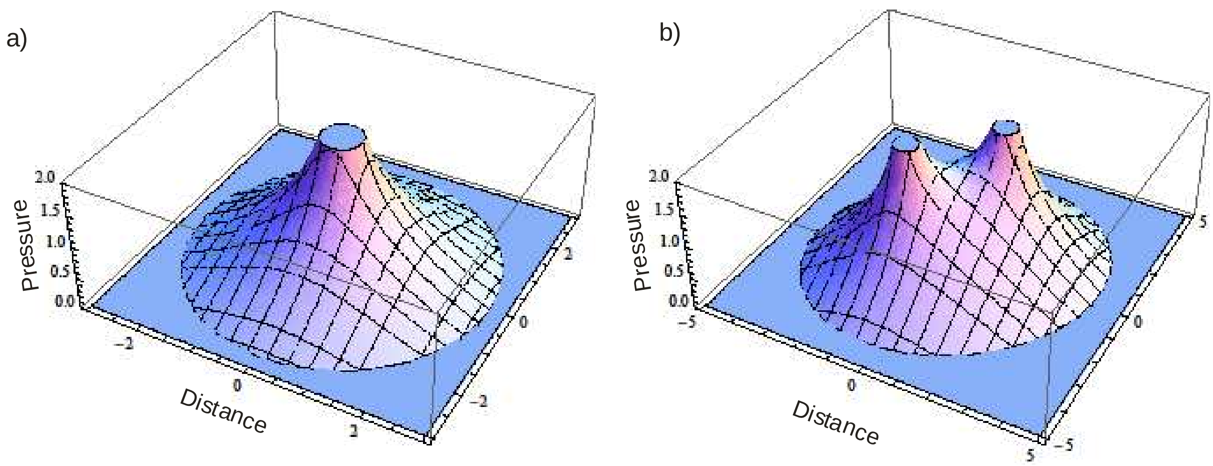


Figure 1. Steady-state pressure distribution in the vicinity of a) a well with a constant injection rate and fixed pressure at an outer radius, and b) two wells with equal injection rates.

Transient single-phase flow in a well

Injectivity tests establish the rate and pressure at which fluids can be pumped without fracturing a fracturing a formation. Analysis of carbon dioxide injection into a storage reservoir is mathematically mathematically similar to a "falloff test" in well testing, except the timescales are years rather than hours. than hours. In a falloff test, fluid is injected (ideally at a constant rate) causing a pressure buildup (Figure buildup (Figure 2), after which the well is shut-in and the pressure at the wellbore declines (Dake, 1978;

Earlougher, 1977; Matthews and Russel, 1967). Normally the equations are framed around fluids that are only slightly compressible such as oil and water. The basic well test equations (

) can be used if the injected CO_2 only causes a small pressure increase and the reservoir conditions are away from the critical point where there are rapid density changes. For gases where compressibility is a strong function of pressure, *real gas pseudopressures* are substituted for pressure (Horne, 2005). Over the range of reservoir conditions for CO_2 storage an ideal gas approximation is inappropriate. To further complicate the situation, in aquifer storage CO_2 is being injected into water so the equations for multiphase well testing with relative permeability terms apply, further complicated by evaporation of residual water near the well (Pruess, 2009). The well testing equations are based on radially symmetric flow ignoring buoyancy. Injectivity with CO_2 buoyancy could potentially be included within a framework of recently developed analytical solutions (Hesse et al., 2007; Mathias et al., 2008; Neufeld and Huppert, 2009; Nordbotten and Celia, 2006).

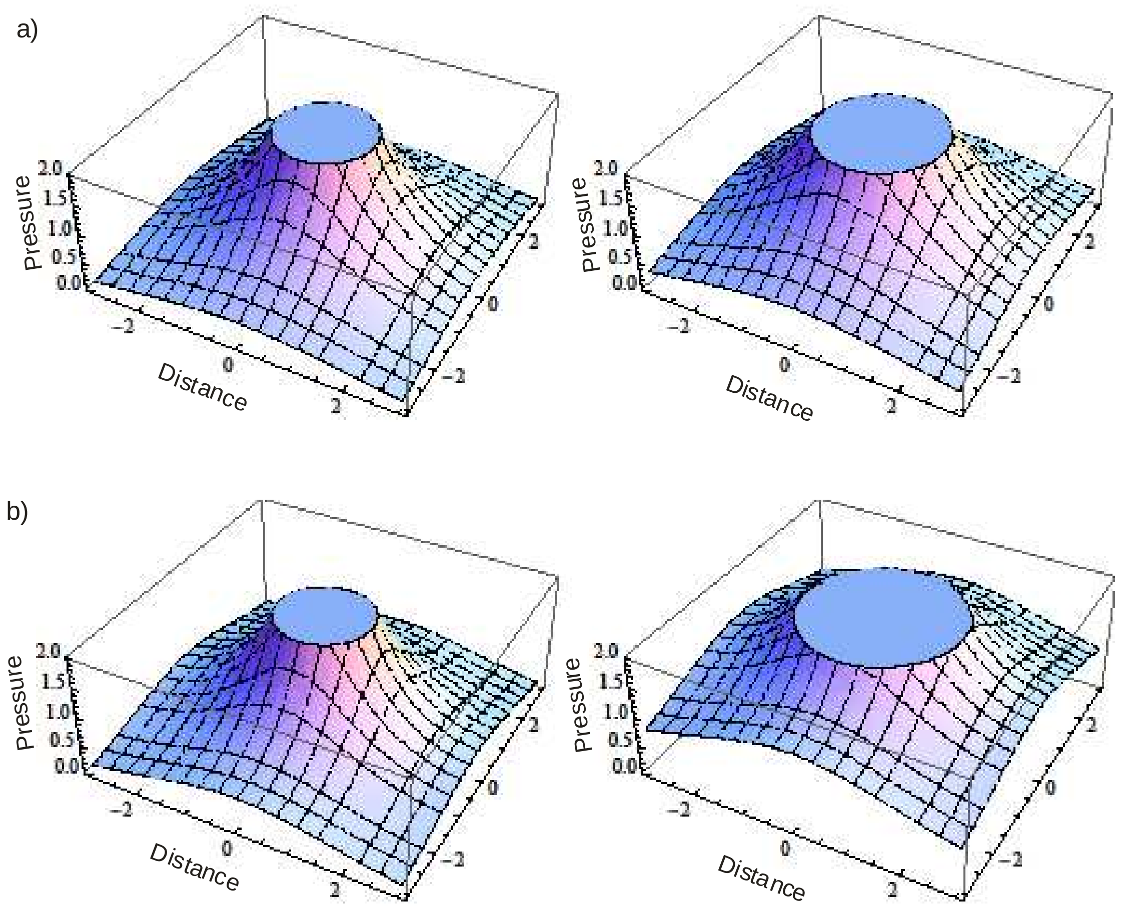


Figure 2. Early time (left) and later time (right) pressure build up in a) an unbounded infinite reservoir and b) a bounded reservoir at the same time steps as a). Pressure values are truncated at p = 2, not the well.

Table 1. Equations for transient single-phase flow from a well.

Quantity/Equation	SI Units (consistent units)	Imperial Units (oilfield units)
dimensionless pressure	$p_D = \frac{2\pi kh}{qB\mu}(p_i - p_{wf})$	$p_D = \frac{2\pi kh}{141.2qB\mu}(p_i - p_{wf})$
dimensionless time	$t_D = \frac{kt}{\phi\mu c_t r_w^2}$	$t_D = \frac{0.000264kt}{\phi\mu c_t r_w^2}$
infinite acting radial flow	$p_{wD} = \frac{1}{2}(\ln t_D + 0.80907) + s$	$p_{wD} = \frac{1}{2}(\ln t_D + 0.80907) + s$

Radius of influence calculations

The maximum radius of the CO_2 plume at the end of injection (assuming a vertical front and piston-like advancement) can be estimated as:

$$r_{p,\max}(t) = \sqrt{\frac{qt}{\pi h\phi(1 - S_{wr})}} \qquad (6)$$

were S_{wr} = irreducible water saturation.

The maximum radius of CO_2 plume spread below the top seal after injection has ceased will be larger due to the mobility contrast between brine and CO_2 (Nordbotten et al., 2005):

$$r_{c,\max}(t) = \sqrt{\frac{k_{rc}\mu_w qt}{\phi\pi\mu_c k_{rw} h}} \qquad (7)$$

Assuming single-phase Darcy flow, the corresponding radius of influence, r_i, at which the pressure difference is a) 1 % or b) 10 % of the maximum injection pressure at the well is (Van Poolen, 1964):

$$r_i(t) = 2 \cdot \sqrt{\frac{kt}{\phi\mu(c_w + c_r)}} \quad (8a), \qquad r_i(t) = 4 \cdot \sqrt{\frac{kt}{\phi\mu(c_w + c_r)}} \quad (8b)$$

where c_w and c_r are water and rock compressibility, respectively.

Bounded reservoirs

Maximum injection pressures in a bounded reservoir with radius r_b can be defined in terms of the average reservoir pressure $\overline{p}$ according to:

$$p_{w,\max} = \frac{q\mu}{2\pi kh}\left(\ln\frac{r_b}{r_w} - 0.75 + s_a\right) + \overline{p} \qquad (9)$$

with pseudo-skin factor $s_a = \frac{1}{2}\ln\frac{4\pi}{\gamma C_A} + 0.75$

where C_A is the Dietz shape factor (31.6 for circular geometry) and γ = 1.781 is the exponential of Euler's constant. The pseudo-skin factor represents the additional pressure drop due to the deviation from pure radial flow. See Earlougher (1977) for shape factors for different reservoir geometries.

Two-phase flow

Carbon dioxide injection with the displacement of water involves two fluid phases. Carbon dioxide is less dense and less viscous than water, and many potential storage sites are not infinite acting, so more complex equations need to be considered.

A basic start on the two-phase flow issue has been made by van der Meer and Egberts (2008). They modify the equation for steady-state radial flow into a moving-boundary problem (Figure 3) for CO_2 displacing water according to:

$$p_{w,\max} = \frac{q\mu_c}{2\pi kh}\ln\left(\frac{r_e}{r_w}\right) + \frac{q\mu_w}{2\pi kh}\left(\ln\frac{r_a}{r_e} - 0.75\right) + \bar{p} \qquad (10)$$

where the maximum reservoir pressure $p_{w,max}$ at the injection well is assumed to occur at the end of CO_2 injection and the average reservoir pressure $\bar{p}$ can be derived from the material balance:

$$V_a\phi\left[c_r + S_w(t)c_w + S_c(t)c_c\right]\left(\bar{p}(t) - p_0\right) = qt \qquad (11)$$

with fluid saturations $S_w = \frac{V_a\phi}{V_a\phi + qt}$ and $S_c = \frac{qt}{V_a\phi + qt}$ for water and CO_2, respectively

V_a is the total volume and c_c is the CO_2 compressibility.

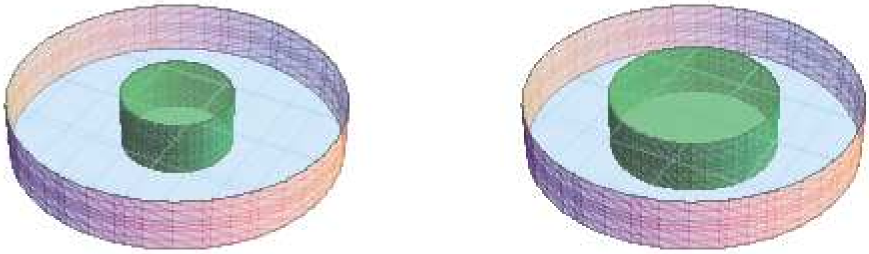


Figure 3. Early time (left) and later time (right) for an expanding CO_2 cylinder (green) in a cylinder of water in the approach used by van der Meer and Egberts (2008).

The van der Meer and Egberts (2008) approach is limited because their case has a fixed outer radius r_a at constant pressure and constant flux, and ignores buoyancy and transient compressibility effects. It also ignores far-field permeability and any boundaries providing resistance to flow.

Usually the constraint on using a storage site is an upper limit on the injection pressure (Economides and Ehlig-Economides, 2009; Mathias et al., 2009). The injection pressure is constrained by the formation fracture pressure, p_f, which depends on the formation fracture gradient. From the equations in Table 1 the injection pressure increases approximately logarithmically with time in a planar unbounded reservoir, so the maximum pressure is at the end of injection. Hence, for low-permeability rocks the injectivity is limited by the near-wellbore permeability, whereas for rocks of reasonable permeability the injectivity is limited by the boundaries of the structure. A new analytical model was developed by Mathias et al. (2008; 2009) which uses the method of asymptotic expansions to derive a new similarity solution for large time scales that accounts for inertial effects with high velocities near the wellbore using the Forchheimer equation. A significant advantage over previous well equations is that, by allowing for slight compressibility of fluids and rock framework, no value for a "radius of influence" or "effective radius" needs to be specified. In the model by Mathias et al. (2008; 2009), the pressure build-up due to CO_2 injection is controlled by seven parameter groups:

$$p_0 = \frac{M_0 \mu_c}{2\pi h \rho_c k},\ t_0 = \frac{2\pi \phi h r_w^2 \rho_c}{M_0}$$ (characteristic pressure and time, respectively)

$$\alpha = \frac{M_0 \mu_c (c_r + c_w)}{2\pi h \rho_c k}$$ (describes the radial extent of CO_2 plume)

$$\beta = \frac{M_0 k b}{2\pi h \mu_c r_w}$$ (inertial loss term)

$$\gamma = \frac{\mu_c}{\mu_w},\ \varepsilon = \frac{c_c - c_w}{c_r + c_w},\ \sigma = \frac{\rho_c}{\rho_w}$$

where M_0 is the mass injection rate, ρ_c is CO_2 density and b is the Forchheimer parameter.

The Forchheimer parameter is assumed to be (Geertsma, 1974):

$$b = 0.005\phi^{-5.5}k^{-0.5}$$

The maximum pressure build-up (at the injection well) is then approximated by:

$$p_I \approx p_0\left\{-0.5\ln\left(\frac{t_0}{2\gamma t}\right) - 1 + \frac{1}{\gamma}\left[\ln\left(\frac{\alpha}{2\gamma^2}\right) + 0.5772\right] + \beta\right\} \qquad (12)$$

for $\alpha < 10^{-3}, |\varepsilon| < 10$ and $t_c > \dfrac{50t_0\beta^2}{\gamma}$

Mathias et al. (2009) also provide a set of empirical correlations from the literature for the estimation of the viscosity, density and compressibility of the fluids that are needed for the calculation of the seven parameter groups. The Mathias et al. (2009) model assumes that there is a sharp interface between the CO_2 and the brine and it does not include relative permeability effects. Economides and Ehlig-Economides (2009) propose an analytical model based on previous work by Burton and Bryant (2008) that includes relative permeability, but it does not include gravitational effects:

$$p_w - p_0 = \frac{q}{2\pi kh}\left[\frac{\mu_c}{k_{r,Sc=1}}\ln\left(\frac{r_{dry}}{r_w}\right) + \left(\frac{k_{rc}}{\mu_c} + \frac{k_{rw}}{\mu_w}\right)^{-1}\Bigg|_{Sc,avg}\ln\left(\frac{r_{BL}}{r_{dry}}\right) + \mu_w\ln\left(\frac{0.472r_e}{r_{BL}}\right)\right] + \frac{V_c}{V_r c_t} \qquad (13)$$

where r_{dry} = radius of the CO_2 drying-front near the wellbore, r_{BL} = radius of the 2-phase Buckley-Leverett zone, V_c = CO_2 volume and V_r = minimum required pore volume. The relative permeability of the CO_2 in the single-phase region $k_{r,Sc=1}$ and the relative permeability values in the 2-phase region are evaluated at the average CO_2 saturation according to Buckley-Leverett displacement theory (Economides and Ehlig-Economides, 2009).

This extends the equations in Table 1 by including two-phase relative permeability and no-flow boundaries, but it neglects gravity and water production. To solve Equation 13, it is necessary to determine the relationship between fluid saturations and relative permeability values in the CO_2-brine-rock system, which requires rock specific measurements that are not widely available at the reservoir scale.

The previous comparison only looked at single-well solutions of pressure build-up due to CO_2 injection into infinite aquifers. Multi-well injection schemes, the impact of horizontal completions and fracturing, as well as injection into open versus closed systems will be discussed in the Economics section (page 46).

Despite the progress that has been made in deriving analytical solutions that also account for gravity effects (Bickle et al., 2007; Hesse et al., 2006, 2007, 2008; Lyle et al., 2005; Neufeld and Huppert, 2009), a full two-phase solution involving gravity and relative permeability has not been obtained. Therefore, numerical simulation remains the usual approach to evaluating injectivity for storage sites.

Reservoir modelling

Fundamentals of simulation

Most numerical simulation codes for multiphase flow in porous media are essentially solving the same basic governing equations i.e. Darcy's law for multiphase flow, plus conservation laws (the main exception is invasion percolation codes, which are useful when the flow is capillary-dominated – see below). Traditionally this is done by finite difference solutions of the partial differential equations, leading to the solution of sparse sets of linear equations. Most available codes operate in this way, but there have also been developments in streamline simulation which have now been applied to CO_2 storage, and which can give significantly shorter run times (Obi and Blunt, 2006). Sometimes additional physics can be introduced into the model e.g. non-Darcy flow, or chemical reactions, and this will differentiate between codes.

The other source of difference between codes is in the representation of fluid properties. In commercial petroleum simulation codes, this is typically done through tables of properties, where the onus is on the user to come up with suitable input data. For CO_2 injection this can done even with "black oil" simulators (Hassanzadeh et al., 2008; Mo and Akervoll, 2005). In some research codes (e.g. TOUGH2, (Pruess et al., 1999)), there is a detailed internal representation of fluid properties (e.g. CO_2 and brine). This is less flexible, as it requires a new module to be written for new combinations of fluids, but allows greater accuracy in representation.

Well representation

In a typical finite difference formulation, wells for production or injection are represented as sources or sinks for fluid. However, for simulation of field projects, it is necessary to tie this internal representation to the practical constraints of well operation. For example, injection is usually constrained by a maximum injection pressure criterion, while production might be done at a fixed bottom hole pressure. In most simulation grids, the size of the grid block containing the well is likely to be tens of metres laterally (unless some local grid refinement is used). Thus the pressure in the grid block is not an accurate representation of the pressure at the well location. The first step is to use reservoir engineering solutions for radial flow about wells, e.g. (Peaceman, 1978, Eq.1):

$$q = -\frac{2\pi k_h h}{\mu(\ln(r_e / r_w) + s)}(p_e - p_{wf}) \qquad (14)$$

where p_e is the volumetric average of the pressure in the block, p_{wf} is the flowing well bottomhole pressure, k_h is the horizontal permeability, and s is the dimensionless skin factor. The use of skin factors to represent alterations to the permeability of the near-wellbore environment is discussed in standard reservoir engineering textbooks (e.g. Ertekin et al 2001).

In rectangular grid blocks, the question arises of how to choose r_e, the "outer" radius. The approach of Peaceman (1978) chooses an equivalent radius r_{eq} at which the wellblock pressure is equal to the steady state pressure. For example, in square blocks with lateral extent Δx, the relation is $r_{eq} = 0.198\ \Delta x$. All these relations have extensions for non-square blocks, anisotropic permeabilities etc. Horizontal wells require further theoretical relations, based on the same general approach.

One of the distinguishing features of commercial petroleum codes for simulation, as compared to research codes, is that they typically have much more detailed control of well features and operation, since these aspects are crucial to petroleum production. The properties of carbon dioxide are quite sensitive to temperature changes, and a comprehensive wellbore model needs to consider non-isothermal effects (Lu and Connell, 2008; Paterson et al., 2008).

Aquifer representation

When injectivity is under scrutiny, it is important to understand the choice of boundary conditions in numerical simulation codes, since these determine how pressure builds up in response to injection. The easiest boundary condition to implement is a no-flow boundary, since that corresponds to having no grid blocks connected on that side. Constant pressure boundary conditions can be implemented by connecting a grid block with very large volume, so that its properties remain essentially unchanged when fluid flows in or out. This is often used in research codes. More complex boundary conditions, such as constant flux, can be implemented by having extra source or sink terms in the boundary blocks.

In commercial simulation codes, there is usually an option to connect analytical aquifer models to some grid blocks. These analytical models typically have an aquifer dimension, a porosity and permeability, and perhaps also a time constant. These parameters are generally sufficient to fit the observed behaviour in field cases. It is commonplace that the properties of boundary aquifers are among the least-known parameters in the initial site characterisation. Thus a history match of the downhole pressure during production or injection (or during recovery from either operation) is needed to constrain the reservoir pressure and characteristics of the analytical aquifer.

There may also be interest in the details of the coupling of the reservoir model to wider hydrogeology. For example, Nicot (2008) and Yamamoto et al. (2009) examine the effect of CO_2 injection upon aquifer systems in Texas and Japan, respectively. This requires further characterisation of recharge rates, and additional boundary conditions to model recharge etc.

Simulation software

Simulation software that has been used for modelling CO_2 injection can be divided into two categories. The first category is commercial software developed primarily for the petroleum industry, and adapted in various ways for CO_2. Most petroleum simulation codes can be used in this way. The most common choices are Eclipse (Schlumberger) and GEM (from the Computer Modelling Group). The second category is in-house or research software, usually developed in research institutions. These codes tend to be more specialised, and not to have the wide range of features to deal with general petroleum simulation. TOUGH2 and its derivatives are the most widespread example, but there are a host of other offerings.

Table 2 gives a list of codes that have been used in simulations of CO_2 injection, with a reference to typical applications. This list is not comprehensive, and doesn't account for a number of in-house codes which are not named. It also leaves out special purpose codes that are 2D and not 3D (e.g. using vertical averaging). The code comparison papers Pruess et al. (2004) and Class et al. (2009) allow for an assessment of how well various codes can simulate model problems for CO_2 storage. Even in those papers, the reality is that the choices of the operator (e.g. gridding) can have a significant effect on the performance of a code on a given problem. Thus it is not possible to give a definitive evaluation of which codes are "better" for modelling CO_2 storage. It is even difficult to summarise the features provided by each code, partly because of the difficulty of access to so many codes (either because they are in-house, or because of licensing). Furthermore, the capabilities of most codes are subject to continual improvement, and a list of features will quickly become dated. Thus Table 2 only contains the high level categorisation into research codes and commercial codes, a comment to distinguish streamline or invasion percolation codes, and a reference to a usage in the context of CO_2 storage.

Table 2: List of some codes that have been used for simulations of CO_2 injection.

Code name	Institution/Provider	Type of code	Example
COORES	Institute Français du Pétrole (IFP)	Research	Class et al. (2009)
DuMux	University of Stuttgart	Research	Class et al. (2009)
ECLIPSE	Schlumberger	Commercial	Krumshansl et al. (2002)
FEHM	Los Alamos National Laboratory (LANL)	Research	Class et al. (2009)
FLOTRAN	Los Alamos National Laboratory (LANL)	Research	Pruess et al. (2004)
GEM	Computer Modeling Group (CMG)	Commercial	Kumar et al. (2005)
GPRS	Stanford University	Research	Class et al. (2009)
IPARS-CO2	University of Texas at Austin	Research	Class et al. (2009)
MPATH	Permedia	Commercial/Invasion Percolation	Cavanagh and Haszeldine (2009)
MUFTE_UG	University of Stuttgart	Research	Pruess et al. (2004)
NUFT	Lawrence Livermore National Laboratory (LLNL)	Research	Johnson and Nitao. (2003)
ROCKFLOW	University of Hanover	Research	Class et al. (2009)
RTAFF2	BRGM	Research	Class et al. (2009)
SIMUSCORP	Institute Français du Pétrole (IFP)	Research	Pruess et al. (2004)
STARS	CMG	Commercial	Pamukcu and Gumrah (2009)
STOMP	Pacific Northwest National Laboratory (PNNL)	Research	Pruess et al. (2004)
TOUGH2 and variants	Lawrence Berkeley National Laboratory (LBNL)	Research	Pruess et al. (2004)
(unnamed)	Imperial College	Research/Streamline	Obi and Blunt (2006)

Streamline simulation

Streamline-based simulation techniques have been developed in the oil industry as an alternative to the traditional grid-based finite-difference methods (Thiele et al 2010). Typically a dual-grid method is used, in which a pressure solution on a traditional static grid is obtained, and a velocity field generated from this gives the streamlines for fluid motion. The streamlines are assumed to be fixed for a time Δt, and 1D numerical solutions are used for transport of components along these streamlines. The process is then repeated. The principle advantages of streamline simulation are computational speed and memory efficiency, allowing the simulation of much finer grids, and the immediate visualisation of flow paths. The difficulties with streamline simulation occur when there is physics that is transverse to the main direction of flow, such as diffusion, compressibility or buoyancy. An existing streamline simulator has been extended to four-component (water, oil, CO_2, and salt) transport applied to CO_2 injection by Qi et al (2009). They have applied this simulator to design CO_2 injection strategies in a highly heterogeneous million-grid-block model of a North Sea reservoir where CO_2 and brine are injected together.

Applications of percolation theory

Conventional reservoir simulation is based on Darcy's law for flow of a viscous fluid. Darcy's law is applicable when permeability and viscosity determine fluid migration. It allows the calculation of pressure changes, such as pressure buildup in the vicinity of an injection well. However, when viscous forces are negligible, very slow two-phase flows are dominated by capillary and gravity forces. There is evidence that these slow flows are best modelled by pore-scale network models, with the simplest of these models being based on percolation theory (Larson et al. 1981). Percolation models have two main variants: ordinary percolation and invasion percolation. Gravity was first introduced into the invasion percolation algorithm through the application of a simple linear weighting on the invasion thresholds in the direction of buoyancy (Wilkinson and Willemsen, 1983; Wilkinson, 1984).

An important application of invasion percolation with buoyancy has been to the secondary migration of oil. Secondary migration is the slow process occurring over geological timescales where oil migrates from the source rocks where it is formed into structural or stratigraphic traps. In a series of papers, researchers at the University of Oslo have explored invasion percolation as a model for secondary migration (Meakin et al., 1995; Meakin et al., 2000; Vedvik et al., 1998; Wagner et al., 1997). For further references see Thomas and Clouse (1995), Ringrose et al. (1996) and Boettcher et al. (2002). In heterogeneous rocks the migration paths are characterised by thin filaments that connect local accumulation pools. Experiments conducted by Hirsch and Thompson (1995) on sandstone samples of different sizes found saturations consistent with the predictions from invasion percolation.

Over the last decade Permedia Research Group has developed a code, MPath, based on invasion percolation for secondary migration (Carruthers, 2003). This code has recently been applied to CO_2 migration at Sleipner (Cavanagh and Haszeldine, 2009) and In Salah (Cavanagh and Ringrose 2009). At present, the code is difficult to evaluate because the details of the methods have not yet been published in the literature to the extent of other codes, nor has this code been involved in code comparison studies.

In a separate application, Zhang et al. (2009) have applied percolation theory to calculate the connectivity of stochastic fracture networks for estimating the probability of CO_2 leakage into shallow aquifers. This applies percolation theory to the solid rather than the fluids. If the fracture density is below the percolation threshold the fractures are disconnected and do not create a migration path.

Injection strategies for CO_2 geological storage

When planning a CO_2 injection scheme the most critical factors, aside from containment security and adequate storage volume, are the injectivity of the potential reservoir unit and storage efficiency. Optimisation of these factors is essential to maximise storage capacity and improve the economics of an injection operation. Therefore, the following sections will discuss the sensitivity of parameters that control injectivity and storage efficiency and will review methods that help in their optimisation.

Injectivity and storage efficiency - parameter sensitivities

Injectivity

The injectivity is defined as the ability of a geological formation to accept fluids by injection through a well. The main limiting factor for injectivity is the bottomhole injection pressure which should not exceed the formation fracture pressure. It is common for regulators to set a criterion for the maximum injection pressure that is somewhat less than this e.g. 90% of the fracture pressure. According to the well testing equations (see section on well hydraulics), critical parameters controlling the bottomhole pressures around an injection well are:

- Injection rate;
- Absolute permeability;
- Relative permeability to CO_2;
- Thickness (net pay) of completed interval;
- Viscosity contrast between brine and CO_2 (mobility);
- Compressibility.

Burton et al. (2008) tested the impact of various parameters on the injectivity assuming a three-phase system (dry CO_2, brine-CO_2 mixing zone, brine) with following conclusion:

- Drying front – the mobility of the drying front causes an increase in injectivity with time;
- Mobility – the higher the mobility in the brine-CO_2 mixing zone (Buckley-Leverett region), the higher the flow rate;
- Relative permeability – injection rates vary significantly for different relative permeability values and injectivity is very sensitive to variables that define relative permeability curves;
- Phase behaviour – considered less important;
- Salt precipitation – salt precipitation in the drying zone can result in permeability reduction; hence reduction in injectivity.

Storage efficiency

The determination of storage capacity is difficult for a number of reasons (Bachu et al., 2007a; Bradshaw et al., 2007; Kopp et al., 2009a, b; Zhou et al., 2008). First there is the problem of defining what constitutes a reservoir, and then the problem of defining what portion can be accessed by injected CO_2. In part this depends on the heterogeneity of the reservoir horizon and on the engineering of the particular injection scheme. The definition of a reservoir is based on decisions involving permeability-porosity cut-offs to delineate non-reservoir rock. The choice of permeability-porosity cut-offs can be influenced by the economics of the particular project as it is possible to use stimulation techniques to enhance effective permeability.

The mass of CO_2 (M_{CO2}) stored in a defined area (A) with formation thickness (h), porosity (ϕ) and CO_2 density (ρ_{CO2}) and application of a storage coefficient (E) can be calculated according to:

$$M_{CO2} = A * h * \phi * \rho_{CO2} * E$$

The *Storage Coefficient* E can be defined as the multiplicative combination of volumetric parameters that reflect the portion of a basin/region/formation pore volume that CO_2 is expected to actually contact (USDOE, 2007):

$$E = A_n/A_t * h_n/h_g * \phi_{eff}/\phi_{tot} * E_A * E_l * E_g * E_d$$

where

- A_n/A_t = Fraction of the total basin or region area that has a suitable formation present;
- h_n/h_g = Fraction of the total geologic unit that meets minimum porosity and permeability requirements for injection;
- ϕ_{eff}/ϕ_{tot} = Fraction of total porosity that is effective (interconnected);
- E_A = Areal displacement efficiency – The fraction of the 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;
- E_l = Vertical displacement efficiency – The fraction of the vertical radial cross section (thickness), with the volume defined 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;
- E_g = Gravity – The fraction of the net thickness that is contacted by CO_2 as consequence of density difference between CO_2 and *in situ* brine. In other words, $(1-E_g)$ is that portion of the net thickness NOT contacted by CO_2, because CO_2 rises within the geologic unit;
- $E_d = (1-S_w)$ = Microscopic displacement efficiency – The function of CO_2-contacted pore volume that can be replaced by CO_2. E_d is directly related to irreducible water saturation in the presence of CO_2.

Following the concepts above, a comprehensive catalogue of storage coefficients for different depositional environments was developed by the Energy & Environmental Research Center (EERC) for the IEA GHG and the US Department of Energy National Energy Technology Laboratory. Storage coefficients were determined by EERC from results of numerical simulations using the Computer Modelling Group (CMG) GEM reservoir simulation package. Evaluation of the effect of parameter sensitivity on storage coefficient for homogeneous models revealed the following (IEAGHG, 2009d; Gorecki et al., 2009):

- Structure – the more confined the structure, the higher the storage coefficient;
- Depth & temperature – the storage coefficient increases with depth as a result of increasing CO_2 density and decreasing buoyancy effects;
- k_{rCO2} & S_{wirr} – the two variables counteract each other and, at least in the homogenous simulations that were performed, relative permeability does not appear to have a strong effect on the storage coefficient;
- Vertical permeability anisotropy (k_v/k_h, where k_v is vertical permeability) – when k_v/k_h is very low, the storage coefficient increases due to low gravity effects, however at ratios above 0.5 gravity effects result in a lower storage coefficient (this might not be the case for heterogeneous reservoirs);
- Injection rate – low injection rates result in high microscopic displacement but low contacted pore space, and the opposite is the case for high injection rates, however the combined results indicate that higher injection rates yield higher storage coefficients.

Comparing CO_2 storage in open versus closed systems revealed that the latter can store on an order of magnitude less mass of CO_2 because storage in closed systems is limited to the total compressibility (rock and fluids) and the maximum allowable pressure build-up. However, water production from the closed reservoir could neutralize this limiting factor.

Storage coefficients in saline aquifers have been studied also by Kopp et al (2009b), and their findings agree to a large degree with those from the EERC study; i.e., deep, cold and/or low-permeability reservoirs have higher storage coefficients. However, Kopp et al. (2009a) find that relative permeability has a high influence on storage capacity, which is not observed as a major contributing factor in the EERC assessment. Kopp et al. (2009b) also find that high storage capacity for a given reservoir is typically achieved for low injectivity values, and they note that this is in conflict with economic objectives.

Effects of heterogeneity

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 become 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 increases 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.

Green et al. (2009) and Green and Ennis-King (in press) derive simple analytical expressions for the mean and variance of the vertical permeability in a reservoir with randomly distributed impermeable barriers. They show that the variance is inversely proportional to the reservoir thickness whereas the mean vertical permeability is scale invariant. Two-dimensional numerical modelling and extension to 3D predict that breakthrough of CO_2 injected at moderate rates at the bottom of the reservoir would scale as the square of reservoir thickness h in 2D and as h^3 in 3D (Green and Ennis-King, in press). Thus, deep injection in thick heterogeneous formations can result in slow vertical migration and high trapping efficiency in the formation (Figure 4). It was also found that, on a small scale, downward convection of dissolved CO_2 (due to the slight density increase of the fluid upon dissolution) began much sooner in heterogeneous cases than in homogeneous cases (Figure 5).

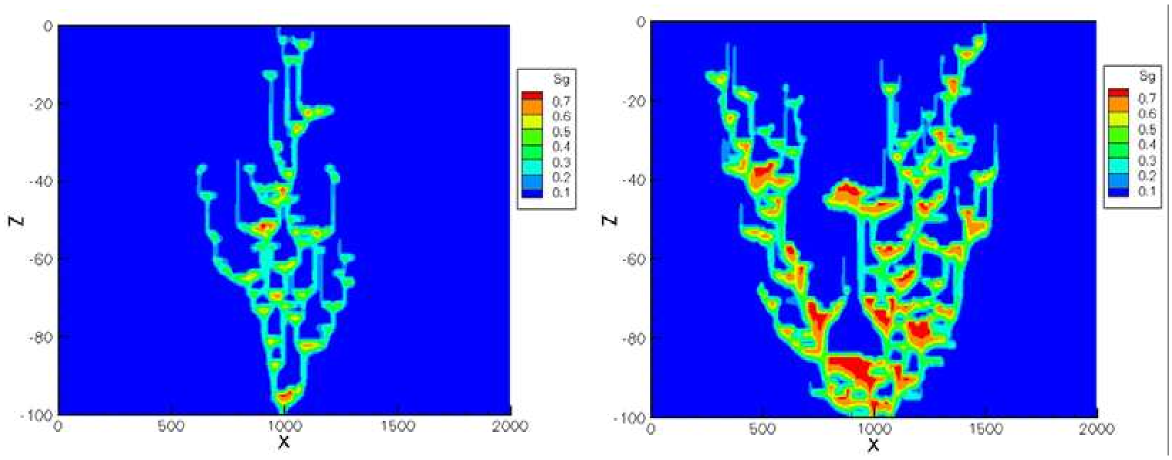


Figure 4. Impact of heterogeneity and injection rates on the vertical spread of CO_2 injected at the bottom of a reservoir. The CO_2 saturation Sg is shown at the time of breakthrough at the top of the reservoir; left: 0.001 kg/s (per meter of thickness), right: 0.01 kg/s (Green et al., 2009).

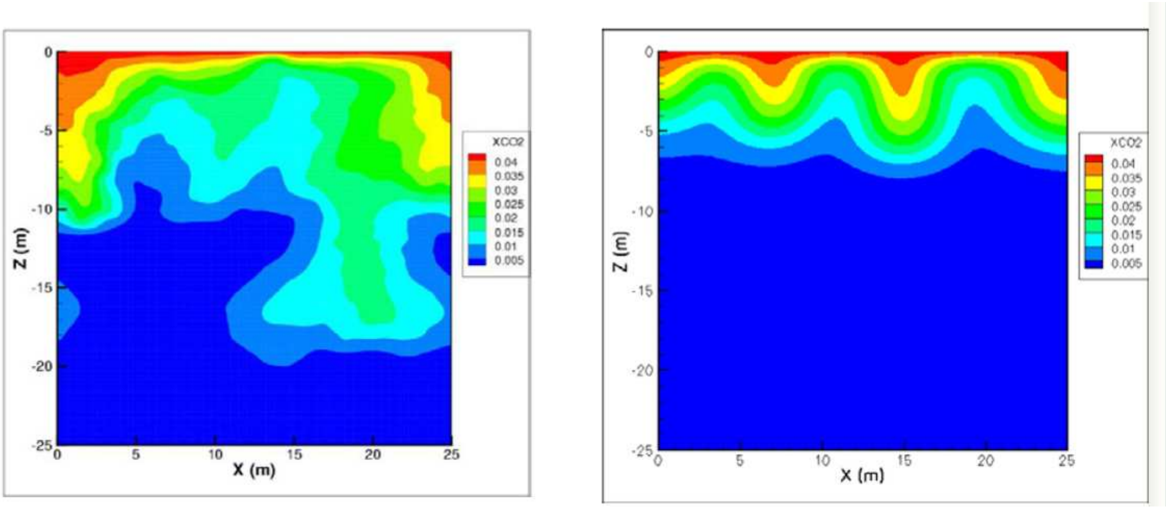


Figure 5. Impact of heterogeneity on the convection of dissolved CO_2, showing initiation of fingering for a 25 m x 25 m domain with a top boundary condition of constant dissolved CO_2. Left: statistical distribution of shales with fraction of impermeable barriers = 0.153 and width = 1.5 m, Right: homogeneous permeability with same effective vertical and horizontal permeability (Green et al., 2009).

Heterogeneity also has an impact on lateral migration distances. It is commonly found that homogeneous models with the appropriate average permeability overestimate breakthrough times at other wells, because the models do not take into the account the lateral continuity of higher permeability streaks in the reservoir. The arrival of injected CO_2 at an observation well might be a condition for limiting injection or taking other remedial action, since it might indicate a risk of leakage out of a structural closure. Thus a better characterisation of heterogeneity might lead to a prediction of lower injectivity in some reservoirs.

Pressure maintenance using water production wells

When injectivity is limited by the boundaries of the structure, water production has been proposed as a method to reduce pressure and hence increase injectivity for CO_2 storage sites (Flett et al., 2008; Yang, 2008). This overcomes pressure buildup concerns providing that water disposal can be accommodated (see Gorgon example on page 32). Another study in a different region of Western Australia also showed that draining brine can greatly relieve the injection pressure for a potential storage site. The studied site (the Carbine Ponded Turbidite Complex) was estimated to be able to contain at least 20 years of CO_2 injection at an injection rate of 1 million tonnes per year before breakthrough of CO_2 at the drainage well (Yang, 2008).

Water disposal is a potential issue, but it is an issue that is familiar to the oil production industry. Approximately 2.4-3.2 billion cubic metres (15-20 billion barrels) of produced water are generated each year in the United States associated with petroleum production (see section on liquid waste disposal). Produced water from saline formations has the advantage that it is not contaminated with oil. Assuming an injection density of 500 kg/m^3, 1 million tonnes of CO_2 injection will occupy the same volume as 2 million tonnes (12.6 million barrels) of water.

Production of water may have an additional advantage for CO_2 geological storage. Lester et al. (2009) propose to enhance transport processes by rotating or alternating injectors and producers in a designated well field over time and thereby creating a stirring effect of the injected fluid with formation water. In the case of CO_2 injection, the stirring effect could be employed to optimise the lateral spread of CO_2 in the subsurface and to enhance dissolution of CO_2 in formation water.

Co-injection of water and CO_2

Trapping of CO_2 can be increased by injecting brine either during or after the CO_2 injection (Ide et al., 2007; Juanes et al., 2006; Keith et al., 2005; Kumar et al., 2004; Leonenko and Keith, 2008; Leonenko et al., 2006). 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 Water Alternating Gas, or 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 as a result of relative permeability effects (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 an anticline (Leonenko and Keith, 2008). A direct comparison of co-injection (brine and CO_2 together) with sequential injection (brine injection 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 a 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).

Qi et al (2009) have proposed a carbon storage strategy where CO_2 and brine are injected into an aquifer together followed by brine injection alone. This increases residual trapping and the security of storage with up to 80-95% of the CO_2 rendered immobile. Furthermore, they argue that the favourable mobility ratio between injected and displaced fluids leads to a more uniform sweep of the aquifer resulting in higher storage efficiency than injecting CO_2 alone. Qi et al (2009) have tested their design strategy using a streamline-based simulator to model storage in a North Sea aquifer. They designed injection to give optimal storage efficiency and to minimize the amount of water injected. For the cases they studied, injecting CO_2 with a fractional flow between 85% and 100% followed by injection of at least 25% of the stored mass of CO_2 with chase brine gave the best performance. Qi et al (2009) estimate the capital cost of brine production, transport and injection is likely to be less than 3% of the capital cost of the full CCS project including the cost of carbon capture.

Dissolution of CO_2 in brine

Surface dissolution has been proposed of a means of increasing storage security (Burton and Bryant, 2009; Leonenko and Keith, 2008), although there are practical difficulties. Dissolving CO_2 at the surface before injection (Figure 6) has been estimated to require an additional power consumption of 3 to 9% of the power plant capacity, with the capital costs increasing by approximately 60% (Burton and Bryant, 2009). There would, however, be a reduction in the cost of monitoring for buoyancy-driven CO_2 leakage. Co-injection of brine and CO_2 would require less additional pumping power; however the dissolution of CO_2 would be less efficient.

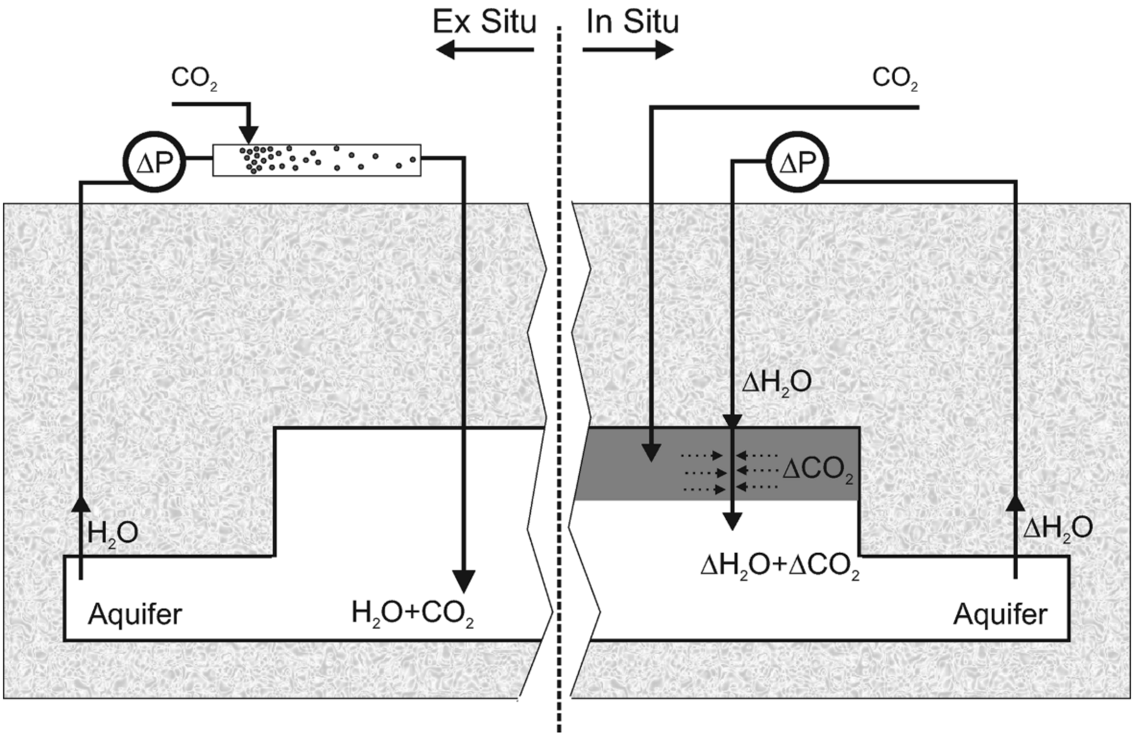


Figure 6. Schematic view of CO_2 dissolution in brine at the surface (left) and in the reservoir (right) (Leonenko and Keith, 2008).

Injection in the saline-only section below the oil-water contact in oil reservoirs

Han and McPherson (2009) have considered CO_2 injection in the saline-only section below the oil-water contact (OWC) in oil reservoirs. Their results suggest that deep saline CO_2 injection immediately below oil formations reduces buoyancy-driven CO_2 migration and, at the same time, minimizes the amount of mobile CO_2 compared to conventional deep saline CO_2 injection. Furthermore they note that most, if not all, oil-bearing basins in North America contain a great volume of such strata, and represent a large CO_2 storage capacity option. An example of such a project is the Heartland Redwater Leduc Reef saline Aquifer CO_2 Capture and Geological Storage Project (HARP) (Gunter et al., 2009). The injection target is the water leg of a Devonian reef structure at a depth below 1000m, with an areal extent of 600 km^2 and 275 m thickness. The reef has proven injectivity based on previous oil production and water disposal, with a potential to inject in excess of 1 $ktCO_2$/day per well in the aquifer portion of the reef structure and a total storage capacity estimated at 1 $GtCO_2$ (Gunter et al., 2009).

Regional-scale storage containment and potential resource impacts

A key aspect of CO_2 storage in saline aquifers is the conflict of interest with respect to aquifer usage, i.e., natural gas storage, deep waste disposal, the potential interference with hydrocarbon production from nearby fields, and the impact on groundwater resources (Bentham and Kirby, 2005). The effects of brine displacement induced by large-scale CO_2 injection have been studied for hypothetical cases in the USA and Japan using large-scale numerical simulations (Nicot, 2008; Yamamoto et al., 2009). A preliminary modelling study in the Gulf Coast region of the USA 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. 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. Sensitivity studies carried out by Yamamoto et al. (2009) suggest that numerical predictions are heavily dependent on generally uncertain parameters like porosity, pore compressibility, and particularly the permeability of the sealing unit.

Birkholzer et al. (2009) modelled the impacts of injecting 100 MtCO_2/year for 50 years into the Mount Simon Sandstone in the Illinois Basin and arrived at following conclusions:

- Pressure build-up associated with large-scale CO_2 injection will be the main limiting factor for storage capacity, which could be managed by the extraction of formation water.
- Monitoring results, particularly far-field measurements from large demonstration projects are needed to reduce model uncertainties.
- Pressure interference between multiple injection operations needs to be considered for the basin resource management and permitting of CO_2 storage projects.
- Requirements for site characterisation and monitoring need to consider both the region of maximum plume extent and the much larger region of pressure impact, yet less stringent for the latter and defined on a case-by-case evaluation of geological conditions and potential environmental impacts.
- Potential brine movement into shallow aquifers and impact of CO_2 leakage in freshwater needs further research.

Chadwick et al. (2009) investigated the impact of flow barriers on aquifer pressurisation and storage capacity. Their modelling studies using TOUGH2 indicate that even in aquifers with lateral and vertical flow boundaries, there probably will be some single-phase water flow through the sealing unit and seal permeability will have an impact on reservoir pressures (Figure 7).

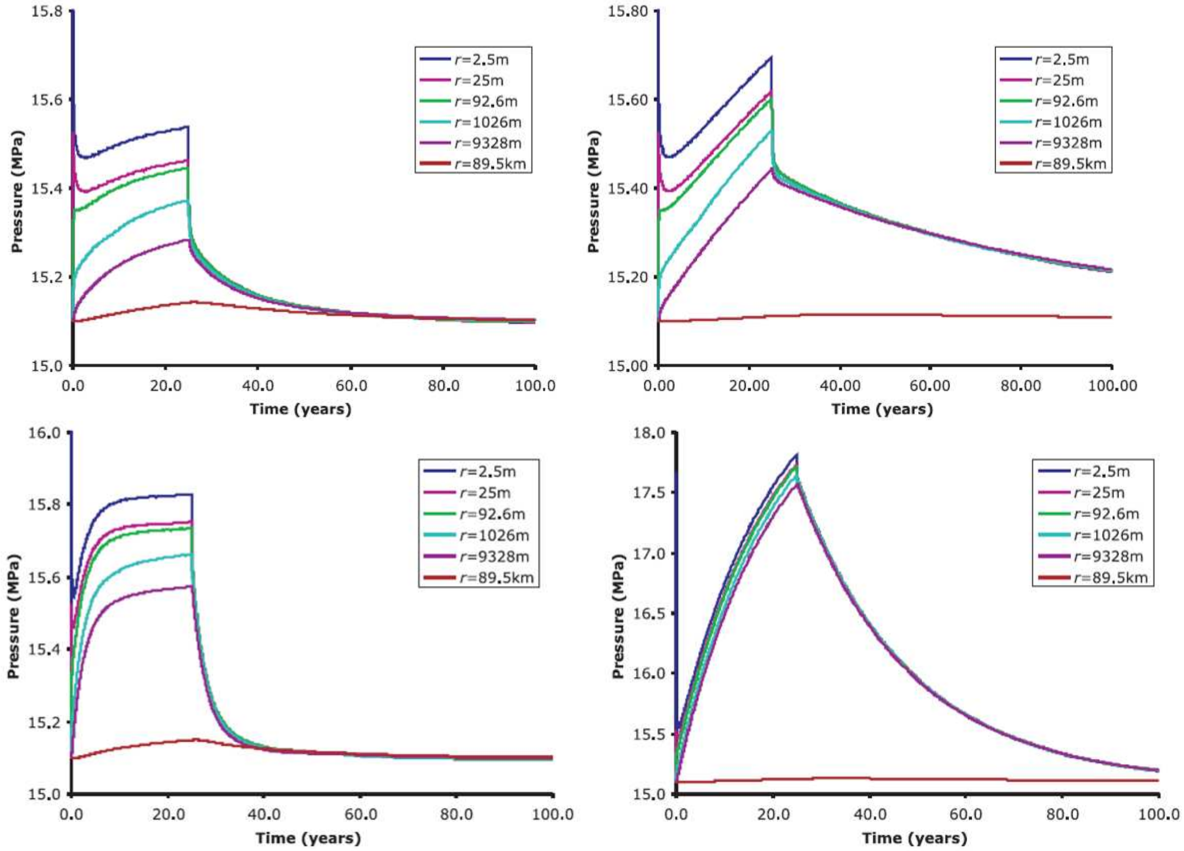


Figure 7. Modelling results (Chadwick et al., 2009) comparing the history of reservoir pressures at various distances from the injection well in an aquifer with a cylindrical barrier (1 m thick), 35 km (upper diagrams) and 10 km (lower diagrams) from the injection point. The permeability of the barrier is 10^{-17} m^2 and 10-^{18} m^2 for in case of the left and right diagrams, respectively.

Evaluation of existing injection schemes

The geological storage of CO_2 from large point sources (i.e. coal-fired power plants) will require unprecedented injection volumes of larger than 10 MtCO_2/year at each site; hence involving multiple injection wells and a large surface infrastructure including compressors and pipelines. Currently, various pilot and commercial storage operations investigate the viability of CO_2 sequestration in the subsurface. These projects provide important information on injection performance, CO_2 behaviour in the subsurface, and storage capacity. However, the injectivity and capacity requirements for large volumes in the order of 10 MtCO_2/year and the interaction of multiple CO_2 injectors for storage purposes have not been demonstrated in practice. With respect to CO_2 injection, the only previous experience in multi-well injection schemes can be derived from various forms of enhanced petroleum recovery operations. Examples for large-scale injection of fluids other than CO_2 include natural gas storage, water disposal, and geothermal fields. This report section will review the aforementioned injection operations with respect to how existing injection technologies and strategies might be applied to future large-scale CO_2 geological storage. Of particular interest are injection well patterns, well interference, injectivity issues and, in the case of multi-phase fluid injection, the optimisation of sweep efficiency.

Commercial CO_2 geological storage operations

Existing commercial CO_2 storage operations each inject in the order of 1 MtCO_2/year through one well (Sleipner, Snohvit) or three wells (In Salah). In these three cases, the CO_2 originates from a gas processing plant and the relatively small volumes of CO_2 combined with sufficient storage capacity does not necessitate significant optimisation of the storage process. Only at In Salah, the low permeability in the target horizon requires the injection of CO_2 through three wells.

Sleipner, Norway

The first commercial geological CO_2 storage project within a saline aquifer was the Statoil operated Sleipner Project in Norway. In the May/Jun issue of the Carbon Capture Journal, Statoil reported that more than 10 Mt of CO_2 have been stored in the Utsira formation since the Sleipner project was started in October, 1996. 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 subsea, directly above the producing formation of the Sleipner field (Figure 8) 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.

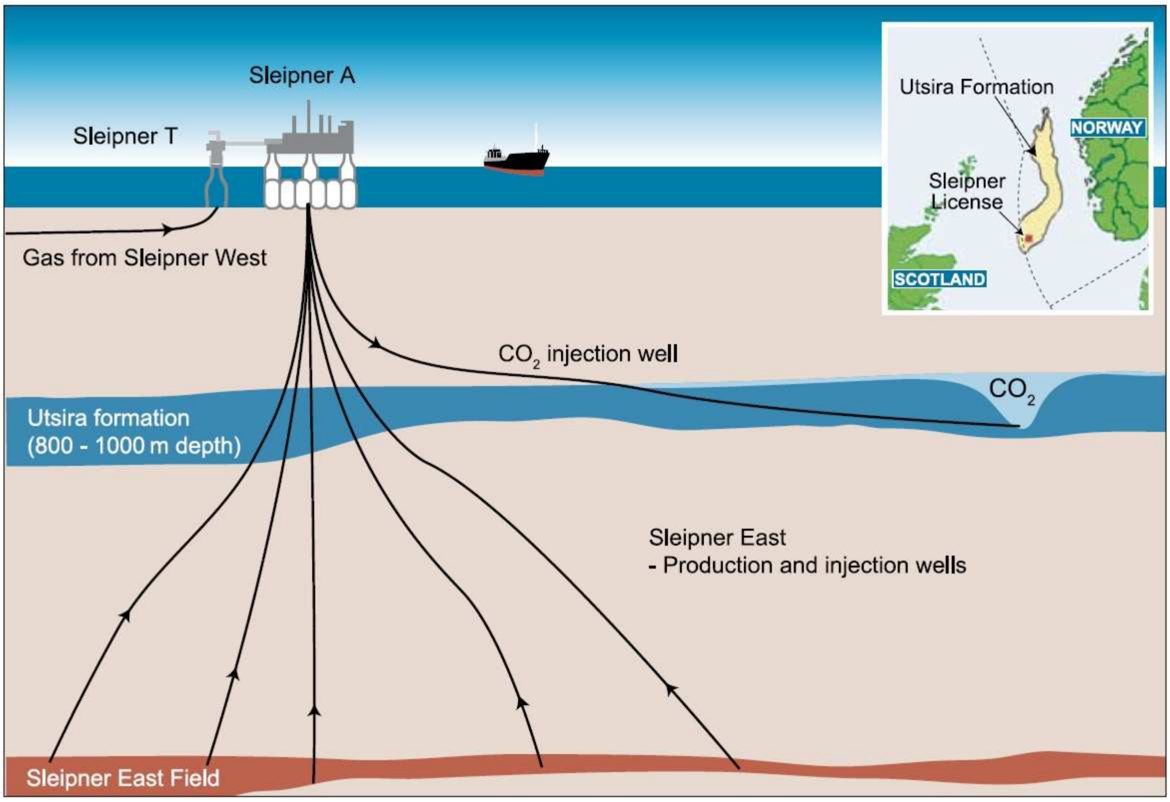


Figure 8. Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira Formation (IPCC, 2005).

The results from time-lapse seismic show the "baffle" effect of intraformational layers with low permeability relative to the main reservoir (Figure 9). Instead of forming a uniform plume below the main top seal, the injected CO_2 spreads out laterally along various horizons within the reservoir; thereby increasing the storage capacity and reducing the overall lateral extent of the plume.

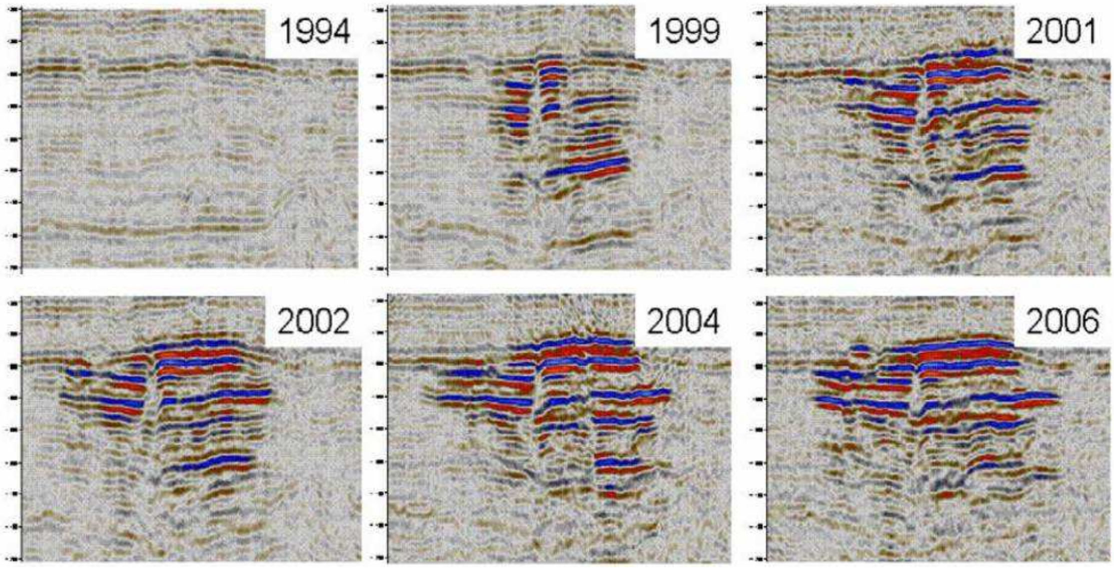


Figure 9. Time-lapse dataset visualising the spread of the injected CO_2 in the Utsira Formation at Sleipner (Arts et al., 2008).

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 10), a Jurassic gas reservoir (Maldal and Tappel, 2004). Injection of CO_2 at Snøhvit commenced in May, 2008.

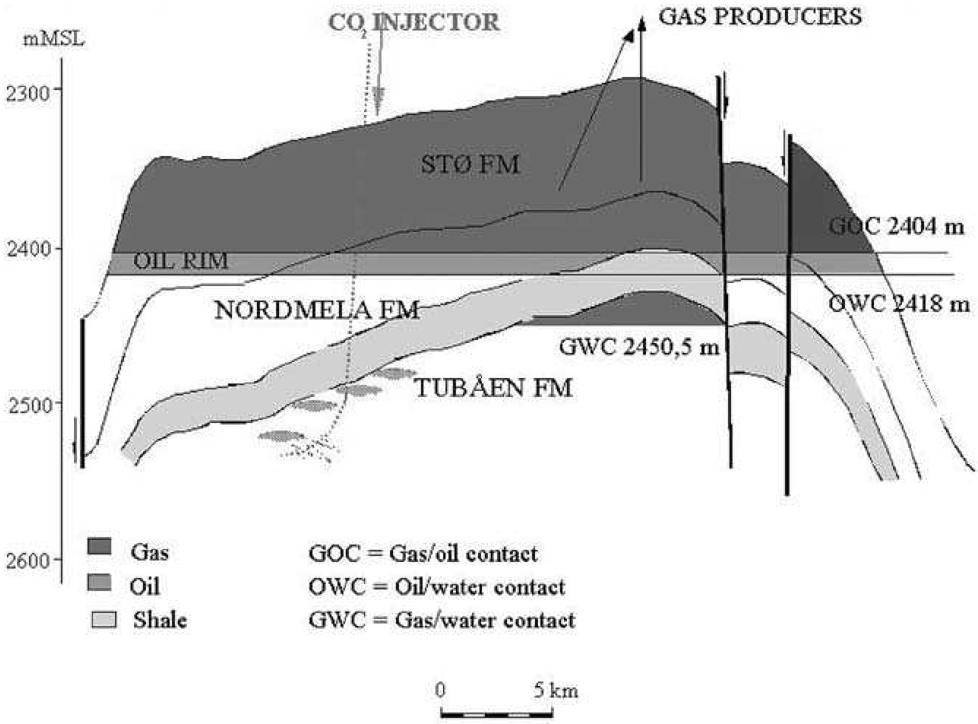


Figure 10. Simplified cross section through the Snøhvit field (from Maldal and Tappel, 2004).

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 (Figure 11). 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 200 bars and dehydrated. It is then injected using three injection wells with 1500 m horizontal completions into the storage formation (Wright, 2007a, b). The horizontal well completions have been directed NE/SW to intersect the main fracture orientation in the reservoir sandstone (Mathieson et al., 2009).

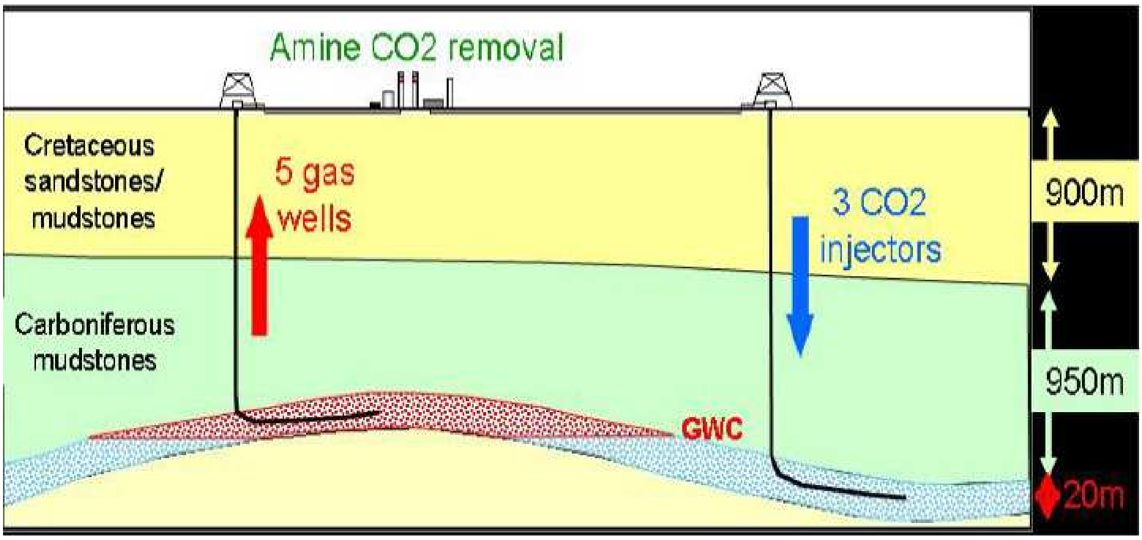


Figure 11. Schematic cross-section through In Salah injection site (Mathieson et al., 2009).

Gorgon, Australia

Having received final regulatory approval in September 2009, the Gorgon Joint Venture (Chevron, Shell and ExxonMobil) will exploit 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 Barrow Island, compressed to a supercritical state, and then transported by a 12 km pipeline to the injection site for storage on the island. If feasible, the project will involve the reinjection of up to 4.9 Mt/yr CO_2 extracted from the field gas into the Dupuy Saline Formation 2,300 m below Barrow Island (Figure 12). A total of 125 Mt CO_2 is expected to be stored over the life of the project. The injection of CO_2 is planned to commence in 2014.

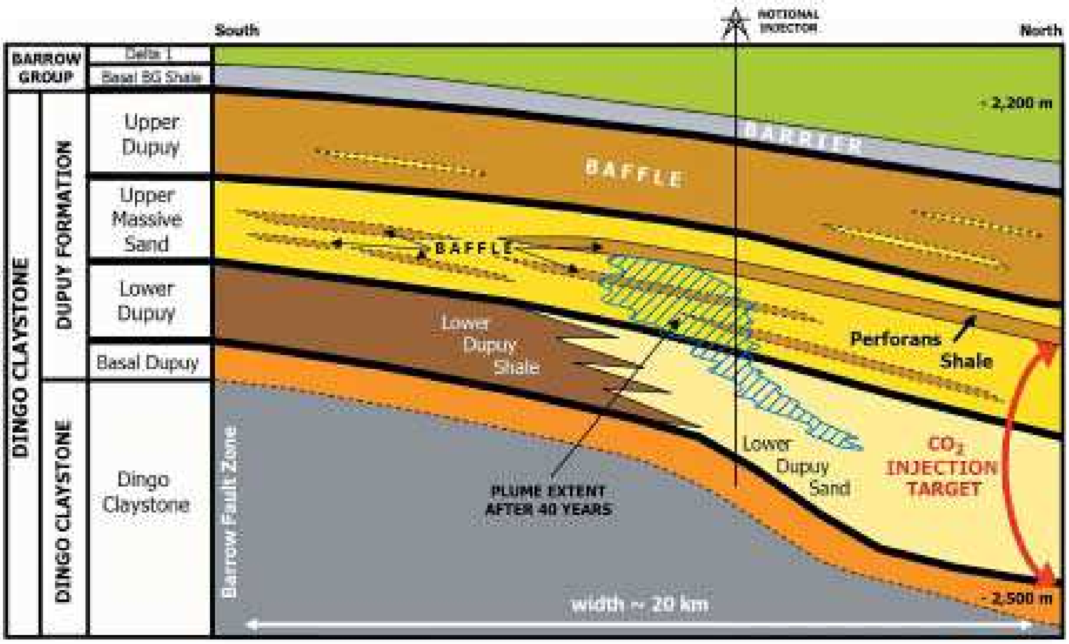


Figure 12. Schematic plume migration of injected CO_2 at Gorgon in the Dupuy Formation (Chevron, 2005).

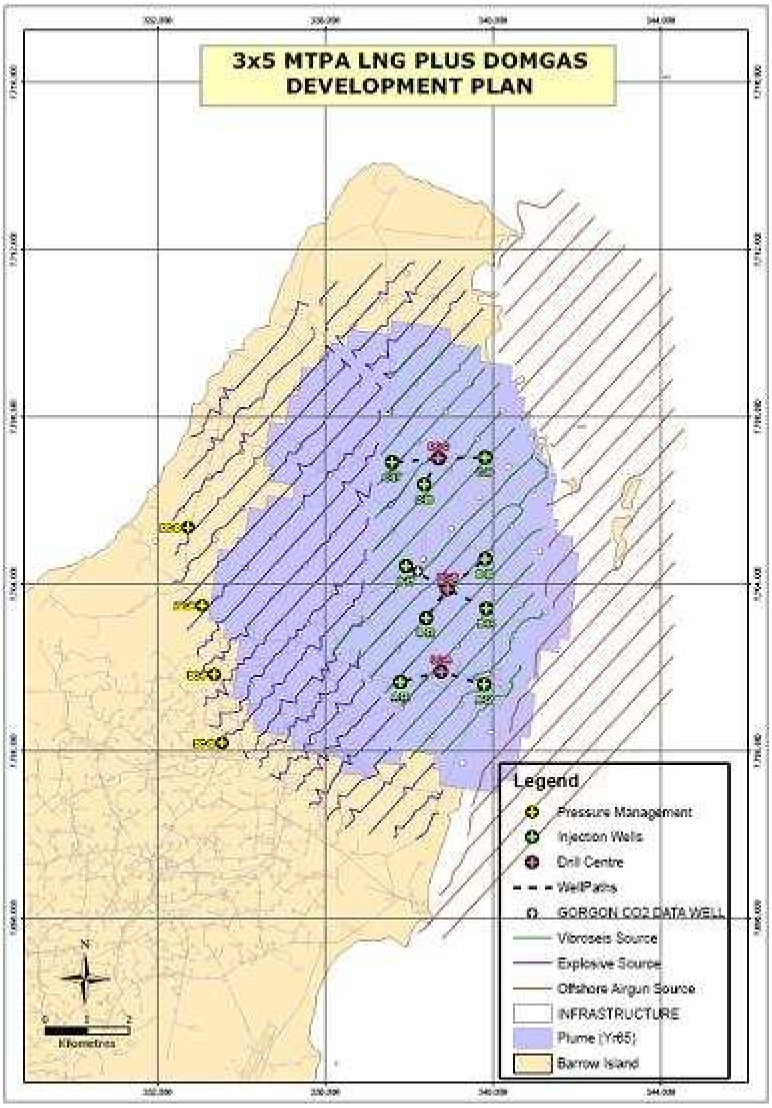


Figure 13. Proposed locations of injection and water production wells at the Gorgon Project, showing the modelled extent of the CO_2 plume after 65 years and seismic lines for monitoring (Trupp, 2009).

Nine injection wells are currently planned, which will be drilled directionally from 3 locations (Figure 13). The modelling of CO_2 migration in the heterogeneous injection horizon with an average permeability of 25 mD predicts preferential CO_2 migration along high-permeability layers resulting in a laterally non-uniform plume spread. 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 (Chevron, 2005, 2006). Four water production wells with a rate of approximately 10 million litres per day are planned to manage reservoir pressures and brine displacement in an updip location of the injection wells (Malek, 2009). In case of excessive pressure build-up due to poor injectivity, remediation options proposed by the operator include increasing the completion interval and additional injection wells.

Acid-gas Injection

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 saline 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 saline 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. 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; Longworth et al., 1996; Michael and Buschkuehle, 2006; Michael and Haug, 2004; Wichert and Royan, 1996).

The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., well 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. A major concern with the injection process is the potential for formation damage and reduced injectivity in the vicinity of the injection well, which could possibly be the result of fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulphur deposition, or hydrate plugging (Bennion et al., 1996). Injection rates are generally relatively low in most cases of acid-gas injection (<100 kt/year). However, a few operations inject at rates close to what can be anticipated for future CO_2 geological storage. Acid-gas injection rates of approximately 1 Mt/year at LaBarge in Wyoming (Benge and Dew, 2006) are comparable to Sleipner injection rates. The next smaller acid-gas injection operations are Talisman's Sukunka operation in British Columbia, injecting up to 300 kt/year, and the Zama (Apache Canada Ltd.) and Brazeau River (Keyspan Energy Canada) operations in Alberta injecting up to 120 kt/year. Independent of the injection rate, problems related to loss of injectivity due to geochemical reactions of the injected gas with the reservoir rock may be applicable to larger-scale injection of CO_2.

The two main remediation options applied in acid-gas injection operations are acid stimulation and completion of additional reservoir intervals. At five injection sites, acid-gas showed up in nearby production wells. In some cases, the breakthrough of CO_2 and H_2S had been previously predicted by reservoir modelling, although a later times, the difference between predicted and actual breakthrough times being mainly due to the accuracy of the geological model and uncertainty of reservoir heterogeneity (Bachu et al., 2007b; Dashtgard et al., 2008; Pooladi-Darvish et al., 2008). In the case of the Acheson site, breakthrough of CO_2 occurred after 13 years of injection at a distance of 3.6 km in a producer that was initially thought to be in separate oil pool (Bachu et al., 2008). An updated geological interpretation resulted in new pool delineations. This example shows that, even at low injection rates (~ 5 kt/year), the hydrodynamic drive imposed by producing wells can have a significant impact on the migration distances and directions of injected CO_2.

At three acid-gas injection sites, acid-gas is or was mixed/dissolved at the surface into disposal water before being injected (Kopperson et al., 1998a, b). The gas to water ratio ranged from 4,200 m^3 (gas) /4,000 m^3 (water) to 12,000 m^3 (gas) /11,000 m^3 (water) (Longworth et al., 1996). The mixing point for the acid gas was either upstream or downstream of the water pumps, the former resulting in lower surface injection pressures; hence lower costs for compression design.

Enhanced oil recovery (EOR) projects

Following the first field test at the Mead Strawn Field in 1964 in Texas, carbon dioxide has been used in commercial EOR projects since the early 1970s. Injection well technology and CO_2 storage potential in depleted oilfields were reviewed recently by Contek Solutions (2008) for the American Petroleum Institute and by Advanced Resources International and Melzer Consulting for the IEA Greenhouse Gas Programme (IEAGHG, 2009). A general review of EOR operation was published by Moritis (2008). Please refer also to a more recent review of CO_2EOR technology by Sweatman et al. (2009). There are 10 CO_2EOR projects in the US that have in excess of 100 injection wells, the largest number being 537 at Wasson in Texas (Table 3). The Weyburn EOR project in Saskatchewan, Canada intends to increase the number on injection wells to 675 over the next 15 years.

Special cases of EOR, generally used in CO_2EOR, are water-alternating-gas (WAG) and simultaneous water alternating gas (SWAG) injection processes, also referred to as combined water/gas injection (CGW). In WAG injection, water is used to improve the sweep efficiency of gas injection by controlling the mobility of the displacement and by stabilization of the front. The experience from WAG field cases has been reviewed in detail by Christensen et al. (2001) and Awan et al. (2008). Of the 64 reviewed CGW operations by these authors, 37 operations use non-CO_2 gases as the injectant (Table 4). All of the offshore projects use hydrocarbon gases as the injection fluid. In the onshore, the preferred injection schemes are the regular 5 spot or 9 spot patterns. The water-gas ratio in the injection wells is generally 1, but can be as high as 3. Adjusting the amount of water and CO_2 is critical because too much water will result in poor microscopic displacement, whereas too much CO_2 will result in poor vertical, and possibly horizontal, sweep.

Typical problems encountered with CO_2EOR operations that could occur similarly in CO_2 geological storage are shown in Table 5 and include: a) corrosion, b) channelling & early breakthrough, c) hydrate formation, d) scaling, e) asphaltene deposition, and f) pressure fluctuations due to CO_2 phase changes along the well tubing.

Table 3. CO_2 EOR operations (Christensen et al., 2001; "Worldwide EOR Survey", Oil & Gas Journal, April 2006).

Name	Location	Startup	Lithology	Injection wells	Well pattern
Mead Strawn	Texas, USA	1964	Sand		
Kelly Snyder	Texas, USA	1972	Carbonate	414	Inv. 9 spot
Willard (Wasson)	Texas, USA	1972	Dolomite	203	
Levelland	Texas, USA	1972	Limestone		5 spot
Lick Creek	Arkansas, USA	1976	Sandstone		
Slaughter Estate (SEU)	Texas, USA	1976	Dolomite		5 spot
Rock Creek	West Virginia, USA	1976	Sandstone		5 spot
Granny's Creek	West Virginia, USA	1976	Sandstone		5 spot
Garber	Oklahoma, USA	1980	Sandstone		5 spot
Purdy Springer NE	Oklahoma, USA	1980	Sandstone		5 spot
Quarantine Bay	Louisiana, USA	1981	Sandstone		
Maljamar	New Mexico, USA	1981	Dolomite		
Little Knife	North Dakota, USA	1981	Carbonate		
Wilmington	California, USA	1982	Sand		Line drive
Seminole	Texas, USA	1983	Dolomite	160	
Joffre Viking	Alberta, Canada	1983	Sandstone		Inv. 5 spot
San Andres	Texas, USA	1983	Dolomite	284	Inv. 9 spot
Wasson Denver	Texas, USA	1983	Dolomite	537	Inv. 9 spot
East Vacuum	New Mexico, USA	1985	Dolomite	103	Inv. 9 spot
Dollarhide	Texas, USA	1985			5 spot
Rangely Weber	Colorado, USA	1986	Sandstone	262	
Hanford	Texas, USA	1986	Dolomite		5 spot
S. Wasson Clearfolk	Texas, USA	1986	Dolomite	165	5 spot
West Mallalieu	Mississippi, USA	1986	Sandstone	27	
Wertz Tensleep	Wyoming, USA	1986	Sandstone		
N. Ward Estes	Texas, USA	1989	Dolomite		5 spot+line
Lost Soldier Field	Wyoming, USA	1989	Sandstone	40	Line drive
Neches	Texas, USA	1993	Sandstone		
Slaughter Sundown (SSU)	Texas, USA	1994	Dolomite	144	
Mattoon	Illinois, USA	1995	Sandstone		
Postle	Oklahoma, USA	1995	Sandstone	100	
Anton Irish	Texas, USA	1997	Dolomite	75	
Weyburn	Saskatchewan, Canada	2000	Carbonate		Inv. 9 spot
Codgdell	Texas, USA	2001	Limestone	37	
North Hobbs	New Mexico, USA	2003	Dolomite	41	
Salt Creek	Wyoming, USA	2004	Sandstone	83	

Table 4. WAG operations that use gases other than CO_2 as injection gas (Christensen et al., 2001; Awan et al., 2008).

Name	Location	Startup	Injectant	Drive/Displ.	Lithology	Injection pattern
North Pembina	Alberta, Canada	1957	HC	Misc.	Sandstone	Inv. 5 spot
Romashkinskoye	Russia	1959				
Juravlevsko-Stepanovskoye	Orenburg, Russia	1960		Immisc.	Carbonate	
University Block 9	Texas, USA	1960	LPG	Misc.	Limestone	Ring
Midlands Farm	Texas, USA	1960	propane	Misc.	Limestone	
South Ward	Texas, USA	1961	propane	Misc.	Sandstone	5 spot
Adena	Colorado, USA	1962	propane	Misc.	Sand	Line drive
Hassi-Messaoud	Algeria	1964	HC	Misc.		
Fairway	Texas, USA	1966	HC	Misc.	Limestone	
Ozek-Suat	Chichen-Inguish, Russia	1968	HC	Misc.	Sandstone	
Goyt-Kort	Chichen-Inguish, Russia	1970	HC	Misc.	Sandstone	
Levelland	Texas, USA	1972	ENG/CO2	Misc.	Limestone	5 spot
South Swan	Alberta, Canada	1973	NGL	Misc.	Carbonate	9 spot
Willesden Green	Alberta, Canada	1977	HC/N2	Misc.	Sandstone	
Twofreds (Delaware)	Texas, USA	1981	Exh. Gas		Sandstone	Modified line
Jay Little Escambia		1981	N2	Misc.	Dolomite	Line drive
Prudhoe Bay	Alaska, USA	1982	enriched	Misc.	Sandstone	
Fenn Big Valley	Alberta, Canada	1983	HC	Misc.	Dolomite	
Magnus	North Sea, U.K.	1983	HC	Misc.	Sandstone	
Caroline	Alberta, Canada	1984		Misc.	Sandstone	
Samotlor	Siberia, Russia	1984		Immisc.	Sandstone	
Thistle	North Sea, U.K.	1984	HC	Immisc.	Sandstone	
Kuparuk River	Alaska, USA	1985	HC	Immisc.	Sandstone	
Kuparuk River	Alaska, USA	1985	HC	Misc.	Sandstone	
Judy Creek	Alberta, Canada	1985	HC	Misc.	Limestone	Inv. 5 spot
Mitsue	Alberta, Canada	1985	HC	Misc.	Dolomite	
Kaybob North	Alberta, Canada	1988	HC	Misc.	Carbonate	
Daqing	China	1989	HC	Immisc.	Sandstone	
Gullfaks	North Sea	1989	HC	Immisc.	Sandstone	Line/pattern
Snorre	North Sea, Norway	1994	HC	Misc.	Sandstone	Line/pattern
Brage	North Sea, Norway	1994	HC	Immisc.	Sandstone	Inj. from rim
Statfjord	North Sea, Norway	1994	HC	Misc.	Sandstone	
Brae South	North Sea, U.K.	1994	HC	Misc.	Sandstone	
Ekofisk	North Sea, Norway	1996	HC	Immisc.	Carbonate	
Oseberg Ost	North Sea, Norway	1999	HC	Immisc.	Sandstone	
Siri (SWAG)	North Sea, Norway	1999	HC		Sandstone	
Veslefrikk	North Sea, Norway	2004	HC		Sandstone	

Table 5. Reported operation problems from WAG injection (Christensen et al., 2001).

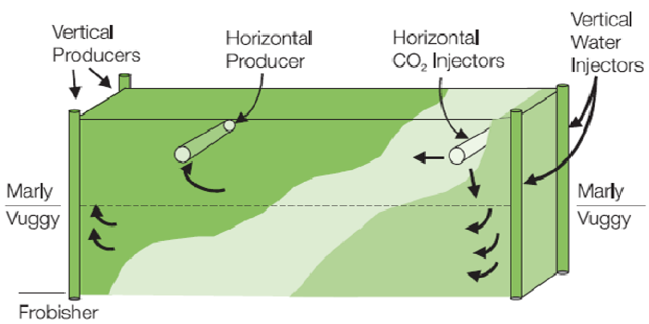
Operation	Problems/limitations reported
Juravlevsko-Stepanovskoye	Premature closedown due to channelling
Hassi-Messaoud	Interval of few days between injection of gas and water for pressure reduction at wellhead
Kelly Snyder	CO_2 delivery problems, compression
Rock Creek	Shortage of CO_2, labour problems
Lick Creek	Channelling, valve problems on compressor, foaming problems in oil, severe corrosion in producers
Granny's Creek	Casing leak, wellhead repair, CO_2 delivery problems, channelling
Slaughter Estate	CO_2 delivery problems
Purdy Springer	Corrosion of submersed pumps
Jay Little Escambia	Injectivity reduction
Quarantine Basy	Downhole corrosion
Wasson Denver	Hydrate formation froze wellhead
Fenn Big Valley	Problems with downhole pumps at high GOR’s
Caroline	Early breakthrough
Mitsue	Asphaltene deposition; relieved by xylene/toluene washes
East Vacuum	Asphaltene deposition after CO_2 breakthrough, corrosion, $CaSO_4$ scaling
Dollarhide	Scaling, asphaltenes
Rangely Weber	Corrosion, asphaltenes, injection problems due to temperature changes at different gas recompression limits
South Wasson	High wellhead pressures with tubing full of CO_2
Tensleep	Minor corrosion, asphaltenes
Lost Soldier	Mechanical problems with pumps due to sour gas injection
Gulfaks	Compressor specs not suitable for enriched gas injection
Brage	Tubing malfunction due to heating and expansion from injected gas
Ekofisk	Injectivity problems due to hydrate formation

Example - Weyburn, Saskatchewan

Although injection of CO_2 at the EnCana Weyburn site has the primary purpose of enhancing oil production, the volume of CO_2 anticipated to be remaining in the reservoir makes it the currently largest CO_2 geological storage site in the world. A detailed description of the IEA GHG Weyburn CO_2 Monitoring and Storage Project was published by Wilson & Monea (Wilson and Monea, 2004) and is the main source of information for this section of the report. The Weyburn oil field was discovered in 1954 with primary production occurring until 1964 and subsequent water flooding being implemented until 2000. The CO_2 based EOR scheme commenced in September 2000 in 18 inverted 9-spot patterns and an initial injection rate of approximately 5 kt/day. The rate of CO_2 injection increased to more than 6 kt/day by 2002, including 1.3 kt/day of recycled CO_2 from the oil production. Subsequent expansion of the injection scheme to a total of 75 patterns is planned over a 15 year period, resulting in a total injection volume of approximately 20 Mt of CO_2 over the project life. The CO_2 is transported to the Weyburn field through a 320 km long pipeline from the Dakota Gasification Company's synthetic fuel plant.

Different injection schemes are employed at Weyburn to optimise the flooding efficiency according to the varying geology and heterogeneity of the carbonate reservoir (Figure 14). The initial CO_2 flooding strategy was specifically designed to target the less permeable Marly unit, which had been largely by-passed during the pure water flood. Separate but simultaneous injection of water in the permeable Vuggy unit below the CO_2 injector enhances the buoyancy-driven CO_2 migration into the overlying Marly unit by pushing the lighter CO_2 upwards.

A)



B)

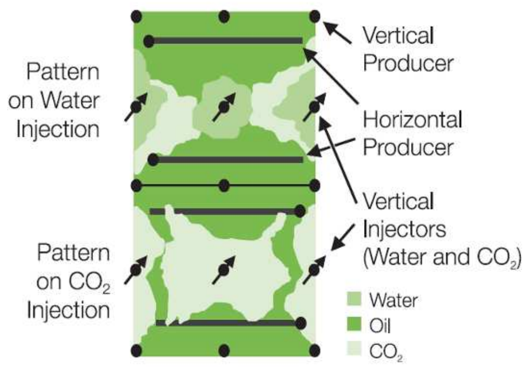


Figure 14. Schematic diagram of injection schemes at the Weyburn EOR site. A) Simultaneous but Separate Water and Gas (SSWG), where water and CO_2 are continually injected into the vertical and horizontal wells, respectively to maximise recovery from a tight Marly zone overlaying a good Vuggy zone (applied at 15 out of 19 patterns); B) Marly-Vuggy Water Alternating Gas (MVWAG), where water and CO_2 injection is alternated to optimise sweep efficiency in areas with thick Marly and Vuggy producing zones. (ENCANA website: www.encana.com/operations/oil/weyburn/pdfs/p006505.pdf).

Other injection schemes

Other cases of fluid injection like natural gas storage, waste water disposal, and geothermal operation also have experience with well economics and general injectivity issues.

Natural-gas storage

In gas storage, natural gas is only stored for a short time, depending on the seasonal change in gas demand, and it has to be possible to extract the majority of the injected gas if needed. Therefore, gas storage occurs mostly into geometrically constrained reservoirs, i.e. depleted petroleum reservoirs and salt caverns. This is contrary to the purpose of large-scale CO_2 geological storage, which is long-term (100s – 1000s of years) and mainly targeting saline aquifers with large areal extent. On the other hand, surface facilities, i.e. compression plants and pipelines will probably be very similar in natural gas and CO_2 storage operations. According to Perry (2005) the following five technologies, mainly associated with gas storage in saline aquifers, could be relevant for CO_2 geological storage:

- Application of all available techniques;
- Observation wells;
- Pump testing techniques;
- Assessment of cap rock sealing; and
- Surface monitoring

Generally, it is expected that reservoir pressures associated with CO_2 storage in depleted oil or gas fields will not exceed initial field pressures to prevent negative impacts on reservoir and caprock integrity. The same was true for some time in gas storage operation. However according to Bruno et al. (1998), the pressure, and consequently the storage capacity, in gas storage reservoirs can be safely increased, if the geomechanical behaviour of the reservoir and overburden is well characterised. In Cooper (2009) the Settala Storage Field in Italy is referred to as an example, in which exceeding the initial reservoir pressure (delta-pressuring) by 7 percent resulted in a 45 % increase of storage capacity. In this case, careful testing of operating pressures and a comprehensive monitoring program are critical to ensure containment of the stored gas.

Liquid waste disposal

Injection of liquid waste generally involves single-phase fluid flow, as opposed to the multiple phases in CO_2 geological storage. Tsang et al. (2008) review the history of liquid-waste disposal by deep injection in the US and present a comparison between liquid-waste and CO_2 injection. A comprehensive compilation of scientific research related to the underground disposal of liquid waste was published by Apps and Tsang (1996) and, including additional references on CO_2 geological storage, by Tsang and Apps (2005). Further evaluations of parallels between liquid waste disposal and CO_2 geological storage can be found in Wilson et al. (2003) and Apps (2005). According to these authors, issues related to the deep injection of liquid waste in the 1960s and 1970s included corrosion of well casings and cements, clogging due to precipitation from the mixing of two incompatible waste streams, and the triggering of seismic events. As a result, specific regulations and standards for the injection of liquid wastes were developed by the US Environmental Protection Agency (EPA) in the 1980s and 1990s, which included requirements for the design and monitoring of injection wells as well as the usage of numerical models to demonstrate containment for at least 10,000 years (Tsang et al., 2008). A 2005 inventory of underground injection in the US estimates that 484 Class I wells annually dispose of approximately 34 billion litres of liquid waste, compared to 170,000 Class II wells injecting 2750 billion litres of brine per year (GWPC: http://www.gwpc.org/uic/uic_data.htm.). See Figure 15 for US EPA well classification. Both well classes are limited to injection zones below and isolated from the base of drinking water resources.

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, low viscosity 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, which is higher in the case of CO_2 geological storage, requires that the hydromechanical effects on the overlying aquitards be assessed along potential leakage pathways extending from the injection horizon to shallow groundwater aquifers; and
- In contrast to liquid waste injection, CO_2 leakage into shallow aquifer systems may not present a serious environmental problem.

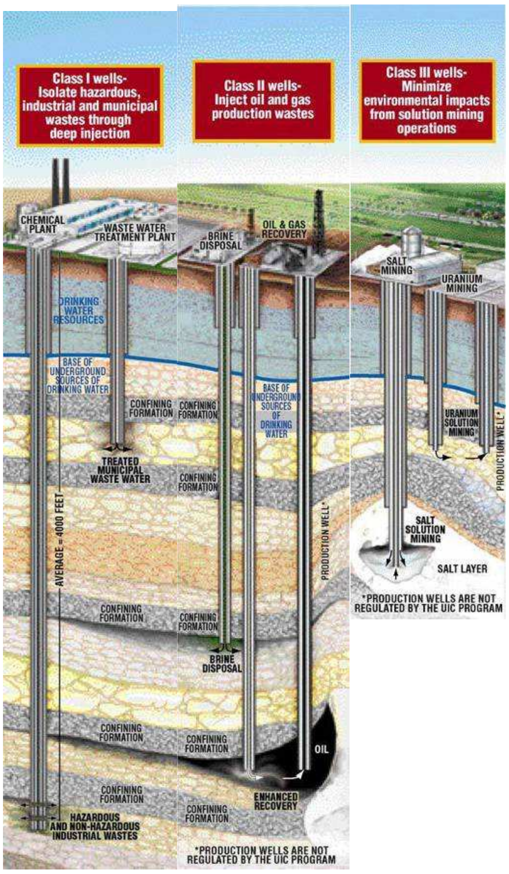


Figure 15. Different EPA classes of wells for the deep injection of fluids regulated by the Underground Injection Control Program (http://www.epa.gov/safewater/uic/index.html).

Lessons learned from existing storage operations

By the year 2009, only three commercial-scale operations, Sleipner, Snøhvit, and In Salah, have been injecting CO_2 in the order of 1 $MtCO_2$/year for the purpose of geological storage. At least in the cases of Sleipner and Snøhvit, optimisation of storage efficiency is of lesser priority because the respective injection horizon has sufficient injectivity and capacity to receive the full volume of CO_2 that is derived from gas processing through a single injection well. Only at In Salah, low permeability in the order of 5 mD limits injectivity of one well to approximately 0.3 $MtCO_2$/year, resulting in the need for 3 injection wells and horizontal completions up to 1500 m. The next larger-sized storage operation will presumably be the recently approved Gorgon project in Western Australia, which plans to inject up to 4.9 $MtCO_2$/year via a scheme of 9 CO_2 injection wells. Due to the risk of overpressuring the heterogeneous injection horizon as predicted by reservoir modelling, the operators intend to include four water production wells for pressure maintenance. The plan is for produced formation water to be disposed of in an overlying, pressure-depleted, formerly hydrocarbon-bearing unit. Experience from the multi-well Gorgon project will provide invaluable information with respect to injection strategies in heterogeneous aquifers and reservoir pressure management for future commercial-scale geological storage projects.

Acid-gas injection represents the best analogue to large-scale CO_2 geological storage, the main difference being the, in the majority of cases, low injection rates and additional complications related to the H_2S in the injection stream. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., well design, materials, leakage prevention and safety) can be adopted directly for large-scale operations for CO_2 geological storage.

Enhanced oil recovery projects, particularly those that employ a combination of water/gas injection, provide important insight into the optimisation of sweep efficiency and geometry of well patterns. The co-injection of water helps to control the gas front and access lower-permeability pore space that would have been otherwise by-passed by the injected gas. The comparison of different EOR and WAG operations shows that, depending on the geological environment, different injection strategies need to be employed to optimise the sweep efficiency. This experience should be directly applicable to comparable geological environments considered for CO_2 geological storage. In the latter case, co-injection of water could be used even more broadly to direct the CO_2 plume and maximise storage capacity, because in contrast to the EOR case, the injected CO_2 does not need to target a specific hydrocarbon-bearing horizon. In addition, remediation options have been successfully applied to operational problems encountered with EOR operations (corrosion, channelling & early breakthrough, hydrate formation, scaling, asphaltene deposition) that would help to solve similar problems in CO_2 storage operations. One should keep in mind however, that the drivers for EOR and CO_2 geological storage are very different. The former aims at maximising oil production while the volume of injected fluid and sustainable flow rate in a single well are less important. In contrast, the priority in geological storage of CO_2 is to maximise the injectivity of each well, simply because of the drilling costs.

Aside from well economics and general injectivity issues, the experience from other cases of fluid injection, i.e. natural gas storage, waste water disposal, is less applicable to the optimisation of CO_2 geological storage, largely due to the differences in fluid properties, injection rates and overall project purpose (Table 6). In gas storage, natural gas is only stored for a short term, depending on the seasonal change in gas demand, and it has to be possible to extract the majority of the injected gas if needed. Therefore, gas storage occurs mostly into geometrically constrained reservoirs, i.e. depleted petroleum reservoirs, salt caverns. This is contrary to the purpose of large-scale CO_2 geological storage, which is long-term (100s – 1000s of years) and mainly targets saline aquifers. Deep injection of liquid waste has many similarities to CO_2 geological storage when it comes to the general purpose, the time-scales of storage containment and the use of injection wells without production wells for pressure maintenance. However, fluid properties and injection volumes are very different.

Table 6. Comparing characteristics of CO_2 geological storage to other injection types (green = comparable, red = not comparable, yellow = comparable only in certain aspects). Well numbers, injection rates and volumes are "site-scale" and refer to a single operation.

Characteristics	CO_2 Storage	EOR	Acid-gas injection	Natural gas storage	Liquid waste disposal (Class I)	Geothermal
Purpose	Reduction of CO_2 emissions	Increase of oil production	Reduction of H_2S flaring and stripping of CO_2 from natural gas	Storage of gas for seasonal and backup energy use	Disposal of liquid waste	Energy production
Time scale	100s - 1000s of years	< 100 years	100s - 1000s of years	seasonal, < 10 years	> 10,000 years	< 100 years
Injection depth	> 800 m	Variable	> 800 m	variable	>1500 m	< 350
Total injection volume						
Injection rate	~ 4 – 20 x 10^6 t/year	<2 x 10^6 t/year	<1 x 10^6 t/year		<25 x 10^6 t/year	
Injection fluid	CO_2	CO_2 (+ water, NG)	H2S (+ CO_2)	NG	Water, organics, other	Water
Reservoir geometry	Saline aquifers (open), depleted hydrocarbon reservoirs (closed)	Depleted hydrocarbon reservoirs (closed)	Saline aquifers (open), depleted hydrocarbon reservoirs (closed)	Depleted hydrocarbon reservoirs (closed), salt caverns (closed) & aquifers	Saline aquifers (open)	Saline aquifers (open)
Number of wells	10s to 100s	< 675	1 - 3		1-3	~ 2 to 20
Well types	Injection (+ monitoring, pressure maintenance)	Injection & production	Injection	Injection & production	Injection	Injection & production
Well completion	Corrosion resistant	Corrosion resistant	Corrosion resistant			
Monitoring	Comprehensive; pre-, syn-, and post-injection	Variable; syn-injection/production	At the Wellhead, syn-injection	Comprehensive; syn-injection	Wellhead, annulus	Variable, syn-injection/production

Economics of injection strategies

The costs of carbon capture and storage can be broken into a number of different categories. These include the CO_2 separation, transportation (typically with compressors and pipelines), injection, power for CCS and on-costs (such as owners' costs and contingency). The injection costs may consist of exploration and appraisal wells, injection & water production wells, platforms and measurement, monitoring and verification (MMV). The key determinants of the cost of injection are injectivity and areal extent. Storage volume is only sometimes a significant determinant of injection cost. The storage volume is a function of aquifer volume, porosity and, most importantly, on volumetric as well as microscopic displacement efficiencies. On the other hand, injectivity is governed not only by permeability, but also by multiphase flow characteristics of the rock and rock compressibility.

Reservoir simulations together with economic analyses provide a useful basis for estimating injectivity, the number of injection wells and their location. Reservoir simulation can take into account reservoir conditions over the whole injection period and therefore assists in the design of the injection scheme, in the economic evaluation of injection alternatives and in assessing overall viability.

The economics of CCS discussed in the literature as well as in this section are scoping, pre-feasibility, or screening-level economics. They are not designed to be used in final investment decisions ("FIDs") for CCS projects. The cost estimates required to make an investment decision on an injection project would need to be based on tenders and detailed vendor quotes for all equipment and services. The estimates would be made over a lengthy period before the final investment decision is made. In contrast, the economic analyses discussed here are based on preliminary cost estimates and are intended to illustrate the relative effects of reservoir characteristics and injection design. The absolute costs shown here might not be indicative of the actual costs or estimates made for FIDs for any particular storage site.

CO_2 injection projects would be based on technologies and engineering practices already established in the oil and gas exploration and production industry over many years. This experience gives a firm methodological basis for scoping, planning and evaluating future injection schemes. However, a characteristic of oil and gas projects is that there are significant uncertainties in predicting reservoir behaviour, project costs and project timing. These uncertainties would apply similarly to CO_2 injection. Often, oil and gas industry evaluations employ some form of uncertainty analysis such as Monte Carlo simulation to reflect the fact that variables used in the evaluation might vary significantly from initial best estimates. Such methods are also very useful in CCS evaluations. However, they are not used in the analyses shown here. This is because the analyses in this report are designed to illustrate the relative economic effects of reservoir characteristics and injection design rather than to make final investment decisions on CCS projects.

A technical report by the IEAGHG (2008) found that since 2003 there have been a number of studies on the costs of CO_2, mainly using models and with estimates varying greatly. They attributed this variability not only to differences in geology, but also to differences in approach to the engineering and economic aspects of their studies. In addition, key economic assumptions or results were either aggregated or not reported, thus denying readers the chance to analyse and reproduce results. They found four key 'road blocks' to comparing cost data:

1. cost data is scattered and patchy
2. costs are quoted for different years
3. costs are quoted for different currencies/regions
4. costs are quoted based on different methodologies

This section focuses on the results of Cinar *et al.* (2009a; 2009b) and Neal *et al.* (2008; 2006) and examines both the effect of geological characteristics and of several injection strategies.

Economic methodology

The results discussed below were estimated using an economic model developed at the University of New South Wales for the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). The model uses simple mass and energy balances to determine the type and size of equipment required. It then makes scoping-level estimates of the capital, operating and abandonment costs for the equipment using algorithms based on rules-of-thumb, published data and vendor quotes. Where appropriate, the costs are updated using standard indices such as the Chemical Engineering Plant Cost Index, the Nelson-Farrar Refinery Cost Indices and the IHS-CERA Upstream Capital Cost Index.

The model also calculates the mass-flow of CO_2 avoided, which is the difference between the amount of CO_2 that would be emitted by the source without CCS and the amount emitted with CCS. The model then determines the specific cost of CO_2 avoided ($/t) or the cost of CCS. The cost of CCS is calculated by dividing the present value of all costs by the present value of CO_2 avoided[1]. The model uses this parameter to optimise the configuration of the storage system; balancing the compressor duty, the pipeline diameter, the numbers of wells and well diameters. However in the studies described below, the number of wells was chosen on the basis of injectivity estimates from reservoir simulation studies.

Cost estimates of this kind are highly dependent on the methodology and assumptions used and the general methodology followed in the studies cited is described elsewhere (Allinson, 2006). The authors estimate costs before-tax in Australian Dollars and calculate present values with a real discount rate of 7%. They assume a construction period of two years for the CCS equipment with 40% of the capital spent in the first year. CO_2 is injected for 25 years and that the process operates for 85% of each year. The project is abandoned in the year after injection stops, the cost of which is estimated to be 25% of transport and injection capital costs.

For the purposes of this report we have translated the costs from Australian conditions in Australian dollars to US conditions in US dollars at a rate of 1:1. This assumption is based on the exchange rate[2], the differing wage and productivity rates, and differing costs of materials, freight and equipment. Further, the purpose of these studies is to illustrate the effect of various reservoir properties and injection strategies on the cost of CCS projects.

[1] The specific cost of CO_2 avoided can also be calculated by dividing the annual equivalent cost for the project by the annual CO_2 avoided. The present value method is preferred because of its simplicity and flexibility.
[2] At the time of writing, one Australian dollar (A$1.00) is worth approximately US$000.

For a more detailed discussion of the assumptions and methodology of individual studies we refer the reader to the works cited.

Please note that not all of the studies cited provide estimates of the entire cost of the capture and storage process. For this reason we define the cost of CO_2 injection as the costs for onshore or offshore wells as well as any well-head boosting or formation treatments. The cost of CO_2 storage includes not only the cost of injection but also the cost of compression, transport via pipeline and any intermediate boosting. The cost of capturing CO_2 together with storing the CO_2 is referred to as the cost of CCS. The cost of transport refers to only the cost of compression, boosting and pipelines.

The effect of storage formation characteristics

The geological properties of the target formation determine how easily CO_2 can be injected. This in turn determines the numbers of wells required for injection or the total annual amount of CO_2 that can be injected and so shapes the cost of injection both in absolute ($) and unit ($/t) terms.

Permeability

Neal *et al.* (2006) examined the effect of different permeabilities on the economics of injecting 15 Mt/yr of CO_2 into the Latrobe Group of the offshore Gippsland basin beneath the Kingfish field. They considered a range of permeabilities from 50 mD to 400 mD with injection occurring using vertical wells. As permeability decreased, the number of required wells increased; from 6 wells at 400 mD to 100 wells at 50 mD. Because of this, the injection cost increased with decreasing permeability. An additional impost was the requirement for multiple platforms at permeabilities below 100 mD because many wells were required. The effect of different permeabilities on the cost of storage is shown in Figure 16. A reduction in permeability from 150 mD to 50 mD leads to a more than doubling in the cost of storage. At permeabilities beyond around 150 mD, the change storage cost is limited and decreases by a few dollars per tonne when the permeability more than doubles. These cost trends mirror the effect of permeability on the number of wells. In fact, if the permeability were 1,000 mD the cost would decrease by only 8% compared to the cost at 400 mD.

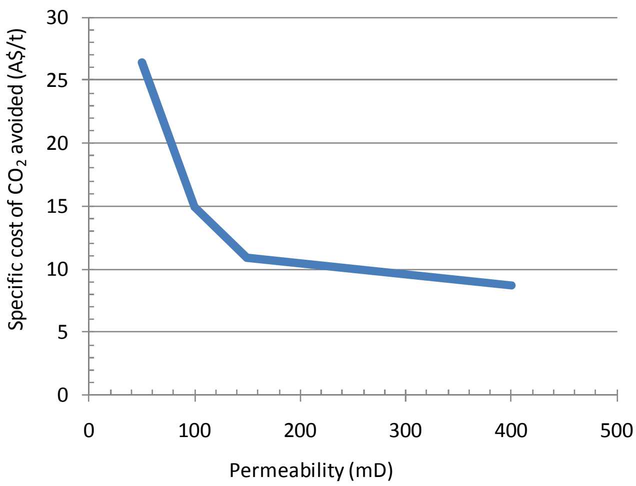


Figure 16. Effect of permeability on the cost of transport and injection for vertical wells injecting 15 Mt/yr (Neal *et al.*, 2006).

Cinar *et al.* (2009a) estimated the cost of CCS for a range of permeabilities between 50 and 5,000 mD. The results for 5-km long horizontal wells are given in Figure 17. These are representative of the trends for each well type. As in Neal *et al.* (2006), the results show that the specific cost generally falls with increasing permeability since fewer wells are required. For example, in Figure 17 at 1.0 Mt/yr the specific cost is more A$68 per tonne at 50 mD and A$65 per tonne for more than 500 mD. A key difference with is that the flow-rates are approximately 10% of the flow-rates shown in Neal *et al.* (2006).

Figure 17 also shows that increasing the flow rate first lowers then raises the costs. For instance, at the lowest permeability, the cost is A$79 per tonne at 0.5 Mt/yr, drops to A$68 per tonne at 1.0 Mt/yr, and then increases to A$70 per tonne at 1.5 Mt/yr. Although raising the rate from 0.5 to 1.0 Mt CO_2/yr doubles the number wells, nevertheless economies of scale more than offsets the increased cost of wells. In contrast, raising the rate from 1.0 to 1.5 Mt CO_2/yr at least quadruples the number of wells without the concomitant additional economics of scale.

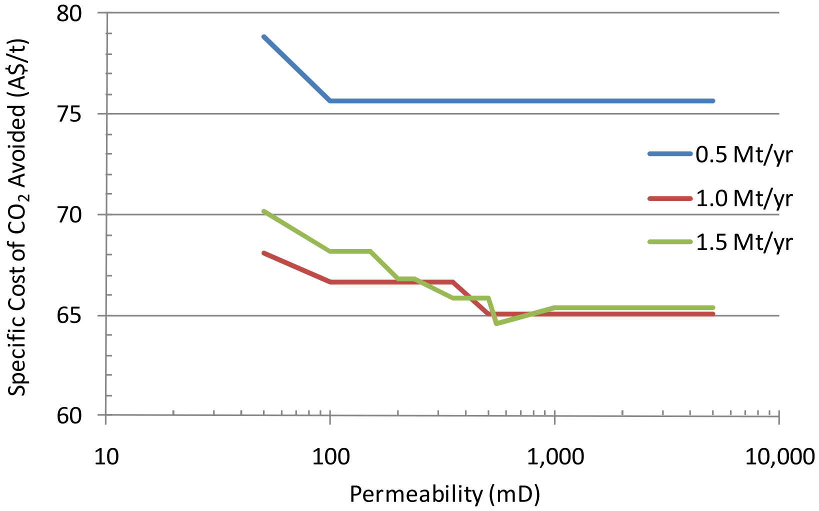


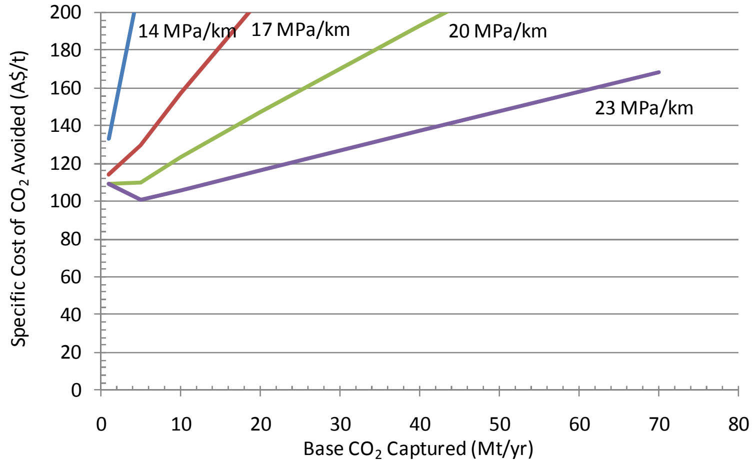
Figure 17. Effect of permeability on the cost of capture and storage (A$/t) for different injection rates with 5 km long horizontal wells (Cinar *et al.*, 2009a).

Fracture gradient

The fracture gradient estimates the point at which the formation rock begins to break. It is a rule of thumb based on empirical data. Effectively, the fracture pressure provides an upper limit to the injection pressure. In concert with the formation pressure, fracture pressure puts an upper limit on the possible range of injection pressures. If the fracture gradient increases, then so does the fracture pressure, giving a larger pressure-potential for injection. This means that fewer wells are required and the cost is lower.

Neal *et al.* (2008) examined the effect of fracture gradient on the cost of CCS. Figure 18(a) shows that the cost of CCS in a formation with 10 mD permeability rapidly increases with flow-rate. The exception to this is the 23 MPa/km case where the cost of CCS initially drops for flow rates between one and five million tonnes per year. The results for the 17 MPa/km and 20 MPa/km cases display discontinuities, but they always increase with flow-rate. The fracture gradient case that is the most sensitive to flow rate is the 14 MPa/km case with the smallest pressure-window. Figure 18(b) shows that the cost of CCS is most sensitive to permeability in the cases with low fracture gradients. As the fracture gradient increases, permeability variations are less important. If the permeability of the formation increases as in Figure 18(b), then it becomes easier to inject CO_2 into the formation. Therefore changes in the pressure-window are less important. Thus cost decreases as fracture pressure increases.

(a)



(b)

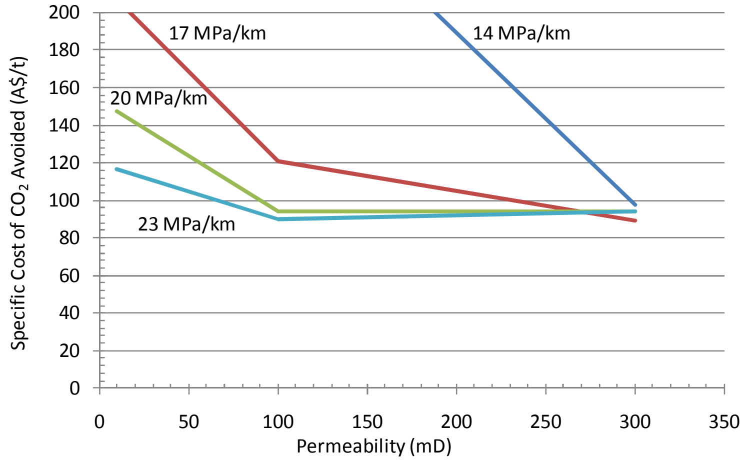
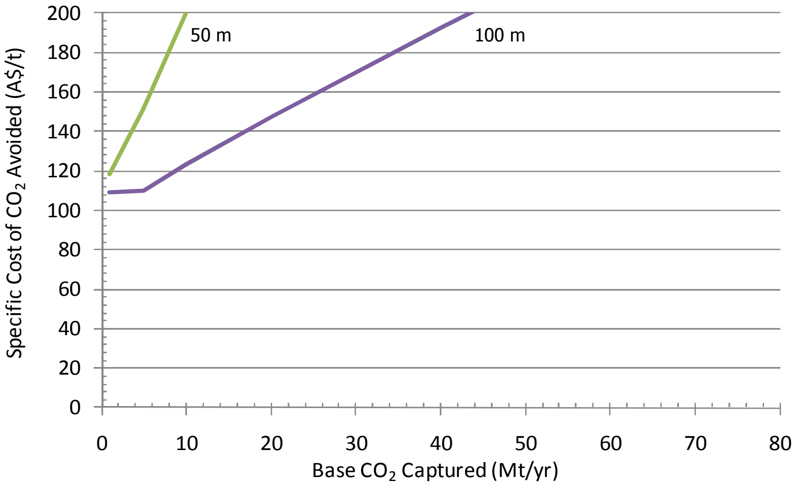


Figure 18. Effect of fracture gradient on the cost of capture and storage (a) for a range of flow-rates for a permeability of 10 mD and (b) for a range of permeabilities for a flow-rate of 20 Mt/yr (Neal *et al.*, 2008).

Formation thickness

According to Darcy's law, injectivity is proportional to formation thickness as it helps define the contact area available for injection. This means that the number of wells and the cost are inversely related to the formation thickness (see Figure 19a). Our results show that the number of wells and cost are strongly affected by formation thickness. Thus as formation thickness decreases, the number of wells increases and so does the cost. Permeability has the same effect as formation thickness. As permeability increases and formation thickness decreases (Figure 19b), the number of wells and the cost are reduced.

(a)



(b)

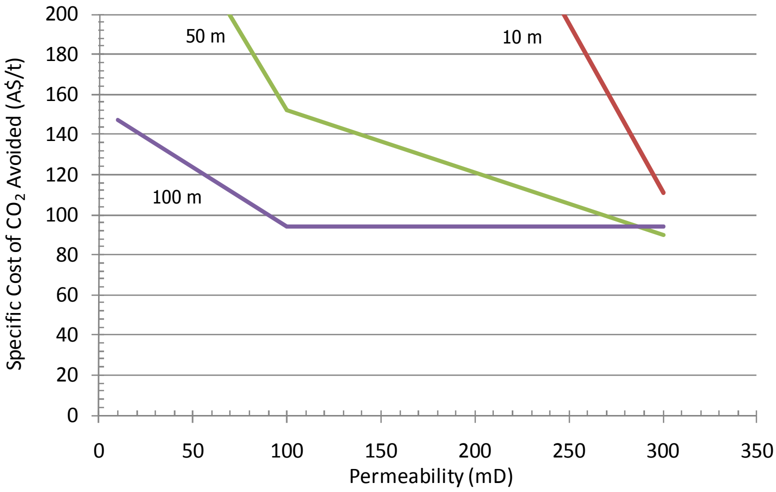


Figure 19. Effect of formation thickness on the cost of capture and storage across (a) a range of flow-rates at a permeability of 10 mD and (b) for a range of permeabilities for a flow-rate of 20 Mt/yr (Neal *et al.*, 2008).

Formation depth

Neal *et al.* (2008) use a hydrostatic-pressure gradient of 9.8 MPa/km and a fracture gradient of 20 MPa/km. This means that the pressure driving force varies with well depth. Figure 20 shows the profiles for formation and fracture pressure in the low-quality formation. We also show the pressure at depth for the high quality formation.

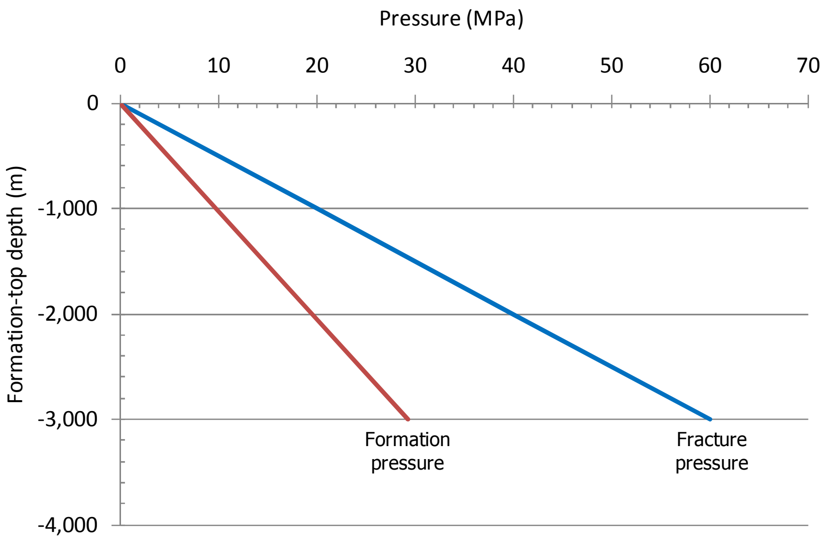
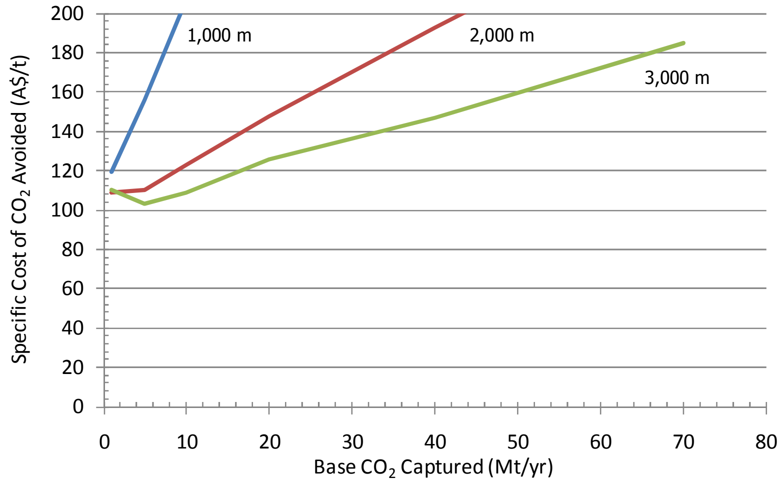


Figure 20. Pressure with depth for the low-quality site (Neal *et al.*, 2008).

As is the case with earlier results, Figure 21(a) shows that the minimum cost of injecting CO_2 is about A$100/t. Figure 21(b) shows how permeability and depth affect the cost. At a depth of 1 km, the cost is very sensitive to decreases in permeability. The 2 and 3 km deep wells are relatively insensitive to changes in permeability until it drops below 100 mD. From then on, costs begin to increase as permeability decreases.

Figure 21 demonstrates the key reason why CCS cost decreases with increases in formation-top depth. Because the formation pressure and fracture pressure are estimated by means of gradients, the pressure-window increases with depth. Thus, as depth increases, it is easier to inject more CO_2. The larger available pressure-range at greater depths means that deeper wells are less sensitive to variations in permeability, plus CO2 can be stored at greater densities in deeper formations. Although it is not clear in this figure, well cost increases with depth and this will to some extent offset the cost reductions made possible in a deeper formation with more favourable injectivity.

(a)



(b)

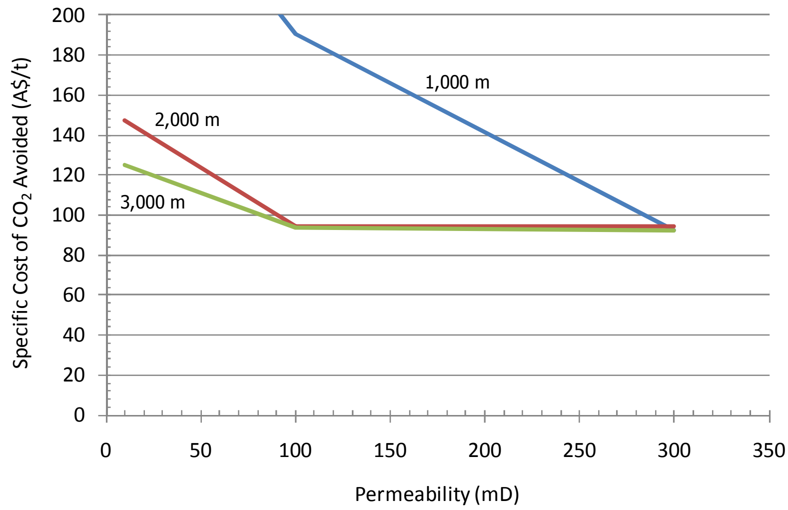


Figure 21. Effect of formation depth on the cost of capture and storage for the low-quality formation compared against the distant, high-quality storage site over (a) a range of flow-rates and (b) a range of permeabilities (Neal *et al.*, 2008).

Well type

Neal *et al.* (2006) also examined the effect of well type on storage cost. Figure 22 shows that using horizontal wells (rather than deviated wells) can reduce CCS costs, because they have greater contact area and therefore the same injectivity can be achieved with fewer wells. However to be cost effective, this reduction must offset the increased cost of horizontal wells. For instance, using wells with a 4 km horizontal section reduces the costs of storage by A$1.5 per tonne avoided. In this analysis, the horizontal section must be at least 1.6 km long for the horizontal wells to be less expensive than the deviated wells.

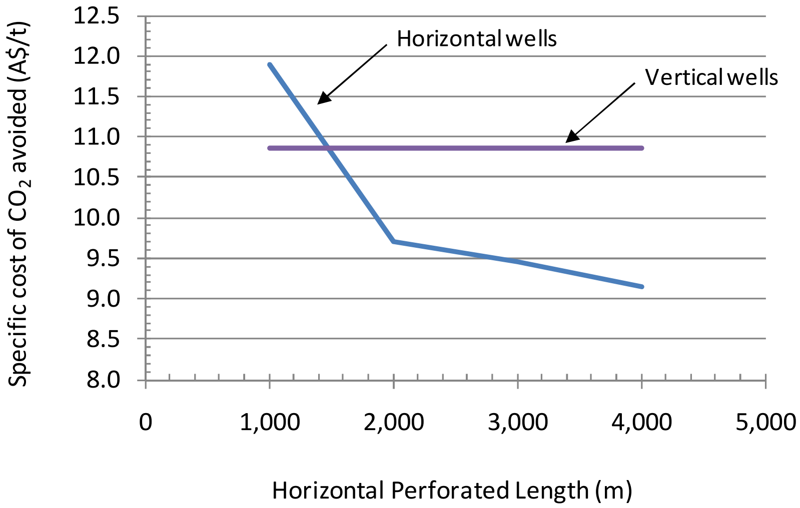


Figure 22. Effect of horizontal well perforated length on the cost of transport and injection (Neal *et al.*, 2006).

In Figure 23, using horizontal wells or increasing horizontal well lengths increases the specific cost of CCS. For some cases there is no difference in numbers of wells for vertical and horizontal wells and so the greater cost of each horizontal well increases the total cost. In the remaining cases, using horizontal wells reduces the number of wells required. However, this reduction is not sufficient to offset the extra unit cost of horizontal wells.

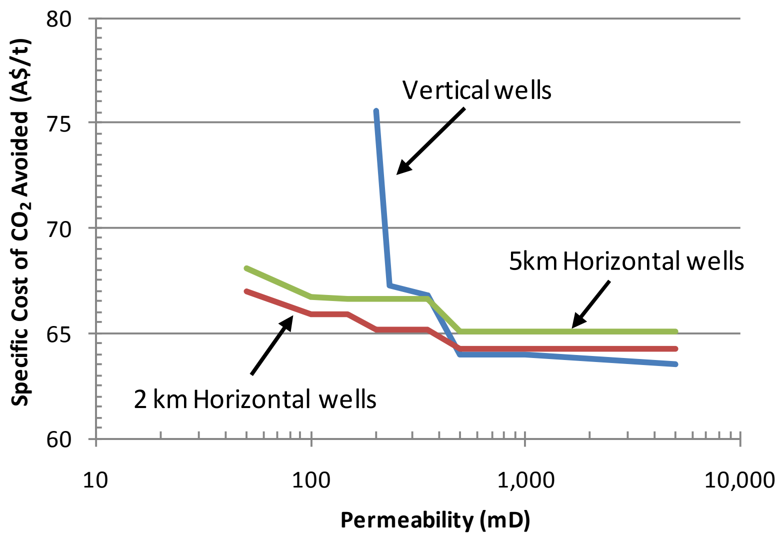


Figure 23. Effect of on the cost of capture and storagefor three different well types across a range of permeabilities (Cinar *et al.*, 2009a).

Cinar *et al.* (2009b) compared the cost of vertical wells with 2 km long and 5 km long horizontal wells. Figure 23 shows the effect of permeability and well type on the cost of CCS. It shows that the cheaper well type depends on the permeability. At high permeabilities, for which few wells are required, vertical wells are cheapest. In contrast, low permeabilities require many wells and horizontal wells are cheaper.

The point at which horizontal wells become cheaper than vertical wells depends on the permeability. As permeability falls, the number of vertical wells required rises faster than the number of horizontal wells. For 1.0 Mt CO_2/yr the approximate cross-over occurs at 500 mD for 2 km long horizontal wells and at 350 mD for 5 km long horizontal wells.

Neal *et al.* (2006) show that cost can be reduced by using horizontal wells instead of vertical wells. Cinar *et al.* (2009b) show that the choice of well type is tied to the formation properties and storage rates desired. Horizontal wells are particularly effective at low fracture gradients, low permeabilities, and high flow rates. In some cases using longer wells can be detrimental to injection cost. Increasing the length of horizontal wells only provides net benefits when it leads to significant reductions in well numbers.

Hydraulic Fracturing

Cinar *et al.* (2009b) studied the economics of fracturing. Hydraulic fracturing creates higher permeability zones near the well bore and so improves injectivity. Figure 24 shows how hydraulic fracturing around horizontal wells affects the cost of CO_2 avoided. The figure shows that in the 1 mD case fracturing reduces the overall cost of CO_2 avoided because its advantages in increasing permeability more than offset its extra cost. In this case the fracturing increases the relative permeability by 3.6 times. Yet fracturing does not have a significant net advantage when a higher permeability of 10 mD is assumed. This is because the increased injectivity does not reduce the number of wells as significantly as in the 1 mD case.

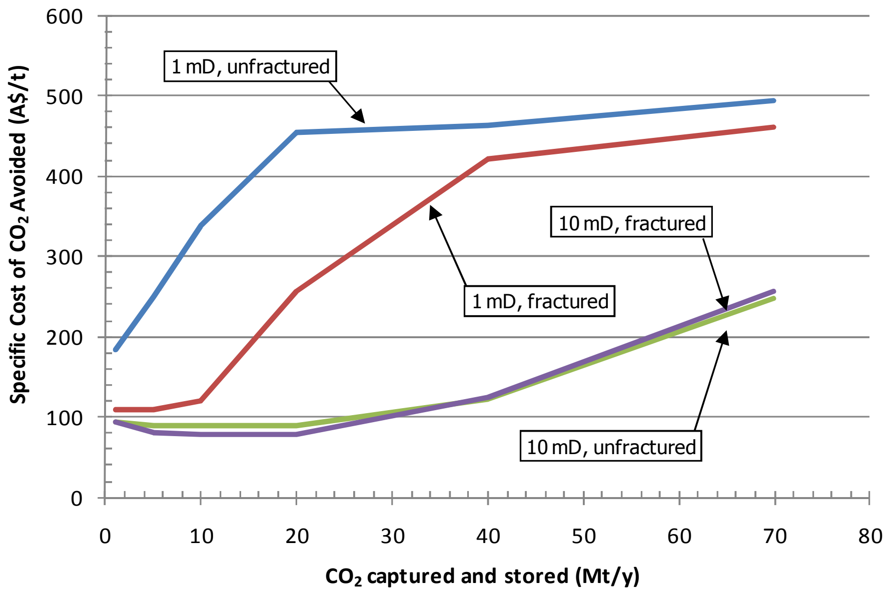


Figure 24. Effect of hydraulic fracturing around horizontal wells on the cost of capture and storageby CCS for two different permeabilities (Cinar *et al.*, 2009b).

Trade-off with transport costs

The cost of injection is only one part of the costs of CCS. There are trade-offs between the different elements of the CCS process. One such trade-off is between transport and injection. Both Cinar et al. (2009b) and Neal et al. (2008) compared the cost of two storage formations. The first formation has generally poor injection characteristics and is 100 km from the capture plant whilst the second formation has generally good injection characteristics but is 1,000 km from the capture plant. The nearby formation has a high injection cost but a low transport cost, whereas the distant formation has a low injection cost but a high transport cost. They conducted a number of sensitivity analyses and looked for the conditions at which the distant site became cheaper than the nearby site.

Figure 25 compares the cost of the distant site with a fractured nearby formation with a permeability of 1 mD and with an unfractured nearby formation with a permeability of 10 mD. The cost of the distant site is presented for a range of flow-rates and distances from the capture plant. The cost of CCS increases with distance since pipeline cost increases with distance. As flow-rate increases the cost decreases as a consequence of economies of scale. Yet, at distances of 2,500 km and 5,000 km, cost begins to increase because of the sheer tonnage of pipe required and reaching the maximum pipeline diameter considered (42” or 1,050 mm).

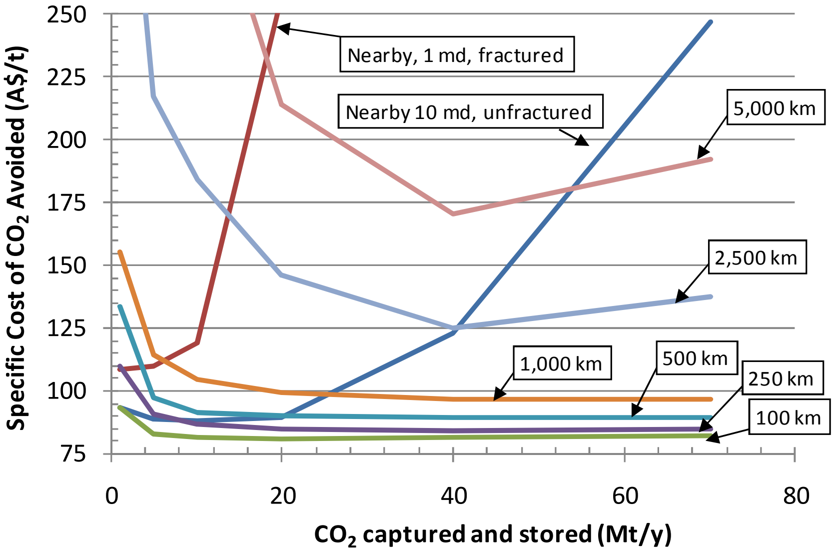


Figure 25. Comparison of two nearby, low injectivity storage formations with a high injectivity storage formation at a range of distances from the capture plant (Cinar *et al.*, 2009b).

In Figure 25, the nearby, fractured 1 mD site is more expensive than the unfractured 100 mD site at the same distance because of the difference in numbers of wells and the cost of fracturing. At a flow-rate of 1 Mt/yr, the distant site would have to be 250 km away to be of similar cost to the nearby, fractured 1 mD site. As the flow-rate increases, the distance at which the two sites cost the same also increases. When the flow-rate is 20 Mt/yr, the distant site would have to be much more than 5,000 km from the capture site to be the same cost as the nearby, fractured 1 mD site. If the nearby site has a permeability of 10 mD and is unfractured, Figure 25 shows that the equivalent cost distances for the distant site are much reduced. At a flow-rate of 1 Mt/yr, the costs of the nearby and distant site are approximately the same. At a flow-rate of 20 Mt/yr, the distant site is cheaper if the distance is less than 500 km. Only when the flow-rate becomes greater than about 50 Mt/yr does the site 5,000 km away become the cheaper option. These results show that not only should formation properties and injection design be considered as part of injection strategy, but the possibility of transporting the CO_2 further to access a higher permeability storage site should be considered.

Figure 26 provides further analyses of the trade-off between distance and injectivity. In the results shown, the high-quality formation is compared against the nearby site over a range of fracture gradients, thicknesses and depths. For all three sensitivity analyses the distant site becomes the cheaper storage option when the injection rate is greater than about 4 Mt/yr.

Trade-off between relief well and injection well costs

A key component of the economics of injection is the cost of wells, which clearly depends on the number and type of wells required. The number of injection wells required is determined from the injection reservoir geological characteristics and multiphase flow properties.

For a given well spacing, the more CO_2 is injected, or the longer the injection period, the greater is the interference between injection wells, which in turn increases the requirement for injection wells and the costs. Alternatively, we might drill water production wells – pressure relief wells – to improve injectivity. However, this would also require water handling facilities at the injection site. This all adds to the costs.

In the end, therefore, it comes down to a trade-off between (a) the costs of injection wells and (b) the costs of water relief wells and the associated costs of water handling. The engineering and economic analysis and optimisation of the trade-off require a detailed knowledge of the characteristics of the reservoir. In other words, both require a good geological model and a detailed reservoir simulation.

Offshore and onshore injection

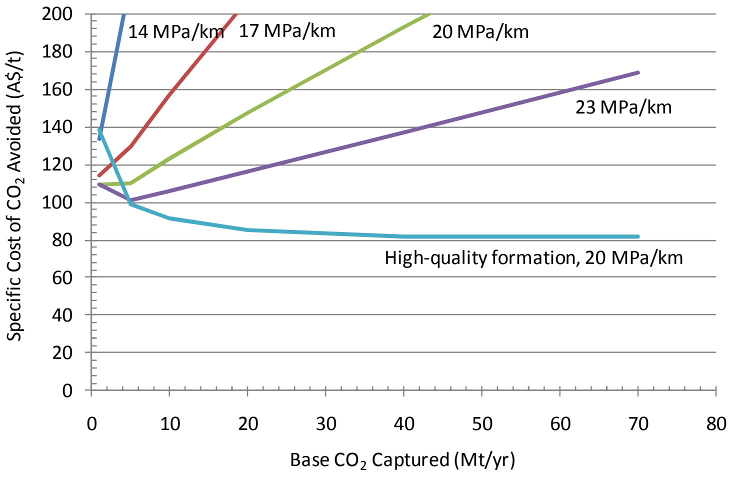
There are significant differences between the costs and logistics of onshore and offshore CO_2 injection and these differences can affect the viability of CO_2 injection markedly. The differences are driven largely by:

(a) The significantly greater cost of drilling in offshore locations, and
(b) The different geographical, legal and physical limitations on locating injection wells and the design of the associated CO_2 distribution pipeline network.

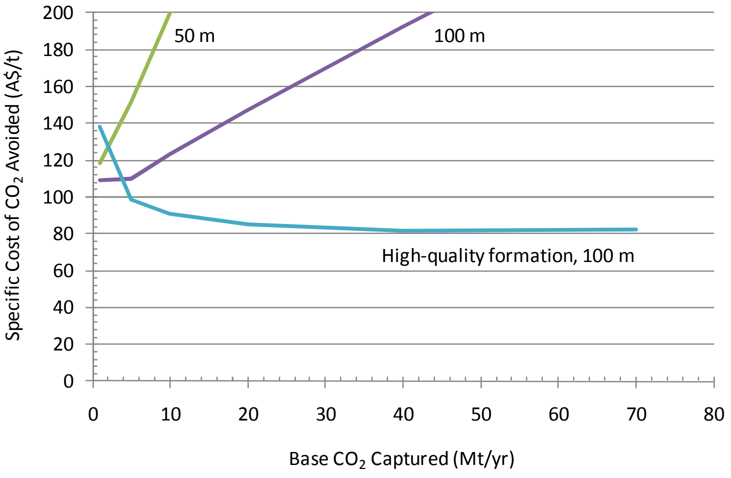
Costs

While onshore drilling is not cheap in absolute terms, the costs are an order of magnitude lower than the costs of drilling an offshore well. As an example, at the time of writing (2009), conventional onshore vertical wells drilled to a depth of over 2,000 metres in Australia are likely to cost over US$2 million including mobilisation and demobilisation charges. In contrast, offshore wells in shallow water less than 100 meters are likely to cost at least ten times this. These differences apply worldwide. Therefore, everything else being the same, the economic viability of injecting a given rate of CO_2 is significantly greater for onshore locations than offshore locations. For a given carbon price, offshore locations might be limited to fewer injection wells and lower CO_2 injection rates than would be possible for onshore locations

(a)



(b)



(c)

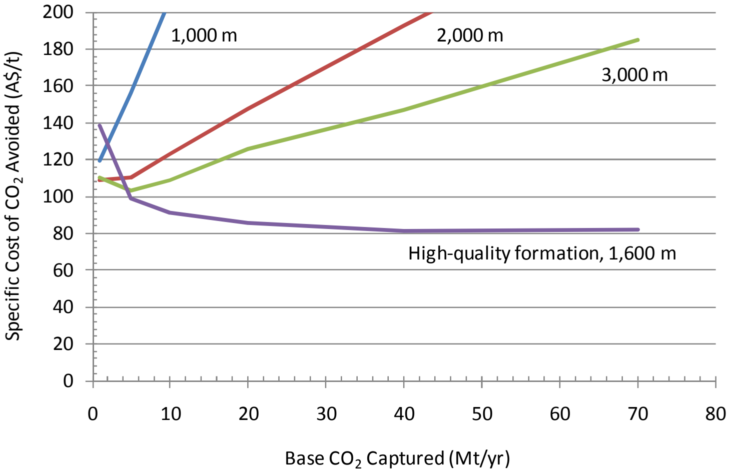


Figure 26. Comparison of a distant, high injectivity site with a nearby, low injectivity site over a range of (a) fracture gradients, (b) formation thicknesses and (c) formation depths (Neal *et al.*, 2008).

Locating injection wells and distributing CO_2

The spatial design of the injection site is very site-specific. However, the general issues involved in locating and distributing injection wells are discussed in BERR et al. (2007) and IEAGHG (2009b).

Whether the site is onshore or offshore, critical determinants of injection well location are the geometry of the reservoir, the presence of faults, the variations in porosity and permeability across the structure. Clearly these factors vary from site to site. The rate of CO_2 injection also affects well location. In general, the greater the flow, the more wells are required and the larger the distribution system.

In some cases, choosing well locations might be affected by the location of existing wells and whether or not they can be re-used. This requires assessments of wellbore and completion integrity. Remedial work might also be required. The spatial and economic advantages and disadvantages of these need to be weighed against those of new wells.

There will be additional constraints when locating onshore wells and designing an onshore CO_2 distribution network. These relate to conflicting uses of the land (property rights, national parks etc) and geography (terrain, the existence of towns, roads, rivers). In remote onshore locations, these might not impose many limitations. However, in heavily populated areas, they might place significant constraints on positioning injection wells and distribution networks.

For onshore locations with many injection wells spread over a large area, the CO_2 distribution pipeline network will need to be designed to minimise costs taking into account the varying injectivity of different well locations as well as the terrain. Such design considerations will be required in addition to legal and geographical constraints.

For offshore locations, the constraints on designing the injection system and locating wells relate to the water depth, the seabed conditions, the number of platforms and the type of injection wells that are feasible. Deep water injection sites will limit the number and type of platforms that can be used and therefore the number of injection wells. For instance, floating or tension-leg platforms might be more appropriate for deep water locations and these will constrain the number of injection wells that can be accommodated. In contrast, shallow water injection sites (200 metres or less) will allow fixed platforms that can accommodate many wells. The condition and topography of the seabed can also affect the positioning of platforms and injection wells.

For offshore injection projects that require few injection wells, sub-sea wells with tie-back flowlines to the host platform might be the most appropriate design for the injection system. This is established technology. Such a design is likely to be less appropriate for projects that require many wells. In these cases, platform wells are likely to be more viable.

Economics screening tool

As part of the terms of reference for this study we have a constructed a simple spreadsheet economic screening tool. This is described in the Appendix.

Injection well design and remediation

The technical details of well design and completion are outside the scope of this study and will not be discussed in length. The reader is referred to other reports (i.e., Contek Solutions, 2007; IEAGHG, 2009b) and articles on this topic in the petroleum literature (Watson and Bachu, 2008; 2009; Bachu and Watson, 2009). The petroleum industry has more than 35 years experience with the drilling and completion of wells for the purpose of CO_2 injection in EOR projects and for the disposal of acid gas. Well construction and integrity for CCS is described in detail in the CO_2 Capture Project (CCP) publication "A technical Basis for Carbon Dioxide Storage" edited by Cooper (2009).

Well design

Wells should be designed and implemented according to the activities associated with the various stages of a CCS project (Table 7).

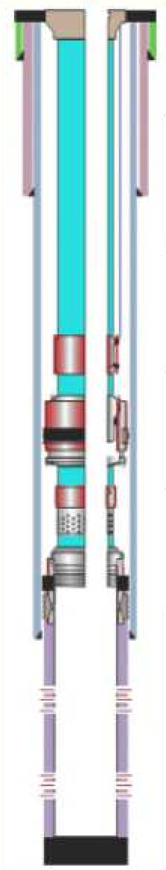
Table 7. Storage project life cycle stages related to wells (Cooper, 2009).

Site Selection and Development	Operations	Closure	Post-Closure
• Determine location and prepare site. • Specify storage requirements for project considering the source, injectant and geological system container. • Create Basis of Design for wells to meet performance-based storage requirements. • Risk assessment. • Obtain regulatory approval of operations plan including monitoring. • Transition existing wells from prior service for injection / monitoring. • Drill new wells as needed. • Baseline monitoring for current conditions of barrier system and zones in project area.	• Injection begins. • Monitor for migration along barrier and test to verify integrity. • Corrosion monitoring and prevention. • Conduct maintenance for injectivity and well performance. • Conduct drilling, workover and abandonment operations as needed to support operational objectives. • Report monitoring results.	• Injection ceases. • Validate barrier integrity of wells. • Request regulatory approval to abandon wells. • Abandon wells in the project area. • Validate abandonment quality. • At closure, regulatory approval gained to close the site.	• Expected permanence of CO_2 in the reservoir is established. • Site fully closed. • Limited monitoring may be required, by exception, during post-closure period to verify site integrity

A typical well assembly for CCS includes:

- Wellhead and tree;
- Tubing and casing;
- Safety valve(s);
- Packer and packer fluid;
- Elastomers
- Sand control

Wells injecting CO_2 must have effective technical barriers that prevent hydraulic communication between various hydrostratigraphic units (particularly across the primary seal), between the well annuli, and between the surface casing and the external environment. These barriers are formed by the various well tubulars (casing, tubing, liner) and the well cement. Figure 27 shows the downhole assembly and specifications of a typical injection well. To prevent corrosion, the injected CO_2 should be sufficiently dehydrated and in a supercritical state. Corrosion resistant materials should be used in areas of potentially high water content and if injection rates result in exceeding the erosional velocity (Cooper, 2009).



Description	Potential Risks and Concerns	Materials
Tubing Hanger	CO_2 corrosion may be associated with well back-flushing provision and process interruptions.	CRA - Generally high Nickel Content
Conductor Casing	Some aquifers have a potential external corrosion risk.	Carbon steel - consider external coating.
Surface Casing		Carbon steel.
Injection Tubing	Provision for periodic back-flushing and process up-sets may yield water exceeding 8,000 mpy	GRE lined Carbon Steel or CRA.
Production Casing	Metallurgy in accordance with industry standards for any contaminants in CO_2.	Carbon Steel - Surface to immediately above base of sealing formation.
Production Liner	Process upsets & provision for back-flushing may result in high water content CO_2 in the injection zone. Also there may be contaminants in the CO_2 such as H_2S.	CRA. Industry standard if required for applicable contaminants.

Abbreviations used: CRA = Corrosion Resistant Alloy; GRE = resin epoxy; NACE = National Association of Corrosion Engineers.

Figure 27. Possible well design for CO_2 injection (from Cooper, 2009).

Cements are used for isolation and well integrity and are supposed to prevent vertical leakage along the borehole. According to Cooper (2009), accurate cement placement and tight interfaces between borehole and casing are the primary requirements for achieving good isolation. Special CO_2 resistant cements (i.e., high-alumina cement system) can be used to further protect against cement degradation (Barlet-Gouedard et al., 2006; Benge and Dew, 2005). Recent results on geochemical interactions between well cements and CO_2 were published by Carey et al. (2007), Jacquemet et al. (2007), and Kutchko et al. (2007). When abandoning wells, cement plugs in combination with other material are used to form a vertical flow barrier in the borehole after injection has ceased (Figure 28).

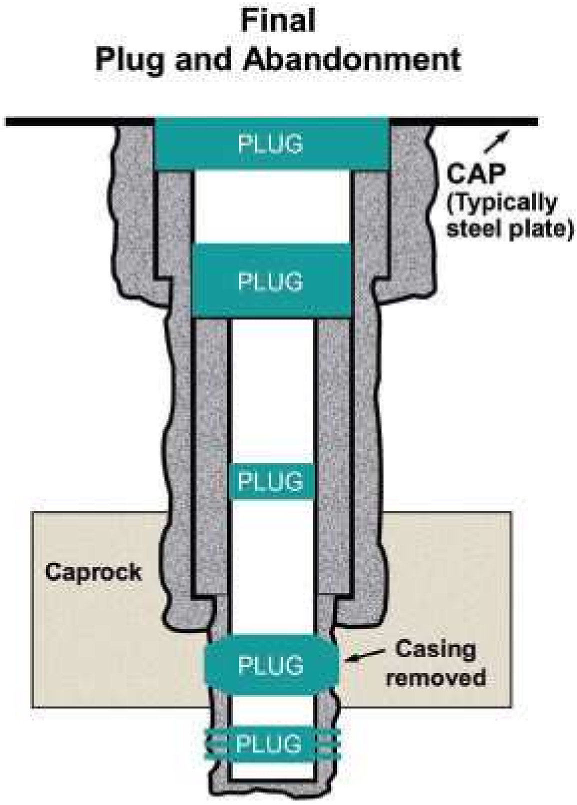


Figure 28. Typical Plug and Abandonment, showing from bottom-up: plugged injection zone, plug in cap-rock interval which includes drilled casing; plug above caprock, plugs at top of casing and steel plate at surface (Cooper, 2009).

Remediation methods for loss of injectivity

There are several factors pertaining to performance management and risk control which need to be considered in the long term storage of CO_2. This section focuses on possible remediation measures which can be adopted when there is loss of injectivity defined as a lower rate of injection of CO_2 into the reservoir than is expected at a given pressure. Table 8 summarises the possible causes of loss of injectivity and the relevant remediation measures which can be taken. Each cause and the subsequent remediation are further discussed in detail below.

Reservoir and wellbore models must be run concurrently in order to optimize and synchronize both models. This applies to a simple single well or a network with multiple wells. In addition, the reservoir and wellbore models must also be run (simulations carried out) for different sensitivities/scenarios depending on the conditions envisaged during the injection life cycle. This process must be carried out during the feasibility stage of a project without exception. The following are a short list of possible sensitivities to be examined:

- Range of compressor pressures/temperatures-minimum and maximum limits from manufacturer
- Range of ambient temperatures-minimum and maximum
- Range of injection rates
- Reservoir parameters e.g.: skin, permeability, reservoir thickness, reservoir boundaries
- Variation of mixtures
- Time steps-plume behaviour

The above process serves as a means of:

- Predicting and having contingency plans in place to mitigate and remedy any problems which may arise during the life of the injection cycle.
- Set minimum and maximum limits on the operating conditions such as:
- Composition of mixture
    - Compressor pressures/temperatures
    - Well head temperatures/pressures
    - Erosional velocity limits
    - Bottom hole pressures/temperatures
    - Injection rates

The best way to achieve the above is to make sure that all individuals in a multidisciplinary team are liaising with each other to share the results from the different models on a regular basis. Such a team will typically consist of geologists, geoscientists, reservoir engineers, production engineers and geo-mechanical engineers. This will facilitate optimizing and synchronizing the different models even in the cases where direct software integration is not available.

Table 8. Summary of causes and remediation measures.

Causes of Loss of Injectivity	Checks to be performed to find root cause of problem	Remediation Measures
1. Insufficient/lower than expected well head pressure	Reading of well head pressure gauge. Leaks in surface pipeline Compressor output pressure	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.
2. Insufficient /lower than expected bottom hole pressure	Reading of bottom hole pressure gauge and flow meter Leaks in surface pipeline Compressor output pressure	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.
3. Insufficient/higher than expected well head temperature	Reading of well head temperature gauge Compressor output temperature Check ambient temperature	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity
4. Change in composition/mixture of CO_2+impurities	Readings from monitoring equipment	Re-run wellbore and reservoir models based on new composition. Use most appropriate thermodynamic equations to define new mixture.
5. Plugged Perforations	Readings of down hole flow meter, pressure and temperature gauges	Acidize to clean up
6. Change in reservoir parameters e.g.: Skin, Permeability	Parameters obtained from previously acquired data e.g.: well test analysis, logs Re-run reservoir simulations to verify model	Re-acquisition/Verification of data • Well Test Analysis • Wireline Logs Based on above results • Update and re-run wellbore and reservoir models • Based on the simulation results above, take necessary steps to regain injectivity - Add more perforations - Acidize - Fracture (controlled)
7. Increased injectivity	Readings of down hole flow meter, pressure and temperature gauges	Re-run wellbore and reservoir simulations to obtain results based on new set of conditions. Note: Above will help to decide on remedy which will help to regain injectivity.

Insufficient/lower than expected well head pressure

One of the factors which determine the bottom hole pressure is the well head pressure. Should the well head pressure be lower than expected then the bottom hole pressure will in turn be lower. This could lead to a loss of injectivity. The bottom hole pressure is essentially the sum of well head and hydrostatic pressures minus the frictional losses (bottom hole pressure = well head pressure + hydrostatic pressure-frictional losses). The loss of or reduction in well head pressure could be due to factors such as:

- Reduction in compressor output pressure
- Leaks in surface pipelines

Monitoring devices should be installed along the pipeline to measure such parameters as pressure, temperature, flow rates, density and composition. The outputs from these devices must be recorded and the data inspected regularly in order to see potential problems, i.e. loss of injectivity. The same applies for the compressor outputs. The necessary action/s need to be taken to rectify the loss of injectivity, once the root cause of the problem is found.

Insufficient/lower than expected bottom hole pressure

Reduction in bottom hole pressure is the most likely cause of loss of injection. This goes hand in hand with lower than expected well head pressure. Refer to the previous section for simple means of calculating bottom hole pressure. The other possible causes of reduction in bottom hole pressures are:

- Higher injection rate-increase in frictional losses
- Leaks in the completion- e.g.: pitting in the tubing
- Density of injection fluid/mixture is less than predicted due to:
    - Change in composition or phase of mixture
    - Well head temperature is higher than expected/predicted

In short it is evident that changes in compressor and/or well head pressure/temperature and phase and/or composition of CO_2 have a direct impact on the bottom hole pressure and hence the injection rate. Monitoring devices such as pressure, temperature gauges, density and flow meters installed along the pipeline, well head, well, and at the compressor can be used to narrow down the cause of the problem. For the case of tubing leaks a corrosion log on wireline can be run to obtain the condition of the completion.

Insufficient/higher than expected well head temperature

Increase in well head temperature gives rise to a reduction in density. This in turn reduces the bottom hole pressure. Increase in well head temperature can be due to the following:

- Heat losses less than expected in the surface pipelines.
- Higher than normal ambient temperature
- Compressor output temperature higher than expected

As mentioned in previous sections, the various monitoring devices in the system can be used to find and rectify the causes of injectivity loss.

Change in composition/mixture of CO_2+impurities/mixtures

A change in phase or a change in composition of CO_2 being injected could give rise to a change in density. This gives rise to a change in bottomhole pressures. There are some mixtures of CO_2 which has not been well defined thermodynamically as yet. However the majority of commonly encountered mixtures of CO_2 have Equation of States (EOS) for example:

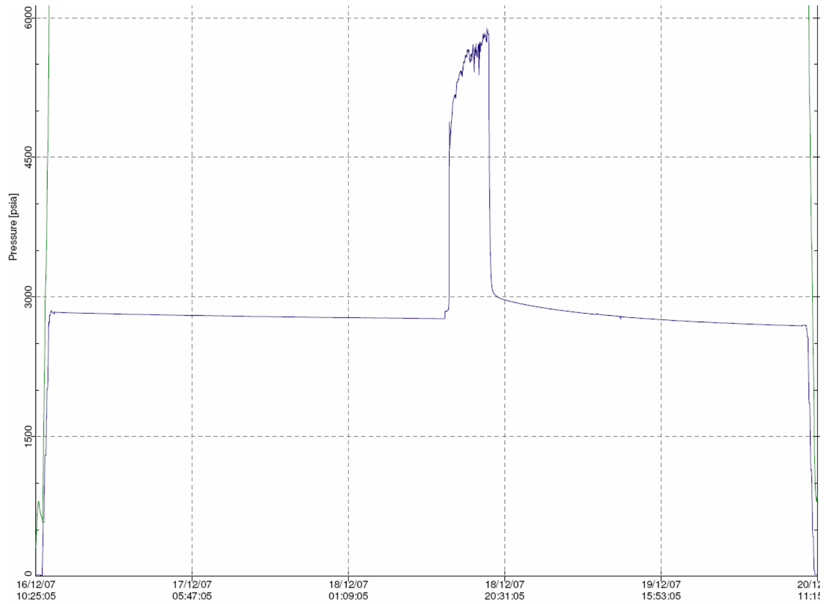
- Span and Wagner (1996) EOS- Pure CO_2
- Spycher et al. (2003) EOS- CO_2+ H_2O.
- GERG-2004 EOS- CO_2 and mixtures of natural gases (Kunz et al., 2007) e.g.: CO_2+ Ar, CO_2+ N_2, CO_2+ CH_4 etc.

Therefore it is vital to use the most appropriate thermodynamic equations pertinent to the composition being injected. This is especially true when considering the reservoir and wellbore models and their simulations. It is also important to carry out sensitivities by which the amount of every component in the mixture is varied between a minimum and maximum values. From the above it is evident that an error in the EOS and/or not considering variation in the amount of each component within the mixture, can lead to a change in bottom hole pressure and hence loss of injectivity.

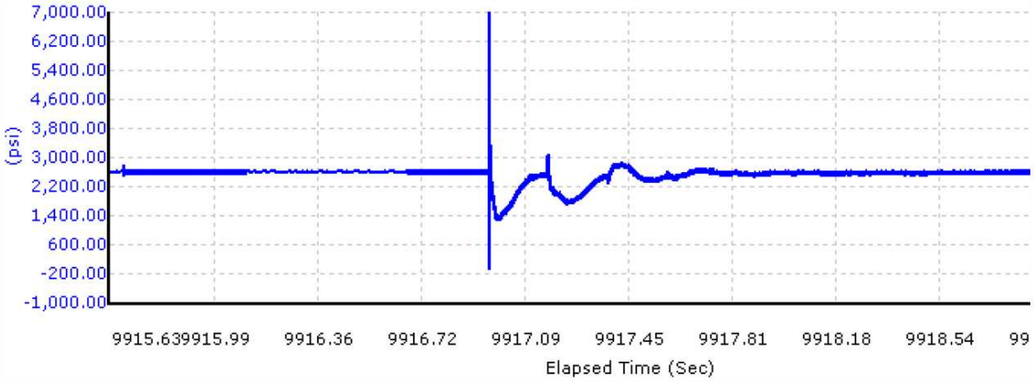
Plugged perforations

This could be due to bad cleanup, scaling, compressor grease or fines trapped at the sandface or to bacterial films. N_2 lifts can be used, as treatment with anti-bacterial products or acidization (e.g. iron hydroxide scaling). Other damage may require fracturing or re-perforating.

An example of this injectivity impairment was seen in the CO2CRC Otway project. The well was perforated in a pressure balanced situation and exhibited poor injectivity during the follow on test with brine. Injection was started at 0.9 bpm and the surface pressure rose quickly to 2000 psi once the well was full. Injection was then stopped to avoid damaging the downhole gauges. These were retrieved and the rapid build up confirmed plugged perforations.



Downhole gauge data showing that the pressure was building up very quickly and the well not taking any fluid.



Downhole fast gauge data (in perforation assembly) showing that a dynamic underbalance of approximately 200 psi had been created to clean up the perforations.

The well was subsequently re-perforated using a dynamic under balance "PURE" perforating system that optimizes the transient underbalance just after creation of the perforation cavity. The fast gauge data from the perforation system showed that a dynamic underbalance had been created (see figure) and the well was able to take fluid. This well has been used for CO_2 injection operations for around 18 months through this reperforated zone. Over 65,000 tonnes of CO_2 have been injected without any problems. This example highlights the importance of cleaning up of perforations as part of an injection system design process.

Change in reservoir parameters (i.e. Near Wellbore Damage)

Change in reservoir parameters could be due to geochemical changes, mostly precipitation of salts (halite, carbonates) and insoluble compounds (hydroxides, sulphates – mostly resulting from contaminants) in the near wellbore as a result of formation water evaporation, injection stream diffusion in the formation water, and direct reaction between the injected gases and the rock matrix (mostly in the water phase).

To prevent geochemical effects, uncontaminated samples of reservoir rocks and brines (and caprock samples as well, if possible) should be taken and flooded with CO_2 and brine in the lab. The original and flooded cores should be analysed for precipitates, and their possible effect on injectivity. Inhibitors (such as glycol) and kelating products can be added to the injection stream to control these phenomena, or an initial flushing with sweet water or low-salinity brine can be considered. In some cases, though, preventive hydraulic fracturing and/or long (horizontal) injection intervals should be adopted.

Also, poorly characterized reservoir could be an issue, where compartmentalization has not been identified, and non representative skin factors and permeabilities have been used. The only possible solution in this case is a redrill or a sidetrack, so adequate prevention (extended well test with water) should be deployed. Well testing with water would serve to validate the factors mentioned above such as reservoir boundaries, skin and permeability. This holds especially true where the characterization has been carried out using analogues or data which are decades old. Therefore it is imperative that the costs involved with extended well tests be factored into all projects. The wellbore and reservoir models have to be re-run with the values obtained from the well test results.

Increased injectivity

Higher than expected injectivity, especially if occurring days to weeks after injection starts, could be the symptom of a deeper issue and its causes should be investigated, solved and addressed. One possible cause could be thermal fracturing of the reservoir, or a pressure-related leak pathway open (since leakage through cemented sheaths is too small to affect injection pressure), also geological pathways, such as fractures or faults, may be at play. The possibility of thermal fracturing of the reservoir forms part of the scenarios which need to be investigated during the feasibility plan of all projects. The costs involved in a geomechanical study must be included in the project budget.

If injection pressure does not increase quickly enough, then it may mean that the boundary conditions in the reservoir model are wrong. Those conditions are normally inferred from geological characterization and well testing, and in general lower-than-expected pressures may mean that impermeable boundaries are not so; permeability could be diffuse (small cracks, matrix permeability, double porosity/double permeability with stress dependence) or concentrated (faults, high-permeability chimneys, fractures). Even if high-permeability streaks within the reservoir are the cause, this should be investigated since it may result in asymmetric plume distribution.

Monitoring and management of well performance

The previous sections have shown that factors which lead to loss of injectivity are wide and varied. Therefore it is important to take them into consideration, during the feasibility stage of every project as part of an injectivity management plan (Table 9). Prevention and remediation measures must be considered as part of the plan. This will serve to minimize the occurrence of injectivity loss and provide adequate means of regaining injectivity during the CO_2 injection phase.

Table 9. Monitoring and management of performance and containment issues (Cooper et al., 2009).

Issue	Unexpected Outcome	Signpost	Monitoring	Timing	Management Action
Well Injectivity	Unable to inject CO_2 at required rate	Unexpected BHP increase	Well head & downhole P gauges & flow rate gauges	< 6 mos.	Once verified, several actions including recompletion, reperforation, drill new wells with different design, consider alternative storage reservoir
	Initial injection rate meets expectations but overall pore space is limited	Gradual increase in BHP	As above	10 years	Consider producing water & reinjecting into another reservoir
	CO_2 cannot be injected at required rates due to formation damage	Unexpected BHP increase and change in formation fluid chemistry	As above & fluid samples/analyses	Ongoing	Workover well & acid or fracture stimulate
Existing Well Failure	CO_2 migrates to overlying formation(s)	Indications of CO_2 in shallower stratigraphy	Surface & borehole geophysics	Ongoing	After validation, assess ability of shallow formations to trap CO_2; if not, remediate wells or modify injection pattern
	CO_2 leakage at surface	Elevated CO_2 present in vicinity of well(s)	Surface soil & atmospheric gas	Ongoing	Remediate well. Implement appropriate environmental remediation
	Leakage of displaced formation water in shallower stratigraphy	Elevated CO_2 detected near well in shallower horizons	Surface & borehole geophysics. Geophysics sampling	Ongoing	Assess impact on overall containment. If needed, remediate leaking wells (particularly if along pro-jected plume path)
Top Seal Failure	CO_2 migrates to overlying formation(s)	Detection of CO_2 above injection formation not associated with wells	Seismic and/or borehole geophysics	Ongoing	Focus monitoring to verify. If needed modify injection pattern or produce water and reinject into another formation
	Seal integrity compromised due to pressure increase from CO_2 injection	Pressure drop during injection or seismic or borehole geophysical indications	Wellhead pressure and downhole pressure & flow gauges; seismic and borehole geophysics; tiltmeter; passive seismic	Ongoing	Focus monitoring to verify. If necessary modify injection pattern, lower injection rates or produce water & reinject into another formation
Fault Seal Failure	Faults transmit CO_2 to shallower formations	Detection of CO_2 above injection formation in proximity of fault	Surface and borehole geophysics; fluid sampling, downhole gauges	Ongoing	Focus monitoring to verify. if necessary modify injection pattern, lower injection rates or produce water from vicinity of fault to reduce pore pressure
	Faults transmit CO_2 to the surface	Elevated CO_2 present in vicinity of well(s). Ecological impacts	Soil & atmospheric monitoring. Ecological changes.	Ongoing	Focus monitoring to verify. if necessary modify injection pattern, lower injection rates or produce water from vicinity of fault to reduce pore pressure
	Faults are vertically & laterally impermeable	Unexpected pressure increase in part of formation thought to be isolated	See Compartmentalization	See Com-partmen-talization	See Compartmentalization
Pore Volume & Distribution	Reduced pore volume or distribution limiting CO_2 injection	Rate of long-term pressure build-up greater than expected	Well head and downhole P gauges & flow rate gauges. Multicomponent seismic for pressure	10-30 years	Focus monitoring to verify. If necessary modify complete injection well over entire length of reservoir, produce water & reinject elsewhere or reduce total CO2 injection volume

Permeability Heterogeneity	CO_2 cannot be injected at required rates	Unexpected bottomhole pressure increase	Wellhead & downhole P gauges & flow rate gauges	See Well Injectivity	See Well Injectivity
	Unexpected migration of CO_2 plume	Detection of unexpected plume distribution possibly related to stratigraphic or depositional geometry (otherwise structure, high permeability layers or hydrodynamic flow) Lower than expected BHP	Seismic imaging. Surface and downhole pressure. Production logging	1-10 years	Focus monitoring to verify. If necessary re-enter well & squeeze off perforations associated with high permeability units. Lower injection rate/drill additional wells or relocate injection wells
Structure (Primarily Geometry of Base Seal)	CO_2 migration diverges from expected path	Significant CO_2 volumes migrate off structure	Surface and borehole geophysics	Ongoing	Focus monitoring to verify. If necessary modify injection pattern or water production wells to drive migration in desired direction
	Insufficient capacity for planned injected volume of CO_2	Unexpected pressure increase during injection	See Pore Volume	See Pore Volume	See Pore Volume
Compartmen-talization (Fault or Stratigraphic controlled)	CO_2 migration restricted to an isolated part of the formation	Unexpected BHP increase. Pressure transient analysis suggests hydraulically isolated wells	Surface & borehole monitoring	Ongoing	Focus monitoring to verify. If necessary modify complete injection well over entire length of reservoir, produce water & reinject elsewhere or drill additional wells outside of the isolated area
High Permeability Layers	CO_2 migrates rapidly & preferentially along a specific stratigraphic horizon (possibly off structure)	Indications of rapid migration through a restricted stratigraphic horizon. Lower than expected downhole pressure & flow rate	Surface seismic or borehole (production logging) monitoring. Wellhead & bottom hole pressure/flow	6-12 mos. to Ongoing	Focus monitoring to verify. If necessary re-enter well & squeeze off perforations associated with high permeability units, modify injection pattern to accommodate or reduce planned total injection volumes
Hydrodynamic Gradients	CO_2 migration path diverges from expected	Significant CO_2 volumes migrate off structure	Surface and borehole monitoring	0-10 years	Focus monitoring to verify. If necessary modify injection pattern or water production wells to drive migration in desired direction
Monitoring (Seismic Resolution)	Subsurface CO_2 is not seismically resolvable	Limited or absence of plume images via seismic	Borehole geophysics	5-10 years	Alter monitoring activities to determine if alternative geophysical methods are effective or develop an alternative observation well-based strategy
Micro Seismicity	Excessive microseismicity attributed to CO_2 injection	Subsidence and seismicity above background levels	Passive seismic/tilt meters	Ongoing	Focus monitoring to verify. If necessary undertake actions to reduce pore pressure & distribution
	Seismicity induced as result of CO_2 injection	Indications of significant fracturing/faulting	Passive seismic/tilt meters	Ongoing	Focus monitoring to verify. If necessary undertake actions to reduce pore pressure (injection pattern, water production or reduced injection volume)
Residual Oil Saturation	Poor injectivity due to oil presence reduction of relative permeability to CO_2	Unexpected BHP increase	Well head & downhole P gauges & flow rate gauges	0-5 years	Focus monitoring to verify. Undertake actions to reduce pressure increase (see Injectivity)

Summary & Discussion

Existing pilot, demonstration and commercial storage projects have demonstrated that CO_2 geological storage is technically feasible. However, these projects do not operate at a scale that is necessary to result in a significant reduction in greenhouse gas emissions into the atmosphere. The infrastructure (platforms, wells, pipelines, compressors) for injecting carbon dioxide will be an order of magnitude larger than current petroleum installations. Also, injectivity of geological formations within adequate distance from industrial point sources may be of lower quality than has been encountered in existing projects. Reservoir quality information is particularly sparse for deep saline aquifers, resulting in large uncertainties in storage capacity estimations and forecasting of injectivity and sweep efficiency. In most cases, it can be expected that the CO_2 injection scheme will have to consist of multiple wells, potentially including wells for monitoring and pressure control. Therefore, it is critical to develop efficient and cost-effective injection strategies that minimise the number of wells and maximise the injection volume and injectivity.

Previous studies and methodologies for storage capacity assessment have largely used a volumetric approach. However, modelling studies and experience from existing operations (i.e., In Salah) have shown that one major limiting factor for CO_2 storage is the injectivity of the injection horizon. In other words, the injection rate is limited by the maximum allowed bottom-hole injection pressure which is determined by the fracture pressure. Analytical models based on well hydraulics and numerical multiphase fluid flow codes can be used to estimate injection pressures for potential storage projects. Analytical models have the advantage that they are easy and quick to use, which is particularly helpful for screening purposes and analytical well equations are widely used in the petroleum industry. However, most existing equations that calculate injection pressures do not account for miscibility of the injected fluid with formation water and gravity effects, and are valid only for moderately compressible fluids. Neglecting these processes can result in the over- or underestimation of reservoir pressures, particularly for high injection rates, low permeabilities and bounded reservoirs. Depending on the specific case of injection schemes, analytical models can still produce adequate estimates of reservoir pressure. The model developed by Mathias et al. (2008; 2009), which is based on Buckley-Leverett flow and considers two-phase injection (but no mixing) produces results for a wide range of reservoir and injection parameters. It is relatively easy to implement in a spreadsheet application because it does not have excessive data requirements and does not need the input of a somewhat arbitrary "effective radius" or "radius of affected area".

More sophisticated equations that account for relative permeability effects in zones of dry CO_2 (near borehole), CO_2-brine, and brine mixing (i.e., Burton and Bryant, 2008; Economides and Ehlig-Economides, 2009) may produce more precise results, but also require elaborate calculation or measurement of fluid saturation-relative permeability relationships. Running a simple numerical model, which would also account for gravity effects, might actually require less time to set up and run.

For a more detailed assessment, numerical models are the only means to adequately capture impacts of reservoir heterogeneity, multiphase fluid flow behaviour and fluid-rock interactions on the pressure distribution in the subsurface. A multitude of commercial and scientific codes have been developed or adjusted for the modelling of CO_2 migration in the subsurface. Code comparison exercises and application of the various modelling codes for existing CCS projects have shown that numerical modelling of CO_2 transport modelling is in a very advanced stage. Still, more data from actual injection projects is needed to verify model predictions and to establish critical parameters like relative permeability and their scaling behaviour.

Despite the advanced understanding of subsurface flow processes and development of modelling tools, there are still some conflicting results in the literature on the estimation of pressure build-up, resulting number of injection wells required for large-scale CO_2 geological storage and storage efficiency. On one extreme end of the spectrum, Economides and Ehlig-Economides (2009) conclude that based on their analytical equations and numerical modelling efforts, only between 0.01 and 1 % of the pore volume are accessible for CO_2 storage. Their findings, based on the example of a relatively thin (30 m) reservoir (depth = 1830 m, k = 100 mD, 20 % porosity), suggest that for a small number of wells a laterally extensive reservoir was needed, whereas a moderately-sized reservoir would require hundreds of wells, rendering large-scale injection of CO_2 over 3 Mt/year unfeasible.

Similarly, modelling of a wide range of reservoir properties and injection rates by Zakrisson et al., (2008) and Cinar et al. (2008) resulted in a relatively high number of required injection wells for industrial-scale injection rates. Generally, it appears that these high well numbers are the result of injectivity models that assume relatively high residual water saturation (i.e., S_{wr} = 0.6, Economides and Ehlig-Economides, 2009) and/or a somewhat related low value for CO_2 relative permeability.

In contrast, modelling results for the Gorgon project suggest that up to 4.5 MtCO_2/year can be safely injected through 9 wells into a reservoir with 25 mD permeability (depth = 2300 m, 20 % porosity), but 4 water production wells are needed to manage reservoir pressures. At In Salah (depth = 1830 m, k = 5 mD, thickness = 30 m), approximately 1 MtCO_2/year are currently injected through 3 wells with horizontal completions up to 1500 m in length. Unfortunately, it is difficult to adequately compare the results from the different studies, because underlying model parameters and boundary conditions, as well as the employed modelling techniques, are different from case to case. Still, the examples of existing sites injecting in the order of 1 Mt/year, even in low-permeability reservoirs as in the case of In Salah, favour the more optimistic estimates. However, injection schemes may have to be optimised by employing horizontal well technology and/or pressure management wells.

As pressure build-up due to injection in both saline aquifers and depleted hydrocarbon reservoirs is probably the most limiting factor for large-scale geological storage, strategies for pressure management will need to be considered for most future CCS projects. Including water production wells in a storage operation as proposed for the Gorgon project in Western Australia seems to be the obvious choice for relieving any potential pressure build-up in the injection formation. Production wells have the additional safety benefits of a) conferring a degree of control over the direction of plume migration as shown in CO_2 EOR applications and b) providing a means of artificially increasing CO_2 dissolution in formation water. A disposal option for the produced formation water, particularly if saline and in an onshore environment, might pose a problem, depending on the local geology and regulations. In the end, the decisions to use water relief wells is a trade-off between: (a) the costs of such wells together with associated water disposal and (b) the costs of additional injection wells to maintain injectivity in the absence of pressure relief wells.

Co-injection of water and CO_2, either alternating through the same well (WAG) or simultaneously via different injectors (SWAG) has been successfully implemented in EOR operations and should be directly applicable to CO_2 geological storage. In the latter case, co-injection of water could be used even more broadly to direct the CO_2 plume and maximise storage capacity by accessing lower-permeability pore space that would otherwise have been by-passed by the injected gas, because in contrast to the EOR case, the injected CO_2 does not need to target a specific hydrocarbon-bearing horizon. Optimisation of producer-injector configurations and alternating well operations through out a multi-well field according to the geology could be used to spread out the plume, increase the area contacted by the injected CO_2 and thereby increasing the dissolution rate, the residually trapped CO_2 and, ultimately, storage efficiency.

Dissolution of CO_2 in water prior to injection would increase storage safety because CO_2 would not be present in the subsurface in a buoyant separate fluid phase. However, additional energy for surface compression of CO_2 as well as large volumes of water are needed for this option. Surface dissolution and injection of sour water is used in acid-gas disposal operations, but it appears to be feasible only for cases with a sufficient source of disposal water, high permeability reservoirs, large storage volume and/or relatively low injection rates.

The design of CO_2 injection wells, wells cements and stimulation methods are well-developed as result of petroleum industry experience of EOR and acid-gas disposal operations. In addition, remediation options have been successfully applied to operational problems encountered with EOR (corrosion, channelling & early breakthrough, hydrate formation, scaling, asphaltene deposition) that would help to solve similar problems in CO_2 storage operations.

Recently, an increasing amount of research has been concerned with the issues of regional containment, brine displacement and potential impacts of large-scale CO_2 geological storage on shallow groundwater resources. For these issues, there do not appear to be adequate analogues. Some EOR operations have comparable number of injections wells, but by the nature of these operations, the extent of pressure build-up is well-constrained by production and partial recycling of injected CO_2. Waste water disposal may be associated with large injection rates, but involves single-phase flow concepts. As a result, studies on the regional impacts of CO_2 storage and the role of hydraulic properties of the sealing unit have been limited to more or less generic numerical modelling exercises (Nicot, 2008; Birkholzer et al., 2009; Chadwick et al., 2009; Yamamoto et al., 2009). Unless model results can be verified with actual measurements, uncertainty in model parameters like relative permeability and the representativeness of up-scaling are aspects that remain unconstrained regardless of the conclusions drawn from such studies.

Probably the largest uncertainty of CO_2 storage is associated with the economics of such operations. Storage costs strongly correlate with injectivity. Therefore the potential variations in injectivity parameters have a significant impact on the economics.

- Permeability - all other things being the same, costs per tonne avoided decrease sharply with increasing permeability up to a point when further permeability increases results only in slight cost reduction. A high permeability target reservoir means that few wells are required. However, further increases in permeability cannot further reduce the number of wells required so does not significantly reduce costs.

- Injection rate - all other things being the same, increasing flow rates increases injection costs because more injection wells are required.
- Formation thickness: -all other things being the same, a decrease in formation thickness results in a larger number of wells for the same injection rate. Therefore, costs increase.
- Formation depth/ fracture gradient - all other things being the same, the allowable pressure build-up (difference between initial formation pressure and fracture pressure) increases with depth. Thus, as depth increases, it is easier to inject more CO_2. The larger available pressure-range at greater depths means that deeper wells are less sensitive to variations in permeability. Moreover, CO_2 can be stored at greater densities in deeper formations. This will be offset to some extent by the higher costs of deep wells.
- Well type - all other things being the same, at high permeabilities vertical wells are cheaper than horizontal wells, whereas the opposite is true for low permeabilities.
- Hydraulic fracturing - all other things being the same, fracturing can reduce cost in low-permeability environments (less than 10 mD). However, at higher permeabilities, the increased permeability does not reduce the number of wells as significantly.

A key component of the economics of injection is the cost of wells, which clearly depends on the number and type of wells required. The number of injection wells required is determined by the geological characteristics of the injection reservoir and multiphase flow properties.

For a given well spacing, the higher the CO_2 injection rate, or the longer the injection period, the greater is the interference between injection wells, which in turn increases the requirement for injection wells and the costs. Alternatively, we might drill water production wells – pressure relief wells – to improve injectivity. However, this would also require water handling facilities at the injection site. In the end, therefore, it comes down to a trade-off between: (a) the costs of injection wells and (b) the costs of water relief wells and the associated costs of water handling. The engineering and economic analysis and optimisation of the trade-off require a detailed knowledge of the characteristics of the reservoir. In other words, both require a good geological model and a detailed reservoir simulation.

In addition, there are trade-offs with transport distance. Distant storage sites with high injectivity become cheaper compared to closer sites with low injectivity if the injection rate reaches a certain threshold on the order of 5 Mt/year. The engineering and economic analysis and optimisation of the trade-offs require a detailed knowledge of the characteristics of the reservoir. In other words, both require well-defined geological models and detailed reservoir simulation.

This report and the discussion in this section has largely ignored the analysis of uncertainties in predicting reservoir properties and therefore in predicting injectivity. However, this factor will clearly affect the design of the injection system. Strategies and contingencies will need to be incorporated in development plans to allow for unforseen changes in injection conditions during project life. As an example, 9 injection wells are planned for the Gorgon CO_2 injection project in Western Australia. However, the Gorgon joint venture has also made contingency plans for additional wells to take into account unexpected reservoir behaviour during the injection process.

The fact that there will always be uncertainties in predicting reservoir properties also implies that there will be a range of views on injectivity and the required number and type of injection wells required for a given CO_2 injection scheme. Therefore, because of subsurface and economic uncertainties, different companies are likely to have different injection strategies, similar to the different approaches in the exploration and exploitation of petroleum resources.

Appendix: First-Order Evaluation Tools for CO_2 Storage Schemes

Two Excel[TM] spreadsheets for evaluating CO_2 injection options accompany this report. The first spreadsheet estimates fluid properties and maximum injection pressures for selected reservoir characteristics and operational parameters of potential CO_2 injection projects and is based on analytical well equations, equations of state and other approximation methods from the petroleum literature. The second spreadsheet combines first-pass engineering and economics estimates of well numbers, injection pipeline distribution requirements and injection costs. The spreadsheet incorporates a look-up table that contains the results of a set of generic reservoir simulations and economic analyses that give estimates of CO_2 injection costs for user-specified input parameters.

Both spreadsheet tools can be used for screening purposes in the early planning stages of a CO_2 geological storage site. Both spreadsheets show estimates of well numbers and other injection conditions, but these are likely to be different because they are based on different approaches.

Due to the simplified underlying assumptions and large uncertainties associated with the evaluation tools, resulting estimates of parameters like maximum injection pressure, number of required injection wells and costs should be regarded as first-order approximations and considered with caution. The next, more rigorous stage in the planning process of a storage site would need to involve numerical reservoir simulations, detailed engineering of the injection system design, as well as detailed cost estimation based on vendor quotes.

Fluid property and injection pressure model

The calculations in this ExcelTM spreadsheet are based on published equations in the petroleum literature. As calculations are based on homogeneous reservoir characteristics, the accuracy of the respective results will probably decrease with increasing injection volumes as the CO_2 plume comes in contact with larger portions of the reservoir (please see report text for a further discussion of applicability and limitations of these equations).

Input

Following are the input parameters to be entered by the user:

Reservoir parameters: depth, thickness, formation pressure, temperature, permeability, porosity, residual water saturation, brine salinity, fracture gradient, and, for bounded reservoirs, areal extent and reservoir shape factor.

Operation parameters: CO_2 injection rate, years of injection, well radius, and, for multi-well injection schemes, number of wells, well spacing

Output

The output fields in the spreadsheet are calculated and should not be changed by hand. The first set of output parameters consists of an estimation of fluid properties that follows largely the methodology proposed by Mathias et al. (2009). The fluid properties at reservoir conditions and references for underlying calculation methods are:

CO_2 density: interpolated from look-up table based on EOS by Span and Wagner (1996)
CO_2 viscosity: (Mathias et al., 2009)
CO_2 compressibility: (Bear, 1979)
Brine density: (Batzle and Wang, 1992)
Brine viscosity: (Batzle and Wang, 1992)
Brine compressibility: (Bear, 1979)

The CO_2 phase diagram displays lines of density variations with temperature for distinct pressure intervals as well as the CO_2 density for the selected pressure-temperature reservoir conditions.

The second set of output parameters consists of estimates of maximum bottomhole injection pressures (BHIP) at the end of injection using different analytical solutions, radius of influence, maximum injection rates and required numbers of injectors:

BHIP (single phase): Equation (4) – (Cinar et al., 2008)
BHIP (2-phase/fixed radius): Equation (10) - (van der Meer & Egberts (2008)
BHIP (2-phase/Buckley-Leverett): Equation (12) - Mathias et al. (2009)
Radius of CO_2 plume: Equation (7) - Nordbotten et al. (2005)
Radius of CO_2 front: Equation (6)
Radius of pressure front: Equation (8)
Percent of fracture pressure: BHIP/ (Depth * fracture gradient) * 100
Maximum injection rate: Equation (10) (solved for rate and 10 % of fracture pressure)
Required number of injectors: Injection rate/Maximum injection rate (rounded up); assumes no interference between injection wells

BHIP (bounded reservoir): Equation (9)
Percent of fracture pressure (bounded reservoir): BHIP/ (Depth * fracture gradient) * 100
Maximum injection rate (bounded reservoir): Equation (9) (solved for rate and 10 % of fracture pressure)

BHIP (multi-well injection): Equation (5)
Percent of fracture pressure (multi-well injection): BHIP/ (Depth * fracture gradient) * 100

Injection cost model

Aim

This Excel™ Based Injection Cost Model is a simplified model that calculates the costs of CO_2 injection based on the data and assumptions that have been specified by users.

The spreadsheet is intended to give very broad-brush, first-pass indications of the costs of injection for a limited set of injection conditions. It is not intended to replace reservoir simulation and detailed costing studies as would be required for a proper evaluation of an injection scheme. Under no circumstances should the spreadsheet be relied on to for detailed evaluations to assist in making investment decisions on a CO_2 injection programme.

Compatibility

This model needs to be operated using Microsoft Excel 2007; it will not work with any older forms of Excel. Enable macros after you open the model. You can do this by clicking the Microsoft Office button, going to Excel Options, Trust Centre, Trust Centre Settings, Macro Settings and then selecting "Enable all Macros".

Limits and restrictions

This injection cost model is a simplified model that calculates the costs of CO_2 injection based on practical experience. More detailed and extensive feasibility studies, based on more data, need to be undertaken before investment in any CO_2 transport and injection projects could be considered.

The limits and restrictions of this model include -

- The model does not calculate the costs of CO_2 capture, including the cost of any compression required at the source and the cost of transport from the source to the injection site. The model does include the costs of compressing CO_2 from a starting pressure of 8,000 kPa before injection.

- The model assumes that energy from gas-fired power plants is used to provide the additional energy required for injection operations. The power plants do not have capture facilities.

- The model does not include the cost of installing power transmission lines to provide power for compression at the point of injection.

- The maximum construction time the model can handle is 10 years. The maximum injection time the model can handle is 50 minus the construction time. The model assumes one year for decommissioning.

- The model can only be applied to vertical wells.

- The product of the permeability, porosity and pressure difference (khΔP) defined by users should range from 1,222 to 1,900,000 mD·m·MPa. Any values outside this range will result in errors or unreliable results.

Contents

The model contains four sheets including this instruction sheet. The other three sheets are "Glossary", "In-Out" and Calculation".

The "Glossary" sheet contains the glossary of the terms used in the model and some useful unit conversion factors. The "In-Out" sheet is the main sheet where input data is entered and results are obtained. The "Calculation" sheet contains more detailed assumptions, calculations and results.

Entering Data in the "In-Out" sheet

Go to the "In-Out" sheet, enter data or select data from the drop-down lists in white cells in the "INPUTS" table; obtain results in the "OUTPUTS" table.

In the "INPUTS" table, select a currency in cell D5 from the drop-down list.
Note that, all inputs must be in US dollars; the model simply converts the outputs into the currency of your choice.

In cell D6, enter the CO_2 flow rate in million tonne per year. This model assumes pure CO_2 at 8000 kPa.

In cell D7, select "onshore" or "offshore" for the injection environment. This determines whether or not platforms are required.

In cells D9 to D13, enter the key formation properties – thickness, permeability, injection depth, formation pressure and fracture pressure for the storage formation. Based on the data entered, the model will calculate the product of permeability, thickness and pressure difference (khΔP). A search is made of a list of defined generic formations to find a formation with a khΔP closest to the calculated khΔP. Based on the formation selected and the flow rate defined, the model will work out the number of wells required.

In cell D16, select one of the four methods for calculating well costs. The choice depends on how much information you have on well costs. If you have aggregated cost data, you might choose Method 1. If you have more detailed information, you might choose Methods 3 or 4. Default data are provided for each method. This model only calculates costs for vertical wells.

- If Method 1 is selected, enter the mob/demob costs and unit well cost.

Total capital costs of injection wells = number of wells * unit well cost + mob/demob costs.

- If Method 2 is selected, enter the mob/demob costs, rig-rate, ratio of day-rate to rig-rate and the drilling time required on the well-site.

Unit well costs = rig-rate * ratio of day-rate to rig-rate * drilling time on well-site

• If Method 3 is selected, enter the mob/demob costs, rig-rate, ratio of day-rate to rig-rate, pre-spud time, slope and exponent for time-to-depth curve and the ratio of completion-time to drilling time.

Drilling time on well-site = pre-spud time + slope * e^(exponent*injection depth in km) * (1 + ratio of completion-time to drilling time)

Unit well costs = rig-rate * ratio of day-rate to rig-rate * drilling time on well-site

If you would like to select Method 3, but do not know the slope and exponent of the time-to-depth curve, you could select Method 4 and provide two sets of data on depth and drilling time in cells C40 to D41. The model will then work out the slope and the exponent for you.

Obtaining results

After entering all of the data required, you can obtain results in the "OUTPUTS" table on the right hand side of the "In-Out" sheet. The results include a break down of capital costs, total CO_2 avoided, annual operating costs, total decommissioning costs, present value of all costs and the specific cost of CO_2 avoided. More detailed results can be found in the "Calculation" sheet.

The "Calculation" sheet contains more detailed information on our assumptions and calculations.

In the sheet, yellow cells are input cells; pink cells are output cells; grey cells are calculations. The values in the input cells are our default assumptions and can be altered when necessary. Do not change the values or formulae in the pink and grey cells.

The "Calculation" sheet has three main sections – Case Description, Assumption and Results.

1. Case Description

The "Case Description" table describes the cases with the flow rate, storage environment, injection well type and the storage formation that the model selected based on the formation properties specified.

2. Assumptions

The "Assumptions" section contains the assumptions made for calculating the number of wells, and various costs.

Economics

The first table under "Assumptions" gives basic economic assumptions. The model calculates the present value of costs using a real discount rate of 7%. The model also assumes a construction period of 3 years and has a default injection period of 25 years after which the project is decommissioned. However, both the construction and injection periods can be altered as long as this does not result in a total longer than 50 years.

Costs as % of Capex

The second table specifies the capital cost phasing, the fixed operating costs and decommissioning costs as a percentage of the total capital costs. If an extra power plant is added, the model will assume default settings of 3 years of construction with 20% of the capital costs spent in year 1, 45% spent in year 2 and 35% spent in year 3. For other injection facilities, the model assumes 2 years of construction with 40% spent in year 2 and 60% spent in year 3. These default settings can be altered, however the capital cost phasing for each facility must add up to 100%.

Present-value factors

The table called “Present-value factors” works out the present-value factors for the costs based on the discount rate assumed and the cost phasing specified in the above table.

Currency

The fourth table contains the currency exchange rates assumed in the model. The exchange rates are the average 2009 rates from January to October.

Reservoir properties and storage sites

The following two tables show the reservoir properties for the 36 generic storage formations we simulated and work out the number of wells required.

We assume a range of permeability, formation thickness and depth from low to extra high. The various combinations of these parameters give 100 generic analyses. The other properties such as areal extent, porosity, formation temperature, formation pressure gradient and fracture pressure gradient are assumed to be the same for all the analyses.

The required number of injection wells is estimated using simple reservoir simulations. A simulation is set up for each formation. Injection takes place in the centre of the formation and occupies 25% of the total area. This assumption is made based on factors such as basin heterogeneity and structure, faulting and sweet spots for injection which mean that the whole basin will not necessarily be available for injection. However, increasing the injection area is expected to increase injectivity for a given total injection rate. Yet, increasing the injection area within the basin lowers the aquifer strength, so that the overall injectivity is not expected to increase significantly.

For each formation and a given number of injection wells, our repeated simulations have established the maximum rate of CO_2 that can be injected over 25 years without the pressure in the reservoir exceeding its fracture pressure. The maximum rate was then established for different numbers of wells. This model interpolates the results from the simulations, and then calculates the theoretical number of wells required for the CO_2 flow rate specified.

The reservoir simulations are simple models that take into account non-Darcy flow and well interference, but ignore many factors that would affect the injectivity of a well, such as skin factor, tubing constraints and reservoir heterogeneity. Therefore, we adjust the simulated maximum well injectivity to give an estimate of its practical injectivity. This adjustment is based on an analysis and review of existing CO_2 injection projects worldwide, as well as discussions and advice from professionals in the industry. Using this adjustment, the model calculates the practical number of wells required.

Well costs

This table summarises the information on well costs based on the method selected and the data entered.

NGCC power plant

The model assumes that energy from gas-fired power plants is used to provide the additional energy for injection operations. These power plants do not have capture facilities. The parameters assumed for power plants can be altered in this table.

3. Results

There are three tables in the "Results" section – (a) engineering results, (b) power and CO_2 results and (c) economic results.

Engineering results

The engineering results include the number of wells, number of platforms, slots per platform, well-spacing and distribution network length.

We have not modeled the injection pipeline distribution system in detail. We assume a simple pipeline connection pattern.

Power and CO_2 results

The power and CO_2 results summarise the extra power and electricity needed for the injection booster and the annual, total and present value of CO_2 flows.

The model calculates the injection booster duty.

Economic results

The "Economic results" table gives a summary of capital costs, operating costs, decommissioning costs, the present value of costs and specific costs of CO_2 injected/avoided.

The capital costs for the injection booster, distribution network and injection platforms are calculated by the model.

Disclaimer
CO2CRC has prepared this spreadsheet using reasonable care and skill consistent with normal industry practice.

The spreadsheet is designed to supply a limited set of indicative, preliminary estimates and should not be relied upon as a sole input to business decisions. Forecasts are inherently uncertain because of events or combinations of events that cannot be foreseen including the actions of government, individuals and third parties. No implied warranty of merchantability or fitness for a particular purpose applies.

References:

Allinson, W.G., Ho, M.T., Neal, P.R., Wiley D.E., The methodology used for estimating the costs of CCS, In Proceedings of the 8th International Conference on Greenhouse Gas Control Technology (GHGT-8), Trondheim, Norway, 19–22 June 2006

Apps, J. A., 2005, The regulatory climate governing the disposal of liquid waste in deep geologic formations: A paradigm for regulations for the sbusurface storage of CO_2, *in* D. Thomas, and S. M. Benson, eds., Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2 Capture Project, v. 2, Elsevier, p. 1173-1188.

Apps, J. A., and C. F. Tsang, eds., 1996, Deep injection disposal of hazardous and industrial waste: scientific and engineering aspects: San Diego, CA, Academic Press, 775 p.

Arts, R., A. Chadwick, O. Eiken, S. Thibeau, and S. L. Nooner, 2008, Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway: First Break, v. 26.

Awan, A. R., R. Teigland, and J. Kleppe, 2008, A survey of North Sea enhanced-oil-recovery projects initiated during the years 1975 to 2005: SPE Reservoir Evaluation & Engineering, v. 11, p. 497-512.

Bachu, S., D. Bonijoly, J. Bradshaw, R. C. Burruss, S. Holloway, N. P. Christensen, and O. M. Mathiassen, 2007a, CO_2 storage capacity estimation: Methodology and gaps: Int. J. Greenhouse Gas Control, v. 1, p. 430-443.

Bachu, S., S. E. Dashtgard, M. Pooladi-Darvish, S. Theys, and R. Stocker, 2007b, Analysis of acid gas injection in the Long Coulee Glauconite F Pool, Alberta Geological Survey/Alberta Energy and Utilities Board, p. 76.

Bachu, S., S. E. Dashtgard, M. Pooladi-Darvish, S. Theys, and R. Stocker, 2008, Analysis of the effects of acid gas injection in the Retlaw Mannville Y Pool, Alberta Geological Survey Report/Alberta Energy and Utilities Board, p. 73.

Bachu, S., and W. D. Gunter, 2004, Acid gas injection in the Alberta Basin, Canada: A CO_2 storage experience *in* S. J. Baines, and R. H. Worden, eds., Geological Storage of Carbon Dioxide for Emissions Reduction: Technology: Bath, UK, Geological Society Special Publication, p. 225-234.

Bachu, S., J. M. Nordbotten, and M. A. Celia, 2005, Evaluation of the spread of acid-gas plumes injected in deep saline aquifers in Western Canada as an analogue for CO_2 injection into continental sedimentary basins: Proc. 7th Intl Conf on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada, p. 479-487.

Bachu, S., and T. Watson, 2009, Review of failures for wells used for CO_2 and acid gas injection in Alberta, Canada: Energy Procedia, Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies, Washington, D.C., November 16-20, 2008, v. 1, p. 3531-3537.

Baklid, A., R. Korbøl, and G. Owren, 1996, Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground aquifer: SPE Annual Technical Conference & Exhibition, Denver, 6-9 October, p. 269-277.

Barlet-Gouédard, V., G. Rimmelé, B. Goffé, and O. Porcherie, 2006, Mitigation strategies for the risk of CO_2 migration through wellbores: IADC/SPE Drilling Conference, Miami, Florida, U.S.A., 21-23 February, p. 1-17.

Batzle, M., and Z. Wang, 1992, Seismic properties of pore fluids: Geophysics, v. 57, p. 1396-1408.
Bear, J., 1979, Hydraulics of groundwater: New York, McGraw-Hill.
Benge, G., and E. G. Drew, 2005, Meeting the challenges in design and execution of two high rate acid gas injection wells: SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February, SPE 91861.
Bennion, D. B., F. B. Thomas, D. W. Bennion, and R. F. Bietz, 1996, Formation screening to minimize permeability impairment associated with acid-gas or sour gas injection/disposal: Petroleum Society of the Canadian Institute of Mining and Metallurgy, 47th Annual Technical Meeting, Calgary, June 10–12, 1996, Paper 96–93.
Bentham, M., and G. Kirby, 2005, CO_2 storage in saline aquifers: Oil Gas Sci. Technol., v. 60, p. 559-567.
BERR (Department for Business Enterprise and Regulatory Reform) in association with Element Energy, Pöyry Energy and the British Geological Survey, 2007. Development of a CO_2 Transport and Storage Network in the North Sea, North Sea Basin Task Force, UK Department for Business, Enterprise & Regulatory Reform, London.
Bickle, M., A. Chadwick, H. E. Huppert, M. Hallworth, and S. Lyle, 2007, Modelling carbon dioxide accumulation at Sleipner: Implications for underground carbon storage: Earth Planet. Sci. Lett., v. 255, p. 164-176.
Birkholzer, J. T., Q. Zhou, and C.-F. Tsang, 2009, Large-scale impact of CO_2 storage in deep saline aquifers: A sensitivity study on pressure response in stratified systems: International Journal of Greenhouse Gas Control, v. 3, p. 181-194.
Bradshaw, J., S. Bachu, D. Bonijoly, R. Burruss, S. Holloway, N. P. Christensen, and O. M. Mathiassen, 2007, CO_2 storage capacity estimation: Issues and development of standards: Int. J. Greenhouse Gas Control, v. 1, p. 62-68.
Bradshaw, J., and T. Dance, 2005, Mapping geological storage prospectivity of CO_2 for the world's sedimentary basins and regional source to sink matching: Proc. 7th Intl Conf on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada, p. 583-591.
Bruno, M. S., M. B. Dusseault, B. T.T., and J. A. Barrera, 1998, Geomechanical analysis of pressure limits for gas storage reservoirs: Int. J. Rock Mech. Min. Sci., v. 35, p. 569-571.
Bryant, S. L., S. Lakshminarasimhan, and G. A. Pope, 2006a, Buoyancy dominated multiphase flow and its impact on geological sequestration of CO_2: SPE/DOE Symposium on Improved Oil Recovery, Tula, Oklahoma, USA, April 22-26.
Bryant, S. L., S. Lakshminarasimhan, and G. A. Pope, 2006b, Influence of buoyancy-driven migration in CO_2 storage capacity and risk assessment: Eighth International Conference on Greenhouse Gas Control Technologies, June 19-22, 2006, Trondheim, Norway.
Burton, M., and S. L. Bryant, 2009, Eliminating buoyant migration of sequestered CO_2 through surface dissolution: implementation costs and technical challenges: SPE Reserv. Eval. Eng., v. 12, p. 399-407.
Burton, M., N. Kumar, and S. Bryant, 2008, Time-dependent injectivity during CO_2 storage: Improved Oil Recovery Symposium, Tulsa, Oklahoma, 19-23 April 2008, SPE 113937.
Buschkuehle, B. E., and K. Michael, 2006, Subsurface characterization of acid-gas injection operations in northeastern British Coulmbia, EUB/AGS Earth Sciences Report, Alberta Energy and Utilities Board / Alberta Geological Survey, p. 154.

Carey, J. W., M. Wigand, S. J. Chipera, G. WoldeGabriel, R. Pawar, P. C. Lichtner, S. C. Wehner, M. A. Raines, and J. G. D. Guthrie, 2007, Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC Unit, West Texas, USA: Int. J. Greenhouse Gas Control, v. 1, p. 75-85.

Carruthers, D. J., 2003, Modeling of secondary petroleum migration using invasion percolation techniques, in S. Duppenbecker, and R. Marzi, eds., Multidimensional basin modeling, , AAPG/Datapages Discovery Series No. 7, p. 21-37.

Cavanagh, A. J., and R. S. Haszeldine, 2009, A calibrated model for the first decade of the Sleipner CO_2 plume development: AAPG/SEG/SPE Hedberg Conference "Geological carbon sequestration: prediction and verification", August 16-19, Vancouver, BC, Canada.

Cavanagh, A. J., and P. Ringrose, 2009, Simulation of CO_2 distribution at the In Salah storage site using high-resolution field scale models: AAPG/SEG/SPE Hedberg Conference "Geological carbon sequestration: prediction and verification", August 16-19, Vancouver, BC, Canada.

Chadwick, R. A., D. J. Noy, and S. Holloway, 2009, Flow processes and pressure evolution in aquifers during the injection of supercritical CO_2 as a greenhouse gas mitigation measure: Petroleum Geoscience, v. 15, p. 59-73.

Chevron, 2005, Draft environmental impact statement/ Environmental review and management programme for the proposed Gorgon development, Chevron Australia Pty Ltd, p. 818.

Chevron, 2006, Final environmental impact assessment and response to submissions on the environmental review and management programme for the proposed Gorgon development, Chevron Australia Pty Ltd, p. 484.

Christensen, J. R., E. H. Stenby, and A. Skauge, 2001, Review of WAG field experience: SPE Reservoir Evaluation & Engineering, v. 4, p. 97-106.

Cinar, Y., O. Bukhteeva, P. Neal, G. Allinson, and L. Paterson, 2008, CO_2 Storage in low permeability formations: SPE/DOE Improved Oil Recovery Symposium held in Tulsa, 19- 23 April 2008, SPE 114028.

Cinar, Y., P. Neal, O. Bukhteeva, G. Allinson, and L. Paterson, 2009a, The trade-off between permeability and distance for CO_2 storage in underground formations: International Journal of Greenhouse Gas Control, v. (submitted).

Cinar, Y., N. P., G. Allinson, and J. Sayers, 2009b, Geoengineering and economic assessment of a potential carbon capture and storage site in southeast Queensland, Australia: SPE Reserv. Eval. Eng., v. 12, p. 660-670.

Class, H., A. Ebigbo, R. Helmig, H. Dahle, J. Nordbotten, M. Celia, P. Audigane, M. Darcis, J. Ennis-King, Y. Fan, B. Flemisch, S. Gasda, M. Jin, S. Krug, D. Labregere, A. Naderi Beni, R. Pawar, A. Sbai, S. Thomas, L. Trenty, and L. Wei, 2009, A benchmark study on problems related to CO_2 storage in geologic formations: Computational Geosciences, v. 13, p. 409-434.

Contek Solutions, 2008, Summary of carbon dioxide enhanced oil recovery (CO_2EOR) injection well technology, prepared for the American Petroleum Institute, p. 63.

Cooper, C., ed., 2009, A technical basis for carbon dioxide storage: CO_2 Capture Project: UK, CPL Press, 92 p.

Craft, B. C., and M. F. Hawkins, 1991, Applied petroleum reservoir engineering. 2nd ed. revised by R.E. Terry: Englewood Cliffs, New Jersey, Prentice-Hall, 431 p.

Dake, L. P., 1978, Fundamentals of reservoir engineering: Amsterdam: Elsevier.

Dashtgard, S. E., M. B. E. Buschkuehle, B. Fairgrieve, and H. Berhane, 2008, Geological characterization and potential for carbon dioxide (CO_2) enhanced oil recovery in the

Cardium Formation, central Pembina Field, Alberta: Bulletin of Canadian Petroleum Geology, v. 56, p. 147-164.

Earlougher, R. C., 1977, Advances in well test analysis, vol. 5: SPE Monograph Series: Richardson,TX.

Economides, M. J., and C. A. Ehlig-Economides, 2009, Sequestering carbon dioxide in a closed underground volume: SPE Annual Technical Conferences & Exhibition, New Orleans, Louisiana, 4-7 October 2009, SPE 113937, p. 1-8.

Ertekin,T., J. Abou-Kassem and G. King, 2001. Basic applied reservoir simulation: SPE Textbook Series Vol 7, Society of Petroleum Engineers, Richardson, Texas, USA.

Flett, M. A., R. M. Gurton, and I. J. Taggart, 2005, Heterogeneous saline formations: Long-term benefits for geo-sequestration of greenhouse gases: Proc. 7th Intl Conf on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada, p. 501-509.

Flett, M., R. Gurton, and G. Weir, 2007, Heterogeneous saline formations for carbon dioxide disposal: Impact of varying heterogeneity on containment and trapping: Journal of Petroleum Science and Engineering, v. 57, p. 106-118.

Flett, M., G. Beacher, J. Brantjes, A. Burt, C. Dauth, F. Koelmeyer, R. Lawrence, S. Leigh, J. McKenna, R. Gurton, W. F. Robinson IV, and T. Tankersley, 2008, Gorgon project: subsurface evaluation of carbon dioxide disposal under Barrow Island: SPE Asia Pacific Oil and Gas Conference and Exhibition, 20-22 October 2008, Perth, Australia, SPE 116372, p. 21.

Geertsma, J., 1974, Estimating the coefficient of inertial resistance in fluid flow through porous media: SPE J., SPE 4706, p. 445-450.

Gibson-Poole, C. M., L. Svendsen, J. Underschultz, M. N. Watson, J. Ennis-King, P. J. van Ruth, E. J. Nelson, R. F. Daniel, and Y. Cinar, 2006, Gippsland Basin geosequestration - a potential solution for the Latrobe Valley brown coal CO_2 emissions: APPEA J., v. 46, p. 413-433.

Gorecki, C. D., Y. I. Holubnyak, S. C. Ayash, J. M. Bremer, J. A. Sorensen, E. N. Steadman, and J. A. Harju, 2009, A new classification system for evaluating CO_2 storage resource/capacity estimates: SPE International Conference on CO_2 Capture, Storage, and Utilization, November 2-4, 2009, San Diego, California USA, SPE 126421.

Green, C., and J. Ennis-King, in press, Effect of vertical heterogeneity on long-term migration of CO_2 in saline formations: Transport in Porous Med.

Green, C., J. Ennis-King, and K. Pruess, 2009, Effect of vertical heterogeneity on long-term migration of CO_2 in saline formations: Energy Procedia, v. 1, p. 1823-1830.

Gunter, W. D., S. Bachu, B. E. Buschkuehle, K. Michael, G. Ordorica-Garcia, and T. Hauck, 2009, Reduction of GHG emissions by geological storage of CO_2: Anatomy of the Heartland Aquifer Redwater Carbon Capture and Geological Storage Project (HARP), Alberta, Canada: International Journal of Climate Change Strategies and Management, v. 1, p. 160-178.

Han, W. S., and B. J. McPherson, 2009, Optimizing geologic CO_2 sequestration by injection in deep saline formations below oil reservoirs: Energy Convers. Mgmt, v. 50, p. 2570-2582.

Hassanzadeh, H., M. Pooladi-Darvish, A. M. Elsharkawy, D. W. Keith, and Y. Leonenko, 2008, Predicting PVT data for CO_2-brine mixtures for black-oil simulation of CO_2 geological storage: Int. J. Greenhouse Gas Control, v. 2, p. 65-77.

Hesse, M. A., H. A. Tchelepi, and F. M. Orr Jr, 2006, Scaling analysis of the migration of CO_2 in saline aquifers: SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 24-27, SPE 102796.

Hesse, M. A., H. A. Tchelepi, B. J. Cantwell, and F. M. Orr, 2007, Gravity currents in horizontal porous layers: transition from early to late self-similarity: J. Fluid. Mech., v. 577, p. 363-383.

Hesse, M. A., F. M. Orr, and H. A. Tchelepi, 2008, Gravity currents with residual trapping: Journal of Fluid Mechanics, v. 611, p. 35-60.

Hirsch, I. M., and A. H. Thompson, 1995, saturations and buoyancy in secondary migration: AAPG Bull., v. 79, p. 696-710.

Horne, R. N., 2005, Modern well test analysis: Palo Alto, CA, Petroway, 2 ed.

Hubbert, M. K., 1953, Entrapment of petroleum under hydrodynamic conditions.: AAPG Bull., v. 37, p. 1944-2026.

Ide, S. T., K. Jessen, and F. M. Orr, 2006, Time scales for migration and trapping of CO_2 in saline aquifers: Eighth International Conference on Greenhouse Gas Control Technologies, June 19-22, 2006, Trondheim, Norway.

Ide, S. T., K. Jessen, and F. M. Orr, 2007, Storage of CO_2 in saline aquifers: Effects of gravity, viscous, and capillary forces on amount and timing of trapping: Int. J. Greenhouse Gas Control, v. 1, p. 481-491.

IEAGHG (International Energy Agency Greenhouse Gas R&D Programme), 2008. Aquifer Storage – Development Issues, Technical Report 2008/12 prepared for the IEA Greenhouse Gas R&D Programme by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), Australia, p. 187.

IEAGHG, 2009a, CO_2 storage in depleted oil fields: global application criteria for carbon dioxide enhanced oil recovery, Technical Report 2009/1 for the IEA Greenhouse Gas R&D Programme by Pöyry Energy Consulting in conjunction with Element Energy and British Geological Survey (BGS), UK, p. 101.

IEAGHG, 2009b, Long term integrity of CO2 storage – well abandonment. Technical Report 2009/08 for the IEA Greenhouse Gas R&D Programme by The Netherlands Organisation for Applied Scientific Research (TNO).

IEAGHG, 2009c, CCS site selection and characterisation criteria. Technical Report 2009/10 for the IEA Greenhouse Gas R&D Programme by Bachu, S., Hawkes, C.D., Lawton, D., Pooladi-Darvish, M. and Perkins, E., p. 121.

IEAGHG, 2009d, CO_2 storage in depleted gas fields: global application criteria for carbon dioxide enhanced oil recovery. Technical Report 2009/12 for the IEA Greenhouse Gas R&D Programme by Advanced Resources International Inc. and Melzer Consulting, p. 153.

IEAGHG, 2009e, Development of storage coefficients for carbon dioxide storage in deep saline formations. Technical Report 2009/13 for the IEA Greenhouse Gas R&D Programme by the Energy & Environmental Research Center (EERC), University of North Dakota, p. 105.

IPCC (Intergovernmental Panel on Climate Change), 2005, IPCC special report on carbon dioxide capture and storage: prepared by Working Group III of the Intergovernmental Panel on Climate Change: Cambridge and New York, Cambridge University Press, 442 p.

Jacquemet, N., J. Pironon, and J. Saint-Marc, 2007, Mineralogical changes of a well cement in various H_2S-CO_2(-brine) fluids at high pressure and temperature: Environ. Sci. Technol., v. 42, p. 282-288.

Johnson, J. W., and J. J. Nitao, 2003, Reactive transport modeling of geologic CO_2 sequestration at Sleipner: Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1-4, Kyoto, Japan, p. 327-332.

Juanes, R., E. J. Spiteri, F. M. Orr Jr, and M. J. Blunt, 2006, Impact of relative permeability hysteresis on geological CO_2 storage: Water Resour. Res., v. 42, p. W12418:1-13.

Keith, D. W., H. Hassanzadeh, and M. Pooladi-Darvish, 2005, Reservoir engineering to accelerate dissolution of stored CO_2 in brines: Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada, p. 2163-2167.

Kopp, A., H. Class, and R. Helmig, 2009a, Investigations on CO_2 storage capacity in saline aquifers--Part 2: Estimation of storage capacity coefficients: International Journal of Greenhouse Gas Control, v. 3, p. 277-287.

Kopp, A., H. Class, and R. Helmig, 2009b, Investigations on CO_2 storage capacity in saline aquifers: Part 1. Dimensional analysis of flow processes and reservoir characteristics: International Journal of Greenhouse Gas Control, v. 3, p. 263-276.

Kopperson, D., S. Horne, G. Kohn, D. Romansky, C. Chan, and G. L. Duckworth, 1998a, Injecting acid gas with water creates new disposal option: Oil Gas J., v. 96, p. 33-37.

Kopperson, D., S. Horne, G. Kohn, D. Romansky, C. Chan, and G. L. Duckworth, 1998b, Two cases illustrate acid gas/water injection scheme: Oil Gas J., v. 96, p. 64-70.

Krumhansl, J. L., R. Pawar, R. B. Grigg, H. R. Westrich, N. R. Warpinski, D. Zhang, C. Jove-Colon, P. C. Lichtner, J. C. Lorenz, R. K. Svec, B. A. Stubbs, S. P. Cooper, C. Bradley, and J. Rutledge, 2002, Geological sequestration of carbon dioxide in a depleted oil reservoir: SPE/DOE Improved Oil Recovery Symposium, 13-17 April 2002, Tulsa, Oklahoma, SPE 75256, p. 1-8.

Kumar, A., M. Noh, G. A. Pope, K. Sepehrnoori, S. Bryant, and L. W. Lake, 2004, Reservoir simulation of CO_2 storage in deep saline aquifers: SPE/DOE Fourteenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, USA 17-21 April.

Kumar, A., M. H. Noh, G. A. Pope, K. Sepehrnoori, S. L. Bryant, and L. W. Lake, 2005, Simulating CO_2 storage in deep saline aquifers, *in* D. Thomas, and S. M. Benson, eds., Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2 Capture Project, v. 2, Elsevier, p. 877-896.

Kunz, O., R. Klimeck, and W. Wagner, 2007, The GERG-2004 wide-range equation of state for natural gases and other mixtures: Technical Report, Groupe Européen de Recherches Gazières, 2007.

Kutchko, B. G., B. R. Strazisar, D. A. Dzombak, G. V. Lowry, and N. Thaulow, 2007, Degradation of well cement by CO_2 under geologic sequestration conditions: Environ. Sci. Technol., v. 41, p. 4787-4792.

Larson, R. G., L.E. Scriven, and H. T. Davis, 1981, Percolation theory of two phase flow in porous media: Chem. Eng. Sci. 36, p.57-73.

Leonenko, Y., and D. W. Keith, 2008, Reservoir engineering to accelerate the dissolution of CO_2 stored in aquifers: Environ. Sci. Technol., v. 42, p. 2742-2747.

Leonenko, Y., D. W. Keith, M. Pooladi-Darvish, and H. Hassanzadeh, 2006, Accelerating the dissolution of CO_2 in aquifers: Eighth International Conference on Greenhouse Gas Control Technologies, June 19-22, 2006, Trondheim, Norway.

Lester, D. R., G. Metcalfe, M. G. Trefry, A. Ord, B. Hobbs, and M. Rudman, 2009, Lagrangian topology of a periodically reoriented potential flow: Symmetry, optimization, and mixing: Physical Review E, v. 80.

Li, X., T. Ohsumi, H. Koide, K. Akimoto, and H. Kotsubo, 2005, Near-future perspective of CO_2 aquifer storage in Japan: Site selection and capacity: Energy, v. 30, p. 2360-2369.

Longworth, H. L., G. C. Dunn, and M. Semchuck, 1996, Underground disposal of acid gas in Alberta, Canada: regulatory concerns and case histories: SPE Gas Technology Conference, April 28 - May 1, 1996 in Calgary, Alberta, SPE 35584, p. 181-192.

Lu, M., and L. D. Connell, 2008, Non-isothermal flow of carbon dioxide in injection wells during geological storage: Int. J. Greenhouse Gas Control, v. 2, p. 248-258.

Lyle, S., H. E. Huppert, M. Hallworth, M. Bickle, and A. Chadwick, 2005, Axisymmetric gravity currents in a porous medium: J. Fluid. Mech., v. 543, p. 293-302.

Maldal, T., and I. M. Tappel, 2004, CO_2 underground storage for Snøhvit gas field development: Energy, v. 29, p. 1403-1411.

Malek, R., 2009, Results of due diligence study Phase 3.5 on feasibility of Gorgon CO_2 sequestration, Petroleum in Western Australia, September 2009, Western Australian Department of Mines and Petroleum, p. 13-17.

Mathias, S., P. Hardisty, M. Trudell, and R. Zimmerman, 2008, Approximate solutions for pressure buildup during CO_2 injection in brine aquifers: Transport in Porous Media, v. 79, p. 265-284.

Mathias, S. A., P. E. Hardisty, M. R. Trudell, and R. W. Zimmerman, 2009, Screening and selection of sites for CO_2 sequestration based on pressure buildup: International Journal of Greenhouse Gas Control, v. 3, p. 577-585.

Mathieson, A., I. W. Wright, D. Roberts, and p. Ringrose, 2009, Satellite imaging to monitor CO_2 movement at Krechba, Algeria: Energy Procedia, v. 1, p. 2201-2209.

Matthews, C. S., and D. G. Russel, 1967, Pressure buildup and flow tests in wells, vol.1: SPE Monograph Series: Richardson, TX.

Meakin, P., G. Wagner, V. Frette, J. Feder, and T. Jossang, 1995, Fractals and secondary migration: Fractals, v. 3, p. 799-806.

Meakin, P., G. Wagner, A. Vedvik, H. Amundsen, J. Feder, and T. Jossang, 2000, Invasion percolation and secondary migration: experiments and simulations: Mar. Pet. Geol., v. 17, p. 777-795.

Michael, K., and B. E. Buschkuehle, 2006, Acid-gas injection at West Stoddart, British Columbia: an analogue for the detailed characterization of a CO_2 sequestration site: Journal of Geochemical Exploration, v. 89, p. 280-283.

Michael, K., and K. Haug, 2004, Hydrodynamic trapping of injected acid gas in the Alberta Basin, Western Canada: 7th International Conference on Greenhouse Gas Control Technologies, p. 1029-1034.

Mo, S., and I. Akervoll, 2005, Modeling long-term CO_2 storage in aquifer with a black-oil reservoir simulator: SPE/EPA/DOE Exploration and Production Environment Conference, Galveston, Texas, USA, March 7-9.

Moritis, G., 2008. Special report: More US EOR projects start but EOR production continues to decline. Oil & Gas J., 106(15), April 21, p. 41-42 and p. 44-46.

Neal, P., Y. Cinar, and G. Allinson, 2008, Trade-offs for injecting carbon dioxide: SPE Eastern Regional/AAPG Eastern Section Joint Meeting, Pittsburgh, Pennsylvania, USA, 11–15 October 2008.

Neal, P., M. Ho, R. Dunsmore, G. Allinson, and G. McKee, 2006, The economics of carbon capture and storage in the Latrobe Valley, Victoria, Australia: Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies (GHGT-8), 19-22 June 2006, Trondheim, Norway.

Neufeld, J. A., and H. E. Huppert, 2009, Modelling carbon dioxide sequestration in layered strata: J. Fluid. Mech., v. 625, p. 353-370.

Nicot, J.-P., 2008, Evaluation of large-scale CO_2 storage on fresh-water sections of aquifers: An example from the Texas Gulf Coast Basin: International Journal of Greenhouse Gas Control, v. 2, p. 582-593.

Nordbotten, J. M., and M. A. Celia, 2006, Similarity solutions for fluid injection into confined aquifers: Journal of Fluid Mechanics, v. 561, p. 307-327.

Nordbotten, J. M., M. A. Celia, and S. Bachu, 2005, Injection and storage of CO_2 in deep saline aquifers: analytical solution for CO_2 plume evolution during injection: Transport Porous Med., v. 58, p. 339-360.

Obi, E.-O. I., and M. J. Blunt, 2006, Streamline-based simulation of carbon dioxide storage in a North Sea aquifer: Water Resour. Res., v. 42.

Pamukcu, Y. Z., and F. Gumrah, 2009, A numerical simulation study of carbon-dioxide sequestration into a depleted oil reservoir: Energy Sources A, v. 31, p. 1348-1367.

Paterson, L., M. Lu, L. D. Connell, and J. Ennis-King, 2008, Numerical modeling of pressure and temperature profiles including phase transitions in carbon dioxide wells: SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA, 21-24 September 2008, SPE 115946.

Peaceman, D. W., 1978, Interpretation of well-block pressure in numerical reservoir simulation: SPE Journal, p. 183-194.

Perry, K. F., 2005, Natural gas storage industry experience and technology: potential application to CO_2 geological storage, *in* D. C. Thomas, and S. M. Benson, eds., Carbon dioxide capture for storage in deep geologica formations, v. 2, p. 815-825.

Pooladi-Darvish, M., H. Hong, S. Theys, R. Stocker, S. Bachu, and S. E. Dashtgard, 2008, CO_2 injection for enhanced gas recovery and geological storage of CO_2 in the Long Coulee Glauconite F Pool, Alberta: SPE Annual Technical Conference and Exhibition, 21-24 September 2008, Denver, Colorado, USA, SPE 115789, p. 2271-2281.

Pruess, K., 2009, Formation dry-out from CO_2 injection into saline aquifers: 2. Analytical model for salt precipitation: Water Resour. Res., v. 45, W03403.

Pruess, K., C. M. Oldenburg, and G. J. Moridis, 1999, TOUGH2 User's Guide, Version 2.0, Berkeley, California, Lawrence Berkeley National Laboratory, University of California, p. 210.

Pruess, K., J. García, T. Kovscek, C. Oldenburg, J. Rutqvist, C. Steefel, and T. Xu, 2004, Code intercomparison builds confidence in numerical simulation models for geologic disposal of CO_2: Energy, v. 29, p. 1431-1444.

Qi, R., T. C. LaForce, and M. J. Blunt, 2009, A three-phase four-component streamline-based simulator to study carbon dioxide storage: Computational Geosciences, v. 13, p. 493-509.

Riddiford, F., I. Wright, C. Bishop, T. Espie, and A. Tourqui, 2005, Monitoring geological storage in the In Salah Gas CO_2 storage project: Proc. 7th Intl Conf on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada, p. 1353-1359.

Riddiford, F. A., A. Tourqui, C. D. Bishop, B. Taylor, and M. Smith, 2003, A cleaner development: the In Salah gas project, Algeria: Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1-4, Kyoto, Japan, p. 595-600.

Ringrose, P. S., S. R. Larter, P. W. M. Corbett, D. L. Carruthers, M. M. Thomas, and J. A. Clouse, 1996, Scaled physical model of secondary oil migration; discussion and reply: AAPG Bulletin, v. 80, p. 292-294.

Span, R., and W. Wagner, 1996, A New Equation of State for Carbon Dioxide Covering the Fluid Region from the Triple-Point Temperature to 1100 K at Pressures up to 800 MPa: J. Phys. Chem. Ref. Data, v. 25, p. 1509-1596.

Spycher, N., K. Pruess and J. Ennis-King, 2003, CO_2-H_2O Mixtures in the geological sequestration of CO_2. I. Assessment and calculation of mutual solubilities from 12 to 100 °C and up to 600 bar: Geochim. Cosmochim. Acta, Vol. 67, No. 16, pp. 3015 - 3031, doi:10.1016/S0016-7037(03)00273-4, 2003.

Sweatman, R. E., M. E. Parker, and S. L. Crookshank, 2009, Industry experience with CO_2-enhanced oil recovery technology: SPE International Conference on CO_2 Capture, Storage, and Utilization, San Diego, California, 2–4 November, SPE 126446.

Thiele, M., R. P. Batycky and D. H. Fenwick, Streamline simulation for modern reservoir-engineering workflows: J. Petrol. Tech. Vol 64, Jan 2010, p. 64-70.

Thomas, M. M., and J. A. Clouse, 1995, Scaled physical model of secondary oil migration: AAPG Bulletin, v. 79, p. 19-29.

Trupp, M., 2009, Gorgon CO_2 injection project – monitoring and verification plans. Presentation at the Roundtable Forum on CO_2 Sequestration, September 2009, University of Western Australia.

Tsang, C. F., and J. A. Apps, eds., 2005, Underground injection science and technology: advances in water sciences, v. 52: Amsterdam, Elsevier, 704 p.

Tsang, C.-F., J. Birkholzer, and J. Rutqvist, 2008, A comparative review of hydrologic issues involved in geologic storage of CO_2 and injection disposal of liquid waste: Environmental Geology, v. 54, p. 1723-1737.

USDOE, 2007, Carbon Sequestration Atlas of the United States and Canada, U.S. Department of Energy/NETL, 88 p.

van der Meer, B., and P. J. P. Egberts, 2008, A general method for calculating subsurface CO_2 storage capacity: Offshore Technology Conference, Texas, USA, 5-8 May 2008, OTC 19309, p. 1-9.

van der Meer, L. G. H., and J. D. van Wees, 2006, Effects of CO_2 solubility on the long-term fate of CO_2 sequestered in a saline aquifer; Carbon sequestration/EOR: The Leading Edge, v. 25.

Van Poolen, H. K., 1964, Radius of drainage and stabilization time equations: Oil and Gas Journal, v. September 14, p. 138-146.

Vedvik, A., G. Wagner, U. Oxaal, J. Feder, P. Meakin, and T. Jossang, 1998, Fragmentation transition for invasion percolation in hydraulic gradients: Physical Review Letters, v. 80, p. 3065-3068.

Wagner, G., P. Meakin, J. Feder, and T. Jossang, 1997, Buoyancy-driven invasion percolation with migration and fragmentation: Physica A, v. 245, p. 217-230.

Watson, T., and S. Bachu, 2008, Identification of wells with high CO_2-leakage potential in mature oil fields developed for CO2-enhanced oil recovery: SPE Improved Oil Recovery Symposium, Tulsa, OK, U.S.A., 19–23 April 2008, SPE 112924.

Watson, T., and S. Bachu, 2009, Evaluation of the potential for gas and CO_2 leakage along wellbores: SPE Drilling & Completion, SPE 106817, v. 24, p. 115-126.

Wichert, E., and T. Royan, 1996, Sulfur disposal by acid-gas injection: SPE Gas Technology Symposium, Calgary, April 28–May 1, 1996, SPE 35585.

Wilkinson, D. and Willemsen, J. 1983. Invasion percolation: a new form of percolation theory. Journal of Physics A: Mathematical and General, 16, 3365–3376.

Wilkinson, D., 1984, Percolation model of immiscible displacement in the presence of buoyancy forces: Physical Review A, v. 30, p. 520-531.

Wilson, E. J., T. L. Johnson, and D. W. Keith, 2003, Regulating the ultimate sink: managing the risks of geologic CO_2 storage: Environ. Sci. Technol., v. 37, p. 3476-3483.

Wilson, M., and M. Monea, eds., 2004, IEA GHG Weyburn CO_2 Monitoring & Storage Project - Summary Report 2000-2004: Proceedings of the 7th International Conference on Greenhouse Gas Technologies, September 2004, Vancouver, Canada, v. 3: Regina, Petroleum technology Research Centre, 273 p.

Wright, I. W., 2007a, CO_2 storage at In Salah, The 2nd International CCS Symposium, 4 October 2007, Paris.

Wright, I. W., 2007b, The In Salah Gas CO_2 storage project. IPTC 11326, International Petroleum Technology Conference, 4-6 December 2007, Dubai, U.A.E.

Yamamoto, H., K. Zhang, K. Karasaki, A. Marui, H. Uehara, and N. Nishikawa, 2009, Numerical investigation concerning the impact of CO_2 geologic storage on regional groundwater flow: International Journal of Greenhouse Gas Control, v. 3, p. 586-599.

Yang, Q., 2008, Dynamic modelling of CO_2 injection in a closed saline aquifer in the Browse Basin, Western Australia: SPE Asia Pacic Oil and Gas Conference and Exhibition, Perth, Australia, 20-22 October 2008, SPE 115236.

Zakrisson, J., I. Edman, and Y. Cinar, 2008, Multiwell injectivity for CO_2 storage: SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia, 20-22 October 2008, SPE 11635, p. 9.

Zhang, Y., C. Oldenburg, and S. Finsterle, 2009, Percolation-theory and fuzzy rule-based probability estimation of fault leakage at geologic carbon sequestration sites: Environmental Earth Sciences, v. published online March 2009.

Zhou, Q., J. T. Birkholzer, C.-F. Tsang, and J. Rutqvist, 2008, A method for quick assessment of CO_2 storage capacity in closed and semi-closed saline formations: International Journal of Greenhouse Gas Control, v. 2, p. 626-636.