Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Geologic Storage of Carbon Dioxide with Monitoring and Verification

Volume 2

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Geologic Storage of Carbon Dioxide with Monitoring and Verification

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Volume 2

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First edition 2005

Library of Congress Cataloging in Publication Data
A catalog record is available from the Library of Congress.

British Library Cataloguing in Publication Data
A catalogue record is available from the British Library.

ISBN: 0-08-044570-5 (2 volume set)

Volume 1: Chapters 8, 9, 13, 14, 16, 17, 18, 24 and 32 were written with support of the U.S. Department of Energy under Contract No. DE-FC26-01NT41145. The Government reserves for itself and others acting on its behalf a royalty-free, non-exclusive, irrevocable, worldwide license for Governmental purposes to publish, distribute, translate, duplicate, exhibit and perform these copyrighted papers. EU co-funded work appears in chapters 19, 20, 21, 22, 23, 33, 34, 35, 36 and 37. Norwegian Research Council (Klimatek) co-funded work appears in chapters 1, 5, 7, 10, 12, 15 and 32.

Volume 2: The Storage Preface, Storage Integrity Preface, Monitoring and Verification Preface, Risk Assessment Preface and Chapters 1, 4, 6, 8, 13, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33 were written with support of the U.S. Department of Energy under Contract No. DE-FC26-01NT41145. The Government reserves for itself and others acting on its behalf a royalty-free, non-exclusive, irrevocable, worldwide license for Governmental purposes to publish, distribute, translate, duplicate, exhibit and perform these copyrighted papers. Norwegian Research Council (Klimatek) co-funded work appears in chapters 9, 15 and 16.

♾ The paper used in this publication meets the requirements of ANSI/NISO Z39.48-1992 (Permanence of Paper).
Printed in The Netherlands.

Carbon Dioxide Capture for Storage in Deep Geologic Formations, Volume 2
D.C. Thomas and S.M. Benson (Eds.)

Chapter 11

LONG-TERM CO_2 STORAGE: USING PETROLEUM INDUSTRY EXPERIENCE

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ABSTRACT

This study comprised a survey of Permian Basin reservoirs where CO_2 is being injected for enhanced oil recovery, or where CO_2 injection was seriously considered. The focus was the assessment of successes and problems in these projects.

There is significant experience and knowledge in the oil and gas industry to separate, compress, transport, inject, and process the quantities of CO_2 that are envisioned for CO_2 storage. Improvements will occur as incentives, time and fluid volumes increase.

In some cases, certain phenomena that had been noted during waterflood were not included in simulating CO_2 processes—an omission that can prove, and has proven in some cases to be detrimental to the success of the project. When the reservoir is well understood, CO_2 has performed as expected. Also, the thermodynamic phase behavior of CO_2 must be honored in predictive models. High-pressure CO_2 performs as expected: it mobilizes oil, dissolves into brine, and promotes dissolution of carbonates. Brine can become supersaturated with dissolved solids; when pressure drops as it advances through the reservoir, precipitants can form. However, the kinetics of dissolution and precipitation under many reservoir conditions requires further study.

In the time frame wherein CO_2 has been actively injected into geological formations, seals appear to have maintained their integrity and retained CO_2. Monitoring and verification of CO_2 flow in geological formations is critical to verification of storage, but additional research and monitoring demonstration are needed.

INTRODUCTION

The petroleum industry has been injecting carbon dioxide (CO_2) into geological formations for about 50 years. The bulk of this injection, taking place over the last two decades, has not been for storage, but to displace/dissolve oil for increased oil production. Currently, about 39 Mt of CO_2 is being injected into geological formations for the purpose of improving oil recovery (IOR). Though most of the injected CO_2 remains in oil reservoirs, the majority of the floods cannot be considered storage projects because the CO_2 source is from naturally occurring CO_2 reservoirs. Geological formations presently producing high-purity CO_2 for IOR are located in southwest Colorado (McElmo Dome), southeast Colorado (Sheep Mountain), northeast New Mexico (Bravo Dome), and Mississippi (Jackson Dome). Combined, these produce about 29 Mt of CO_2 annually. There are a number of notable exceptions in which the CO_2 source is an industrial by-product. Industrial projects such as the coal gasification plant in North Dakota, fertilizer plants in Oklahoma and Michigan, and hydrocarbon gas purification plants in Texas (Val Verde gas plants) and Wyoming (La Barge gas plant) supply CO_2 to a number of IOR field projects. These can also be considered CO_2 storage projects. These projects are supplying about 10 Mt of CO_2 annually. The experience that operators have obtained from injecting CO_2 in diverse oil-bearing reservoirs and the potential storage capacity of oil reservoirs are resources that ought to be tapped for CO_2 storage knowledge and future storage potential.

During this study, we identified over 135 reservoirs in the United States (USA) into which CO_2 is being injected or has been injected, or the operating company has indicated that there would be a future CO_2 miscible flood. These include:

- 70 field projects that are currently operating.
- 47 terminated projects, of which at least 20 were field demonstration pilots. Most of the others are field projects that have been completed or abandoned.
- 18 projects that have not been started. Of these, about 10 are still listed as future projects and the remainder were announced in the past as future projects but for one reason or another (mergers, changes in company philosophy, downturn in oil prices) were not.

These projects are distributed throughout the continental USA. Table 1 summarizes the number of total and active projects by region and state. In addition, about 25 immiscible CO_2 projects have been initiated in the USA; most began and terminated in the 1980s. Only a few projects persisted into the 1990s. Thus, there are around 160 projects on record that have been studied as prospects for CO_2 injection with about 140 having actually had CO_2 injected into a geological formation. Figure 1 shows the approximate density and location of these projects on a USA map. The injection time varied from a few months for some pilots to about 30 years for some field projects. These numbers do not include fields considered for CO_2 injection but never announced outside the company as an imminent project.

TABLE 1
CO_2 MISCIBLE PROJECT LOCATIONS IN THE UNITED STATES WITH THE NUMBER OF TOTAL AND ACTIVE PROJECTS LISTED BY STATE

Region	State	Total projects	Active projects
East	Pennsylvania	2	0
	West Virginia	2	0
Midwest	Kansas	1	1
	Michigan	2	2
	North Dakota	1	0
South	Alabama	1	0
	Louisiana	10	0
	Mississippi	4	3
Southwest	New Mexico	8	3
	Oklahoma	6	5
	Texas	80	47
West	California	2	0
	Colorado	2	1
	Montana	1	0
	Utah	3	3
	Wyoming	11	6

Of the miscible tests, about 65% of the total projects and 70% of the current operating projects are located in the Permian Basin. At least 30 different organizations have operated CO_2 projects in the Permian Basin. Projects have been performed in sandstone, limestone, and dolomite reservoirs, with more than half being located in San Andres formation. The other projects are found in more than a dozen different formations. Because of the concentration of CO_2 projects in the Permian Basin, this region was the focus of this.

This type of study becomes more difficult to conduct as time progresses, because of mergers, property sales, and personnel changes that will result in lost or limited access to valuable information. Several fields have

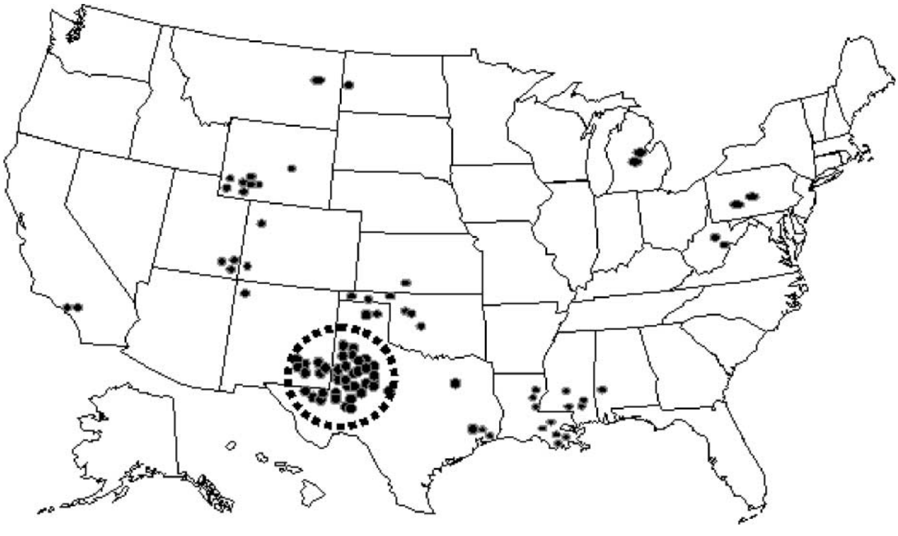

Figure 1: Map of the USA with black dots indicating location and approximate density of CO_2 injection projects for IOR in the USA. The study area, Permian Basin, is indicated by the circle.

changed operators since termination and often the new operators have little incentive to relay information on previous operations. In some cases information was obtained from earlier publications and interaction with engineers from before the operators were changed.

This study was not carried out as a simple survey, but included visits to the engineering center sites and archives of the appropriate operating companies to gather information and obtain clarifications. The goal was 100% coverage, with a minimum goal of 75% since it was not assured that all operators would participate. This survey had 80% participation from the operators that cover about 60% of the fields. Two operators that did not participate have considerable holdings.

STUDY METHODOLOGY

Steps that were taken to identify and analyze CO_2 injection project in the Permian Basin included:

1. Identification of CO_2 field projects from the biannual EOR Survey published in the *Oil & Gas Journal* in each even year since 1978 [1–13]. These surveys always list present projects, including pilot and full-scale projects and often mention announced future projects and projects terminated since the last publication.
2. Identification of those projects in the lists mentioned above which are within the Permian Basin (the defined study area).
3. A literature search on the projects identified above, most of which was available from the Society of Petroleum Engineer conferences and publications.
4. Selection of a number of parameters, items, and questions to answer for each project.
5. Gathering information from the literature of the items listed in "4" and entering them into spreadsheets. Each spreadsheet was then sent to a representative of the operating company, usually the field or project engineer, for review and additions.
6. A facility visit with each project engineer that could accommodate the survey team.
7. Analysis of information in hand in order to aid those considering CO_2 injection into a geological formation.

8. Finally, interpretation of the information obtained from each engineer and literature source. Note that this information was based on data gathered from reliable sources; it cannot be construed as an official stance or opinion of the production company.

RESULTS AND DISCUSSION

Below is a summary of the data we have in hand.

1. Over 160 CO_2 projects were initially identified in the United States in 16 states.
2. Over 100 projects were identified in Texas and New Mexico. Among these we found some that had not been CO_2 flooded, nor did the operator ever intend it to be a CO_2 project, as in a number of early projects outside the Permian Basin. We also combined some pilot project with a later field projects or several pilot projects in the same field into a single one. Table 2 contains a list of projects that were considered in this study. Among these, some had little available information. Where present project operators declined to participate, results from earlier work were considered [14]. Also listed in Table 2 are the state and operating status of projects. Found in an earlier publication is a list of Society of Petroleum Engineer published papers related to the indicated reservoir, most with some mention of CO_2 injection [15].
3. A spreadsheet of two to four pages for each reservoir was prepared, though not included in this paper.

Listed below are some general observations from this study. Some of these probably seem intuitive. More details are provided in the following sections.

1. Many of the problems that have been encountered could have been avoided or at least anticipated and minimized with better reservoir characterization. Such problems could become more severe when CO_2 is injected into a geological formation that had not been flooded and/or studied extensively previously. Generally, produced petroleum reservoirs are extensively studied formations with a fair amount of detail developed from their production history. These reservoirs still present challenges when starting injection of a fluid such as CO_2.
2. The flow paths of the CO_2 are not always well understood.
3. Retention of CO_2 is significant in most reservoirs.
4. CO_2 injectivity is often lower than expected and in many cases is a critical parameter when considering economics.
5. In one reservoir that has been CO_2 flooded and is about to be plugged and abandoned, the produced CO_2 is being injected into a brine aquifer.
6. In many cases, CO_2-saturated water seems to be reacting with formation rock and might be at least part of the cause of significant formation injectivity changes.
7. Reservoir engineers working on these projects believe that there is still much to learn with regard to the long range implications of CO_2 injection and storage in geological formations.

The following subsections summarize responses to questions on parameters that were included in the survey sent to engineers for each CO_2 injection project and from subsequent discussions. Very few respondents answered all questions.

TYPES OF RESERVOIR ROCK

Table 3 lists the rock types with the number of reservoirs reporting the indicated rock type(s). For example, out of 81 reservoirs reporting rock types, 43 reported dolomite only as a rock type and 17 others had a mixture of dolomite and one of the other rock types. Thus, dolomite is the principal reservoir type being flooded in the Permian Basin CO_2 floods. Limestone and sandstone are about equal. Of the 81, 72 are all or partly carbonate (dolomite, limestone, tripolite). Thus, the general statements in this report are for carbonate reservoirs.

Types of Seals

The number of responses to this inquiry was relatively low. Of the 12 responses to the question on type of seals, four indicated that the seal was structural, two seals were salt barriers, and six seals were evaporites or anhydrites. The integrity of the seal is vital for long-term storage. Reservoir engineers were the principal

TABLE 2
CO_2 FIELD PROJECTS IN THE PERMIAN BASIN, USA LISTED BY UNIT NAME, STATE, CURRENT OPERATING STATUS, AND RESERVOIR FLUID VOLUME

Unit name	State	Current status	Total reservoir fluid (vol. $\times 10^6$ m^3)
Adair San Andres	Texas	Operating	46.4
Anton Irish	Texas	Operating	134.8
Bennett Ranch	Texas	Operating	143.1
Brahaney	Texas	Future	4.0
Brahaney Plains	Texas	Future	4.0
Cedar Lake	Texas	Operating	49.1
Central Vacuum	New Mexico	Operating	13.0
Cogdell	Texas	Operating	16.1
Cordona Lake	Texas	Operating	38.2
Dollarhide (Clearfork “AB”)	Texas	Future	39.4
Dollarhide (Devonian)	Texas	Operating	49.4
East Ford	Texas	Operating	11.1
East Huntley	Texas	Terminated	6.7
East Penwell (SA)	Texas	Operating	3.3
East Vacuum	New Mexico	Operating	72.0
El Mar	Texas	Operating	80.6
Ford Geraldine	Texas	Terminated	26.6
Garza	Texas	Terminated	20.0
GMK South	Texas	Operating	7.0
Goldsmith	Texas	Field demonstration	4.8
Hanford	Texas	Operating	7.6
Hanford East	Texas	Operating	2.2
Hansford Marmaton	Texas	Terminated	8.9
Jess Burnes	Texas	Never started	1.3
Kingdom Abo	Texas	Terminated	19.7
Leamex	New Mexico	Pilot terminated	2.4
Levelland	Texas	Pilots terminated	205.6
Levelland	Texas	Never started	26.4
Loco Hills	New Mexico	Pilot terminated	14.5
Mabee	Texas	Operating	92.5
Maljamar Pilot & Field	New Mexico	Terminated	44.5
McElroy	Texas	Terminated	22.9
McElroy	Texas	Field demonstration	1073.3
Means (San Andres)	Texas	Operating	89.7
Mid Cross-Devonian	Texas	Operating	14.8
North Cowden	Texas	Pilots terminated	1.7
North Cross (Crossett)	Texas	Operating	27.0
North Dollarhide	Texas	Operating	17.3
North El Mar	New Mexico	Never started	24.6
North Farnsworth	Texas	Terminated	3.5
North Hansford Cherokee	Texas	P&A	13.5
North Hobbs	New Mexico	Future	61.7
North Van Rueder	Texas	Never started	7.9
North Ward Estes	Texas	Terminated	596.8
Philmex	New Mexico	Pilot terminated	3.2
Ranger Lake	New Mexico	Never started	4.0

(*continued*)

TABLE 2
CONTINUED

Unit name	State	Current status	Total reservoir fluid (vol. $\times 10^6$ m^3)
Rankin	Texas	Pilot Terminated	1.0
Reeves	Texas	Never started	63.0
Reinecke	Texas	Operating	4.6
Robertson (Central and N.)	Texas	Future	21.5
Russell	Texas	Never started	59.5
Sable	Texas	Terminated	4.3
SACROC	Texas	Operating	795.2
Salt Creek	Texas	Operating	177.6
Seminole-Main Pay	Texas	Operating	274.2
Seminole-ROZ Phase 1	Texas	Operating	14.6
Sharon Ridge	Texas	Operating	136.2
Slaughter (started June 1989)	Texas	Operating	6.2
Slaughter (started May 1985)	Texas	Operating	63.3
Slaughter Alex Estate	Texas	Operating	9.9
Slaughter Central Mallet	Texas	Operating	18.6
Slaughter Estate & Pilot	Texas	Operating	54.4
Slaughter Frazier	Texas	Operating	3.5
Slaughter HT Boyd Lease	Texas	Operating	96.5
Slaughter Sundown	Texas	Operating	86.2
South Cowden	Texas	Operating	3.5
South Cowden (Emmons)	Texas	Future	15.6
South Cross (Crossett)	Texas	Operating	15.6
South Huntley	Texas	Terminated	11.8
South Welch & Pilots	Texas	Operating	58.3
Spraberry Trend	Texas	Pilot	2654.5
State 35 Unit (Hale Mable)	New Mexico	Operating	5.1
T-Star	Texas	Operating	4.3
Twofreds-East & West	Texas	Operating	21.3
University Waddell	Texas	Terminated	6.8
VGSAU	New Mexico	Future	13.0
Wasson	Texas	Operating	8.7
Wasson Cornell	Texas	Operating	40.9
Wasson Denver	Texas	Operating	564.7
Wasson ODC & Pilot	Texas	Operating	173.1
Wasson South	Texas	Operating	70.4
Wasson Willard & Pilot	Texas	Operating	166.3
Wellman	Texas	Terminated	33.1
West Brahaney	Texas	Terminated	2.5
West Welch	Texas	Operating	4.8

respondents to this study. Many do not worry about the reservoir seal as long as it is sufficient to trap crude oil. It seems to be assumed it will trap CO_2. If the oil contains significant amounts of methane and the lighter hydrocarbons it is expected to trap the CO_2, which is similar in molecular size. It is concluded that for at least the foreseeable future, or life of the CO_2 project, that the seal will be maintained. CO_2 IOR projects consider decades of containment compared to a minimum of hundreds or preferably thousands of years when considering long-term storage.

TABLE 3
INVENTORY OF ROCK TYPES IN CO_2 IOR OPERATIONS IN THE USA PERMIAN BASIN

Rock type	Dolomite	Sandstone	Limestone	Tripolite
Dolomite	43			
Sandstone	6	9		
Limestone	10	1	7	
Tripolite	1	1	0	3

Injectivity
In many IOR injection projects, injectivity is a key parameter dictating the success or failure of the process. In many reservoirs, injectivity has been lower than expected. When injecting water alternating with gas (WAG), brine and/or CO_2 injectivities are often lower than the waterflood injectivity. This decrease in injectivity is more dramatic and persistent as predicted when considering relative permeability effects of multiphase flow. As shown in Table 4, the majority of operators indicated changes in injectivity after CO_2 injection. For those that changed, most of them decreased. There were no reports of water injectivity increasing once CO_2 injection occurred. The decreases ranged from 10 to 100% decrease. In one case after CO_2 injection, no brine could be injected during the water half-cycle. The problems seemed to be greater in the carbonates, especially dolomite. The average decrease was in the 40–50% range.

TABLE 4
INJECTIVITY CHANGES AFTER START OF WAG, COMPARED TO WATERFLOOD INJECTIVITIES IN IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Injectivity changes	Brine	CO_2
None noted	4	5
No comment	7	9
Changed (decreased for all brine and about half the CO_2)	16	13

During the CO_2 half-cycle the change from waterflood injectivity was not as severe as during brine half-cycles. Because of the lower viscosity of CO_2 (at reservoir conditions at least 90% less than the brine) one might expect the injectivity during the CO_2 half-cycle to be much higher than the waterflood injectivity. In most cases brine saturation remains sufficient to reduce the relative permeability close to that of waterflood injectivity, but even with this, CO_2 injectivity is expected to be higher than brine. For the projects reporting CO_2 injectivity changes, the changes ranged from a decrease of 40% to an increase of 30% with an average near-zero change from waterflood injectivity. This result is disappointing when an increase was generally expected. Seven projects reported a decrease without indicating the magnitude.

One might ask what it means when a respondent indicates no injectivity change was noted or had no comment. In discussions with engineers, this generally meant that the desired injection rates were maintained, whether or not injectivity changed. Thus, there could be a significant decrease in injectivity that was not noted because injectivity was still sufficient to achieve desired injection rate.

In one reservoir there were no injection problems in one area of the field, but in another area the brine injectivity decreased, and in the third area both CO_2 and brine injectivity decreased. The difference among the three areas of the reservoir was that they had relatively high, medium, and low permeability, respectively. This is an indication that if a reservoir is operating a waterflood near the injection limit and it is converted to a CO_2 flood, there is a high probability that the project will be injection limited.

CO_2 Reservoir Retention

Reservoir CO_2 retention is a key storage parameter. In an IOR project, CO_2 retention is the quantity of the purchased CO_2 that remains in the reservoir at the present time and ultimately remaining in the reservoir at the time the reservoir is plugged and abandoned. One has to be careful not to include recycled gas when determining the retention quantities. The objective of IOR is not to maximize reservoir CO_2 retention rates, but to maximize profit. The maximum retention might correspond to the maximum sweep efficiency and thus maximum oil production, but often this is not the optimum economical scenario. In several reservoirs that were relatively homogeneous, the sweep was too efficient and the production rate was too slow and/or the timing of significant oil production increases took too long to obtain the desired rate of return on the capital investment. It appears that sufficient heterogeneity in the reservoirs is necessary for some relatively early oil recovery to recoup investment. Then, after breakthrough, action can be taken to mitigate the early breakthrough caused by heterogeneity and continue oil recovery while minimizing CO_2 production.

As we look at CO_2 storage in depleted petroleum reservoirs, heterogeneity in both producing petroleum reservoirs and aquifers will have a similar effect. A need for the economy of high injectivity over maximum storage efficiency of the reservoir may be an important trade-off.

Many of the floods in the Permian Basin are not mature enough to predict final retention. Retention was reported for eight reservoirs and ranged from 38 to 100% with an average of 71%. The reservoir that had 100% retention was a pilot. Respondents speculate that insufficient CO_2 was injected and insufficient time was allowed to detect CO_2 breakthrough. After 10 years they have not seen CO_2 in the produced gas above background concentrations. In mature reservoirs retention was listed as low as 38% of the total CO_2 injected, including recycled volumes. This is the estimated total amount of CO_2 that does not return to the surface once injected, thus not recycled. Essentially 100% of the purchased CO_2 is still in the system. Practically, 100% of the fluid will be stored in the reservoir unless a reservoir blowdown is instigated. To date, six other projects reported retentions in the range of 60–90% of the CO_2 remaining in the reservoir, with an average of 71% retention. These estimates were from reservoirs that had been undergoing CO_2 injection from 5 to 30 years. Most of the projects are early in their lifecycles and thus not reporting ultimate retention.

CO_2 Distribution

In some cases CO_2 is not going where it had been expected to go and engineers made statements such as

1. CO_2 left the intended target area.
2. CO_2 went into upper and lower zones with much of the reservoir in between untouched. Sweep efficiency was less than what had been expected.
3. CO_2 was not detected at a producer after 2 years of injection. It is believed CO_2 had greater sweep—both vertical and horizontal—than expected; thus not enough time and insufficient injection occurred for a successful project.

Each of the three comments above demonstrates that a better understanding of the reservoir would improve predictions, and the project's technical and economic success.

Monitoring/Detection Methods

The most common method used to determine CO_2 movement in IOR projects is tracking produced gas composition. Logging of pilot project observation wells has also been one of the more successful methods used to detect CO_2 movement and saturation changes. Monitoring tools being considered for widespread monitoring are seismic methods that include crosswell tomography, 3D and 4D seismic, and microseismic. Each method has been used with varying levels of success. Cases of the successful use of seismic tools were cited, but respondents were not sure if the signal changes were activated by fluid saturation changes or formation deformation. If the formation deformation tracks fluid movement, it will not be of consequence, but if the deformations do not track fluid movement, it will be difficult to interpret. In one test, seismic changes were noted in a formation several hundred meters above the injection zone. It was feared that CO_2 was flowing into a higher zone that could potentially cause problems. Perforations into the zone in question found no CO_2, no compositional changes in reservoir fluids, or any pressure changes. The reason for the anomaly is unknown. Thus, more work is required in the area of seismic monitoring.

Losses Out of Zone

It is desirable to know how successfully CO_2 is delivered to the intended zone. Generally, CO_2 was retained in the formation intended and could be accounted for within engineering accuracy. Many respondents noted that CO_2 was going into zones that were in communication with the injection zone. Generally, CO_2 is less dense than liquids in the reservoir and might be expected to migrate upwards in the formation, but CO_2 has been found migrating into water or residual oil zones below the zone of interest. This is probably caused by several phenomena, e.g. diffusion and brine density caused by dissolved CO_2. Diffusion is thought to be slow compared to injection fluid flow rates, but especially for long-term storage, diffusion may be important.

Unexpected fractures, thief zones, and loss out of the flanks of the structure have been suspected as culprits of CO_2 loss. However, often the ratio of injection to production fluid has not been tracked as closely as it could be and water production is not tracked as closely as oil or gas, resulting in mass balance uncertainty.

What has Gone Well?

To provide some idea of what petroleum producers look for when considering success of a project, engineers were asked, “What had gone well in the project?” The foremost concern was the timing of the oil response (see Table 5). Most modeling and engineering studies center on optimizing and predicting oil response. Respondents mentioned injectivity in a couple of cases, confirming this as a concern in many projects.

TABLE 5
WHAT HAS GONE WELL IN IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Response	**Number**
Oil response at or above that predicted	20
Project performed well (usually oil response was at or above expectations)	5
Injectivity is sufficient	2
Gas production within designed limits	4
Other: minimum asphaltene deposit, cost in line with predictions, lower corrosion than expected, acceptable well failure rate	4

What has not Gone Well?

The question of what has not gone as well as expected in the project was also asked. The answers again provide some idea of parameters to consider when designing a project. Oil response time and magnitude were premier among concerns and were disappointing in a number of CO_2 miscible floods. The second most undesirable situation (Table 6) often occurs with low oil response, i.e. early CO_2 breakthrough and high gas production. At essentially the same level of negative response was low injectivity that also resulted in a low or late oil response. Scaling/deposition was identified in a number of responses. Deposition in the reservoir can result in increased CO_2 retention as well as modified injectivity.

TABLE 6
WHAT HAS NOT GONE WELL IN IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Response	**Number**
Low and/or late oil response	19
CO_2 early breakthrough or high cycling, high GOR, conformance	13
Low injectivity	12
Scaling	7
Other: corrosion, cost too high, completion problems, old wellbores	6

Attempted Remediation and Success Rates

Methods employed to remedy problems mentioned in the previous sections are listed in Table 7. Most of the remediation methods were used to reduce CO_2 production, to improve on CO_2 reservoir sweep efficiency, or to increase injectivity. WAG management to control/improve (decrease) CO_2 production while maintaining or increasing oil production has generally made improvements. Control of conformance with gels, foams, or squeeze jobs has had fair technical success, but with a concern for expense. Attempts to improve injectivity have met with temporary or no success.

TABLE 7
REMEDIATION ACTIONS IN IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Responses[a]	**Number**
WAG management	8
Conformance control (foam, gel, etc.)	7
Cement squeeze	4
Acid stimulation	5
Scale inhibitor	2
Other: horizontal well, infill drilling, increase reservoir pressure, increase production	5

[a] Remediation actions listed above may not increase storage, but some would be effective in increasing injectivity and thus might improve on the economics of CO_2 storage.

What would You do Differently if Starting Over, or for Another Flood?

Hindsight does not profit a company unless it is used to improve subsequent projects. Today, almost without exception, new CO_2 floods start with a large CO_2 slug (Table 8) and do not switch to WAG before CO_2 breakthrough or a targeted amount such as a 20% pore volume slug size has been injected. The large CO_2 slug has the advantage of minimizing the time of the first occurrence of a significant oil response, as well as reducing the impact of reduced injectivity in the brine half-cycle by delaying brine injection as long as practical. Additionally, possible reduction in CO_2 injectivity is delayed in subsequent CO_2 half-cycles. Again, reservoir characterization was near the top of concerns by a number of individuals.

Mysteries of the System

Project engineers were asked if they had any unresolved problems (Table 9). These are items that, if better understood, would improve the project. This could mean improved profits and in some cases a modification

TABLE 8
FUTURE IMPROVEMENTS SUGGESTED BY OPERATORS OF IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Responses	**Number**
Lower CO_2 and lower surface facilities cost, and effective government incentives	12
Start with a larger CO_2 slug, more aggressive with CO_2	10
Better reservoir characterization or honor waterflood characterization	9
Start CO_2 earlier in waterflood	2
Conformance control	2
Horizontal and infill wells, patience, lower reservoir pressure, stimulate early	5

of the project area. Thirty-one of the responses (~90% of the total) indicated a desire to better understand fluid flow patterns in the reservoir, reservoir characterization, and injectivity, which all concern the interconnection of reservoir petrophysics, fluid flow, and fluid-reservoir rock interactions.

TABLE 9
UNSOLVED ISSUES IN IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Responses	**Number**
Fluid flow patterns in the reservoir	12
Reservoir characterization	12
Injectivity	7
Scaling, asphaltenes, conformance, equipment	4

Research Focus

Petroleum producers want improved sweep and productivity/injectivity to increase reservoir efficiency. The first three items in Table 10 are relevant to long-term storage of CO_2. First, an understanding of the fluid flow patterns in the reservoir is critical. This is connected to the second response of injection and production rates. The third response shows that, even though it is important for IOR to monitor CO_2, the ability to monitor the CO_2 plume is essential to understanding and predicting long-term CO_2 storage.

TABLE 10
RESEARCH FOCUS SUGGESTED BY OPERATORS OF IOR CO_2 MISCIBLE FLOOD OPERATIONS IN THE PERMIAN BASIN, USA

Responses	**Number**
Sweep/profile/conformance	10
Productivity/injectivity	8
Monitoring	3
Predictions, mechanism, improve economics of known technology	8

Safety

Safety is an item that was not mentioned in the discussions. In the author's experience, more than 20 years in the area of CO_2 production, transportation, and injection into geological formations of significant quantities of CO_2 have passed without a fatality. Since CO_2 is not flammable and is much less toxic than many other fluids that are transported in great quantities and at high pressure, it is well within the capability of the industry to separate, compress, transport, inject, and process enormous quantities of CO_2 at acceptable safety levels for the public.

CONCLUSIONS/RECOMMENDATIONS

Listed below are major lessons from CO_2 injection into geological formation for IOR that are most applicable to CO_2 storage.

1. Significant experience and knowledge in the industry exists to separate, compress, transport, inject, and process the quantities of CO_2 that are envisioned for CO_2 storage. As the volume of injected CO_2 increases, significant technological improvements are expected.
2. Monitoring and verification of CO_2 flow in geological formations is in the infancy of its development.
3. Experience has shown that CO_2 goes where expected. The challenge is developing detailed reservoir characterizations and honoring them. In some cases, phenomena have been noted during waterflood, but not included when simulating the CO_2 oil recovery process, resulting in surprises during the project that could have been avoided. The phase behavior of CO_2 must be honored also.
4. CO_2 does what is expected: mobilizes oil, dissolves in brine, and promotes dissolution of carbonates. Saturated brine will become supersaturated as it flows away from the injector, dropping the pressure and resulting in precipitation. The kinetics of these processes under a wide range of reservoir conditions requires further studies.
5. In the short geological timeframe that CO_2 has been actively injected into geological formations for IOR, seals generally are retaining the CO_2 subsurface. Oil reservoir seals, to date are generally performing as expected, but it must be remembered that a maximum of several decades is short compared to the longer time periods required for effective CO_2 storage.

ACKNOWLEDGEMENTS

We would like to express our gratitude for the support of the members of the CO_2 Capture Project, for their financial support and the opportunity to work with them. We express our thanks also for the support of the State of New Mexico for its financial support through the New Mexico Petroleum Recovery Research Center, a research division of New Mexico Institute of Mining and Technology. Finally we appreciate the effort of the many project engineers from the various CO_2 injection projects that took their time to review their projects, answer many questions, and offer their support to this effort.

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